June 5, 2017

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: ***Martha Coakley, Massachusetts Attorney General, et al. v. Bangor Hydro-Electric Company, et al.***

Filing of the New England Transmission Owners To Return Transmission Rates to the *Status Quo Ante*

Docket No. EL11-66-____
Docket No. ER15-414-____
(not consolidated)

Dear Secretary Bose:

The New England Transmission Owners ("NETOs")[1] respectfully submit this filing to document the reinstatement of their transmission rates under ISO New England Inc.'s ("ISO-NE") open access transmission tariff ("OATT") to the *status quo ante* as a result of the mandate of the United States Court of Appeals for the District of Columbia Circuit in *Emera Maine v. FERC*, Case No. 15-1118 *et al.* expected to be issued on June 6, 2017. This mandate will make effective the Court's opinion and order in *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017), vacating the Commission's Opinion Nos. 531, 531-A, and 531-B.[2] One effect of the Court's vacatur is to reverse the compliance filing made by the NETOs to comply with the vacated Opinion No. 531-A. This filing includes the eTariff tariff records to reflect the vacatur to be effective June 6, 2017.[3] As explained below, however, the NETOs do not intend to commence billing under the reinstated rates until 60 days after the Commission has a quorum.

[1] For purposes of this filing, the NETOs consist of Emera Maine (f/k/a Bangor Hydro Electric Company); Central Maine Power Company; Eversource Energy Service Company (f/k/a Northeast Utilities Service Company) on behalf of: The Connecticut Light and Power Company, NSTAR Electric Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire; New England Power Company d/b/a National Grid; New Hampshire Transmission LLC; The United Illuminating Company; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company; and Vermont Transco LLC.

[2] Opinion No. 531, *Martha Coakley v. Bangor Hydro-Electric Co.*, 147 FERC ¶ 61,234 (2014), *order on paper hearing*, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), *order on reh'g*, Opinion No. 531-B, 150 FERC ¶ 61,165 (2015).

[3] The eTariff tariff records are included in the version of this filing submitted in Docket No. ER15-414.

I. BACKGROUND

A. The NETOs' Transmission Rates

The NETOs own the great majority of the electric transmission facilities in New England. The NETOs have transferred operational control of these facilities to ISO-NE, the Regional Transmission Organization for the region. Access to these facilities is provided under the ISO-NE OATT. In accordance with Commission policy, the NETOs have made large investments in the region's electric grid infrastructure in order to modernize the New England transmission grid, address numerous reliability concerns, reduce congestion, and provide planning and operational flexibility. This infrastructure investment has resulted in substantial benefits to consumers, including but not limited to savings due to the relief of congestion.

The rates for transmission service provided under the OATT are based on the transmission revenue requirements of the NETOs and certain other transmission owners, which include a rate of return on equity ("ROE") that is approved by the Commission. The ROE component of the NETOs' rates includes both a base ROE and various ROE adders approved by the Commission as incentives to promote the development and operation of electric transmission infrastructure and the transfer of operational control of these assets to ISO-NE. For many years the NETOs' base ROE in the ISO-NE OATT has been 11.14 percent. This base ROE was established by the Commission in Docket No. ER04-157 in *Bangor Hydro-Electric Co.*[4] The discounted cash flow ("DCF") range of reasonableness that the Commission approved in Docket No. ER04-157 was 7.3 percent to 13.5 percent.[5]

B. Opinion No. 531 and the Compliance Filing Directed by the Commission

On September 30, 2011, a number of parties filed in Docket No. EL11-66 a complaint under section 206 of the Federal Power Act alleging that the NETOs' 11.14 percent base ROE was unjust and unreasonable. On June 19, 2014, the Commission issued Opinion No. 531, wherein the Commission applied a modified DCF methodology to a proxy group of comparable utilities and established a DCF zone of reasonableness "from 7.03 percent to 11.74 percent."[6] The NETOs' existing base ROE of 11.14 percent was within that zone. The Commission nevertheless found that the NETOs should be required to use a new base ROE of 10.57 percent. Moreover, while the complaint in Docket No. EL11-66 sought only to revise the base ROE, the

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[4] *Bangor Hydro-Electric Co.*, 117 FERC ¶ 61,129 (2006) (Opinion No. 489), *order on reh'g*, 122 FERC ¶ 61,265 (2008) ("March 2008 Rehearing Order"), *aff'd sub nom. Conn. Dep't of Pub. Util. Control v. FERC*, 593 F.3d 30 (D.C. Cir. 2010).

[5] In Opinion No. 489 at P 14, the Commission determined the upper boundary of the zone of reasonableness for the NETOs to be 13.1 percent. However, in the March 2008 Rehearing Order, the Commission made two adjustments to the "br + sv" growth factor to make the computation consistent with Commission precedent. March 2008 Rehearing Order at PP 19 to 22. This change raised the upper end of the zone of reasonableness to 13.5 percent.

[6] Opinion No. 531 at P 9.

Commission also reduced ROE incentives previously approved for the NETOs based on the new zone of reasonableness.[7]

In Opinion No. 531-A, the Commission directed the NETOs to submit a compliance filing with revised rates reflecting a 10.57 percent base ROE and a total or maximum ROE not exceeding 11.74 percent (inclusive of transmission incentive ROE adders).[8] The Commission also directed the NETOs to provide refunds, with interest calculated pursuant to 18 C.F.R. § 35.19a, for the 15-month refund period.[9] In compliance with the Commission's order, the NETOs submitted a compliance filing that included changes to the rate provisions of the ISO-NE OATT on November 17, 2014, as amended on April 22, 2015, to become effective on October 16, 2014, the date Opinion No. 531-A was issued.[10] The NETOs also issued refunds as required by Opinion No. 531-A.

C. The Appeal of Opinion No. 531

The NETOs and other parties appealed Opinion Nos. 531, 531-A and 531-B. On April 14, 2017, the United States Court of Appeals for the District of Columbia Circuit issued an opinion in *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017), in Case No. 15-1118 (consolidated with Case No. 15-1119 and Case No. 15-1121). Among other things, the Court held that "FERC did not meet the first requirement of section 206 that it demonstrate the unlawfulness of Transmission Owners' base ROE." 854 F.3d at 23. The Court further ruled, "Because FERC's single ROE analysis failed to include an actual finding as to the lawfulness of Transmission Owners' existing base ROE, FERC acted arbitrarily and outside of its statutory authority in setting a new base ROE for Transmission Owners." *Id.* at 27. With respect to the capping of the NETOs' ROE incentives, the Court held that, "In light of FERC's failure to satisfy its dual burden under section 206, we need not reach Transmission Owners' arguments concerning their previously approved ROE incentives." *Id*. The Court granted petitions for review and concluded, "We therefore vacate FERC's orders and remand the case for proceedings consistent with this opinion." *Id.* at 30.[11]

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[7] Opinion No. 531 at P 164.

[8] Opinion No. 531-A at Ordering Paragraph (B). Opinion No. 531-A addressed a paper hearing on the long-term growth rate under the modified two-step DCF methodology

[9] Opinion No. 531-A at Ordering Paragraph (C).

[10] In order to facilitate new requirements to submit tariffs in an electronic format (*i.e.*, "eTariff"), the Commission adopted new procedures "for compliance filings made in the context of complaint cases." *Order Establishing Procedures Relating to Tariffs Filed Electronically*, 130 FERC ¶ 61,047 at P 10 (2010). Specifically, the Commission directed that "the compliance filing made through the electronic tariff filing portal will receive a new root docket, rather than a subdocket from the original complaint case." *Id.* at P 14. In this case, the Commission assigned the filing made by the NETOs in compliance with Opinion No. 531-A a root docket of ER15-414.

[11] In *Emera Maine v. FERC*, the Court also granted a petition for review submitted by other parties concerning the placement of a base ROE within a DCF zone of reasonableness.

II. THE IMPACT OF *EMERA MAINE v. FERC* ON THE NETOs' RATES

A. The Legal Effect of the Court's Decision to Vacate Opinion Nos. 531, 531-A, and 531-B

In *Emera Maine v. FERC*, the Court ***vacated*** the Commission's orders in Opinion Nos. 531, 531-A, and 531-B. The effect of the order of vacatur is to return the parties to the *status quo ante*. *See Transcontinental Gas Pipe Line Corp v. FPC*, 488 F.2d 1325, 1330 (D.C. Cir. 1973). Responding to a motion for clarification in *Transcontinental Gas Pipe Line*, which concerned daily entitlements of volume of gas, the D.C. Circuit explained, "[A]ll parties are now restored to the respective daily volumes of natural gas *to which they would have been entitled absent [the Commission Order that was vacated.]*" *Id.* at 1330-31 (emphasis added). *See also Action on Smoking and Health v. Civil Aeronautics Bd.*, 713 F.2d 795, 797-98 (D.C. Cir. 1983) ("To 'vacate' … means 'to annul; to cancel or rescind; to declare, to make, or to render void; to defeat; to deprive of force; to make of no authority or validity; to set aside.' Thus, by vacating or rescinding [an agency order that had rescinded certain rules] the judgment of this court had the effect of reinstating the rules previously in force.") (citations omitted); *Indep. U.S. Tankers Owners Comm. v. Dole* 809 F.2d 847, 855 (D.C. Cir. 1987) ("As of [the date of the mandate], the present rule will be vacated and conditions returned to the *status quo ante*, before the payback rule took effect, subject of course to any further action that may have been taken in the interim.").

The Court's order vacating Opinion Nos. 531, 531-A, and 531-B will become effective when the Court issues its mandate in Case No. 15-1118 *et al.*[12] The NETOs expect that mandate to be issued on June 6, 2017.[13] Once the mandate has been issued, the only lawful ROEs to be used for the NETOs' transmission rates under the ISO-NE OATT are those that were in effect prior to the issuance of Opinion No. 531-A, including a base ROE of 11.14 percent.

B. Process to Return to *Status Quo Ante* Transmission Rates Prospectively

As of the date of the mandate, Opinion Nos. 531, 531-A, and 531-B will be rendered void *ab initio,* and the legal rate of return for the NETOs' transmission rates under the ISO-NE OATT

This aspect of the Court's decision would only become relevant if the Commission were to satisfy the first requirement of section 206.

[12] *See Bryant v. Ford Motor Co.*, 886 F.2d 1526, 1529 (9th Cir. 1989) (" 'An appellate court's decision is not final until its mandate issues.' ") (*quoting Mary Ann Pensiero, Inc. v. Lingle,* 847 F.2d 90, 97 (3d Cir. 1988).

[13] "The court's mandate must issue 7 days after the time to file a petition for rehearing expires, or 7 days after entry of an order denying a timely petition for panel rehearing, petition for rehearing *en banc*, or motion for stay of mandate, whichever is later. The court may shorten or extend the time." Fed. R. App. P. 41(b). Petitions for rehearing of *Emera Maine v FERC* were due by May 30, 2017.

will be restored to the rate of return that was in effect prior to the issuance of Opinion No. 531-A, *i.e.*, the ROE approved by the Commission in Docket No. ER04-157. The base ROE for the NETOs will return to 11.14 percent and the 11.74 percent cap on the NETOs' ROE incentives will be eliminated, returning to the prior cap of 13.5 percent. These changes must occur as a matter of law and require no action from the Commission. However, because the NETOs made a compliance filing in response to Opinion No. 531-A, it is now necessary to reverse that compliance filing by reinstating the pre-Opinion No. 531 ROEs in the tariff sheets on file with the Commission. That is the purpose of this filing. The tariff changes submitted in this filing are an amended compliance filing documenting the legal effect of the Court's decision in *Emera Maine v FERC*.[14]

Although the NETOs believe that Commission approval of this filing is not a prerequisite to recognizing the legal effect of the Court's decision in *Emera Maine v. FERC*, the NETOs acknowledge that this change is occurring when the Commission does not have a quorum. In light of these highly unusual circumstances, the NETOs are voluntarily delaying the date when they will commence billing under the rates reinstated by *Emera Maine v FERC* until 60 days after the Commission has a quorum again.[15] This voluntary delay in implementing the return to *status quo ante* transmission rates will ensure that the Commission has the opportunity to review this filing before any change in billing takes effect should it choose to do so. If the Commission takes no action within this 60-day period, the NETOs will commence billing under the reinstated rates resulting from the vacatur of Opinion No 531 *et seq*. However, the effective date of this reinstatement will be June 6, 2017, the date of issuance of the mandate, and the NETOs plan to implement surcharges for the period between June 6 and the date it commences billing under the reinstated rates.[16]

Attachment F to the ISO-NE OATT, including the Attachment F Implementation Rule, sets forth the annual transmission revenue requirements for determining Regional Network Service rates. In this filing, the NETOs revise Section II.A.2.(a)(iii) of the Attachment F Implementation Rule to replace references to an ROE of 11.07 percent (the 10.57 percent base ROE directed by the Commission in the vacated Opinion No. 531-A plus the 50 basis point

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[14] Filings of tariff revisions to comply with legal orders and decisions are not filings under section 205 of the Federal Power Act. The Commission lacks the authority to require public utilities to make filings under section 205 or otherwise cede their section 205 rights. *See, e.g.*, *Atlantic City v. FERC*, 295 F.3d 1, 26 (2002). Because this filing is not a section 205 filing, it does not require any action by the Participating Transmission Owner ("PTO") Administrative Committee, and it is not subject to any stakeholder advisory procedures that would apply to section 205 filings by the NETOs to change transmission rates under the ISO-NE OATT.

[15] Under section 401(e) of the Department of Energy Organization Act, "a quorum for the transaction of business shall consist of at least three members present." The Commission will have a quorum again on the date when there are three sitting Commissioners.

[16] Because this is a compliance filing rather than a section 205 filing, no prior notice requirement applies to this filing.

adder for ISO-NE participation) with references to an ROE of 11.64 percent(the 11.14 percent base ROE approved by the Commission in Docket No. ER04-157 plus the 50 basis point adder for ISO-NE participation).

Opinion No. 531-A, as clarified in Opinion No. 531-B, also required the NETOs to add language to the opening of the Attachment F Implementation Rule stating that the "total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period," thereby setting the maximum ROE by transmission project as part of the calculation of the NETO's transmission revenue requirement. The NETOs were also required to add similar language to Section II.A.2.(a)(iii) of the Attachment F Implementation Rule. This filing removes the tariff language the NETOs were previously required to submit to comply with this aspect of the vacated orders.

The NETOs also individually maintain their Local Service Schedules in Schedule 21 of the ISO-NE OATT. In this filing, the NETOs have made appropriate revisions to their individual Local Service Schedules. These changes simply reverse their prior compliance filings and return the ROE in their transmission rates under the ISO-NE OATT to the *status quo ante* as a result of the mandate of the Court in *Emera Maine v. FERC.* [17]

As noted above, the effective date for all of the tariff changes described above is June 6, 2017, the date of the mandate vacating Opinion No. 531 *et seq.*

C. Reservation of Rights for Periods Prior to Issuance of the Mandate

The Court's decision to vacate Opinion Nos. 531, 531-A, and 531-B also affects the NETOs' transmission rates for periods prior to issuance of the mandate on June 6, 2017, because the Commission directed the NETOs to begin charging transmission rates based on a 10.57 percent base ROE and a project-specific ROE incentive cap of 11.74 percent as of October 16, 2014, and directed the NETOs to pay refunds for the fifteen-month refund period of October 1, 2011, to December 31, 2012. However, the NETOs recognize that the Commission will issue further orders on remand in Docket No. EL11-66 that will establish the final rates to be charged during some of these past periods.[18] Some, but not all, of the periods between December 31, 2012, and June 6, 2017, are also subject to statutory refund periods established by the

[17] It is not necessary for The United Illuminating Company ("UI") to revise its Local Service Schedule 21 to reflect the return to the status quo ante ROE. The Schedule 21 for UI already incorporates by reference the base ROE under Attachment F of the ISO-NE OATT.

[18] Any new rate established by the Commission on remand will be effective for the original fifteen month refund period in Docket No. EL11-66 (October 1, 2011 to December 31, 2012) and prospectively from Commission approval of a new rate in the order on remand. *See City of Anaheim v. FERC,* 558 F.3d 521, 523-24 (D.C. Cir. 2009) ("On its face, § 206(a) prohibits retroactive adjustment of rates."). *Compare Elec. Dist. No. 1 v. FERC*, 774 F.2d 490, 492-93 (D.C. Cir. 1985) (holding rates directed under section 206 are only effective when specified in a compliance filing) *with Transwestern Pipeline Co. v. FERC*, 897 F.2d 570, 578 (D.C. Cir. 1990) (explaining that a formula may provide the necessary specificity).

Commission in response to other section 206 complaints in Docket Nos. EL13-33, EL14-86, and EL16-64.[19]

In light of the uncertainty and the complexity associated with potential refunds and surcharges during all of these prior periods in multiple dockets, the NETOs are not implementing surcharges at this time for the time periods prior to the issuance of the Court's mandate during which the Commission required the NETOs to charge a 10.57 percent base ROE and a cap of 11.74 percent. Rather, the NETOs believe that, at least for reasons of reducing administrative burdens, any refunds or surcharges for these prior periods can and should be addressed after the Commission revisits Opinion No. 531 *et seq*. on remand. Issuing re-settlement statements for past periods can require a substantial amount of time and effort. Much of the burden for re-settling transmission rates for past periods would be borne by ISO-NE in its capacity as the NETOs' billing agent for Regional Network Service rates. For example, the refunds required by the Commission's Opinion No. 531-A as clarified in Opinion No. 531-B required multiple rounds of rate re-settlements between December 2014 and December 2015.[20] Lengthy rounds of re-settlements while there is still uncertainty as to some prior periods would also have an impact on transmission customers in New England. The NETOs are therefore deferring implementing re-settlements for periods prior to June 6, 2017, at this time. The NETOs, however, hereby reserve all of their rights to recover the shortfall in revenues during past periods resulting from the vacated orders.

III. SECTIONS OF THE ISO-NE OATT MODIFIED BY THE VACATUR

Clean and redlined versions of the following portions of the ISO-NE OATT are included in this filing:[21]

Regional Rates

Attachment F and Attachment F Implementation Rule

Local Rates

Schedule 21-CMP

Schedule 21-EM

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[19] The period from October 31, 2015, to April 28, 2016, is not within any statutory refund period.

[20] *See* the NETOs' November 6, 2014, and March 31, 2015, Motions for Extension of Time in Docket Nos. EL11-66 and ER15-414 and the accompanying affidavit of ISO-NE's Supervisor, Monthly Markets, in the ISO-NE Market Analysis and Settlements group.

[21] The tariff records to comply with the Commission's eTariff regulations are included in the version of this filing submitted in Docket No. ER15-414. The version of this filing submitted in Docket No. EL11-66 includes a PDF version of these tariff provisions.

Schedule 21-ES (formerly Schedule 21-NU)

Schedule 21-FG&E

Schedule 21-NEP

Schedule 21-NHT

Schedule 21-NSTAR

Schedule 21-UES

Schedule 21-VTransco

III. CONCLUSION

For all of the foregoing reasons, the NETOs respectfully submit this filing to document the return of the ROE in their transmission rates under the ISO-NE OATT to the *status quo ante* as a result of the mandate of the United States Court of Appeals for the District of Columbia Circuit in *Emera Maine v. FERC*, Case Nos. 15-1118 *et al*.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service lists compiled by the Secretary in Docket Nos. EL11-66 and ER15-414.

Dated at Washington, D.C., this 5th day of June, 2017

/s/ Sean A. Atkins
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SCHEDULE 21 - EM

EMERA MAINE
BANGOR HYDRO DISTRICT
LOCAL SERVICE SCHEDULE

SCHEDULE 21-EM

I. COMMON SERVICE PROVISIONS

1 Definitions

1.1 Annual Transmission Costs: The total annual cost of the BHD Transmission System for purposes of Local Network Service shall be the amount specified in Attachment H until amended by Emera Maine or modified by the Commission.

1.2 BHD or Bangor Hydro District: Emera Maine's electric assets consisting of and/or directly interconnected with the BHD Transmission System.

1.2A BHD Transmission System: The facilities owned, controlled or operated by Emera Maine *and*, in accordance with the Transmission Operating Agreement, subject to the Operating Authority of the ISO, that are used to provide transmission service under Schedule 21 and Schedule 21-EM of the OATT.

1.3 Designated Agent: Any entity that performs actions or functions on behalf of Emera Maine, an Eligible Customer, or the Transmission Customer required under Schedule 21 and Schedule 21-EM of the OATT.

1.4 Direct Assignment Facilities: Facilities or portions of facilities that are constructed by Emera Maine for the sole use/benefit of a particular Transmission Customer requesting service under Schedule 21 and Schedule 21-EM of the OATT. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.5 Distribution Facilities: Facilities or portions of facilities directly interconnected with the BHD Transmission System but not reflected in transmission rates.

1.5A Emera Maine: Emera Maine, formerly named Bangor Hydro Electric Company. Except where the context clearly indicates otherwise, all references herein to Emera Maine shall be understood to refer to the BHD Transmission System as that term is defined herein, also known as the Emera Maine - Bangor Hydro District.

1.5B Monthly BHD Transmission System Peak: The maximum firm usage of the BHD Transmission System in a calendar month as calculated pursuant to the rate formula in Attachment

P-EM.

1.6 Network Load: The load that a Network Customer designates for Local Network Service under this Schedule 21-EM. The Network Customer's Network Load shall include all load served by the output of any Local Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under this Schedule 21-EM for any Local Point-To-Point Service that may be necessary for such non-designated load.

1.7 Local Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Schedule 21 and Schedule 21-EM of the OATT.

1.8 Local Network Operating Committee: A group made up of representatives from the Network Customer(s) and Emera Maine established to coordinate operating criteria and other technical considerations required for implementation of Local Network Service

1.9 Local Network Resource: Any designated generating resource owned, purchased or leased by a Network Customer under the Local Network Service provisions of Schedule 21 and Schedule 21-EM of the OATT. Local Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

1.10 Local Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support the overall BHD Transmission System for the general benefit of all users of the BHD Transmission System.

1.11 Parties: Emera Maine and the Transmission Customer receiving service under Schedule 21-EM of the OATT.

1.12 Point(s) of Delivery: Point(s) on the BHD Transmission System where capacity and energy transmitted by Emera Maine will be made available to the Receiving Party under the local point-to-point service provisions of Schedule 21-EM of the OATT. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Local Point-To-Point Service.

1.13 Point(s) of Receipt: Point(s) of interconnection on the BHD Transmission System where capacity and energy will be made available to Emera Maine by the Delivering Party pursuant to the local point-to point service provisions of Schedule 21-EM of the OATT. The Point(s) of Receipt shall be specified in the Service Agreement for Local Long-Term Firm Point-To-Point Service.

1.14 Point-To-Point Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the local point-to-point service provisions of Schedule 21-EM of the OATT.

1.15 Reserved Capacity: The maximum amount of capacity and energy that Emera Maine agrees to transmit for the Transmission Customer over the BHD Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Schedule 21 and Schedule 21-EM of the OATT. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.16 Transmission Customer: Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that Emera Maine file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of this Schedule 21-EM. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Schedule 21-EM.

1.17 [Reserved].

1.18 Transmission Service: Local Point-To-Point Service provided over the BHD Transmission System under Schedule 21 and Schedule 21-EM of the OATT on a firm and non-firm basis.

2 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transfer Capability: For purposes of determining whether existing capability on the BHD Transmission System is adequate to accommodate a request for firm service under Schedule 21 and Schedule 21-EM of the OATT, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the OATT will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section I.1.b. of Schedule 21 of the OATT.

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. Emera Maine is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services: (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

Emera Maine is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within Emera Maine's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve - Spinning, and (iv) Operating Reserve - Supplemental. The Transmission Customer serving load within Emera Maine's Control Area is required to acquire these Ancillary Services, whether from Emera Maine, from a third party, or by self-supply. The Transmission Customer may not decline Emera Maine's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from Emera Maine. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by Emera Maine associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve.

Emera Maine shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer. In the event of an unauthorized use of any Ancillary Service by the Transmission Customer, Emera Maine may require the Transmission Customer to pay a penalty up to 200% of the specific Ancillary Service charge for the entire length of the reserved period but not exceeding one month.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of this Schedule 21-EM. Three principal requirements apply to discounts for Ancillary Services provided by Emera Maine in conjunction with its provision of transmission service as follows: (i) any offer of a discount made by Emera Maine must be announced to all Eligible Customers solely by posting on the ISO OASIS, (ii) any customer-initiated request for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (iii) once a discount is negotiated, details must be immediately posted on the ISO OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on Emera Maine's system. Sections 3.1 through 3.6 below list the six Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1-EM.

3.2 Reactive Supply and Voltage Control from Generation or Other Sources Service: The rates and/or methodology are described in Schedule 2-EM.

3.3 Regulation and Frequency Response Service: Where applicable the rates and/or methodology are described in Schedule 3-EM.

3.4 Energy Imbalance Service: Where applicable the rates and/or methodology are described in Schedule 4-EM.

3.5 Operating Reserve - Spinning Reserve Service: Where applicable the rates and/or methodology are described in Schedule 5-EM.

3.6 Operating Reserve - Supplemental Reserve Service: Where applicable the rates and/or methodology are described in Schedule 6-EM.

4 Billing and Payment

4.1 Billing Procedure: Within a reasonable time after the first day of each month, Emera Maine shall submit an invoice to the Transmission Customer for the charges for all services furnished under Schedule 21 and Schedule 21-EM of the OATT during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to Emera Maine, or by wire transfer to a bank named by Emera Maine.

4.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by Emera Maine.

4.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to Emera Maine on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after Emera Maine notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, Emera Maine may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between Emera Maine and the Transmission Customer, Emera Maine will continue to provide service under the Service Agreement as long as the Transmission Customer: (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then Emera Maine may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5 Accounting for Emera Maine's Use of the Tariff: Emera Maine shall record the following amounts, as outlined below.

5.1 Transmission Revenues: Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Schedule 21 and Schedule 21-EM of the OATT.

6 Regulatory Filings: Nothing contained in the Tariff (including this Schedule 21-EM of the OATT) or any Service Agreement shall be construed as affecting in any way the right of Emera Maine to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the OATT (including this Schedule 21-EM) or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under this Schedule 21-EM to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

7 Creditworthiness: The applicable Creditworthiness procedures are specified in Attachment Q-EM.

8 Dispute Resolution Procedures

8.1 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer and Emera Maine involving transmission service under Schedule 21 and Schedule 21-EM of the OATT (excluding applications for rate changes or other changes to Schedule 21-EM, or to any Service Agreement entered into under Schedule 21-EM, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of Emera Maine and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

8.2 External Arbitration Procedures: Any arbitration initiated under Schedule 21-EM shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

8.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of Schedule 21 and Schedule 21-EM of the OATT and any Service Agreement entered into under Schedule 21-EM and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

8.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(i) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(ii) one half the cost of the single arbitrator jointly chosen by the Parties

8.5 Rights Under The Federal Power Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act

II. LOCAL POINT-TO-POINT SERVICE

Preamble

Emera Maine will provide Firm and Non-Firm Local Point-To-Point Service pursuant to the applicable terms and conditions of Schedule 21 and Schedule 21-EM of the OATT. To the extent any terms of Schedule 21-EM conflict with any other provisions of the OATT, the terms of Schedule 21-EM shall control. Local Point-To-Point Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery. Service Agreements for Local Point-To-Point Service shall be based on the standard form service agreements in Attachment A of Schedule 21. Service Agreements for Local Retail Point-To-Point Service shall be based on the standard form service agreements in Attachment L-EM and Attachment M-EM of this Schedule 21-EM.

9 Nature of Firm Local Point-to-Point Service

9.1 Service Agreements: Emera Maine shall offer a standard form Firm Local Point-To-Point Service Agreement (Attachment A of Schedule 21) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Local Point-To-Point Service. Emera

Maine shall offer a standard form Firm Local Point-To-Point Service Agreement (Attachment A of Schedule 21) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Local Point-To-Point Service pursuant to Schedule 21 and Schedule 21-EM of the OATT. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement.

If Emera Maine determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on the BHD Transmission System, Emera Maine will offer the Firm Transmission Service with the condition that Emera Maine may curtail the service prior to the curtailment of other Firm Transmission Service for a specified number of hours per year or during System Condition(s). If the Transmission Customer accepts the service, Emera Maine will use due diligence to provide the service until: (i) Network Upgrades are completed for the Transmission Customer, (ii) the Emera Maine determines through a biennial reassessment that it can no longer reliably provide such service, or (iii) the Transmission Customer terminates the service because the reassessment increased the number of hours per year of conditional curtailment or changed the System Conditions.

The Service Agreement shall, when applicable, specify any conditional curtailment options selected by the Transmission Customer. Where the Service Agreement contains conditional curtailment options and is subject to a biennial reassessment as described in above, Emera Maine shall provide the Transmission Customer notice of any changes to the curtailment conditions no less than 90 days prior to the date for imposition of new curtailment conditions. Concurrent with such notice, Emera Maine shall provide the Transmission Customer with the reassessment study and a narrative description of the study, including the reasons for changes to the number of hours per year or System Conditions under which conditional curtailment may occur.

9.2 Emera Maine Penalties Applicable to Curtailment of Firm Local Service. Pursuant to Schedule 21, Part I.1.f of the OATT, in the event the Transmission Customer fails to curtail service in response to a directive by Emera Maine, the Transmission Customer shall pay any applicable charges and the following penalty at the election of Emera Maine: up to 200% of the Firm Point-to-Point Transmission Service charge for the entire length of the reserved period but not exceeding one month. This penalty shall apply only to the portion of the service that the

Transmission Customer fails to curtail in response to a Curtailment directive. If the Curtailment is for reliability purposes, Emera Maine may assess the penalty charge for failure to curtail if the Transmission Customer does not make the required reductions within 10 minutes of the Curtailment directive. If the Curtailment is for economic purposes, Emera Maine may assess the penalty charge for failure to curtail if the Transmission Customer does not make the required reductions within 20 minutes of the Curtailment directive.

9.3 Emera Maine Penalties for Exceeding Firm Reserved Capacity: Pursuant to Schedule 21, Part I.1.g of the OATT, in the event that a Transmission Customer (including Third-Party Sales by Emera Maine) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery, the Transmission Customer shall pay the following penalty at the election of Emera Maine: up to 200% of the Firm Point-to-Point Transmission Service charge for the period during which the Transmission Customer exceeded its firm reserved capacity.

The penalty for one or more hours of exceeding firm reserved capacity within a given day will be based on the rate for daily Firm Point-to-Point Transmission Service; the penalty for exceeding firm reserved capacity for a period of one or more days within a given week will be based on the rate for weekly Firm Point-to-Point Transmission Service; the penalty for exceeding firm reserved capacity for a period equal to one or more weeks within a given month will be based on the rate for monthly Firm Point-to-Point Transmission Service; and the penalty for exceeding firm reserved capacity for a period equal to one or more months within a given year will be based on the rate for annual Firm Point-to-Point Transmission Service.

More than one assessment for a given duration (e.g., daily) shall result in an increase of the penalty period to the next longest duration (e.g., weekly).

For the amounts exceeding firm reserved capacity, the Transmission Customer also must replace losses as required by this Schedule 21-EM.

All penalties collected under this provision shall be allocated equally to all Transmission Customers under this Schedule 21-EM that have not exceeded their firm reserved capacity.

10 Nature of Non-Firm Local Point-to-Point Service

10.1 Service Agreements: Emera Maine shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment A of Schedule 21-EM) to an Eligible Customer when it first submits a Completed Application for Non-Firm Local Point-To-Point Service pursuant to Schedule 21 and Schedule 21-EM of the OATT. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

10.2 Emera Maine Penalties for Exceeding Non-Firm Capacity Reservation: Pursuant to Schedule 21, Part I.2.e of the OATT, in the event that a Transmission Customer (including Third-Party Sales by Emera Maine) exceeds its non-firm capacity reservation, the Transmission Customer shall pay the following penalty at the election of Emera Maine: up to 200% of the Firm Point-to-Point Transmission Service charge for the period during which the Transmission Customer exceeded its firm reserved capacity.

The penalty for one or more hours of exceeding firm reserved capacity within a given day will be based on the rate for daily Firm Point-to-Point Transmission Service; the penalty for exceeding firm reserved capacity for a period of one or more days within a given week will be based on the rate for weekly Firm Point-to-Point Transmission Service; the penalty for exceeding firm reserved capacity for a period equal to one or more weeks within a given month will be based on the rate for monthly Firm Point-to-Point Transmission Service; and the penalty for exceeding firm reserved capacity for a period equal to one or more months within a given year will be based on the rate for annual Firm Point-to-Point Transmission Service.

More than one assessment for a given duration (e.g., daily) shall result in an increase of the penalty period to the next longest duration (e.g., weekly).

For the amounts exceeding the non-firm capacity reservation, the Transmission Customer must replace losses as required by this Schedule 21-EM.

All penalties collected under this provision shall be allocated equally to all Transmission Customers under this Schedule 21-EM that have not exceeded their firm reserved capacity.

10.3 Emera Maine Penalties Applicable to Curtailment of Non-Firm Local Point-to-Point Service: Pursuant to Schedule 21, Part I.2.g of the OATT, in the event the Transmission Customer fails to curtail service in response to a directive by Emera Maine, the Transmission Customer shall pay any applicable charges and the following penalty at the election of Emera Maine: up to 200% of the Non-Firm Point-to-Point Transmission Service charge for the entire length of the reserved period but not to exceed one month. This penalty shall apply only to the portion of the service that the Transmission Customer fails to curtail in response to a Curtailment directive. If the

Curtailment is for reliability purposes, Emera Maine may assess the penalty charge for failure to curtail if the Transmission Customer does not make the required reductions within 10 minutes of the Curtailment directive. If the Curtailment is for economic purposes, Emera Maine may assess the penalty charge for failure to curtail if the Transmission Customer does not make the required reductions within 20 minutes of the Curtailment directive.

11 Service Availability

11.1 Determination of Available Transfer Capability: A description of Emera Maine's specific methodology for assessing available transfer capability is contained in Attachment C of Schedule 21-EM. In the event sufficient transmission capability may not exist to accommodate a service request, Emera Maine will respond by performing a System Impact Study.

11.2 Real Power Losses: Pursuant to Schedule 21, Part I.3.g of the OATT, the applicable Real Power Loss factor for Emera Maine Local Transmission Service is 1.99%.

12 Procedures for Arranging Firm Local Point-To-Point Service

12.1 Deposit: A Completed Application for Firm Local Point-To-Point Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month; provided, however, Emera Maine shall have the right to waive the requirement of a deposit on a nondiscriminatory basis if Emera Maine determines that the Eligible Customer is creditworthy pursuant to Section 7 and is not in default of its obligations as defined in Section 4.3 at the time of the Application. Emera Maine will bill the Eligible Customer for any reasonable costs incurred by Emera Maine in connection with its review of the Application. If the Application is rejected by Emera Maine because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by Emera Maine in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by Emera Maine, if Emera Maine is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Local Point-To-Point Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by Emera Maine to the extent such costs have not already been recovered by Emera Maine from the Eligible Customer. Emera Maine will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Part I.7 of Schedule 21 of the OATT. If a Service Agreement for Firm Local Point-To-Point Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Local Point-To-Point Service. Applicable interest shall be computed in accordance with the Commission's regulations at 18 CFR § 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to Emera Maine's account.

13 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

13.1 Determination of Available Transfer Capability: Following receipt of a tendered schedule Emera Maine will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 11.2 of this Schedule 21-EM. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service: <u>(i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service</u>.

14 Additional Study Procedures For Firm Point-To-Point Transmission Service Requests

14.1 Expedited Procedures for New Facilities: In lieu of the procedures set forth in Part I.7 of Schedule 21 of the OATT, the Eligible Customer shall have the option to expedite the process by requesting Emera Maine to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate Emera Maine for all costs incurred pursuant to the terms of Schedule 21 and Schedule 21-EM. In order to exercise this option, the Eligible Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While Emera Maine agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate Emera Maine for all costs incurred pursuant to the provisions of Schedule 21 and Schedule 21-EM of the OATT. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

III. LOCAL NETWORK SERVICE

Preamble

Emera Maine will provide Local Network Service pursuant to the applicable terms and conditions contained in Schedule 21 and Schedule 21-EM of the OATT and Service Agreement. Local Network Service allows the Network Customer to integrate, economically dispatch, and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which Emera Maine utilizes the BHD Transmission System to serve its Native Load Customers. Local Network Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Schedule 21 and Schedule 21-EM of the OATT. Service Agreements for Local Network Service shall be based on the standard form service agreement in Attachment A of Schedule 21. Service Agreements for Local Retail Network Service shall be based on the standard form service agreement in Attachment N-EM and Umbrella Network Operation Agreement for Retail Local Network Service in Attachment O-EM of this Schedule 21-EM.

15. Nature of Local Network Service

15.1 Real Power Losses: As explained in Schedule 21, Part II.2.f. of the OATT, Real Power Losses are associated with all transmission service. Emera Maine is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by Emera Maine. The applicable Real Power Loss factor is 1.99%.

16 Initiating Service

16.1 Condition Precedent for Receiving Service: Subject to the terms and conditions of Schedule 21 and Schedule 21-EM of the OATT, Emera Maine will provide Local Network Service to any Eligible Customer, provided that: (i) the Eligible Customer completes an Application for Local Network Service as provided under Schedule 21 and Schedule 21-EM of the OATT, (ii) the Eligible Customer and the Emera Maine complete the technical arrangements set forth in Sections 16.3 and 16.4 of Schedule 21-EM, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment A of Schedule 21 or requests in writing that a proposed unexecuted Service Agreement be filed with the Commission, and (iv) the Eligible Customer executes a Local Network

Operating Agreement with Emera Maine pursuant to Attachment G-EM.

16.2 Application Procedures: An Eligible Customer requesting Local Network Service pursuant to Schedule 21 and Schedule 21-EM of the OATT must submit an Application, with a deposit approximating the charge for one month of service, to the ISO as far as possible in advance of the month in which service is to commence. Emera Maine shall have the right to waive the requirement of a deposit on a nondiscriminatory basis if Emera Maine determines that the Transmission Customer is creditworthy pursuant to Section 7 of Schedule 21-EM and is not in default of its obligations as defined in Section 4.3 of Schedule 21-EM at the time of the Application. Emera Maine will bill the Eligible Customer for any reasonable costs incurred by Emera Maine in connection with its review of the Application. Unless subject to the procedures in Section 2 of Schedule 21-EM, Completed Applications for Local Network Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. A Completed Application may be submitted by transmitting the required information by telefax. This method will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Schedule 21 and Schedule 21-EM of the OATT;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Emera Maine substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection). For each on-system Network Resource, such description shall include:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions
- Any periods of restricted operations throughout the year
- Maintenance schedules
- Minimum loading level of unit
- Normal operating level of unit
- Any must-run unit designations required for system reliability or contract reasons
- Arrangements governing sale and delivery of power to third parties from generating facilities located in Emera Maine’s Control Area, where only a portion of unit output is designated as a Network Resource;

For each off-system Network Resource, such description shall include:

- Identification of the Network Resource as an off-system resource
- Amount of power to which the customer has rights
- Identification of the control area(s) from which the power will originate
- Delivery point(s) to the BHD Transmission System;
- Transmission arrangements on the external transmission system(s)
- Operating restrictions, if any
- Any periods of restricted operations throughout the year
- Maintenance schedules
- Minimum loading level of unit
- Normal operating level of unit
- Any must-run unit designations required for system reliability or contract reasons

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by Emera Maine
- Operating restrictions needed for reliability
- Operating guides employed by system operators

- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- 10 year projection of system expansions or upgrades
- Transmission system maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested Local Network Service. The minimum term for Local Network Service is one year; and

(viii) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to Section 16.2(v) satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a noninterruptible basis.

Unless the Parties agree to a different time frame, the ISO or Emera Maine must acknowledge the request within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the ISO or Emera Maine shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, Emera Maine will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the ISO or Emera Maine shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. Emera Maine shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

16.3 Technical Arrangements to be Completed Prior to Commencement of Service: Local Network Service shall not commence until Emera Maine and the Network Customer, or a third party, have completed installation of all equipment specified under the Local Network

Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the BHD Transmission System. Emera Maine shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

16.4 Network Customer Facilities: The provision of Local Network Service shall be conditioned upon the Network Customer's constructing, maintaining, and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the BHD Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

17 Network Resources

17.1 Operation of Network Resources: The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Emera Maine's Control Area such that the output of those facilities exceeds its designated Network Load, plus Non-Firm sales delivered pursuant to Schedule 21 and Schedule 21-EM of the OATT, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of Emera Maine to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the BHD Transmission System. For all Network Resources not physically connected with the BHD Transmission System, the Network Customer may not schedule delivery of energy in excess of the Network Resource's capacity, as specified in the Network Customer's Application pursuant to Schedule 21, Part II, section 3, unless the Network Customer supports such delivery within the BHD Transmission System by either obtaining Point-to-Point Transmission Service or utilizing secondary service pursuant to Schedule 21, Part II, section 2(g). Emera Maine shall specify the rate treatment and all related terms and conditions applicable in the event that a Network Customer's schedule at the delivery point for a Network Resource not physically interconnected with the BHD Transmission System exceeds the Network Resource's designated capacity, excluding energy delivered using secondary service or Point-to-Point Transmission Service.

17.2 Use of Interface Capacity by the Network Customer: There is no limitation upon a Network Customer's use of the BHD Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of Emera Maine’s total interface capacity between the BHD Transmission System and other transmission systems may not exceed the Network Customer's Load.

18 Designation of Network Load

18.1 Network Load: The Network Customer must designate the individual Network Loads on whose behalf Emera Maine will provide Local Network Service. The Network Loads shall be specified in the Service Agreement.

18.2 New Network Loads Connected with Emera Maine: The Network Customer shall provide Emera Maine with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to the BHD Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. Emera Maine will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network

18.3 Network Load Not Physically Interconnected with Emera Maine: This section applies to both initial designation and the subsequent addition of new Network Load not physically interconnected with Emera Maine. To the extent that the Network Customer desires to obtain transmission service for a load outside the BHD Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Schedule 21 and Schedule 21-EM of the OATT and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Local Point-To-Point Service under Schedule 21 and Schedule 21-EM of the OATT. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

18.4 New Interconnection Points: To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the BHD Transmission System and a Network Load, the Network Customer shall provide Emera Maine with as much advance notice as reasonably practicable.

18.5 Changes in Service Requests: Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Local Network Service (e.g. the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by Emera Maine and charged to the Network Customer as reflected in the Service Agreement. However, Emera Maine must treat any requested change in Local Network Service in a non-discriminatory manner.

18.6 Annual Load and Resource Information Updates: The Network Customer shall provide Emera Maine with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Local Network Service under Schedule 21 and Schedule 21-EM of the OATT. The Network Customer also shall provide Emera Maine with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities, or operations affecting Emera Maine's ability to provide reliable service.

19 Load Shedding and Curtailments

19.1 Load Shedding: To the extent that a system contingency exists on the BHD Transmission System and Emera Maine determines that it is necessary for Emera Maine and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement.

20 Rates and Charges

The Network Customer shall pay Emera Maine for any Direct Assignment Facilities, Local Distribution Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

20.1 Monthly Demand Charge: The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its monthly Network Load times the monthly Local Network Service rate listed in the rate formula in Attachment P-EM.

20.2 Determination of Network Customer's Monthly Network Load: The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with Emera Maine under Section 18.3 of Schedule 21-EM) coincident with the Monthly BHD Transmission System Peak.

20.3 Stranded Cost Recovery: Emera Maine may seek to recover stranded costs from the Network Customer pursuant to Schedule 21 and Schedule 21-EM of the OATT in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However Emera Maine must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

21 Operating Arrangements

21.1 Operation Under The Local Network Operating Agreement: The Network Customer shall plan, construct, operate, and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement.

21.2 Local Network Operating Agreement: The terms and conditions under which the Network Customer shall operate its facilities, and the technical and operational matters associated with the implementation of Schedule 21 and Schedule 21-EM of the OATT, shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to: (i) operate and maintain equipment necessary for integrating the Network Customer within the BHD Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between Emera Maine and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the BHD Transmission System, interchange schedules, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Schedule 21 and Schedule 21-EM of the OATT, including scheduling protocols. The Local Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO) as defined in 18 C.F.R. § 39.1, (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with Emera Maine, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO. Emera Maine shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G-EM.

21.3 Local Network Operating Committee: A Local Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Local Network Operating Agreement. Each local Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 1-EM

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by Emera Maine (if Emera Maine is the Control Area operator) or indirectly by Emera Maine making arrangements with the Control Area operator that performs this service for the BHD Transmission System. The Transmission Customer must purchase this service from Emera Maine or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for Emera Maine, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Emera Maine by that Control Area operator.

The Transmission Customer shall pay up to the following transmission rates for service under Schedule 21-EM of the OATT:

1) **Yearly delivery:** (a) for all wholesale customers, customers who wheel-off the Emera Maine system, and retail point-to-point customers, the Annual Rate established pursuant to Attachment P-EM Section VI.A1 per KW of Reserved Capacity per year or (b) for retail network customers, the Annual Rate established pursuant to Attachment P-EM Section VI.A2 per KW of Reserved Capacity per year.

2) **Monthly delivery:** (a) for all wholesale customers, customers who wheel-off the Emera Maine system, and retail point-to-point customers, the Monthly Rate established pursuant to Attachment P-EM Section VI.A1 per KW of Reserved Capacity per month or (b) for retail network customers, the Monthly Rate established pursuant to Attachment P-EM Section VI.A2 per KW of Reserved Capacity per month.

3) **Weekly delivery:** (a) for all wholesale customers, customers who wheel-off the Emera Maine system, and retail point-to-point customers, Weekly Rate established pursuant to Attachment P-EM Section VI.A1 per KW of Reserved Capacity per week or (b) for retail network customers, the Weekly Rate established pursuant to Attachment P-EM Section VI.A2 per KW of Reserved Capacity per week.

4) **Daily delivery:** (a) for all wholesale customers, customers who wheel-off the Emera Maine system, and retail point-to-point customers, the Daily Rate established pursuant to Attachment P-EM Section VI.A1 per KW of Reserved Capacity per day or (b) for retail network customers, the Daily Rate

established pursuant to Attachment P-EM Section VI.A2 per KW of Reserved Capacity per day.

5) **Hourly delivery:** (a) for all wholesale customers, customers who wheel-off the Emera Maine system, and retail point-to-point customers, the Hourly Rate established pursuant to Attachment P-EM Section VI.A1 per KW of Reserved Capacity per hour or (b) for retail network customers, the Hourly Rate established pursuant to Attachment P-EM Section VI.A2 per KW of Reserved Capacity per hour.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

SCHEDULE 2-EM

REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION OR OTHER SOURCES SERVICE

In order to maintain transmission voltages on Emera Maine's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on Emera Maine's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by Emera Maine.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by Emera Maine (if Emera Maine is the Control Area operator) or indirectly by Emera Maine making arrangements with the Control Area operator that performs this service for the BHD Transmission System. The Transmission Customer must purchase this service from Emera Maine or the Control Area operator. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for Emera Maine, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Emera Maine by the Control Area operator.

The Transmission Customer shall pay up to the following transmission rates for service under Schedule 21 and Schedule 21-EM of the OATT:

Emera Maine is not the Control Area operator, and has divested itself of the generation in its service territory that provides Reactive Supply and Voltage Control from Generation Sources Service. To the extent Transmission Customers are also Transmission Customers under provisions of the OATT besides Schedule 21 and Schedule 21-EM, which provide Reactive Supply and Voltage Control from Generation Sources Service throughout the ISO Control Area, no additional charges for this service shall be charged hereunder. To the extent a Transmission Customer is a customer under Schedule 21 and Schedule 21-EM of the OATT, but not a customer under the other provisions of the OATT, Emera Maine will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer's account.

SCHEDULE 3-EM

REGULATION AND FREQUENCY RESPONSE SERVICE

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with Emera Maine (or the Control Area operator that performs this function for Emera Maine). Emera Maine must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from Emera Maine or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for Emera Maine, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Emera Maine by that Control Area operator.

The Transmission Customer shall pay up to the following transmission rates for service under Schedule 21-EM of the OATT:

Regulation and Frequency Response Service is provided within the ISO Control Area by a market in Automatic Generation Control administered for the benefit of the ISO Participants and non-Participants alike by the ISO. To the extent Transmission Customers under Schedule 21 and Schedule 21-EM of the OATT are also Transmission Customers under other provisions of the OATT, Regulation and Frequency Control Service will be provided under those other provisions of the OATT, and not hereunder. To the extent a Transmission Customer is a customer under the Schedule 21 and Schedule 21-EM of the OATT, but not a customer under the other provisions of the OATT, Emera Maine will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer’s account.

SCHEDULE 4-EM

ENERGY IMBALANCE SERVICE

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. Emera Maine must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from Emera Maine or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for Emera Maine, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Emera Maine by that Control Area operator.

Within the ISO Control Area, Energy Imbalance Service is provided to load serving entities, which choose not to balance their hourly energy requirements with their own resources or bilateral arrangements, via the energy market administered by the ISO. Emera Maine has divested itself of the generation in its service territory, and is no longer capable of supplying this service itself. To the extent Transmission Customers under Schedule 21 and Schedule 21-EM of the OATT are also Transmission Customers under other provisions of the OATT, Energy Imbalance Service shall be provided under the other provisions of the OATT, and no additional charges for this service shall be charged hereunder. To the extent a Transmission Customer is a customer under the Schedule 21 and Schedule 21-EM of the OATT, but not a customer under the other provisions of the OATT, Emera Maine will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer's account.

SCHEDULE 5-EM

OPERATING RESERVE - SPINNING RESERVE SERVICE

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. Emera Maine must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from Emera Maine or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below.

Within the ISO Control Area, Spinning Reserve Service is provided to load serving entities, which choose not to supply their hourly spinning reserve requirements with their own resources or bilateral arrangements, via the 10-Minute Spinning Reserve Market administered by the ISO. Emera Maine has divested itself of the generation in its service territory, and is no longer capable of supplying this service itself. To the extent Transmission Customers under Schedule 21 and Schedule 21-EM of the OATT are also Transmission Customers under other provisions of the OATT, Spinning Reserve Service shall be provided under those other provisions, and no additional charges for this service shall be charged hereunder. To the extent a Transmission Customer is a customer under Schedule 21 and Schedule 21-EM of the OATT, but not a customer under other provisions of the OATT, Emera Maine will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer's account.

SCHEDULE 6-EM

OPERATING RESERVE - SUPPLEMENTAL RESERVE SERVICE

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. Emera Maine must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from Emera Maine or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below.

Within the ISO Control Area, Supplemental Reserve Service is provided to load serving entities, which choose not to supply their hourly supplemental reserve requirements with their own resources or bilateral arrangements, via the 10-Minute Non-Spinning and 30-Minute Reserve Markets administered by the ISO. Emera Maine has divested itself of the generation in its service territory, and is no longer capable of supplying this service itself. To the extent Transmission Customers under Schedule 21 and Schedule 21-EM of the OATT are also Transmission Customers under other provisions of the OATT, Supplemental Reserve Service shall be provided under the other provisions, and no additional charges for this service shall be charged hereunder. To the extent a Transmission Customer is a customer under Schedule 21 and Schedule 21-EM of the OATT, but not a customer under other provisions of the OATT, Emera Maine will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer’s account.

SCHEDULE 7-EM

WHOLESALE OR WHEELING LONG-TERM FIRM AND SHORT-TERM FIRM LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall pay up to the following transmission rates for service under Schedule 21-EM of the OATT:

1) **Yearly delivery:** (a) in the case of wholesale load located on the Emera Maine system, the Annual Rate established pursuant to Attachment P-EM Section VI.B, plus the Annual Rate established pursuant to Attachment P-EM Section VI.C, plus, if applicable, the Annual Rate established pursuant to Attachment P-EM Section VI.D, all per KW of Reserved Capacity per year; or (b) in the case of wheeling off the Emera Maine system, the Annual Rate established pursuant to Attachment P-EM Section VI.E per KW of Reserved Capacity per year.

2) **Monthly delivery:** (a) in the case of wholesale load located on the Emera Maine system, the Monthly Rate established pursuant to Attachment P-EM Section VI.B, plus the Monthly Rate established pursuant to Attachment P-EM Section VI.C, plus, if applicable, the Monthly Rate established pursuant to Attachment P-EM Section VI.D, all per KW of Reserved Capacity per month; or (b) in the case of wheeling off the Emera Maine system, the Monthly Rate established pursuant to Attachment P-EM Section VI.E per KW of Reserved Capacity per month.

3) **Weekly Delivery:** (a) in the case of wholesale load located on the Emera Maine system, the Weekly Rate established pursuant to Attachment P-EM Section VI.B, plus the Weekly Rate established pursuant to Attachment P-EM Section VI.C, plus, if applicable, the Weekly Rate established pursuant to Attachment P-EM Section VI.D, all per KW of Reserved Capacity per week; or (b) in the case of wheeling off the Emera Maine system, the Weekly Rate established pursuant to Attachment P-EM Section VI.E per KW of Reserved Capacity per week.

4) **Daily delivery:** (a) in the case of wholesale load located on the Emera Maine system, the Daily Rate established pursuant to Attachment P-EM Section VI.B, plus the Daily Rate established pursuant to Attachment P-EM Section VI.C, plus, if applicable, the Daily Rate established pursuant to Attachment P-EM Section VI.D, all per KW of Reserved Capacity per day; or (b) in the case of wheeling off the Emera Maine system, the Daily Rate established pursuant to Attachment P-EM Section VI.E per KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Emera Maine must be announced to all Eligible Customers solely by posting on the ISO OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (3) once a discount is negotiated, details must be immediately posted on the ISO OASIS.

6) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Emera Maine must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the BHD Transmission System.

7) **Direct Assignment Costs:** Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule. Losses on Direct Assignment Facilities shall be the responsibility of the Transmission Customer.

8) **Network Upgrades:** Where a Facilities Study identifies the need for Network Upgrades to relieve a capacity constraint and Emera Maine undertakes such Network Upgrades, in addition to any charges for Direct Assignment Facilities and losses, as applicable, the Transmission Customer shall be required to pay the higher of the following two charges:

a) the base charge for Transmission Service set forth in this schedule, modified to include the cost of required Network Upgrades on a rolled-in basis; or

b) a charge based on the incremental cost of any Network Upgrades that would not have been needed for the Service requested by the Transmission Customer. Such incremental cost charge shall be based upon the Transmission Customer's appropriate share of the cost of such Network Upgrade up to one hundred percent of such cost.

If the requested Firm Point-to-Point Service requires use of Network Upgrades previously determined to have been necessary to provide Transmission Service for another Transmission Customer and if the costs of such Network Upgrades already are reflected in the rate for Transmission Service paid by such other Customer and are not reflected in the base rate for Firm Transmission Service, the subsequent Transmission Customer receiving Transmission Service shall pay a contribution to cover a portion of the cost of such Network Upgrades. The amount of the contribution shall be based on the subsequent Transmission Customer's pro-rata use of the Network Upgrades, as determined by FERC, and in the period of time over which the use occurs. The rate of the Transmission Customer(s) for whom the Network Upgrades originally were made shall be reduced by an amount equivalent to the contribution(s) made by other Transmission Customers pursuant to this section.

9) **Local Distribution Costs:** Any customer requiring transmission over facilities not included in the base transmission charge facilities below 34.5 KV shall pay a separate charge for service over those facilities. These charges shall be pursuant to Maine Public Utilities Commission rates, where applicable, and specified in a service agreement filed with the Commission.

10) **Taxes:** There shall be added to any amount calculated pursuant to any of the foregoing provisions of this Schedule 21-EM an amount in dollars sufficient to reimburse Emera Maine for any amounts paid or payable by them as sales, excise or similar taxes in respect of the total amount payable to Emera Maine pursuant to this Schedule 21-EM, in order to allow Emera Maine, after provision for such taxes, to realize the net amount payable to them under this Schedule 21-EM. The amount of these taxes shall be detailed in the Service Agreement. If the taxes or tax rates change, then Emera Maine shall have the right to revise the Service Agreement and file it with FERC.

SCHEDULE 8-EM

WHOLESALE OR WHEELING NON-FIRM LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall pay up to the following transmission rates for service under this Schedule 21-EM:

1) **Monthly delivery:** (a) in the case of wholesale load located on the Emera Maine system, the Monthly Rate established pursuant to Attachment P-EM Section VI.B, plus the Monthly Rate established pursuant to Attachment P-EM Section VI.C, plus, if applicable, the Monthly Rate established pursuant to Attachment P-EM Section VI.D, all per KW of Reserved Capacity per month; or (b) in the case of wheeling off the Emera Maine system, the Monthly Rate established pursuant to Attachment P-EM Section VI.E per KW of Reserved Capacity per month.

2) **Weekly delivery:** (a) in the case of wholesale load located on the Emera Maine system, the Weekly Rate established pursuant to Attachment P-EM Section VI.B, plus the Weekly Rate established pursuant to Attachment P-EM Section VI.C, plus, if applicable, the Weekly Rate established pursuant to Attachment P-EM Section VI.D, all per KW of Reserved Capacity per week; or (b) in the case of wheeling off the Emera Maine system, the Weekly Rate established pursuant to Attachment P-EM Section VI.E per KW of Reserved Capacity per week.

3) **Daily delivery:** (a) in the case of wholesale load located on the Emera Maine system, the Daily Rate established pursuant to Attachment P-EM Section VI.B, plus the Daily Rate established pursuant to Attachment P-EM Section VI.C, plus, if applicable, the Daily Rate established pursuant to Attachment P-EM Section VI.D, all per KW of Reserved Capacity per day; or (b) in the case of wheeling off the Emera Maine system, the Daily Rate established pursuant to Attachment P-EM Section VI.E per KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) **Hourly delivery:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed: (a) in the case of wholesale load located on the Emera Maine system, the Hourly Rate established pursuant to Attachment P-EM Section VI.B, plus the Hourly Rate established pursuant to Attachment P-EM Section VI.C, plus, if applicable, the Hourly Rate established

pursuant to Attachment P-EM Section VI.D, all per KW of Reserved Capacity per hour; or (b) in the case of wheeling off the Emera Maine system, the Hourly Rate established pursuant to Attachment P-EM Section VI.E per KW of Reserved Capacity per hour. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Emera Maine must be announced to all Eligible Customers solely by posting on the ISO OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (3) once a discount is negotiated, details must be immediately posted on the ISO OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Emera Maine must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the BHD Transmission System.

6) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

7) **Direct Assignment Costs:** Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule. Losses on Direct Assignment Facilities shall be the responsibility of the Transmission Customer.

8) **Network Upgrades:** Where a Facilities Study identifies the need for Network Upgrades to relieve a capacity constraint and Emera Maine undertakes such Network Upgrades, in addition to any charges for Direct Assignment Facilities and losses, as applicable, the Transmission Customer shall be required to pay the higher of the following two charges:

a) the base charge for Transmission Service set forth in this schedule, modified to include the cost of required Network Upgrades on a rolled-in basis; or

b) a charge based on the incremental cost of any Network Upgrades that would not have been needed for the Service requested by the Transmission Customer. Such incremental cost charge shall be based upon the Transmission Customer's appropriate share of the cost of such Network Upgrade up to one hundred percent of such cost.

If the requested Firm Point-to-Point Service requires use of Network Upgrades previously determined to have been necessary to provide Transmission Service for another Transmission Customer, and if the costs of such Network Upgrades already are reflected in the rate for Transmission Service paid by such other Customer and are not reflected in the base rate for Firm Transmission Service, the subsequent Transmission Customer receiving Transmission Service shall pay a contribution to cover a portion of the cost of such Network Upgrades. The amount of the contribution shall be based on the subsequent Transmission Customer's pro-rata use of the Network Upgrades, as determined by FERC and in the period of time over which the use occurs. The rate of the Transmission Customer(s) for whom the Network Upgrades originally were made shall be reduced by an amount equivalent to the contribution(s) made by other Transmission Customers pursuant to this section.

9) **Local Distribution Costs:** Any customer requiring transmission over facilities not included in the base transmission charge facilities below 34.5 KV shall pay a separate charge for service over those facilities. These charges shall be pursuant to Maine Public Utilities Commission rates, where applicable, and specified in a service agreement filed with the Commission.

10) **Taxes:** There shall be added to any amount calculated pursuant to any of the foregoing provisions of this Schedule 21-EM an amount in dollars sufficient to reimburse Emera Maine for any amounts paid or payable by them as sales, excise, or similar taxes in respect of the total amount payable to Emera Maine, pursuant to Schedule 21-EM in order to allow Emera Maine, after provision for such taxes, to realize the net amount payable to them under Schedule 21-EM. The amount of these taxes shall be detailed in the Service Agreement. If the taxes or tax rates change, then Emera Maine shall have the right to revise the Service Agreement and file it with FERC.

SCHEDULE 9-EM

RETAIL FIRM LOCAL POINT-TO-POINT SERVICE

The rates, terms and conditions of Retail Firm Local Point-To-Point Service shall be as stated in this Schedule 21-EM for Firm Local Point-To-Point Service, except as stated below. In the event that there are differences between this Schedule 9-EM and other provisions of Schedule 21-EM, this Schedule 9-EM shall control in all cases.

This Schedule 9-EM shall apply to retail customers, their Designated Agents, and to other entities taking transmission service under Schedule 21-EM to sell power to such retail customers. A retail customer is an entity that purchases electricity at retail Emera Maine or another entity, including the retail customer's Designated Agent.

A. The rates for Retail Firm Local Point-To-Point Service are as follows:

1) Yearly delivery: the Annual Rate established pursuant to Attachment P-EM Section VI.F.1, plus the Annual Rate established pursuant to Attachment P-EM Section VI.G.1, plus, if applicable, the Annual Rate established pursuant to Attachment P-EM Section VI.H.1, all per KW of Reserved Capacity per year.

2) Monthly delivery: the Monthly Rate established pursuant to Attachment P-EM Section VI.F.1, plus the Monthly Rate established pursuant to Attachment P-EM Section VI.G.1, plus, if applicable, the Monthly Rate established pursuant to Attachment P-EM Section VI.H.1, all per KW of Reserved Capacity per month.

3) Weekly delivery: the Weekly Rate established pursuant to Attachment P-EM Section VI.F.1, plus the Weekly Rate established pursuant to Attachment P-EM Section VI.G.1, plus, if applicable, the Weekly Rate established pursuant to Attachment P-EM Section VI.H.1, all per KW of Reserved Capacity per week.

4) Daily delivery: the Daily Rate established pursuant to Attachment P-EM Section VI.F.1, plus the Daily Rate established pursuant to Attachment P-EM Section VI.G.1, plus, if applicable, the Daily Rate established pursuant to Attachment P-EM Section VI.H.1, all per KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Emera Maine must be announced to all Eligible Customers solely by posting on the ISO OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (3) once a discount is negotiated, details must be immediately posted on the ISO OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Emera Maine must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the BHD Transmission System.

6) Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

7) Direct Assignment Costs: Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule. Losses on Direct Assignment Facilities shall be the responsibility of the Transmission Customer.

8) Network Upgrades: Where a Facilities Study identifies the need for Network Upgrades to relieve a capacity constraint and Emera Maine undertakes such Network Upgrades, in addition to any charges for Direct Assignment Facilities and losses, as applicable, the Transmission Customer shall be required to pay the higher of the following two charges:

a) the base charge for Transmission Service set forth in this schedule, modified to include the cost of required Network Upgrades on a rolled-in basis; or

b) a charge based on the incremental cost of any Network Upgrades that would not have been needed for the Service requested by the Transmission Customer. Such incremental cost charge shall be based upon the Transmission Customer's appropriate share of the cost of such Network Upgrade up to one hundred percent of such cost.

If the requested Retail Firm Point-to-Point Service requires use of Network Upgrades previously determined to have been necessary to provide Transmission Service for another Transmission Customer, and if the costs of such Network Upgrades already are reflected in the rate for Transmission Service paid by such other Customer and are not reflected in the base rate for Retail

Firm Transmission Service, the subsequent Transmission Customer receiving Transmission Service shall pay a contribution to cover a portion of the cost of such Network Upgrades. The amount of the contribution shall be based on the subsequent Transmission Customer's pro-rata use of the Network Upgrades, as determined by FERC, and in the period of time over which the use occurs. The rate of the Transmission Customer(s) for whom the Network Upgrades originally were made shall be reduced by an amount equivalent to the contribution(s) made by other Transmission Customers pursuant to this section.

9) Local Distribution Costs: Any customer requiring transmission over facilities not included in the base transmission charge facilities below 34.5 KV shall pay a separate charge for service over those facilities. These charges shall be pursuant to Maine Public Utilities Commission rates, where applicable, and specified in a service agreement filed with the Commission.

10) Taxes: There shall be added to any amount calculated pursuant to any of the foregoing provisions of Schedule 21-EM an amount in dollars sufficient to reimburse Emera Maine for any amounts paid or payable by them as sales, excise, or similar taxes in respect of the total amount payable to Emera Maine pursuant to Schedule 21-EM, in order to allow Emera Maine, after provision for such taxes, to realize the net amount payable to them under the Schedule 21-EM. The amount of these taxes shall be detailed in the Service Agreement. If the taxes or tax rates change, then Emera Maine shall have the right to revise the Service Agreement and file it with FERC.

B. The following sections of Schedule 21 and Schedule 21-EM are modified for a Transmission Customer taking Retail Firm Local Point-To-Point Service pursuant to Schedule 9-EM and under a Service Agreement for Retail Firm Local Point-To-Point Service.

a. Schedule 21: The reservation priority for existing firm service customers section is modified such that retail customers, irrespective of term, have the right to continue to take transmission service from Emera Maine when the contract expires, rolls over, or is renewed.

b. Section 4 of Schedule 21-EM: The billing, payment, and default section is applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from Emera Maine. If the Transmission Customer is a Designated Agent, Emera Maine shall bill directly and receive payment from the Designated Agent's retail customers for applicable transmission and ancillary charges (except for Energy Imbalance Service) unless other mutually agreeable provisions for payment are made. Emera Maine shall bill directly the Designated Agent, if it is not Emera Maine, for Energy Imbalance

Service, unless other mutually agreeable provisions for payment are made. For the direct billing of retail customers taking transmission service through a Designated Agent, the billing, payment, and default provisions shall be pursuant to Emera Maine's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-EM.

c. Section 8 of Schedule 21-EM: The dispute resolution procedures are applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from Emera Maine. For retail customers taking transmission service through a Designated Agent, the dispute resolution procedures shall be pursuant Emera Maine's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-EM.

d. Section 9.1 of Schedule 21-EM: The service agreements section is modified to add the following: "If the Eligible Customer submits a Completed Application for Retail Firm Point-To-Point Transmission for service to retail load, Emera Maine shall offer a standard form Retail Firm Local Point-To-Point Service Agreement (Attachment L-EM) or Retail Non-Firm Local Point-To-Point Service Agreement (Attachment M-EM), as applicable, to Eligible Customer."

e. Part I.5.a of Schedule 21: The first sentence of the application section is modified to state the following: "A request for Retail Firm Local Point-To-Point Service for periods of one year or longer must be made in a completed Application submitted to Emera Maine at least sixty (60) days in advance of the calendar month in which service is to commence." The second to last sentence of the application is modified to state the following: "A Completed Application may be submitted by transmitting the required information to Emera Maine by telefax."

f. Part I.5.d of Schedule 21: The first sentence of the notice of deficient application section is modified to state the following: "If an Application fails to meet the requirements of the Tariff, Emera Maine shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure." The third sentence is modified to state the following: "If such efforts are unsuccessful, Emera Maine shall return the Application."

SCHEDULE 10-EM

RETAIL NON-FIRM LOCAL POINT-TO-POINT SERVICE

The rates, terms, and conditions of Retail Non-Firm Local Point-To-Point Service shall be as stated in this Schedule 21-EM for Non-Firm Local Point-To-Point Service, except as stated below. In the event that there are differences between this Schedule 10-EM and Schedule 21-EM, this Schedule 10-EM shall control in all cases.

This Schedule 10-EM shall apply to retail customers, their Designated Agents, and to other entities taking transmission service under Schedule 21-EM to sell power to such retail customers. A retail customer is an entity that purchases electricity at retail from Emera Maine or another entity, including the retail customer's Designated Agent.

A. The rates for Retail Non-Firm Local Point-To-Point Service are as follows:

1) Monthly delivery: the Monthly Rate established pursuant to Attachment P-EM Section VI.F.1, plus the Monthly Rate established pursuant to Attachment P-EM Section VI.G.1, plus, if applicable, the Monthly Rate established pursuant to Attachment P-EM Section VI.H.1, all per KW of Reserved Capacity per month.

2) Weekly delivery: the Weekly Rate established pursuant to Attachment P-EM Section VI.F.1, plus the Weekly Rate established pursuant to Attachment P-EM Section VI.G.1, plus, if applicable, the Weekly Rate established pursuant to Attachment P-EM VI.H.1, all per KW of Reserved Capacity per week.

3) Daily delivery: the Daily Rate established pursuant to Attachment P-EM Section VI.F.1, plus the Daily Rate established pursuant to Attachment P-EM Section VI.G.1, plus, if applicable, the Daily Rate established pursuant to Attachment P-EM Section VI.H.1, all per KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the Hourly Rate established pursuant to Attachment P-EM Section VI.F.1, plus the Hourly Rate established pursuant to Attachment P-EM Section VI.G.1, plus, if applicable, the Hourly Rate established pursuant to Attachment P-EM Section VI.H.1, all per KW of Reserved Capacity per hour. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Emera Maine must be announced to all Eligible Customers solely by posting on the ISO OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (3) once a discount is negotiated, details must be immediately posted on the ISO OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Emera Maine must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the BHD Transmission System.

6) Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

7) Direct Assignment Costs: Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule. Losses on Direct Assignment Facilities shall be the responsibility of the Transmission Customer.

8) Network Upgrades: Where a Facilities Study identifies the need for Network Upgrades to relieve a capacity constraint and Emera Maine undertakes such Network Upgrades, in addition to any charges for Direct Assignment Facilities and losses, as applicable, the Transmission Customer shall be required to pay the higher of the following two charges:

a) the base charge for Transmission Service set forth in this schedule, modified to include the cost of required Network Upgrades on a rolled-in basis; or

b) a charge based on the incremental cost of any Network Upgrades that would not have been needed for the Service requested by the Transmission Customer. Such incremental cost charge shall be based upon the Transmission Customer's appropriate share of the cost of such Network

Upgrade up to one hundred percent of such cost.

If the requested Retail Non-Firm Local Point-to-Point Service requires use of Network Upgrades previously determined to have been necessary to provide Transmission Service for another Transmission Customer and if the costs of such Network Upgrades already are reflected in the rate for Transmission Service paid by such other Customer and are not reflected in the base rate for Retail Non-Firm Local Service, the subsequent Transmission Customer receiving Transmission Service shall pay a contribution to cover a portion of the cost of such Network Upgrades. The amount of the contribution shall be based on the subsequent Transmission Customer's pro-rata use of the Network Upgrades, as determined by FERC, and in the period of time over which the use occurs. The rate of the Transmission Customer(s) for whom the Network Upgrades originally were made shall be reduced by an amount equivalent to the contribution(s) made by other Transmission Customers pursuant to this section.

9) Local Distribution Costs: Any customer requiring transmission over facilities not included in the base transmission charge facilities below 34.5 KV shall pay a separate charge for service over those facilities. These charges shall be pursuant to Maine Public Utilities Commission rates, where applicable, and specified in a service agreement filed with the Commission.

10) Taxes: There shall be added to any amount calculated pursuant to any of the foregoing provisions of Schedule 21-EM an amount in dollars sufficient to reimburse Emera Maine for any amounts paid or payable by them as sales, excise or similar taxes in respect of the total amount payable to Emera Maine pursuant Schedule 21-EM, in order to allow Emera Maine, after provision for such taxes, to realize the net amount payable to them under Schedule 21-EM. The amount of these taxes shall be detailed in the Service Agreement. If the taxes or tax rates change, then Emera Maine shall have the right to revise the Service Agreement and file it with FERC.

B. The following sections of Schedule 21 and Schedule 21-EM are modified for a Transmission Customer taking Retail Non-Firm Local Point-To-Point Service pursuant to Schedule 10-EM and under a Service Agreement for Retail Non-Firm Local Point-To-Point Service.

a. Schedule 21: The reservation priority for existing firm service customers section is modified such that retail customers, irrespective of term, have the right to continue to take transmission service from Emera Maine when the contract expires, rolls over or is renewed.

b. Section 4 of Schedule 21-EM: The billing, payment, and default section is applicable to a

Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from Emera Maine. If the Transmission Customer is a Designated Agent, Emera Maine shall bill directly and receive payment from the Designated Agent's retail customers for applicable transmission and ancillary charges (except for Energy Imbalance Service), unless other mutually agreeable provisions for payment are made. Emera Maine shall bill directly the Designated Agent, if it is not Emera Maine, for Energy Imbalance Service unless other mutually agreeable provisions for payment are made. For the direct billing of retail customers taking transmission service through a Designated Agent, the billing, payment, and default provisions shall be pursuant to Emera Maine's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-EM.

c. Section 8 of Schedule 21-EM: The dispute resolution procedures are applicable to a Designated Agent taking transmission service on behalf of its retail customers and shall be pursuant Emera Maine's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-EM.

d. Section 10.4 of Schedule 21-EM: The service agreements section is modified to add the following: "If the Eligible Customer submits a Completed Application for Retail Non-Firm Local Point-To-Point Service for service to retail load, Emera Maine shall offer a standard form Retail Non-Firm Local Point-To-Point Service Agreement (Attachment M-EM) to Eligible Customer."

e. Part I.6.a of Schedule 21: The first two sentences of the application section are modified to state the following: "Eligible Customers seeking Retail Non-Firm Local Point-To-Point Service must submit a Completed Application to Emera Maine. A Completed Application may be submitted by transmitting the required information to Emera Maine by telefax."

SCHEDULE 11-EM

RETAIL LOCAL NETWORK SERVICE

The rates, terms and conditions of Retail Local Network Service shall be as stated in Schedule 21-EM, for Local Network Service, except as stated below. In the event that there are differences between this Schedule 11-EM and Schedule 21-EM, this Schedule 11 shall control in all cases.

This Schedule 11-EM shall apply to retail customers, their Designated Agents, and to other entities taking transmission service under Schedule 21-EM to sell power to such retail customers. A retail customer is an entity that purchases electricity at retail from Emera Maine or another entity, including the retail customer's Designated Agent.

A. The rate for Monthly Retail Local Network Service shall be the Monthly Rate established pursuant to Attachment P-EM SectionVI.F.2, plus the Monthly Rate established pursuant to Attachment P-EM Section VI.G.2, plus, if applicable, the Monthly Rate established pursuant to Attachment P-EM Section VI.H.2.

B. The following sections of Schedule 21 and Schedule 21-EM are modified for a Transmission Customer taking Retail Local Network Service pursuant to Schedule 11-EM and under a Service Agreement for Local Retail Network Service.

a. Schedule 21: The reservation priority for existing firm service customers section is modified such that retail customers, irrespective of term, have the right to continue to take transmission service from Emera Maine when the contract expires, rolls over or is renewed.

b. Section 4 of Schedule 21-EM: The billing, payment, and default section is applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from Emera Maine. If the Transmission Customer is a Designated Agent, Emera Maine shall bill directly and receive payment from the Designated Agent's retail customers for applicable transmission and ancillary charges (except for Energy Imbalance Service), unless other mutually agreeable provisions for payment are made. Emera Maine shall bill directly the Designated Agent, if it is not Emera Maine, for Energy Imbalance Service, unless other mutually agreeable provisions for payment are made. For the direct billing of retail customers taking transmission service through a Designated Agent, the billing, payment, and default provisions shall be pursuant to Emera Maine's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-EM.

c. Section 8 of Schedule 21-EM: The dispute resolution procedures are applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from Emera Maine. For retail customers taking transmission service through a Designated Agent, the dispute resolution procedures shall be pursuant Emera Maine's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-EM.

d. Section 16.1 of Schedule 21-EM: The condition precedent for receiving service section is modified to add the following provision: "Unless retail Transmission Customers elect otherwise as provided in this Schedule 21 and Schedule 21-EM, retail Transmission Customers shall take service from Emera Maine as their Designated Agent pursuant to an Umbrella Service Agreement for Retail Local Network Service pursuant to Attachment N-EM; these retail Transmission Customers are not required to execute the service agreement which will be filed with FERC. Such retail Transmission Customers shall be obligated to comply with the applicable terms and conditions of Schedule 21 and Schedule 21-EM including paying for service notwithstanding the absence of a customer signature on a Service Agreement. If a retail Transmission Customer elects to take Retail Local Network Service directly from Emera Maine or through a Designated Agent other than Emera Maine, the Eligible Customer shall execute a Service Agreement for Retail Local Network Service pursuant to Attachment N-EM for service under Schedule 21-EM or request in writing that Emera Maine file a proposed unexecuted Service Agreement for Retail Local Network Service with the Commission and the Eligible Customer shall execute a Local Network Operating Agreement for Retail Local Network Service with Emera Maine pursuant to Attachment O-EM. The following additional requirement applies to a retail Transmission Customer that takes at least 500 KW of transmission service in any one hour in the calendar year from Emera Maine and takes Retail Local Network Service from Emera Maine as its Designated Agent: it shall execute a Service Agreement for Retail Local Network Service pursuant to Attachment N-EM for service under Schedule 21-EM or request in writing that Emera Maine file a proposed unexecuted Service Agreement for Retail Local Network Service with the Commission, if Emera Maine must construct either Direct Assignment Facilities or Network Upgrades in order to provide Transmission Service to the retail Transmission Customer."

e. Sections 16.2, 16.3, 16.4 of Schedule 21-EM: A retail Transmission Customer taking Retail Local Network Service from Emera Maine as its Designated Agent shall not be required to satisfy the application procedures and technical arrangements in sections 16.2, 16.3 and 16.4 of Schedule 21-EM, except that a retail Transmission Customer that takes at least 500 KW of transmission service in any one hour in the calendar year from Emera Maine and takes Retail Local Network Service from Emera Maine as its Designated Agent shall be required to comply with sections 16.3 and 16.4 of Schedule 21-EM to the extent Emera Maine deems it necessary to provide service.

f. Section 16.2(vii) of Schedule 21-EM: The minimum term application procedures section is modified, to change the last sentence to the following: "The minimum term for Local Network Service is one year, except that for service provided with respect to a state required retail access program, the minimum term is Emera Maine's typical monthly billing cycle for retail customers taking Retail Local Network Service directly from Emera Maine as its Designated Agent that are not required to execute a Service Agreement for Retail Local Network Service or provide notice that an unexecuted Service Agreement for Retail Local Network Service should be filed."

g. Section 18 of Schedule 21-EM: The designation of network load sections are modified to allow load distribution profiles of customer classes to be used for determining retail customer peak loads.

h. Sections 20.1 and 20.2 of Schedule 21-EM: The sections are superseded by the charges set out in this Schedule 11-EM.

i. Section 21 of Schedule 21-EM: The operating arrangements sections are not applicable for a retail Transmission Customer that takes Retail Local Network Service from Emera Maine as its Designated Agent. The operating arrangements for a Transmission Customer taking Retail Local Network Service directly from Emera Maine or through a Designated Agent other than Emera Maine shall be set forth in the Operating Agreement for Retail Local Network Service entered into between the Transmission Customer Emera Maine.

SCHEDULE 12-EM

RETAIL TERMS AND CONDITIONS

4-A PAYMENT OBLIGATION - GENERAL. The supply of service for any purpose at any location, is contingent upon payment of all charges provided for in this Rate Schedule as applicable to the Location and the character of service. Other terms including deposit requirements, late payment charges, and disconnection of service for non-payment are governed by several Maine Public Utilities Commission (MPUC) Rules and Regulations, namely:

MPUC Chapter 815 - Consumer Protection Standards For Electric And Gas Transmission And Distribution Utilities

MPUC Chapter 870 - Late Payment Charges, Interest Rates to be Paid on Customer Deposits, and Charges for Returned Checks

Copies of these Rules and Regulations hereinafter referred to as Chapters 815 and 870 of the MPUC Rules and Regulations are available for inspection at the MPUC's website.

Bills for utility service shall be due twenty-five (25) days after the postmarked date of the bill in accordance with Section 8(B) - Chapter 815 of the Commission's Rule and Regulations. No bill shall be subject to discount.

4-B GUARANTEE OF PAYMENTS:

Residential Accounts:

Emera Maine may require a deposit as security for the payment of bills and compliance with the Terms and Conditions as a prerequisite to the rendering or continuing of residential utility service by Emera Maine in accordance with Section 7(C) - Chapter 815 of the MPUC 's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

Non-Residential Accounts:

Emera Maine may require a deposit as security for the payment of bills and compliance with the Terms and Conditions as a prerequisite to the rendering or continuing of non-residential utility service by Emera

Maine in accordance with Section 7(B) - Chapter 815 of the MPUC's Rules and Regulations as in effect on the effective date hereof or amended from time to time hereafter.

4-C AMOUNT OF DEPOSIT.

Residential Accounts:

The amount of the deposit for residential utility service shall be determined in accordance with the provisions of Section 7(E) - Chapter 815 of the MPUC's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

Non-Residential Accounts:

The amount of the deposit for non-residential utility service shall be determined in accordance with the provisions of Section 7(D) - Chapter 815of the MPUC's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

4-D REFUND OF DEPOSIT.

Residential Accounts:

Refund of deposits for residential utility service shall be determined in accordance with Section 7(I) - Chapter 815 of the MPUC's Rules and Regulations as in effect on the effective date hereof and amended from time to time hereafter.

Non-Residential Accounts:

Refund of deposits for non-residential utility service shall be determined in accordance with Section 7(I) - Chapter 815 of the MPUC's Rules and Regulations as in effect on the effective date hereof and amended from time to time thereafter.

4-E INTEREST ON DEPOSITS. Emera Maine will pay interest on all customer deposits in accordance with Section 2 - Chapter 870 of the MPUC's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

4-F LATE PAYMENT CHARGE. All customers having bills not paid within twenty-five (25) days from the postmark date of the bill shall be subject to a late payment charge. The late payment charge shall be the maximum rate allowed in accordance with Section 1 - Chapter 870 of the MPUC's Rules and

Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

4-G DISCONNECTION OF SERVICE FOR CAUSE.

Residential Accounts:

The disconnect of residential customers for cause shall be governed by Chapter 815 of the MPUC's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

Non-Residential Accounts:

The disconnect of non-residential customers for cause shall be governed by Chapter 815 of the MPUC's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

4-H COLLECTION CHARGE. When an employee is sent to the Customer's premises for the purpose of disconnecting service and the Customer tenders payment in full of the bill to prevent disconnection, the employee shall either accept payment, give a receipt and leave the service intact, or else, without disconnecting, direct the Customer to go to the utility's nearest office within a reasonable time and tender payment there. The employee must know the full amount to be paid but shall not be required to make change or negotiate payment arrangements. When payment is made under these circumstances, Emera Maine will charge the Customer an amount not to exceed $10.00.

4-I CHARGE FOR RETURNED CHECKS. Customers whose checks have been returned to Emera Maine by financial institutions for non-payment shall be subject to a charge of $5.00 per check.

4-J SINGLE-METER, MULTI-UNIT DWELLINGS. In cases of disconnection of single-meter, multi-unit dwellings in which the Customer is the landlord, in addition to any other applicable fees, the landlord shall be required to pay a collection fee of $50.00. In addition, Emera Maine may require each dwelling unit to be individually metered at the landlord's expense before service will be restored.

ATTACHMENT A-EM

[Reserved]

ATTACHMENT B-EM

[Reserved]

ATTACHMENT C-EM

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

Following receipt of a Completed Application for Service, Emera Maine will assess its available transfer capability (ATC) to determine if sufficient capability exists to accommodate firm transmission service in accordance with Schedule 21 and Schedule 21-EM of the OATT.

ATC will be assessed considering Emera Maine's existing and projected native load requirements, existing firm transactions and all other requests for firm transmission service on a priority basis as per Schedule 21 and Schedule 21-EM of the OATT.

The Emera Maine assessment of ATC involves calculating, using Transmission Reliability Margins (TRM), the Incremental Transfer Capability and Total Transfer Capability (TTC) of the interface between Emera Maine and the ISO and specific path availabilities when they are requested by potential transmission customers.

The assessment of available transfer capability uses the basic North American Electric Reliability Council (NERC) transfer capability measures of First Contingency Incremental Transfer Capability (FCITC) and First Contingency Total Transfer Capability (FCTTC). Additionally, the assessment will comply with acceptable adjacent operating system standards and utilize the Northeast Power Coordinating Council (NPCC) criteria and guidelines. The assessment of available transmission will be performed using system models and load flow analysis. The following is a more detailed description of the process for determining ATC.

1. Roles of ISO New England and Emera Maine

As explained in Attachment C of the OATT, while the ISO is the Transmission Service Provider for Regional Network Service associated with Pool Transmission Facilities (PTF), there are additional Transmission Service Providers within the RTO footprint that calculate ATC associated with transmission services offered over the non-PTF external tielines and that calculate TTC and ATC associated with Local Transmission Service. The ISO is not responsible for the calculation of these values.

Pursuant to the terms of the Transmission Operating Agreement executed between Emera Maine as a Participating Transmission Owner (PTO) and ISO, Emera Maine is a Transmission Service Provider and calculates TTC and ATC for certain facilities over which Local Point-to-Point Service is provided under Schedule 21-EM. These are primarily radial paths that provide transmission service to directly interconnected generators.

1.1 Scope of Attachment C-EM

As the Transmission Service Provider of Schedule 21-EM Local Point-to Point Service pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT, Emera Maine performs the following functions within the scope of Attachment C-EM:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)

As explained further below in Section 2, TTC,ATC, and ETC are calculated only for certain non-PTF internal paths over which Local Point-to-Point Service is required under Schedule 21-EM pursuant to NERC Standards (MOD-001-1) regarding Available BHD Transmission System Capability and (MOD-029-1) regarding Rated System Path Methodology. TTC, ATC, and ETC are not calculated by Emera Maine for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and Emera Maine does not require advance reservation for such network service.

As defined by ISO and as applicable to all Transmission Service Providers under the RTO footprint, the following functions will be performed:

- Use of Capacity Benefit Margin (CBM) methodology
- Use of Transmission Reliability Margin (TRM) methodology
- Use of Rollover Rights (ROR) in the calculation of ETC

In addition, as explained further below in Sections 4 and 5, the NERC Standards (MOD 004-1) regarding Capacity Benefit Margin and (MOD 008-1) regarding Transmission Reliability Margin calculation methodology.

2. Transmission Service in the New England Markets

As explained in Attachment C of the OATT, the process by which generation located inside New England supplies energy to bulk electric system differs from the pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides supply offers to the New England energy market which are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, market participants may submit energy transactions to move energy into the ISO Area, out of the ISO Area or through the ISO Area. The New England Real-Time Energy Market clears these energy transactions based on forecast Locational Marginal Pricing (LMPs) and the availability of the external interfaces. With those external energy transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

This process for submitting energy transactions into the New England Real-Time energy market does not require an advance physical reservation for use of the PTF. In the event that the net of economic energy transactions is greater than the capability of an external interface, the energy transactions selected to flow are selected based on the New England Wholesale Market rules. For any energy transactions that are scheduled to flow in Real-Time based on the economics of the system, a transmission reservation is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, Emera Maine owns Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service is required. On those Local Facilities, the market participant must obtain a transmission service reservation from Emera Maine under Schedule 21-EM prior to delivery of energy into the New England Wholesale Market. Attachment C-EM addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. Schedule 21-EM Total Transfer Capability

The TTC on Emera Maine’s non-PTF Local Facilities that require Local Point-to-Point Service reservations are relatively static values. Consistent with the NERC definition, TTC is the amount of electric power that can be moved or transferred reliably between the BHD Transmission System and other interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. Emera Maine thus calculates the TTC for posted paths as the rating of the particular radial transmission path.

3.1 Posting TTCs

Emera Maine will calculate and post TTC on its OASIS site for all non-PTF posted paths that require Local Point-to-Point Service reservations. The posting of the TTCs is performed for those non-PTF facilities that serve as a path for Emera Maine's Transmission Customers. TTC is calculated as the rating of the limiting element that constitutes that path.

4. Capacity Benefit Margin

The use of CBM within the ISO Area is governed by the overall ISO approach to capacity planning requirements. Load Serving Entities (LSEs) operating within the ISO Area are required to arrange their Installed Capability requirements prior to the beginning of any given month in accordance with New England Wholesale Market rules. As such, Load Serving Entities do not utilize CBM to ensure their capacity needs are met, and CBM is, therefore, not relevant within the New England market design. As long as this market design is in place in New England, the CBM is set to zero.

Wherever applicable, the administration of Schedule 21-EM is consistent with the services provided under the ISO OATT by ISO. Emera Maine provides local transmission service over its non-PTF facilities that are connected only to the New England system and they do not interconnect with other systems. Therefore, Emera Maine does not reserve CBM for these paths, and the CBM is presently set to zero.

5. Transmission Reliability Margin

The TRM is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation. It is used only for external interfaces under the New England market design. As Emera Maine under Schedule 21 provides transmission service over its non-PTF facilities that are connected only to the internal New England system, Emera Maine does not reserve TRM for these paths, and the TRM is presently set to zero.

6. Calculation of ATC for Emera Maine's Local Facilities

6.1 ATC Calculation General Description

This section defines the ATC calculations performed by Emera Maine for its non-PTF internal interfaces. Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$. Additionally, consistent with NERC definition, ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for

ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$). As discussed above, the TRM and CBM for Emera Maine's non-PTF posted paths is zero. The purpose of the ETC (Existing Transmission Commitment) component of the ATC equation is for the Transmission Provider to ensure all existing transmission service commitments that reduce the ATC available to Firm and Non-Firm Local Point-to-Point Service Customers are accounted for. As described in Section 2, under Schedule 21-EM, Emera Maine requires the purchase of transmission service in advance of delivery of energy to the New England Wholesale Market over certain non-PTF paths, and those existing transmission commitments would be applied to the ATC equation for the specific posted path. As a practical matter, the ratings of the radial transmission paths are generally higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be generally available.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. In Real-Time, ETC effectively becomes equal to 0 (zero), as the ISO does not recognize nor utilize OASIS scheduled transmission reservations in its determination of generation dispatch pursuant to the Market Rules. Therefore, in Real-Time, the ATC is equal to TTC minus the amount of net energy transactions subject to ISO security constrained dispatch for each non-PTF interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC minus total Real-Time generation dispatch for each non-PTF interface. Because ISO Real-Time generation dispatch determines transmission usage in this time period for those non-PTF facilities that serve as a path for Schedule 21-EM Point-to-Point Transmission Customers, and existing transmission reservations are not determinate of transmission capacity usage in Real-Time, Emera Maine posts the ATC as 9999, consistent with industry practice. Actual ATC on these paths varies depending on the time of day. Thus, ATC is posted with an ATC of "9999" to reflect the fact that there are generally no restrictions on these paths for commercial transactions.

6.2 Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservation (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

6.3 Existing Transmission Commitments, Non-Firm (ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

7. Posting of ATC Related Information

7.1 Calculation of ATC Values

As described above, the Real-Time ATC values for Emera Maine's non-PTF internal assets that are utilized for Point-to-Point transmission service are almost always positive, and are thus set at 9999. The Real-Time ATC values for these internal posted paths are posted in accordance with NAESB standards on Emera Maine's OASIS website.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described in Section 6.1 where ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

To the extent a posted path is constrained, Emera Maine shall post the ATC in accordance with the general formula set forth in Section 6.1 of this Attachment C-EM.

Further, the mathematical algorithm and mathematical definition of Available Transmission Capability (ATC) for non-PTF for Emera Maine under Schedule 21-EM are posted on Emera Maine's website at www.emeramaine.com.

8. Non-PTF Transmission Path ATC Process Flow Diagram

TTC = Rating of the non-PTF Transmission Path

CBM = 0 TRM = 0

ATC Planning = Rating of the non PTF Path - Existing Transmission Reservations (Firm and non Firm Reservations) Because Existing Transmission Reservations (Firm and non Firm) are should be less than the rating of the non PTF path, ATC should always be positive ATC Operation = Rating of the non PTF Path - generation scheduled by ISO-NE and operating on the path

CBM = 0 TRM = 0

ATC Planning = Rating of the non PTF Path - Existing Transmission Reservation (Firm Reservations) Because Existing Transmission Reservations (Firm) should be less than the rating of the path, ATC should always be positive ATC Operation = ATC Planning

Note: Firm includes Conditional Firm

ATTACHMENT D-EM

METHODOLOGY FOR COMPLETING A SYSTEM IMPACT STUDY

Emera Maine will respond to an executed System Impact Study Agreement as per time outlined in Schedule 21 and Schedule 21-EM of the OATT. The System Impact Study shall identify any system constraints and redispatch options, additional required Direct Assignment facilities, or network upgrades to provide the requested service.

The transmission capability will be calculated in accordance with both the NERC definitions for "First Contingency Incremental Transfer Capability" and "First Contingency Total Transfer Capability."

First Contingency Incremental Transfer Capability (FCITC) - is the amount of electric power, incremental above normal base power transfers, that can be transferred over the interconnected BHD Transmission System in a reliable manner based on all of the following conditions:

1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits.

2. The electric systems are capable of absorbing the dynamic power swings and remaining stable following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit, and

3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

With reference to condition 1 above, in the case where pre-contingency facility loadings reach normal thermal ratings at a transfer level below that at which any first contingency transfer limits are reached, the transfer capability is defined as that transfer level at which such normal ratings are reached. Such a transfer capability is referred to as a normal incremental transfer capability (NTC).

First Contingency Total Transfer Capability (FCTTC) - is the total amount of electric power (net of normal base power transfers plus first contingency incremental transfers) that can be transferred between two areas of the interconnected transmission systems in a reliable manner based on conditions 1, 2, and 3 in the FCITC definition above.

The capability evaluation will utilize load flow analysis based on the Emera Maine's system load flow database. When Emera Maine feels no stability problems exist, it will generally use the Transmission 2000 Power Flow Program for software to conduct the study. This software may change in the future, without notice, but the replacement software will have the same minimum capabilities as its predecessor. If stability concerns exists, the studies may require a contractor to perform the studies. In conducting the studies, Emera Maine will adhere to good utility practice including the NPCC documents, relating to design and operation of interconnected power systems, and information submitted in the FERC Form No. 715.

The Emera Maine database will be modified to include the resources and the load information to be provided by the Customer as well as additional detail on the BHD Transmission System.

Emera Maine will perform the same types of studies related to transmission service requests as it performs transmission studies for its own use of the system. However, as a practical matter, it must be noted that planning studies must gauge the performance of the system based on a limited number of simulations. In actual daily operations of the system, the limits as determined in the transfer capability study may vary due to system conditions.

The transfer capability studies will analyze the impact of the proposed transmission request on the thermal capability, voltage profile, and stability of the BHD Transmission System. The transfer capability available will be the remaining capacity after accounting for Company import requirements to service its Native Load Customers reliably and prior contractual commitments, including any network transmission service or firm transmission service contract(s) previously filed and submitted as applications for Local Network or Firm Local Point-To-Point Service. In addition, Emera Maine will take into account Non-Firm Transmission Service when evaluating the transfer capability available for Non-Firm Transmission Service.

Emera Maine will notify the Eligible Customer immediately upon completion of the System Impact Study, if the BHD Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. A copy of the completed System Impact Study and related work papers will be made available to the Eligible Customer.

ATTACHMENT E-EM

INDEX OF EMERA MAINE POINT-TO-POINT TRANSMISSION SERVICE CUSTOMERS

[See Electric Quarterly Reports]

ATTACHMENT G-EM
EMERA MAINE LOCAL NETWORK OPERATING AGREEMENT

Example

THIS AGREEMENT, entered into this __________________________ day of _____________________,

__________ is between the Transmission Customer and Emera Maine, either or both of which area hereinafter referred as "Party" or "Parties".

WHEREAS, the Transmission Customer is directly interconnected with Emera Maine's electric system and the Parties desire to formalize that interconnection; and

WHEREAS, Emera Maine has certain duties and obligations to meet its own capacity and energy requirements and to support its own system safely and economically; and

WHEREAS, the Transmission Customer has certain duties and obligations to meet its own capacity and energy requirements and to support its own system safely and economically; and

WHEREAS, to the extent provided herein the Transmission Customer and Emera Maine are willing to operate their facilities in a manner that assists each Party in meeting its own system reliability, economics, and obligations;

NOW THEREFORE, in consideration of the mutual covenants and agreements hereinafter set forth, the Parties agree as follows:

I. ADDITIONAL DEFINITIONS NOT CONTAINED IN THE OATT OR SCHEDULE 21-EM OF THE OATT

The following terms shall have the following meanings under this Agreement, including the Attachments hereto:

A. "Transmission Customer's Interconnection Equipment" is all equipment and facilities (1) necessary for the interconnection of the Transmission Customer's system and Emera Maine's system, and (2) located on the Transmission Customer's side of the Point(s) of Delivery. This equipment may include, but is not limited to, connection, switching, and safety equipment.

B. "Emera Maine's Interconnection Equipment" is all equipment and facilities (1) necessary for the interconnection of Emera Maine's system and the Transmission Customer's system, and (2) located on Emera Maine's side of the Point(s) of Delivery. This equipment may include, but is not limited to, connection, switching, and safety equipment.

C. "System Emergency" is a condition on Emera Maine's system or on a system with which Emera Maine's system is interconnected which, in Emera Maine's sole judgment at the time of the occurrence, is likely to result in imminent disruption of service to a network service customer or is imminently likely to endanger life or property.

II. TERM

This Agreement shall become effective on the date specified or such other date as FERC may approve (the "Effective Date"). This Agreement terminates on the later of the date of termination of the Transmission Customer being a Transmission Customer of Emera Maine or of the date of termination of the Transmission Service Agreement between Emera Maine and the Customer.

III. CHARACTER OF SERVICE

A. All electric energy delivered to the Transmission Customer shall be in the form of three-phase alternating current at a frequency of approximately sixty (60) Hz.

B. Emera Maine agrees that it will only curtail or interrupt service to the interconnection as provided under this Agreement or in accordance with Schedule 21, Parts I.1.f, I.2.g., II.7, and Schedule 21-EM, sections 13.6 and 14.7, of the OATT.

C. Except as expressly provided in this Agreement, the interconnection may not be de-energized without the approval of FERC.

IV. INTERCONNECTION EQUIPMENT DESIGN AND CONSTRUCTION

A. Each Party, at its own expense, shall design, purchase, construct, install, and be responsible for maintaining all of its Interconnection Equipment that connects its Interconnection Equipment to the other Party's Interconnection Equipment.

B. Each Party's Interconnection Equipment and any changes to its Interconnection Equipment shall meet all standards of Good Utility Practices.

C. The construction, design, installation, and maintenance of each Party's Interconnection Equipment shall meet all standards of Good Utility Practice. Each Party shall allow the other Party reasonable access to the construction site during any construction for the purpose of inspecting the Interconnection Equipment.

D. Neither Party will bear any costs of the other Party's Interconnection Equipment required by this Agreement. The cost of Direct Assignment Facilities currently used by Emera Maine is set forth in Appendix A of this Agreement and will be paid for by the Transmission Customer.

Emera Maine may recover from the Transmission Customer costs in connection with Direct Assignment Facilities in accordance with the OATT. Prior to Emera Maine incurring any such expense, the Transmission Customer shall be responsible for forwarding to Emera Maine funds sufficient to cover the expense or may pay directly for changes to the interconnection. Emera Maine will provide the Transmission Customer with actual expenses associated with the funding of new Direct Assignment Facilities within sixty (60) days of completion of construction, and appropriate payment will be made within (30) days thereafter.

E. Each Party may inspect the other Party's Interconnection Equipment to determine if all standards of Good Prudent Utility Practice are met. Neither Party shall be required to deliver to or receive electricity from the other Party's Interconnection Equipment until those standards are met, subject to the provisions of Section III.C, Article VII and Section VIII.C of this Agreement.

F. The Transmission Customer shall not connect any generators after the execution of this Agreement without first informing Emera Maine in writing six months in advance of such connection. Any third party generating facilities connected after the date of the execution of this Agreement shall comply with the then-existing interconnection requirements for non-utility generation as it is used by Emera Maine and as it applies to generation connected directly to the Emera Maine system. The Transmission Customer shall be responsible to ensure compliance with these requirements as set forth in writing by Emera Maine.

G. The Transmission Customer agrees to provide to Emera Maine complete documentation, to the extent available, of the Transmission Customer's Interconnection Equipment, including, but not limited to, power one-line diagrams, relaying diagrams, plan, sectional and elevation views, grading plans, conduit plans, foundation plans, fence and grounding plans, and detailed steel erection diagrams. In addition, the Transmission Customer agrees to provide to Emera Maine complete documentation of any changes to the Transmission Customer's Interconnection Equipment. Emera Maine agrees to provide the Transmission Customer complete documentation for all Direct Assignment Facilities constructed by Emera Maine for the Transmission Customer or provided by Emera Maine to the Transmission Customer.

H. Based on the representations of the Parties to one another, the Parties agree that as of the Effective Date of this Agreement, all of Emera Maine's Interconnection Equipment and the Transmission Customer's Interconnection Equipment satisfy the requirements of this Agreement.

V. METERING

A. Emera Maine shall own, install, and maintain all metering devices and equipment required to measure the energy and capacity delivered to the Transmission Customer at the point of interconnection with the BHD Transmission System.

B. Emera Maine will measure the energy and capacity delivered on an hourly basis using 15-minute interval integrating meters with recorded readings. The readings will be remotely recorded by Emera Maine and will be made available to the Transmission Customer or a third party designated by the Transmission Customer. These readings will include the integrated kWh load for the Transmission Customer for 2, 15, and 60 minute intervals, the integrated load for the Transmission Customer for the previous 24-hour period, and the kVAR/hour.

C. Emera Maine shall provide pulses from its metering (kWh, kVAR) for use in the Transmission Customer-owned and maintained electronic recorder(s). Emera Maine shall permit the Transmission Customer to install a telecommunications link with the Transmission Customer-owned recorder(s).

D. Emera Maine shall provide pulses (kWh) to the Transmission Customer-owned and maintained load management systems (totalizer and transponder), and agrees (1) that the Transmission Customer may own and maintain a V2h meter and (2) to pulse readings from that meter to the Transmission Customer-owned recorder(s).

E. All metering equipment used to measure energy and capacity shall be sealed, and the seals shall be broken only by Emera Maine and only upon occasions when the meters are to be inspected, tested or adjusted.

F. Emera Maine shall provide access, including telecommunications access, to the Emera Maine meters for a representative of the Transmission Customer at reasonable times for the purposes of reading and inspecting, provided that the Transmission Customer's access shall not interfere with Emera Maine's normal business operations.

G. Unless otherwise mutually agreed, the meters shall not be tested or recalibrated, and none of the connections, including those of the transformers, shall be disturbed or changed, except in the presence of duly authorized representatives of each of the Parties or unless either Party, after reasonable notice, fails or refuses to have its representative present.

H. Emera Maine shall make annual tests of the metering devices and equipment for measuring all energy and capacity. The cost of this annual test shall be shared equally between Emera Maine and the Transmission Customer. The transmission Customer will reimburse Emera Maine for all expenses and cost incurred under this Section within thirty (30) days after Emera Maine provides the Transmission Customer with an invoice for such cost and expenses. Upon request in writing within 90 days and at the expense of the Transmission Customer, Emera Maine will make additional tests; provided, however, if the Transmission Customer requests an additional test and errors greater than 2% are discovered, Emera Maine shall pay the expense of the additional test. If a meter fails to register or if the measurement made by a meter is found to be inaccurate, then a retroactive billing adjustment shall be made by Emera Maine in accordance with Article X of this Agreement correcting all previous bills from Emera Maine to the Transmission Customer that were based upon measurements made by the meter during the actual period in which the meter failed to register or was inaccurate. A payment for the adjusted billing shall be made by the Transmission Customer in accordance with Articles X and XI of this Agreement.

I. Emera Maine shall notify the Transmission Customer prior to all metering tests and the Transmission Customer shall have the right to observe the tests. If a meter is found to be inaccurate or defective, it shall be adjusted, repaired, or replaced at the Transmission Customer's expense in order to provide accurate metering. Emera Maine shall provide to the Transmission Customer a written report of results of all meter tests.

VI. MONITORING

A. Emera Maine shall own, install, and maintain all automatic control and monitoring devices and equipment on its system up to the POD with the Transmission Customer required under this Agreement. This equipment shall: (i) be compatible with the Emera Maine System Operators SCADA control system; (ii) permit direct control of the interconnecting circuit breaker and motor-operated switch by Emera Maine system operators; (iii) provide for the transmission of all data that Emera Maine deems necessary to permit the Emera Maine system operator to monitor the overall operation of the interconnection equipment; (iv) provide for necessary data to permit Emera Maine to monitor Unscheduled Energy; and (v) provide such other capabilities as Emera Maine deems necessary, including, but not limited to, the ability to open the interconnection between the Transmission Customer and Emera Maine under the conditions specified in Articles VII and VIII of this Agreement.

B. The Transmission Customer shall provide to Emera Maine on a daily basis, at the Transmission Customer's expense, the following: (1) the instantaneous kW and kVARh load for the Transmission Customers; (2) the integrated kWh load for the Transmission Customer for 2, 15, and 60 minute intervals; (3) the integrated load for the Transmission Customer for the previous 24-hour period; and (4) any other information, as may be reasonably requested by Emera Maine. Emera Maine agrees that the Transmission Customer has provided sufficient devices and equipment for these purposes.

VII. PROTECTION AND CONTROL OF INTERCONNECTION EQUIPMENT

The Transmission Customer, at its expense, shall design, purchase, construct, install, and be responsible for the expense of maintaining all of the Interconnection Equipment that isolates the Transmission Customer's equipment from Emera Maine's system. All such Interconnection Equipment shall be of sufficient size to accommodate the delivery of energy and capacity under the Service Agreement between Emera Maine and the Transmission Customer and shall be of utility grade, acceptable to Emera Maine.

The required protective relay system shall be capable of detecting faults to allow for disconnection of the Transmission Customer's load at the POD to facilitate restoration of service, maintain system stability, mitigate any fault damage, and protect the general public, the Transmission Customer and Emera Maine personnel. This protective relay system must be approved by Emera Maine, which approval shall not be unreasonably withheld. Emera Maine shall provide relay settings and have the right to review and make recommendations with respect to the design, equipment selection, operation, and routine maintenance and testing of the protective relay system. The Transmission Customer shall purchase and install the protective relay system at its own expense. The Transmission Customer shall maintain the protective relay system in accordance with Section IX.B.

The protective relay system shall include, without limitation, the following:

A. Linkable main disconnect switch with arc restrictions that permits isolation of the load from the BHD Transmission System;

B. An automatic circuit breaker that is (1) capable of tripping the Transmission Customer both automatically and by remote control from Emera Maine and (2) capable of synchronizing the Transmission Customer load to the BHD Transmission System;

C. Underfrequency protective relays used in conjunction with the automatic circuit breaker in Section VII.B above;

D. Potential and current transformers;

E. Phase fault protection and ground fault protection.

Should Emera Maine consistent with Good Utility Practices, determine that the Transmission Customer is not providing proper operation of the protective relay system, Emera Maine shall so notify the Transmission Customer in writing, providing specific engineering detail of the acceptable testing operation and maintenance procedures and shall provide the Transmission Customer with a period of time that is reasonable under the circumstances to accomplish the specified corrective actions, but in no event less than five (5) days. If the Transmission Customer fails to accomplish the required corrective actions within the time specified in the notice, Emera Maine may, after giving such actual further notice (including no further notice) to the Transmission Customer as Emera Maine shall, in its sole discretion, determine to be reasonable under the terms of the OATT (including Schedule 21-EM) open the Interconnection between the Transmission Customer and Emera Maine until the required corrective action is accomplished. Emera Maine shall take the action contemplated in the previous sentence only if the Transmission Customer's failure to take the corrective action could, in Emera Maine's reasonable judgment, result in a System Emergency or is otherwise required by Good Utility Practices. Emera Maine shall not be responsible for any loss, damage, expense, or liability whatsoever experienced by the Transmission Customer resulting from the opening of the interconnection as permitted under this paragraph. The Transmission Customer moreover agrees to indemnify and hold harmless Emera Maine, its officers, agents, employees, and directors from and against all loss, damage, expense, and liability of any type whatsoever for any claim or other liability resulting from such opening of the interconnection.

VIII. INTERCONNECTION OPERATION

A. Emera Maine will operate and maintain its nominal transmission voltage within a range of +/- 5% at the point of interconnection between Emera Maine and the Transmission Customer. The Transmission Customer, at its expense, shall maintain appropriate voltage on its system in accordance with Good Utility Practice

B. The Transmission Customer shall have a reactive operating range (power factor) that is continuous throughout the 95% lead to 95% lag range; provided, however, that under normal operating conditions the Transmission Customer shall not deliver excess reactive power to the Emera Maine system unless otherwise agreed to by Emera Maine.

C. During a System Emergency, the Transmission Customer at Emera Maine's request, shall operate its system in a manner to mitigate the System Emergency. That operation may call for full or partial interruption of power, but in an amount and duration only as reasonably required by the System Emergency.

D. The Transmission Customer shall, in the event of an unscheduled outage or limitation of transmission facilities, report that outage or limitation immediately to Emera Maine's dispatcher. Further, the Transmission Customer shall notify Emera Maine when the outage or limitation has been remedied.

E. In the event the Transmission Customer load requires Emera Maine to serve the load, curtailment of delivery to the Transmission Customer will be in accordance with the Backup Service Agreement between Emera Maine and the Transmission Customer in effect at the time. The Backup Service Agreement is attached as Appendix B to the Agreement.

IX. MAINTENANCE AND MODIFICATION TO THE INTERCONNECTION

A. Each Party shall maintain and replace at its expense during the term hereof all its Interconnection Equipment, in accordance with established practices and standards for the operation and maintenance of power system equipment.

B. The Transmission Customer shall arrange with Emera Maine for an annual, visual inspection of all Interconnection Equipment and associated maintenance records. Every two years, the Transmission Customer shall arrange a relay calibration test and operation test of the Transmission Customer's Interconnection Equipment. These tests must be performed by a qualified contractor, approved by Emera Maine and acceptable to the Transmission Customer, or by Emera Maine itself. After the relay calibration tests are completed, Emera Maine may perform a relay system functional test. The Transmission Customer shall bear the cost of any relay testing and other assistance that may be requested of Emera Maine before and after the system is made operational. The Transmission Customer shall reimburse Emera Maine for all its costs and expenses, including administrative expenses, incurred under this Section within thirty (30) days after Emera Maine provides the Transmission Customer with an invoice for such costs and expenses.

C. At the Transmission Customer's request during the Term of this Agreement, Emera Maine shall move any of its lines or other equipment used exclusively for the purpose of furnishing and delivering to the Transmission Customer electric energy, if: (i) the Transmission Customer furnishes without charge or expense to Emera Maine a new, suitable, and sufficient right(s)-of-way to enable Emera Maine to deliver electric energy, and (ii) the Transmission Customer reimburses Emera Maine in advance on a progress payment basis for all costs incurred by Emera Maine in connection with the moving of said lines or equipment. The Transmission Customer is responsible for securing for Emera Maine such new location and new right(s)-of-way.

D. Emera Maine retains the right, after prior consultation with the Transmission Customer, to increase the transmission voltage level to accommodate system requirements. In the event of an interconnection voltage upgrade, the Transmission Customer shall be responsible, at its own expense, for making all equipment alterations to receive energy at the new transmission voltage. Emera Maine shall provide the Transmission Customer with two (2) years written notice of the planned upgrade and shall coordinate its construction schedule with the Transmission Customer.

E. In the event of a failure of the Transmission Customer facilities, Emera Maine shall, at the Transmission Customer's expense, make best efforts, consistent with its own practices, to transfer service to the backup facilities owned by the Transmission Customer. Such transfer may include, but would not be limited to, removal and installation of substation buswork and field relocation of protective relay sensing circuits.

X. BILLING AND PAYMENTS

Billing and Payments shall be in accordance with Section 4 of the Schedule 21-EM of the OATT.

XI. AUDITS OF ACCOUNTS AND RECORDS

Within three (3) years following any calendar year, during which service was rendered hereunder, Emera Maine and the Transmission Customer shall have the right to audit each other's applicable accounts and records during normal business hours at the offices where such accounts and records are maintained; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service under the OATT for said calendar year. The costs of the audit shall be borne by the party requesting the audit.

XII. SCHEDULING

A. Local Point-to-Point Service

Schedules for Local Point-to-Point Service must be submitted pursuant to Part I.1.h and Part I.2.f of Schedule 21 of the OATT.

B. Local Network Service

Schedules for the Transmission Customer Local Network Service must be submitted to Emera Maine no later than 10:00 a.m. of the day prior to commencement of such service. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour. The Transmission Customer will arrange for monthly schedules of hourly transfer from the network resources to Emera Maine and any Transmission Provider involved in scheduling of control area interchanges. The Transmission Customer schedule change will be permitted on an instantaneous basis if Emera Maine and the Transmission Customer and all intervening control areas agree and agreements are in place to provide for scheduling modifications. Emera Maine will furnish to dispatchers of the Delivering Party hour-to-hour schedules equal to those furnished by the Receiving Party and shall deliver capacity and energy at the POD's in an amount provided by the schedules. Should the Transmission Customer, Delivering Party, or Receiving Party revise or terminate any schedule, such party shall notify Emera Maine.

XIII. ACCESS

A. Emera Maine will grant, with a reasonable notification and without cost to the Transmission Customer for the Term of this Agreement, any access that may be necessary for reasonable ingress and egress over property owned by Emera Maine in order to operate, inspect, maintain, replace, and remove control facilities, meters, recorders, load management system (totalizer and transponder), telecommunications link, and any other Transmission Customer-owned Interconnection Equipment, provided that such access shall not disrupt or otherwise interfere with the normal operations of Emera Maine.

B. The Transmission Customer will grant, with a reasonable notification and without cost to Emera Maine for the Term of this Agreement, any access that may be necessary for reasonable ingress and egress over property owned by the Transmission Customer in order to operate, inspect, maintain, replace, and remove Emera Maine-owned Interconnection Equipment, provided that such access shall not disrupt or otherwise interfere with the normal operations of the Transmission Customer.

IN WITNESS WHEREOF the Parties hereto have caused this instrument to be executed in their corporate names by their duly authorized representatives.

WITNESSES:	EMERA MAINE
	______________________________
	By: ______________________________

Its: ______________________________

Dated: ______________________________

TRANSMISSION CUSTOMER

____

By: ______________________________

Its: ______________________________

Dated: ______________________________

APPENDIX A-EM

CUSTOMER DIRECT ASSIGNMENT FACILITIES

ATTACHMENT H-EM

[Reserved]

ATTACHMENT I-EM

INDEX OF NETWORK CUSTOMERS

[See Electric Quarterly Reports]

ATTACHMENT J-EM

[Reserved]

ATTACHMENT K-EM

[Reserved]

ATTACHMENT L-EM

UMBRELLA SERVICE AGREEMENT FOR
RETAIL FIRM LOCAL POINT-TO-POINT SERVICE

1.0 This Service Agreement, dated as of _______, including the specifications for Retail Firm Local Point-To-Point Service attached hereto and incorporated herein, is entered into, by and between Emera Maine and ______________, ("Transmission Customer") (hereinafter referred to individually as "Party" or collectively as "Parties").

2.0 The Transmission Customer has been determined by Emera Maine to have a completed application for Firm Point-To-Point Service under Schedule 21 and Schedule 21-EM of the OATT and to have satisfied the conditions for service imposed by Schedule 21 and Schedule 21-EM of the OATT to the extent necessary to obtain service with respect to its participation in the State of Maine's retail access program.

3.0 Service under this agreement shall commence on the later of: (1) __________, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as permitted by the Commission. Service under this Service Agreement shall terminate on _________, unless earlier terminated for default. Upon termination the Transmission Customer will remain responsible for any outstanding charges incurred under Schedule 21 and Schedule 21-EM of the OATT and this Service Agreement, including any costs incurred and apportioned or assigned to the Transmission Customer by FERC, including any costs associated with Direct Assignment Facilities and/or Network Upgrades.

4.0 The Transmission Customer agrees to supply information Emera Maine deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Customer has provided Emera Maine with assurance of creditworthiness in accordance with the provisions of Section 11 of Schedule 21-EM of the OATT. The Transmission Customer has provided an application deposit in the amount of $_________ in accordance with the provisions of Schedule 21-EM of the OATT.

6.0 If the Transmission Customer is a Designated Agent delivering power to retail customers, the Transmission Customer represents and warrants that it is duly authorized to sign this agreement on behalf of its retail customers and shall provide reasonable documentation upon request demonstrating such authorization.

7.0 Emera Maine agrees to provide and the Transmission Customer agrees to take and pay for Retail Firm Local Point-To-Point Service in accordance with the provisions of Schedule 21 and Schedule 21-EM of the OATT, and this Service Agreement. Retail Transmission Customers taking service directly or through a Designated Agent pursuant to this Service Agreement and under Schedule 21 and Schedule 21-EM of the OATT shall continue to pay Maine Public Utilities Commission ordered stranded costs and other distribution-related cost, as applicable. If the Transmission Customer is a Designated Agent delivering power to retail customers and taking transmission service on their behalf, the Transmission Customer agrees that Emera Maine shall collect receipts for applicable transmission and ancillary charges (except for Energy Imbalance Service) directly from retail customers served by Emera Maine unless other mutually agreeable provisions for payment are made. Emera Maine shall bill directly the Designated Agent, if it is not Emera Maine, for Energy Imbalance Service.

8.0 Monthly bills will be sent to the Transmission Customer at the following address:

____

____

____

9.0 Payment to Emera Maine by the Transmission Customer must be made by electronic wire transfer or such other means as will cause payment to be available for Emera Maine's use on the date payment is due. Unless other arrangements are made with Emera Maine, the Transmission Customer shall transfer all payments by wire to the following:

Bank: _______________________

ABA No.: ____________________

Account Name: _______________

Account No.: _________________

10.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Emera Maine:

____

____

____

Transmission Customer:

____

____

____

11.0 The OATT (including Schedule 21 and Schedule 21-EM) are incorporated herein and made a part hereof.

12.0 Nothing contained in this Service Agreement shall be construed as affecting in any way Emera Maine's right unilaterally to file with FERC, or to make application to FERC, or other regulatory bodies having jurisdiction for changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act, and pursuant to FERC's rules and regulations promulgated thereunder, or under applicable statutes or regulations or the Transmission Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

13.0 This Service Agreement may be executed in any number of counterparts with the same effect as if all parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

14.0 The OASIS Standards and Protocols document states that if a Transmission Provider approves a request for service, the Transmission Customer must confirm. Once the Transmission Customer confirms an approved purchase, a reservation is considered to exist. In order for a request to remain valid, the Transmission Customer must confirm within the following time periods or the request is deemed withdrawn:

Transmission Provider approves request within ______________	Transmission Customer must confirm within __________ or request

before start of service	is deemed withdrawn
24 hours or less	1 hour
25-48 hours	24 hours before transaction begins
2-6 days	24 hours
7-30 days	72 hours
31-90 days	1 week
90 days or more	15 days

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Emera Maine:

By:______________________ ________________ ________________

Name Title Date

Transmission Customer:

By:______________________ ________________ ________________

Name Title Date

Specifications For Retail Firm Local Point-To-Point Service

1.0 Term of Service: ____

Start Date: ____

Termination Date: ____

2.0 Description of capacity and energy to be transmitted by Emera Maine including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt: ____

Delivery Party: ____

4.0 Point(s) of Delivery: ____

Receiving Party: ____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved

Capacity): ____

6.0 Designation of Party subject to reciprocal service obligation: ______________________

7.0 Name(s) of any intervening systems providing transmission service:

____

____

8.0 Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of Schedule 21 and Schedule 21-EM of the OATT)

8.1 Transmission Charge:

____

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:

____

____

8.4 Ancillary Services Charges:

Schedule 1 (Scheduling): ____

Schedule 2 (Reactive Supply): ____

Schedule 3 (Regulation): ____

Schedule 4 (Energy Imbalance): ____

Schedule 5 (Spinning Reserve): ____

Schedule 6 (Supplemental Reserve): _______________________________________

8.5 Losses: ____

8.6 Taxes: ____

8.7 Local Distribution Costs: ____

9.0 Description of Method of Supplying of Losses: ___________________________________

____

10.0 Source of supply of each Ancillary Service not provided by Emera Maine:

ATTACHMENT M-EM

UMBRELLA SERVICE AGREEMENT FOR
RETAIL NON-FIRM LOCAL POINT-TO-POINT SERVICE

1.0 This Service Agreement, dated as of _______, including the specifications for Retail Non-Firm Local Point-To-Point Service attached hereto and incorporated herein, is entered into, by and between Emera Maine and ______________, ("Transmission Customer") (hereinafter referred to individually as "Party" or collectively as "Parties").

2.0 The Transmission Customer has been determined by Emera Maine to have a completed application for Non-Firm Local Point-To-Point Service under Schedule 21 and Schedule 21-EM of the OATT and to have satisfied the conditions for service imposed by Schedule 21 and Schedule 21-EM of the OATT to the extent necessary to obtain service with respect to its participation in the State of Maine's retail access program.

3.0 Service under this agreement shall commence on the later of: (1) __________, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as permitted by the Commission. Service under this Service Agreement shall terminate on _________, unless earlier terminated for default. Upon termination the Transmission Customer will remain responsible for any outstanding charges incurred under Schedule 21 and Schedule 21-EM of the OATT and this Service Agreement, including any costs incurred and apportioned or assigned to the Transmission Customer by FERC, including any costs associated with Direct Assignment Facilities and/or Network Upgrades.

4.0 The Transmission Customer agrees to supply information Emera Maine deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Customer has provided Emera Maine with assurance of creditworthiness in accordance with the provisions of Section 11 of Schedule 21-EM of the OATT.

6.0 If the Transmission Customer is a Designated Agent delivering power to retail customers, the Transmission Customer represents and warrants that it is duly authorized to sign this agreement on behalf of its retail customers and shall provide reasonable documentation upon request demonstrating such authorization.

7.0 Emera Maine agrees to provide and the Transmission Customer agrees to take and pay for Retail Non-Firm Local Point-To-Point Service in accordance with the provisions of Schedule 21 and Schedule 21-EM of the OATT and this Service Agreement. Retail Transmission Customers taking service directly or through a Designated Agent pursuant to this Service Agreement and under Schedule 21 and Schedule 21-EM of the OATT shall continue to pay Maine Public Utilities Commission ordered stranded costs and other distribution-related costs, as applicable. If the Transmission Customer is a Designated Agent delivering power to retail customers and taking transmission service on their behalf, the Transmission Customer agrees that Emera Maine shall collect receipts for applicable transmission and ancillary charges (except for Energy Imbalance Service) directly from retail customers served by Emera Maine, unless other mutually agreeable provisions for payment are made. Emera Maine shall bill directly the Designated Agent, if it is not Emera Maine, for Energy Imbalance Service.

8.0 Monthly bills will be sent to the Transmission Customer at the following address:

____

____

____

9.0 Payment to Emera Maine by the Transmission Customer must be made by electronic wire transfer or such other means as will cause payment to be available for Emera Maine's use on the date payment is due. Unless other arrangements are made with Emera Maine, the Transmission Customer shall transfer all payments by wire to the following:

Bank: _______________________

ABA No.: ____________________

Account Name: _______________

Account No.: _________________

10.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Emera Maine:

____

____

____

Transmission Customer:

____

____

____

11.0 The OATT (including Schedule 21 and Schedule 21-EM) are incorporated herein and made a part hereof.

12.0 Nothing contained in this Service Agreement shall be construed as affecting in any way the Emera Maine's right unilaterally to file with FERC, or to make application to FERC, or other regulatory bodies having jurisdiction for changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act, and pursuant to FERC's rules and regulations promulgated thereunder, or under applicable statutes or regulations, or the Transmission Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

13.0 This Service Agreement may be executed in any number of counterparts with the same effect as if all parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

EMERA MAINE:

By:______________________ ________________ ________________

Name Title Date

Transmission Customer:

By:______________________ ________________ ________________

Name Title Date

Specifications For Retail Non-Firm Local Point-To-Point Service

1.0 Term of Service: ____

Start Date: ____

Termination Date: ____

2.0 Description of capacity and energy to be transmitted by Emera Maine including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt: ____

Delivery Party: ____

4.0 Point(s) of Delivery: ____

Receiving Party: ____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

____

6.0 Designation of Party subject to reciprocal service obligation: ______________________

7.0 Name(s) of any intervening systems providing transmission service:

____

____

8.0 Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of Schedule 21 and Schedule 21-EM of the OATT.)

8.1 Transmission Charge:

____

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:

____

____

8.4 Ancillary Services Charges:

Schedule 1 (Scheduling): ____

Schedule 2 (Reactive Supply): _______________________________________

Schedule 3 (Regulation): ____

Schedule 4 (Energy Imbalance): _____________________________________

Schedule 5 (Spinning Reserve): ______________________________________

Schedule 6 (Supplemental Reserve): __________________________________

8.5 Losses: ____

8.6 Taxes: ____

8.7 Local Distribution Costs: ____

9.0 Description of Method of Supplying of Losses: ________________________________

____

10.0 Source of supply of each Ancillary Service not provided by Emera Maine:

____

ATTACHMENT N-EM

UMBRELLA SERVICE AGREEMENT FOR RETAIL LOCAL NETWORK SERVICE

1.0 This Service Agreement, dated as of ___________, including the specifications for Retail Local Network Service attached hereto and incorporated herein, is entered into, by and between Emera Maine, and ______________, ("Network Customer") (hereinafter referred to individually as "Party" or collectively as "Parties").

2.0 A retail customer of Emera Maine that does not elect to (i) take transmission service directly from Emera Maine, or (ii) take transmission service from Emera Maine through a Designated Agent other than Emera Maine, shall be deemed to take Retail Local Network Service from Emera Maine as its Designated Agent. Such retail customer is not required to sign a Service Agreement, but shall take Retail Local Network Service from the Emera Maine as its Designated Agent under this Service Agreement. A retail customer that takes at least 500 KW of transmission service in any one hour in the calendar year from Emera Maine and takes Retail Local Network Service from Emera Maine as its Designated Agent is not required to sign a Service Agreement for Retail Local Network Service, unless Emera Maine must construct either Direct Assignment Facilities or Network Upgrades in order to provide Transmission Service to the retail customer.

3.0 If an application is required under Schedule 21 and Schedule 21-EM of the OATT, the Network Customer has been determined by Emera Maine to have a completed application for Local Network Service under Schedule 21 and Schedule 21-EM of the OATT and to have satisfied the conditions for service imposed by Schedule 21 and Schedule 21-EM of the OATT to the extent necessary to obtain service with respect to its participation in the State of Maine's retail access program.

4.0 Service under this agreement shall commence on the later of: (1) __________, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as permitted by the Commission. The Service Agreement shall be effective for an initial term of one year for a retail customer taking Retail Local Network Service directly from Emera Maine or through a Designated Agent other than Emera Maine or for any Network Customer required to execute a Service Agreement or provide notice that an unexecuted Service Agreement should be filed. Thereafter, it will continue from year to year unless terminated by the Network Customer or Emera Maine by giving the other one-year advance written notice or by mutual agreement of the Parties, unless earlier terminated for default. The Service Agreement shall be effective for an initial term of one of Emera Maine's typical monthly billing cycles for retail customers taking Retail Local Network Service from Emera Maine as their Designated Agent that are not required to execute a Service Agreement or provide notice that an unexecuted Service Agreement should be filed. Thereafter, it will continue from typical monthly billing cycle to typical monthly billing cycle unless terminated by the Network Customer or Emera Maine by giving the other one month advance written notice or by a mutual agreement of the Parties, unless earlier terminated. Upon termination the Network Customer shall remain responsible for any outstanding charges incurred under Schedule 21 and Schedule 21-EM of the OATT and this Service Agreement, including any costs incurred and apportioned or assigned to the Network Customer by FERC, including any costs associated with Direct Assignment Facilities and/or Network Upgrades.

5.0 The Network Customer agrees to supply information Emera Maine deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

6.0 The Network Customer has provided Emera Maine with assurance of creditworthiness in accordance with the provisions of Section 7 of Schedule 21-EM of the OATT.

7.0 If the Network Customer is a Designated Agent delivering power to retail customers, the Network Customer represents and warrants that it is duly authorized to sign this agreement on behalf of its retail customers and shall provide reasonable documentation upon request demonstrating such authorization.

8.0 Emera Maine agrees to provide and the Network Customer agrees to take and pay for Retail Local Network Service in accordance with the provisions of Schedule 21 and Schedule 21-EM of the OATT and this Service Agreement. Retail customers taking service directly or through a Designated Agent pursuant to this Service Agreement and under Schedule 21 and Schedule 21-EM of the OATT shall continue to pay Maine Public Utilities Commission ordered stranded costs and other distribution-related costs, as applicable. If the Network Customer is a Designated Agent delivering power to retail customers and taking transmission service on their behalf, the Network Customer agrees that Emera Maine shall collect receipts for applicable transmission and ancillary charges (except for Energy Imbalance Service) directly from retail customers served by Emera Maine unless other mutually agreeable provisions for payment are made. Emera Maine shall bill directly the Designated Agent, if it is not Emera Maine, for Energy Imbalance Service.

9.0 Monthly bills will be sent to the Network Customer at the following address:

____

____

____

10.0 Payment to Emera Maine by the Network Customer must be made by electronic wire transfer or such other means as will cause payment to be available for Emera Maine's use on the date payment is due. Unless other arrangements are made with Emera Maine, the Network Customer shall transfer all payments by wire to the following:

Bank: _______________________

ABA No.: ____________________

Account Name: _______________

Account No.: _________________

11.0 Any notice or request made to or by either Party regarding this Service Agreement shall

be made to the representative of the other Party as indicated below.

Emera Maine:

____

____

____

Network Customer:

____

____

____

12.0 The OATT (including Schedule 21 and Schedule 21-EM) are incorporated herein and made a part hereof.

13.0 Nothing contained in this Service Agreement or any associated Operating Agreement shall be construed as affecting in any way Emera Maine's right unilaterally to file with FERC, to make application to FERC, or other regulatory bodies having jurisdiction for changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act, and pursuant to FERC's rules and regulations promulgated thereunder, or under applicable statutes or regulations; or the Network Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

14.0 This Service Agreement may be executed in any number of counterparts with the same effect as if all parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

EMERA MAINE:

By:______________________ ________________ ________________

Name Title Date

Network Customer:

By:______________________ ________________ ________________

Name Title Date

Specifications For Retail Local Network Service

1.0 Term of Service: ____

Start Date: ____

Termination Date: ____

2.0 Description of capacity and energy to be transmitted by Emera Maine including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt: ____

Delivery Party: ____

4.0 Point(s) of Delivery: ____

Receiving Party: ____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved

Capacity): ____

6.0 Designation of Party subject to reciprocal service obligation: ______________________

7.0 Name(s) of any intervening systems providing transmission service:

____

____

8.0 Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of Schedule 21 and Schedule 21-EM of the OATT.)

8.1 Transmission Charge:

____

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:

____

____

8.4 Ancillary Services Charges:

Schedule 1 (Scheduling): ____

Schedule 2 (Reactive Supply): ______________________________________

Schedule 3 (Regulation): ____

Schedule 4 (Energy Imbalance): ____________________________________

Schedule 5 (Spinning Reserve): _____________________________________

Schedule 6 (Supplemental Reserve): __________________________________

8.5 Losses: ____

8.6 Taxes: ____

8.7 Local Distribution Costs: ____

9.0 Description of Method of Supplying of Losses: ______________________________

____

10.0 Source of supply of each Ancillary Service not provided by Emera Maine:

____

ATTACHMENT O-EM

UMBRELLA NETWORK OPERATING AGREEMENT
FOR RETAIL LOCAL NETWORK SERVICE

1.0 This Network Operating Agreement, dated as of ________, is entered into, by and between Emera Maine and _________________ ("Network Customer") (hereinafter referred to individually as "Party" or collectively as "Parties").

2.0 The Network Customer has been determined by Emera Maine to have a completed application for Local Network Service under Schedule 21 and Schedule 21-EM of the OATT and to have satisfied the conditions for service imposed by Schedule 21 and Schedule 21-EM of the OATT to the extent necessary to obtain service with respect to its participation in the State of Maine's retail access program.

3.0 The Parties have entered into a Service Agreement for Retail Local Network Service under Schedule 21-EM of the OATT.

4.0 All terms used in this Operating Agreement shall have the meaning defined in Schedule 21 and Schedule 21-EM of the OATT unless a different definition is specifically provided for herein.

5.0 Emera Maine and the Network Customer agree that the provisions of this Operating Agreement, the Service Agreement for Retail Local Network Service, and Schedule 11-EM of Schedule 21-EM of the OATT govern Emera Maine's provision of Retail Local Network Service to the Network Customer in accordance with Schedule 21 and Schedule 21-EM of the OATT, as it may be amended from time to time.

6.0 Power and energy transmitted by Emera Maine for the Network Customer shall be delivered as three-phase alternating current at a frequency of approximately 60 Hertz, and at the nominal voltages at the delivery and receipt points. When multiple delivery points are provided to a specific Network Load, they shall not be operated in parallel by the Network Customer without the approval of Emera Maine. Emera Maine and the Network Customer shall also establish and monitor standards and operating rules and procedures to assure that BHD Transmission System integrity and the safety of customer, the public, and employees are maintained or enhanced when such parallel operation is permitted either on a continuing basis or for intermittent switching or other service needs. Each Party shall exercise due diligence and reasonable care in maintaining and operating its facilities so as to maintain continuity of service.

7.0 Emera Maine reserves the right to inspect the facilities and operating records of a Network

Customer upon mutually agreeable terms and conditions.

8.0 The Network Customer shall be required at all times to maintain, consistent with North American Electric Reliability Council ("NERC") and Northeast Power Coordinating Council ("NPCC") guidelines, a balance between its owned or purchased generation resources and load. The provision of Transmission Service under Schedule 21 and Schedule 21-EM of the OATT is not an offer to provide generation sufficient to meet the Network Customer's load requirements. The Network Customer must meet its load reliability either through the construction and ownership of generation facilities and/or the purchase of power from a third party and the purchase of such Ancillary Services from Emera Maine or a third party.

9.0 The Network Customer shall purchase in appropriate amounts all of the required Ancillary Services described in Schedule 21 and Schedule 21-EM of the OATT from Emera Maine or, where applicable, self-supply or obtain these services from other providers. Where the Network Customer elects to self-supply or have others provide Ancillary Services, the Network Customer must demonstrate that it has either acquired the Ancillary Services from another source or is capable of self-supplying the services. The Network Customer must designate the supplier of Ancillary Services.

10.0 Emera Maine reserves the right to take whatever actions it deems necessary to preserve the reliability and integrity of its electric system, limit or prevent damage, expedite restriction of service, ensure safe and reliable operation, avoid adverse effects on the quality of service, or preserve public safety. If the Transmission Service is causing harmful physical effects to the BHD Transmission System facilities or to its customers (e.g., harmonics, undervoltage, overvoltage, flicker, voltage variations, etc.), Emera Maine shall promptly notify the Network Customer and if the Network Customer does not take the appropriate corrective actions immediately, Emera Maine shall have the right to interrupt Transmission Service in order to alleviate the situation and to suspend all or any portion of the Transmission Service until appropriate corrective action is taken.

11.0 If the function of any Party's facilities is impaired, the capacity of any delivery point is reduced, or synchronous operation at any delivery point(s) becomes interrupted, either manually or automatically, as a result of force majeure or maintenance coordinated by the Parties, the Parties will cooperate to remove the cause of such impairment, interruption, or reduction, so as to restore normal operating conditions expeditiously.

12.0 It is recognized by the Parties that the BHD Transmission System is, and will be, directly or indirectly interconnected with BHD Transmission Systems owned or operated by others, that the flow of power and energy between such systems will be controlled by the physical and electrical characteristics of the facilities involved and the manner in which they are operated, and that part of the power and energy being delivered under this Operating Agreement may flow through such other systems rather than through the facilities of Emera Maine. Each Party will at all times cooperate with other interconnected systems in establishment of arrangements that may be necessary to relieve any hardship in such other systems and in the systems of the other entities caused by energy flows of scheduled deliveries hereunder.

13.0 No later than December 15 of each year, the Network Customer shall provide Emera Maine the following information:

a) a three (3) year projection of monthly peak demands with the corresponding power factors and annual energy requirements on an aggregate basis for each delivery point. If there is more than one delivery point, provide the monthly peak demands and energy requirements at each delivery point for the normal operating configuration;

b) a three (3) year projection by month of planned generating capabilities and committed transactions with third parties which resources are expected to be used by the Network Customer to supply the peak demand and energy requirements provided in (a);

c) a three (3) year projection by month of the estimated maximum demand in kilowatts that the Network Customer plans to acquire from the generation resources owned by the Network Customer, and generation resources purchased from others;

d) a projection for each of the next three (3) years of transmission facility additions to be owned and/or constructed by the Network Customer which facilities are expected to affect the planning and operation of the BHD Transmission System.

Information exchanged by the Parties under Section 13 will be used for system planning and protection only, and will not be disclosed to third parties absent mutual consent or order of a court or regulatory agency.

Emera Maine will incorporate this information in its system load flow analyses performed during the first half of each year. Following the completion of these analyses, Emera Maine will provide the following to the Network Customer only in the event of a constraint or a partial limitation:

a) A statement regarding the ability of the BHD Transmission System to meet the forecast deliveries at each of the delivery points;

b) A detailed description of any constraints on Emera Maine's system within the three (3) year horizon that will restrict forecast deliveries.

c) In the event that studies reveal a potential limitation of Emera Maine's ability to deliver power and energy to any of the delivery points, Emera Maine and Network Customer shall identify appropriate remedies for such constraints including but not limited to: construction of new transmission facilities, upgrade or other improvements to existing transmission facilities, or temporary modification to operation procedures designed to relieve identified constraints. Emera Maine will, consistent with Good Utility Practice, endeavor to construct and place into service sufficient transmission capacity to maintain reliable service to the Network Customer. An appropriate sharing of the costs to relieve such constraints will be determined by the Parties, consistent with FERC rules, regulations, policies, and precedents then in effect. If the Parties are unable to agree upon an appropriate remedy or sharing of the costs, Emera Maine shall submit its proposal for the remedy or sharing of such costs to the FERC for approval consistent with Schedule 21 and Schedule 21-EM of the OATT.

14.0 Prior to service commencing under this Operating Agreement and the Service Agreement for Retail Local Network Service, and prior to the beginning of each month thereafter, the Network Customer shall provide to Emera Maine, the Network Customer's daily peak load expressed in terms of tenths of a megawatt and shall include all losses within the BHD Transmission System.

15.0 Prior to the beginning of each month, the Network Customer shall provide to Emera Maine forward hourly loads and energy schedules for all energy flowing into the BHD Transmission System.

16.0 The Network Customer shall provide Emera Maine, at least twelve (12) hours in advance of every calendar day, Network Customer's hourly energy schedules for the next calendar day for all energy flowing into the BHD Transmission System. The Network Customer may modify its hourly energy schedules up to twenty (20) minutes before the start of the next clock hour. The hourly schedule must be stated in increments of tenths of a megawatt and shall include all losses within the BHD Transmission System. These hourly schedules will be used by Emera Maine to determine whether any Energy Imbalance Service charges apply, pursuant to Schedule 4 of the OATT and Schedule 4-EM of Schedule 21-EM of the OATT.

17.0 The procedures by which a Network Customer will determine the peak and hourly loads reported to Emera Maine pursuant to this Operating Agreement may be set forth in a separate schedule to this Operating Agreement. Load distribution profiles of customer classes may be used to determine peak and hourly loads.

18.0 Prior to service commencing under this Operating Agreement and the Service Agreement for Retail Local Network Service, the Network Customer shall designate its Network Resources consistent with Schedule 21 and Schedule 21-EM of the OATT. Consistent with Schedule 21 and Schedule 21-EM of the OATT, changes in the designation of Network Resources will be treated as an application for modification of service.

19.0 In accordance with Part II.4.d of Schedule 21 and Section 33 of Schedule 21-EM of the OATT, the ISO and/or Emera Maine may require redispatching of generation resources or curtailment of loads to relieve existing or potential BHD Transmission System constraints.

20.0 The Network Customer and Emera Maine shall implement load-shedding procedures to maintain the reliability and integrity of the BHD Transmission System as provided in Section 45 of the OATT and in accordance with applicable NERC and NPCC requirements and Good Utility Practice. Load shedding may include (1) automatic load shedding, (2) mutual load shedding, and (3) rotating interruption of customer load. When manual load shedding or rotating interruptions are necessary, Emera Maine shall notify the Network Customer of the required action and the Network Customer shall comply immediately.

21.0 This Operating Agreement shall become effective, and remain in effect, for the same term as the term of the Retail Local Network Service Agreement entered into by Emera Maine and Network Customer pursuant to which Emera Maine will provide Retail Local Network Service under Schedule 21 and Schedule 21-EM of the OATT.

22.0 Any dispute among the Parties regarding this Operating Agreement shall be resolved pursuant to Section 12 of Schedule 21-EM of the OATT, or otherwise, as mutually agreed by the Parties.

23.0 This Operating Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns, but shall not be assigned by any Party, except to successors to all or substantially all of the electric properties and assets of such Party, without the written consent of the others. Such written consent shall not be unreasonably withheld.

24.0 The interpretation, enforcement, and performance of this Operating Agreement shall be governed by the laws of the State of Maine, except laws and precedent of such jurisdiction concerning choice of law shall not be applied.

25.0 The OATT (including Schedule 21 and Schedule 21-EM) and Retail Local Network Service Agreement, as they are amended from time to time, are incorporated herein and made a part hereof. To the extent that a conflict exists between the terms of this Operating Agreement and the terms of Schedule 21 and Schedule 21-EM of the OATT, Schedule 21 and Schedule 21-EM of the OATT shall control.

26.0 Nothing contained in this Operating Agreement or any associated Service Agreement shall be construed as affecting in any way Emera Maine's right unilaterally to file with FERC, or make application to FERC, or other regulatory body for changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act and pursuant to FERC's rules and regulations promulgated thereunder, or under other applicable statutes or regulations, or to the Network Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

27.0 Except as otherwise provided, any notice that may be given to or made upon any Party by the other Party under any of the provisions of the Operating Agreement shall be in writing, unless otherwise specifically provided herein and shall be considered delivered when the notice is either personally delivered or deposited in the United States mail, certified, or registered postage prepaid, to the following:

Emera Maine

[name]

[title][address]

[phone]

[fax]

Network Customer

[name]

[title]

[address]

[phone]

[fax]

Any notice, request, or demand pertaining to operating matters may be delivered in person or by first class mail, messenger, telephone, telegraph, or facsimile transmission as may be appropriate and shall be confirmed in writing as soon as practical thereafter, if any Party so requests in any particular instance.

28.0 This Operating Agreement may be executed in any number of counterparts with the same effect as if all parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

IN WITNESS WHEREOF, the Parties have caused this Operating Agreement to be executed by their respective authorized officials:

EMERA MAINE: Date:

By: _____________________________ _______________

TRANSMISSION CUSTOMER: Date:

By: _____________________________ _______________

ATTACHMENT P-EM

FORMULAIC RATES DESCRIPTION

I. INTRODUCTION

This Attachment P-EM sets forth details with respect to the determination each year of Emera Maine's Transmission Revenue Requirement and its Scheduling Revenue Requirement. Except where otherwise noted or where the context otherwise indicates, all values referenced herein shall be understood to be end of year or full calendar year values as reflected on Emera Maine's FERC Form 1 ("FF1").

The Transmission Revenue Requirement will reflect the costs for the BHD Transmission System, as detailed in Section III below. The Transmission Revenue Requirement will be calculated annually, effective each June 1, based in part on the previous calendar year's data and the FF1 data for that previous year (the "Reported Year"), and based in part on forecasted amounts. The calendar year immediately following the Reported Year is referred to herein as the "Forecast Period." Reported Year load, revenue and sales data may be adjusted, as appropriate, to reflect known and measurable anticipated changes for the subject rate year. To the extent any such adjusted data used in the annual calculation of charges differs from actual data for the Forecast Period, Emera Maine will apply a true-up (equal to the difference between adjusted and actual data multiplied by the applicable tariff rate), with interest, through the Annual True-Up with Interest provided for in Section III.N, herein.

The Scheduling Revenue Requirement will reflect the costs of provision of the Ancillary Service "Scheduling, System Control and Dispatching Service" ("Scheduling") for the BHD Transmission System, as detailed in Section IV below. The Scheduling Revenue Requirement will be calculated annually, effective each June 1, based on the previous calendar year's data and the FF1 data for the Reported Year.

If and to the extent such FF1 data are not applicable to the BHD in whole or in part, such data (i) where practicable, will be expressly excluded from the calculations in this Attachment P-EM (*i.e.*, directly assigned to an Emera Maine business unit other than the BHD) or (ii) allocated between the BHD and one or more other business units of Emera Maine, as detailed herein.

Retail transmission price changes will take effect contemporaneously with annual changes to distribution rates. The transmission revenue effect of any difference (positive or negative) between when transmission price changes would normally occur (June 1) and when they actually occur will be accrued with interest, calculated pursuant to Section 35.19a of FERC's regulations and included in the next determination of transmission prices for retail transmission customers.

Subject to the foregoing, separate Transmission Revenue Requirements will be calculated pursuant to this Attachment P-EM, applicable to the following:

A. Wholesale Load on the BHD Transmission System
   1. for Non-Pool Transmission Facilities ("PTF") Service
   2. for PTF Service
   3. for Emera Maine's unit costs of acting as customer's agent for service

B. Wheeling Off the BHD Transmission System (Non-PTF Service)

C. Retail Load on the BHD Transmission System
   1. for Non-PTF Service
   2. for PTF Service
   3. for Emera Maine's unit costs of acting as customer's agent for service

Each revenue requirement will be calculated in accordance with the general formula set forth in Section III (modified, as appropriate, for each specified revenue requirement in accordance with the detailed provisions of this Attachment P-EM).

Capitalized terms not otherwise defined in Section 1 of the OATT and as used in this Attachment P-EM have the definitions provided herein.

II. ALLOCATORS/ADJUSTMENT FACTORS

This Section II establishes three types of allocation factors (allocators) to be used in this Attachment P-EM: (i) factors that allocate values between the BHD and other Emera Maine business units ("Company Allocators"), (ii) factors that allocate values within the BHD, such as between transmission and distribution, or between PTF and non-PTF ("BHD Allocators"), and (iii) a factor that allocators values based on salaries and wages. Additionally, this Section establishes an adjustment factor based on the Settlement reached in Docket No. ER00-980-000 on November 1, 2000.

A. Definitions

For purposes of this Section II, the following terms shall be defined as follows.

(1) BHD Total Transmission Plant (Recorded) shall equal the balance of Account Nos. 350-359.1 [FF1 at 207:58g] as directly assigned to the BHD, excluding any values for transmission investments for which Emera Maine received up-front customer contributions that it does not have to repay.

(2) BHD Total Transmission Plant (Adjusted) shall equal:

(a) BHD Total Transmission Plant (Recorded), less

(b) the amounts therein applicable to generator step-ups and generator radial lines, plus

(c) the gross book value of distribution plant reclassified to transmission in accordance with the FERC approved jurisdictional delineation of facilities for retail transmission,

provided that the foregoing values in

(a), (b), and (c) reflect values for BHD only and exclude any values for transmission investments for which Emera Maine received up-front customer contributions that it does not have to repay.

B. Allocators

(1) Company Allocators

(a) Company Customer Count Allocator (BHD) shall equal:

(i) the number of BHD customers contributing to the total average number of customers per rate schedule as reported on FF1 at 304:43d, divided by

(ii) the total of average number of customers per rate schedule as reported on FF1 at 304:43d.

(b) Company Customer/Load/Sales Allocator (BHD) shall equal:

(i) Company Customer Count Allocator (BHD) divided by three, plus

(ii) Company Monthly Peak Loads Allocator (BHD) divided by three, plus

(iii) Company Energy Sales Allocator (BHD) divided by three.

(c) Company Customer/Revenue Allocator (BHD) shall equal:

(i) the Company Revenue Allocator (BHD) (described below) divided by two, plus

(ii) the Company Customer Count Allocator (BHD) (described below) divided by two.

(d) Company Customer/Sales Allocator (BHD) shall equal:

(i) Company Customer Count Allocator (BHD) divided by two, plus

(ii) Company Energy Sales Allocator (BHD) divided by two.

(e) Company Energy Sales Allocator (BHD) shall equal:

(i) the contribution by BHD loads to the total quantity of electricity sold for the year as reported on FF1 at 304:43b, divided by

(ii) the total quantity of electricity sold for the year as reported on FF1 at 304:43b.

(f) Company Monthly Peak Loads Allocator (BHD) shall equal:

(i) the contribution by BHD loads to the total of monthly peak loads for the year as reported on FF1 at 400:17b, divided by

(ii) the total of monthly peak loads for the year as reported on FF1 at 400:17b.

(g) Company Revenue Allocator (BHD) shall equal:

(i) the contribution by BHD loads to the revenues from electricity sales as reported on FF1 at 304:43c, divided by

(ii) total Emera Maine revenues from electricity sales as reported on FF1 at 304:43c.

(h) Company Total Plant Allocator (BHD) shall equal:

(i) the value reported as Total Electric Plant in Service on FF1 at 207:104g as directly assigned to the BHD, divided by

(ii) the value reported as Total Electric Plant in Service on FF1 at 207:104g.

(2) BHD Allocators

(a) BHD Plant Allocator (Transmission) shall equal:

(i) BHD Total Transmission Plant (Adjusted) plus Transmission-Related General and Intangible Plant (defined in Section III.A.1.b below), divided by

(ii) the value reported as Total Electric Plant in Service on FF1 at 207:104g as directly assigned to the BHD.

(b) BHD Revenue Allocator (Transmission) shall equal:

(i) the contribution by BHD loads to that amount of revenues reported on FF1 at 304:43c attributable to transmission service (either bundled or unbundled), divided by

(ii) the contribution by BHD loads to total revenues as reported on FF1 at 304:43c.

(c) BHD Transmission Plant Allocator (PTF) shall equal:

(i) the balance of Account Nos. 350-359.1 [FF1 at 207:58g] attributable to PTF based on company records, excluding any values for transmission investments for which Emera Maine received up-front customer contributions that it does not have to repay, divided by

(ii) BHD Total Transmission Plant (Adjusted).

(3) Salaries and Wages Allocator, Adjustment Factor

(a) Company Salaries and Wages Allocator (Transmission) shall equal:

(i) transmission salaries and wages as reported on FF1 at 354:21b, divided by

(ii) the difference between (i) total operations and maintenance salaries and wages as reported on FF1 at 354:28b, less (ii) administrative and general salaries and wages as reported on FF1 at 354:27b.

(b) BHD Transmission Plant Adjustment Factor shall equal:

(i) BHD Total Transmission Plant (Adjusted), divided by

(ii) BHD Total Transmission Plant (Recorded).

III. CALCULATION OF TRANSMISSION REVENUE REQUIREMENT

In general, the Transmission Revenue Requirement shall equal:

(A) Return and Associated Income Taxes,

plus (B) Transmission-Related Depreciation Expense,

minus (C) Transmission-Related Amortization of Investment Tax Credits,

plus (D) Transmission-Related Property Tax Expense,

plus (E) Transmission-Related Payroll Tax Expense,

plus (F) Transmission Operation and Maintenance Expense,

plus (G) Transmission-Related Administrative and General Expense, minus (H) Revenues from Point-to-Point Transactions Under the Tariff,

minus (I) Other Transmission-Related Revenues,

plus (J) RNS and ISO Costs,

minus (K) RNS and ISO Revenues,

plus (L) Support Payments,

plus (M) Incremental Forecasted Transmission Revenue Requirement,

plus (N) Annual True-Up with Interest.

For service provided to retail loads in the BHD, the Transmission Revenue Requirement shall also include as part of the Annual True-Up with Interest: (a) the product of (i) Total Customer Accounts Expenses as reported on FF1 at 322:164b multiplied first by (ii) the Company Customer/Revenue Allocator (BHD) and then multiplied by (iii) the BHD Revenue Allocator (Transmission).

Through the application of the BHD Allocators described in Section II.B.2. above, the Transmission Revenue Requirement shall be functionalized between PTF and Non-PTF, resulting in the PTF Revenue Requirement and Non-PTF Revenue Requirement, respectively.

There shall be separately calculated, in addition to the PTF and Non-PTF revenue requirements, Emera Maine's costs of acting as customer's agent for service as directly assigned to the BHD.

A. Return and Associated Income Taxes shall equal Transmission Investment Base multiplied by Cost of Capital Rate.

(1) Transmission Investment Base shall equal:

(a) BHD Total Transmission Plant (Adjusted),

plus (b) Chester SVC Plant,

plus (c) Transmission-Related General and Intangible Plant,

plus (d) Transmission Plant Held for Future Use,

less (e) Transmission-Related Depreciation Reserve,

less (f) Transmission-Related Accumulated Deferred Taxes,

plus (g) Other Transmission-Related Regulatory Assets/Liabilities,

plus (h) Transmission-Related Prepayments,

plus (i) Transmission Materials and Supplies, plus (j) Transmission-Related Cash Working Capital.

(a) BHD Total Transmission Plant (Adjusted) is as defined above and shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

(b) Chester SVC Plant shall equal one-half of the gross value recorded on the books of Chester SVC Partnership of the control system upgrades placed in service in 2014, and shall be directly assigned to PTF function.

(c) Transmission-Related General and Intangible Plant shall equal the following value calculated in the following arithmetic order:

(i) the balance of Account Nos. 301-303 and 389-399.1 [FF1 at 205:5g and 207:99g] as directly assigned to the BHD, less

(ii) any amounts attributable to FERC hydroelectric relicensing recorded in Account No. 302 [FF1 at 205:2g], less

(iii) any Customer Information System ("CIS") costs recorded in Account No. 303 [FF1 at 205:4g] as directly assigned to the BHD, multiplied by

(iv) Company Salaries and Wages Allocator (Transmission), plus

(v) the CIS costs recorded in Account No. 303 [FF1 at 205:4g] multiplied by the BHD Revenue Allocator (Transmission).

The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

(d) Transmission Plant Held for Future Use shall equal the balance recorded in Account No. 105 attributable to transmission plant as directly assigned to the BHD [FF1 at 214:d] multiplied by the BHD Transmission Plant Adjustment Factor and further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

(e) Transmission-Related Depreciation Reserve shall equal:

(i) the balance of Account No. 108 attributable to transmission plant [FF1 at 219:25b] as directly assigned to the BHD Transmission System multiplied by the BHD Transmission Plant Adjustment Factor, plus

(ii) the balance recorded in Account No. 108 attributable to intangible plant and general plant [FF1 219:28b] as directly assigned to the BHD Transmission System, exclusive of any amounts attributable to FERC hydroelectric relicensing or the CIS, multiplied by the Company Salaries and Wages Allocator (Transmission), plus

(iii) the balance recorded in Account No. 108 attributable to the CIS as directly assigned to the BHD multiplied by the BHD Revenue Allocator (Transmission), plus

(iv) one-half of the accumulated depreciation recorded on the books of Chester SVC Partnership of the control system upgrades placed in service in 2014.

The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF), provided however that all Chester SVC amounts shall be directly assigned to PTF function.

(f) Transmission-Related Accumulated Deferred Taxes shall equal:

(i) the balance of Account No. 282 [FF1 at 113:63c] attributable to transmission plant and directly assigned to the BHD, but exclusive of ASC-740 amounts (formerly FASB 109), plus

(ii) the balance of Account No. 282 [FF1 at 113:63c] attributable to general and intangible plant and directly assigned to the BHD, but exclusive of amounts attributable to ASC-740 and the CIS, multiplied by the Company Salaries and Wages Allocator (Transmission), plus

(iii) the balance of Account No. 282 [FF1 at 113:63c] attributable to the CIS as directly assigned to the BHD multiplied by the BHD Revenue Allocator (Transmission), plus

(iv) the balance of Account No. 283 [FF1 at 113:64c] as directly assigned to the BHD, but exclusive of amounts attributable to property taxes, stranded costs, retail rate-making, affiliated companies, or any ASC-740 amounts, multiplied by the Company Salaries and Wages Allocator (Transmission), plus

(v) the balance of Account No. 283 [FF1 at 113:64c] attributable to property taxes multiplied first by the Company Total Plant Allocator (BHD) and then multiplied by the BHD Plant Allocator (Transmission), plus

(vi) the balance of Account No. 190 [FF1 at 111:82c] as directly assigned to the BHD, exclusive of amounts associated with accrued vacation, stranded costs, retail rate-making, affiliated companies, or any ASC-740 amounts, multiplied by the Company Salaries and Wages Allocator (Transmission), plus

(vii) the balance of Account No. 190 [FF1 at 111:82c] attributable to accrued vacation multiplied first by the Company Customer/Load/Sales Allocator (BHD) and then multiplied by the Company Salaries and Wages Allocator (Transmission).

The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

(g) <u>Other Transmission-Related Regulatory Assets/Liabilities</u> shall equal:

The Company Salaries and Wages Allocator (Transmission) multiplied by the sum of:

(i) pension and post-retirement benefits other than pension amounts recorded in Account Nos. 182.3, 228.3 and 254 [FF1 at 111:72c, 112:29c and 113:60c], as directly assigned to the BHD, plus

(ii) deferred employee transition costs recorded in Account No. 228.3 [FF1 at 112:29c] as directly assigned to the BHD, plus

(iii) pension and post-retirement benefits other than pension amounts reported as Accumulated Other Comprehensive Income [FF1 at 122a:10c] as directly assigned to the BHD.

The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

(h) Transmission-Related Prepayments shall equal the balance of Account No. 165 [FF1 at 111:57c] multiplied first by the Company Total Plant Allocator (BHD) and then multiplied by the Company Salaries and Wages Allocator (Transmission). The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

(i) Transmission Materials and Supplies shall equal the balance of Account No. 154 of transmission plant materials and supplies [FF1 at 227:8c] multiplied by the Company Total Plant Allocator (BHD). The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

(j) Transmission-Related Cash Working Capital shall equal 12.5% (45 days/360 days) multiplied by the sum of Transmission Operation and Maintenance Expense (as defined herein in Section III.F.) and Transmission-Related Administrative and General Expense (as defined herein in Section III.G.), with the resultant value allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF). In addition, the value for Transmission-Related Cash Working Capital for PTF function shall also include 12.5% of the value of Support Payments (as defined herein in Section III.L.).

For calculation of the revenue requirement for transmission service to retail loads, this figure shall also include 12.5% (45 days/360 days) of the product of (i) Total Customer Accounts Expenses as reported on FF1 at 322:164b multiplied first by (ii) the Company Customer/Revenue Allocator (BHD) and then multiplied by (iii) the BHD Revenue Allocator (Transmission).

(2) Cost of Capital Rate

shall equal (a) Weighted Cost of Capital, plus (b) Federal Income Tax, plus (c) State Income Tax.

(a) Weighted Cost of Capital will be calculated based upon the average beginning and end of year capital structure at the end of each year and will equal the sum of:

(i) the long-term debt component, which shall equal the product of Emera

Maine's long-term debt cost rate calculated on a net proceeds basis, and the ratio that Total Long-Term Debt as reported on FF1 at 112:24 is to Emera Maine Total Capital (defined below), plus

(ii) the preferred stock component, which shall equal the product of Emera Maine's preferred stock cost rate, and the ratio that Preferred Stock Issued as reported on FF1 at 112:3 is to Emera Maine Total Capital, plus

(iii) the return on equity component, which shall equal the product of 11.14 percent and the ratio that Emera Maine Common Equity Adjusted (defined below) is to Emera Maine Total Capital,

Where:

(x) Emera Maine Common Equity Adjusted equals (aa) Total Proprietary Capital as reported on FF1 at 112:16 less (bb) goodwill associated with the transactions approved by the Commission in Docket Nos. EC01-13 and EC10-67 less (cc) the balance of Account No. 216.1 [FF1 at 112:12] less (dd) the balance of Account No. 204 [FF1 at 112:3] plus (ee) the absolute value of the balance of Account No. 219 [FF1 at 112:15]; and

(y) Emera Maine Total Capital equals (aa) Total Long-Term Debt as reported on FF1 at 112:24 plus (bb) Preferred Stock Issued as reported on FF1 at 112:3 plus (cc) Emera Maine Common Equity Adjusted.

(b) Federal Income Tax shall equal:

$$\frac{(A+[(B+C)/D]) \times FT}{1-FT}$$

where

FT = Emera Maine's federal income tax rate;

A = the sum of the preferred stock component and the return on equity component determined in Sections III.A.2.(a)(ii) and (iii) above;

B = Transmission-Related Amortization of Investment Tax Credits, as determined in Section III.C., below;

C = the equity AFUDC component of transmission depreciation expense as directly assigned to the BHD;

D = Transmission Investment Base.

(c) State Income Tax shall equal:

$$\frac{((A+[(B+C)/D]) + E) \times ST}{1-ST}$$

where:

ST = Emera Maine's state income tax rate;

A = the sum of the preferred stock component and return on equity component determined in Sections III.A.2.(a)(ii) and (iii) above;

B = Transmission-Related Amortization of Investment Tax Credits as determined in Section III.C. below;

C = the equity AFUDC component of transmission depreciation expense as directly assigned to the BHD;

D = Transmission Investment Base; and

E = Federal Income Tax calculated in Section III.A.2(b) above.

B. Transmission-Related Depreciation Expense shall equal:

(1) the balance of Account No. 403 attributable to transmission plant as directly assigned to the BHD [FF1 at 336:7b] multiplied by the BHD Transmission Plant Adjustment Factor, plus

(2) the balance of Account No. 403 attributable to intangible plant or general plant [FF1 at 336:1b and 336:10b] as directly assigned to the BHD, exclusive of any amounts attributable to FERC hydroelectric relicensing and the CIS, multiplied by the Company Salaries and Wages Allocator (Transmission),

(3) the balance of Account No. 403 attributable to the CIS as directly assigned to the BHD, multiplied by the BHD Revenue Allocator (Transmission), plus

(4) one-half of the depreciation expense recorded on the books of Chester SVC Partnership of the control system upgrades placed in service in 2014of Chester SVC Partnership.

The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF), provided however that all Chester SVC amounts shall be directly assigned to PTF function.

For purposes of calculating charges under this Schedule 21-EM, the following depreciation rates shall apply:

FERC Account	Description	Proposed Rate
350.2	Rights of Way	1.39%
353	Station Equipment	2.13%
353.1	Station Equipment - SCADA	3.61%
354	Towers and Fixtures	2.19%
354.1	Towers and Fixtures - 115 kV	6.47%
354.2	Towers and Fixtures - 345 kV	2.69%
355	Poles and Fixtures	3.36%
355.1	Poles and Fixtures - 115 kV	3.06%
355.2	Poles and Fixtures - 345 kV	2.69%
355.3	Poles and Fixtures - Steel Poles	2.02%
356	Overhead Conductors and Devices	3.34%
356.1	Overhead Conductors and Devices - 115 kV	2.31%
356.2	Overhead Conductors and Devices - 345 kV	2.51%
357	Underground Conduit	1.41%
358	Underground Conductors and Devices	1.76%
359	Roads and Trails	1.68%
390	Structures and Improvements (Average Rate)	4.83%*
390 - Item	Park Street	2.81%
390 - Item	Main St. - Bus Garage and Store / Boiler Bldg.	15.47%
390 - Item	Main St. - Stockroom	0.55%
390 - Item	Main St. - Quonset Hut	2.35%
390 - Item	Main St. - Meter / Planner Bldg.	0.84%
390 - Item	Eddington	6.10%
390 - Item	Ellsworth Office Bldg. - New	4.05%
390 - Item	Graham Sta. - Internal Combustion Bldg.	0.81%
390 - Item	Graham Sta. - Steam Plant Bldg.	1.19%
390 - Item	Graham Sta. - Transformer Bldg.	2.13%
390 - Item	Graham Sta. - Car Barn	2.69%
390 - Item	Lamoine Service Center	2.74%
390 - Item	Lamoine Transformer Bldg.	0.00%
390 - Item	Lincoln Service Center - New	2.67%
390 - Item	Lincoln Transformer Bldg. (Northern)	2.39%
390 - Item	Machias Transformer Bldg.	1.65%
390 - Item	Machias Division Office	0.75%
390 - Item	Machias Garage and Washbay	2.40%
390 - Item	West Enfield	0.00%
390 - Item	Charleston	2.10%
390 - Item	Hampden Fleet Maintenance Bldg.	1.83%
390 - Item	Hampden Rte. 202 Site	1.81%
390 - Item	Cranberry Isle	1.12%
390 - Item	Illinois Avenue	2.81%
390 - Item	Telecom	2.73%
391.12	Office Furniture and Equipment - PC	25.90%
391.13	Office Furniture and Equipment - Office Machines	14.19%
391.14	Office Furniture and Equipment - Furniture	5.82%
391.15	Office Furniture and Equipment - Unallocated	20.51%

392	Transportation Equipment - Cars	3.18%
393	Stores Equipment	9.47%
394	Tools, Shop and Garage Equipment	5.82%
395	Laboratory Equipment	7.67%
396	Power Operated Equipment - Trucks	6.97%
397.1	Communication Equipment - General Equip.	6.52%
397.2	Communication Equipment - AMR Substation Equip.	4.42%
397.21	Communication Equipment - Fiber	4.28%
397.3	Communication Equipment - General Equip. - SCADA	3.45%
398	Miscellaneous Equipment	6.30%
* This value represents the average rate of the structure-specific depreciation rates that will be applied to Account No. 390.		

C. <u>Transmission-Related Amortization of Investment Tax Credits</u> shall equal the balance of Account No. 411.4 [FF1 at 266:8f] as directly assigned to the BHD multiplied by the BHD Plant Allocator (Transmission). The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

D. <u>Transmission-Related Property Tax Expense</u> shall equal the balance of Account No. 408.1 [FF1 at 114:14c] attributable to property tax multiplied first by the Company Total Plant Allocator (BHD) and then multiplied by the BHD Plant Allocator (Transmission). The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

E. <u>Transmission-Related Payroll Tax Expense</u> shall equal the balance of Account No. 408.1 [FF1 at 263:i] attributable to payroll tax multiplied first by the Company Customer/Load/Sales Allocator (BHD) and then multiplied by the Company Salaries and Wages Allocator (Transmission). The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

F. <u>Transmission Operation and Maintenance Expense</u> shall equal:

(1) the balance of Account Nos. 560, 562-564 and 566-573 [FF1 at 321:83b, 321:93b-95b, 321:97b, 321:98b, 321:111b] attributable to transmission plant and as directly assigned to the BHD, less

(2) expenses for the support of other utilities' facilities recorded in Account Nos. 560, 562-564 and 566-573 [FF1 at 321:83b, 321:93b-95b, 321:97b, 321:98b, 321:111b] attributable to transmission plant and as directly assigned to the BHD, with the resulting difference

multiplied by

(3) the BHD Transmission Plant Adjustment Factor.

The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

G. <u>Transmission-Related Administrative and General Expense</u> shall equal:

(1) (a) the balance of Account Nos. 920-935 [FF1 at 323:197b], less (b) the balance of Account Nos. 924 and 928 [FF1 at 323:185b and 323:189b], less (c) the balance of Account No. 923 [FF1 at 323:184b] attributable to regulatory proceedings or regulatory compliance activities, less (d) the balance of account No. 926 attributable to post-retirement benefits other than pensions ("PBOP"), all multiplied first by the Company Customer/Sales Allocator (BHD) and then multiplied by the Company Salaries and Wages Allocator (Transmission), plus

(2) the balance of Account No. 924 [FF1 at 323:185b] multiplied first by the Company Total Plant Allocator (BHD) and then multiplied by the BHD Plant Allocator (Transmission), plus

(3) the balance of Account No. 928 [FF1 at 323:189b] applicable to Commission Annual Charges as required by 18 C.F.R. § 382.201 as directly assigned to BHD and then multiplied by the BHD Transmission Plant Adjustment Factor, plus

(4) the balance of Account No. 928 [FF1 at 323:189b] constituting transmission-related expenses or assessments, other than Commission Annual Charges, and either (a) directly assigned to the BHD or (b) if not so directly assigned, multiplied by the Company Salaries and Wages Allocator (Transmission), plus

(5) the balance of Account No. 923 [FF1 at 323:184b] attributable to regulatory proceedings or regulatory compliance activities involving the BHD Transmission System or services provided over the BHD Transmission System, multiplied by the BHD Transmission Plant Adjustment Factor, plus

(6) $1,344,505 (a fixed figure for PBOP as directly assigned to the BHD) multiplied by the Company Salaries and Wages Allocator (Transmission), plus

(7) the balance of Account No. 407.3 [FF1 at 114:12c] applicable to pension and post-retirement benefits other than pension regulatory amortization expense, as directly assigned to the BHD and multiplied by the Company Salaries and Wages Allocator (Transmission), plus

(8) the balance of Account No. 407.3 [FF1 at 114:12c] attributable to deferred employee transition costs multiplied by the Company Salaries and Wages Allocator (Transmission).

The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

H. Revenues from Point-to-Point Transactions Under the Tariff shall equal:

(1) the balance of Account No. 456 [FF1 at 300:21b] as directly assigned to the BHD, plus

(2) the transmission component of revenues for sales that use the BHD Non-PTF transmission system, as recorded in Account No. 456.1 [FF1 at 300:22b] (if the transactions are not reflected in adjusted monthly peak loads).

Ninety percent of the resulting value shall be credited only to the Non-PTF Revenue Requirement.

I. Other Transmission-Related Revenues shall equal the sum of the following values as directly assigned to the BHD:

(1) the balance of Account No. 454 [FF1 at 300:19b] attributable to electric property associated with transmission plant multiplied by the BHD Transmission Plant Adjustment Factor, plus

(2) all transmission-related revenues recorded in the balance of Account No. 456 [FF1 at 300:21b] attributable to transmission except: (a) non-penalty revenues associated with the rolled-in base transmission rates for point-to-point or network transmission service or ancillary services, (b) revenues associated with service provided under the Tariff, (c) revenues associated with operations and maintenance performed on other utilities' facilities; (d) revenues associated with the assignment of Hydro Quebec DC support obligations, and (e) revenues associated with generator radial lines and step-up transformers for which Emera Maine did not receive up-front customer capital contributions, or for which Emera Maine received up-front customer capital contributions

that Emera Maine is obligated to repay, plus

(3) the balance of Account No. 454 [FF1 at 300:19b] attributable to rents from the use of general plant multiplied by the Company Salaries and Wages Allocator (Transmission).

The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

J. RNS and ISO Costs shall equal the transmission payments Emera Maine makes to the ISO for Regional Network Service ("RNS") and all associated regional transmission-related services, such amounts fully assigned to PTF function.

K. RNS and ISO Revenues shall equal the transmission revenues Emera Maine receives from the ISO, less any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment, such amounts fully assigned to PTF function.

L. Support Payments shall equal, as the case may be: (1) PTF support payments (exclusive of such amounts attributable to the Hydro Quebec HVDC tie), such amounts fully assigned to PTF function or (2) Non-PTF integrated support payments (inclusive of such amounts associated with Non-PTF facilities integrated with the BHD Transmission System), such amounts fully assigned to Non-PTF function.

M. Incremental Forecasted Transmission Revenue Requirement shall equal (1) Forecasted Transmission Plant Additions multiplied by the Carrying Charge Factor, plus (2) Incremental Forecasted RNS Charges, less (3) Incremental Forecasted RNS Credits,

where:

Forecasted Transmission Plant Additions represents the costs attributable to transmission assets that are projected to go into service during the Forecast Period,

Carrying Charge Factor represents the costs to service the BHD Transmission System and is inclusive of the investment return associated with Emera Maine's pre-tax weighted average cost of capital, plus interest and other certain expenses,

Incremental Forecasted RNS Charges represents the difference in the forecast RNS charges for the Forecast Period as compared to the actual Reported Year RNS charges, and

Incremental Forecasted RNS Credits represents the difference in the forecast RNS credits for the Forecast Period as compared to the actual Reported Year RNS credits, with each reduced by any incremental revenues associated with Commission-approved adders for RTO participation and new transmission investment.

N. Annual True-Up with Interest shall equal (1) Prior Year Annual True-Up plus (2) Interest on Annual True-Up.

(1) Prior Year Annual True-Up shall equal (a) Prior Year Actual Transmission Revenue Requirement less (b) Prior Year Implemented Transmission Revenue Requirement.

(a) Prior Year Actual Transmission Revenue Requirement represents the actual costs and revenues incurred during the Reported Year as calculated in accordance with the methodology set forth in this Section III. For service provided to retail loads in the BHD, the Prior Year Actual Transmission Revenue Requirement shall also include: (a) the product of (i) Total Customer Accounts Expenses as reported on FF1 at 322:164b multiplied first by (ii) the Company Customer/Revenue Allocator (BHD) and then multiplied by (iii) the BHD Revenue Allocator (Transmission).

(b) Prior Year Implemented Transmission Revenue Requirement represents the previous year's Transmission Revenue Requirement upon which transmission rates were based upon during the previous rate period.

(2) Interest on Annual True-Up equals the monthly interest accrued on the Prior Year Annual True-Up from June 1 through May 31 of the previous rate period calculated in accordance with 18 C.F.R. Section 35.19a.

IV. SCHEDULING REVENUE REQUIREMENT

A. Definitions

For purposes of this Section IV, the following terms shall be defined as follows.

(1) Scheduling, System Control and Dispatching Expense shall equal the balance of Account Nos. 561.1-561.8 [FF1 at 321:85b-92b].

(2) ISO Scheduling Credits and Schedule 1 Revenues shall equal such amounts associated

with short-term and non-firm transactions and penalties for unauthorized use of Schedule 1 service as set forth in ISO monthly billing statements to Emera Maine.

B. Scheduling Revenue Requirement

The Scheduling Revenue Requirement shall equal the following:

(1) Scheduling, System Control and Dispatching Expense,

minus (2) ISO Scheduling Credits and Schedule 1 Revenues.

V. ANNUAL UPDATE AND INFORMATIONAL FILING

By June 15 of each year, Emera Maine shall make an informational filing with the FERC and serve copies of such filing on FERC Trial Staff, the Maine Public Utilities Commission ("MPUC"), and all OATT customer that request to receive a copy (collectively, "Interested Parties"). Through this informational filing, Emera Maine will show its implementation of the Rate Formula for the rates that became effective the previous June 1. Emera Maine shall include in the informational filing the following:

- Excel spreadsheets detailing the calculation of the formula rate as described in this Attachment P-EM, including all applicable worksheets.

- FERC Form 1 cites for those applicable inputs, including supporting material for all calculations and all formula inputs that reflect a level of detail not reported in the FERC Form 1.

- Information regarding the discounts given to transmission customers over the prior rate period. This information shall include the name of the transmission customer, the transmission path, the price, the quantity, and the period of the discount. Emera Maine shall provide a brief explanation of the transmission customer's justification of the discount. Emera Maine shall not provide to any Interested Party any customer's confidential information absent the Interested Party's execution of the Commission's model protective order. Emera Maine shall not be required to provide explanations for discounts provided pursuant to a settlement agreement, except that (1) Emera Maine shall provide an explanation in the first informational filing after the discount begins, and (2) if terms of the discount not previously applied are implemented after the first year of the discount, Emera Maine shall provide an explanation of the new terms.

Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the Rate Formula, including the discounts for which Emera Maine is required to provide explanations, under the same discovery rules that were in effect in FERC Docket No. ER00-980-000, including the requirement that responses be provided within ten (10) Business Days on a best efforts basis. Discovery requests may be served through the 30th day, or the first Business Day following the 30th day if the 30th day is not a Business Day, following the informational filing.

If an Interested Party disputes the implementation of the Rate Formula, such Interested Party shall communicate and detail its dispute in writing to Emera Maine and the other Interested Parties by the close of business on the 60th day, or the first Business Day following the 60th day if the 60th day is not a Business Day, following the informational filing. Thereafter, Emera Maine and the Interested Parties shall make a good faith effort to meet by appropriate means to resolve such dispute. If such dispute is not resolved in a timely manner, Interested Parties shall have until the close of business on the 90th day, or the first Business Day following the 90th day if the 90th day is not a Business Day, following the informational filing, to file a complaint with the Commission concerning the implementation of the Rate Formula for the current rate year.

If no such complaint is filed, and no investigation is instituted by the Commission of its own accord, such rates shall become final; provided, however, that Emera Maine's compliance with the filed rate under the Federal Power Act Section 306, 16 U.S.C. § 825e, is not limited by the informational filing procedures of this Attachment P-EM (1) where the costs included in the filed rate were imprudently incurred, (2) where the costs claimed were fraudulently included in the filed rates, or (3) where the costs were otherwise improperly included in the filed rate and where, despite the exercise of due diligence, that fact would not ordinarily come to the attention of the Interested Parties, provided, however, a party may not assert this right if it could have through the exercise of due diligence determined that the costs were improperly included in the filed rate. Further, the procedures established in this Attachment P-EM do not limit the ability of the Commission to investigate and render decisions on Emera Maine's FERC-jurisdictional rates.

These procedures similarly do not limit the ability of the MPUC to investigate and render decisions on Emera Maine's MPUC-jurisdictional rates or to use its processes to obtain information from Emera Maine. These procedures established in Attachment P-EM do not limit the rights of any party to contest under section 206 of the Federal Power Act, 16 U.S.C. § 824e, the prudence of any costs included in the informational filing.

VI. RATE DESIGN FOR FORECASTED TRANSMISSION REVENUE REQUIREMENT WITH ANNUAL TRUE UP AND INTEREST

A.1. Wholesale (Point-to-Point and Network), Wheeling Off (Point-to-Point) and Local Retail Point-to-Point Scheduling, System Control and Dispatch Service

The components of the Scheduling, System Control and Dispatch Service rates are (1) the Scheduling Revenue Requirement and (2) the average monthly Network Load for the Reported Year that includes loads associated with wheeling off the Emera Maine system.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

A.2. Local Retail Network Scheduling, System Control and Dispatch Service

The components of the rates for retail customers interconnected on the Emera Maine system and taking Local Retail Network Service are (1) the Scheduling Revenue Requirement, (2) the average monthly Network Load for the Reported Year that includes loads associated with wheeling off the Emera Maine system, and (3) the applicable retail conversion factors for the applicable retail customer class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW) is calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2) x (3)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

B. Rates for Wholesale Customers Interconnected on the Emera Maine System - Non-PTF Service

The components of the transmission rates for wholesale customers interconnected on the Emera Maine system and taking Non-PTF Service are (1) the Non-PTF Revenue Requirement and (2) the average monthly Network Load for the Reported Year that includes loads associated with wheeling off the Emera Maine system.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

C. Rates for Wholesale Customers Interconnected on the Emera Maine System - PTF Service

The components of the rates for wholesale customers interconnected on the Emera Maine system and taking PTF Service are (1) the PTF Revenue Requirement and (2) the average monthly Network Load for the Reported Year that excludes loads associated with wheeling off the Emera Maine system.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

D. Rates for Wholesale Customers Interconnected on the Emera Maine System - Emera Maine's Unit Costs of Acting as Customer's Agent for Service

The components of Emera Maine's unit costs of acting as customer's agent for service are (1) the Reported

Year plus Incremental Forecasted RNS Charges and (2) the average monthly Network Load for which Emera Maine provides ISO services.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

E. Rates for Wheeling Off the Emera Maine System

The components of the rates for wheeling off the Emera Maine system are (1) the Non-PTF Revenue Requirement and (2) the average monthly Network Load for the Reported Year that includes loads associated with wheeling off the Emera Maine system.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

F.1. Rates for Local Retail Point-to-Point Customers Interconnected on the Emera Maine System - Non-PTF Service

The components of the rates for Local Retail Point-to-Point Customers interconnected on the Emera Maine system and taking Non-PTF Service are (1) the Non-PTF Revenue Requirement and (2) the average monthly Network Load for the Reported Year that includes loads associated with wheeling off the Emera Maine system.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

F.2. Rates for Local Retail Network Customers Interconnected on the Emera Maine System - Non-PTF Service

The components of the rates for Local Retail Network Customers interconnected on the Emera Maine system and taking Non-PTF Service are (1) the Non-PTF Revenue Requirement, (2) the average monthly Network Load for the Reported Year that includes loads associated with wheeling off the Emera Maine system, and (3) the applicable retail conversion factors for the applicable retail customer class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The rates (after conversion of rate units to kW) are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2) x (3)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

G.1. Rates for Local Retail Point-to-Point Customers Interconnected on the Emera Maine System - PTF Service

The components of the rates for Local Retail Point-to-Point Customers interconnected on the Emera Maine system and taking PTF Service are (1) the PTF Revenue Requirement, and (2) the average monthly

Network Load for the Reported Year that excludes loads associated with wheeling off the Emera Maine system.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

G.2. Rates for Local Retail Network Customers Interconnected on the Emera Maine System - PTF Service

The components of the rates for Local Retail Network Customers interconnected on the Emera Maine system and taking PTF Service are (1) PTF Revenue Requirement and (2) the average monthly Network Load for the Reported Year that excludes loads associated with wheeling off the Emera Maine system, and (3) the applicable retail conversion factors for the applicable retail customer class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW) is calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2) x (3)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

H.1. Rates for Local Retail Point-to-Point Customers Interconnected on the Emera Maine System - Emera Maine's Unit Costs of Acting as Customer's Agent for Service

The components of the rates for Local Retail Point-to-Point Customers interconnected on the Emera Maine system and taking PTF Service are (1) Reported Year plus Incremental Forecasted RNS Charges and (2) the average monthly Network Load for which Emera Maine provides ISO services.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

H.2. Rates for Local Retail Network Customers Interconnected on the Emera Maine System - Emera Maine's Unit Costs of Acting as Customer's Agent for Service

The components of the rates for Local Retail Network Customers interconnected on the Emera Maine system and taking PTF Service are (1) the Reported Year plus Incremental Forecasted RNS Charges and (2) the average monthly Network Load for which Emera Maine provides ISO services and (3) the applicable retail conversion factors for the applicable retail customer class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW) is calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2) x (3)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

ATTACHMENT Q-EM

CREDITWORTHINESS GUIDE

1. General Information:

This Creditworthiness Guide details the specific requirements for the creditworthiness for Emera Maine. All customers taking (i) any service under Schedule 21-EM, the Local Service Schedule ("LSS") for Emera Maine under the OATT, (ii) any service provided under the Schedule 20A service schedule of Emera Maine under the OATT, for service over the Phase I/II HVDC-TF or (iii) any FERC-regulated interconnection service from Emera Maine must meet the terms of this Guide (where all the above, collectively, are referred to as "Services"). The creditworthiness of each customer must be established prior to receiving transmission service from Emera Maine. A customer will be evaluated at the time its application for transmission service is provided to Emera Maine. A credit review shall be conducted for each transmission customer periodically or upon reasonable request by the transmission customer. This Creditworthiness Guide ("Guide") when updated, will be done so in accordance with Section 4 of this Guide:

The information requested under this Guide should be forwarded to the individual identified on Emera Maine's website, www.emeramaine.com <http://www.emeramaine.com>.

Upon receipt of a customer's information, Emera Maine will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a Customer under this Guide, Emera Maine will forward a written evaluation if the customer is required to provide Financial Assurance. Emera Maine also will provide a written evaluation, upon request, to customers who are not required to provide Financial Assurance.

2. Financial Information

Customers receiving transmission service or requesting Interconnection Service may submit, if available, the following:

- All current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch of the customer.

- Audited financial statements provided by a registered independent auditor for the two most recent years, or the period of its existence, if shorter, for the customer.

3. Creditworthiness Requirements

A. The customer must meet at least one of the following criteria based on the information provided in Section 2 of this Guide:

a) If rated, the customer must have either for itself or for its outstanding debt the following:

- Standard and Poor's or Fitch rating of at least a **BBB**, or

- Moody's rating of at least a **Baa2**.

b) If un-rated or if rated below BBB/Baa2, as stated in a), the customer must meet all of the following:

- A Current Ratio of at least 1.0 times (current assets divided by all current liabilities);

- A Total Capitalization Ratio of less that 60% debt: total debt (including all short-term borrowing) divided by total shareholders' equity plus total debt;

- "Earnings before interest, taxes, depreciation, and amortization" in most recent fiscal quarter divided by expense for interest" (EBITDA-to-Interest Expense Ratio) of at least 2.0 times; and

- Audited Financial Statement with an unqualified audit opinion.

c) If the customer relies on the creditworthiness of a parent company, the customer's parent company must meet the criteria set out in (a) or (b) above, and must provide to Emera Maine a written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from Emera Maine.

d) If the customer is a municipal that is a member of the Massachusetts Municipals Wholesale Electric Cooperative (MMWEC), MMWEC must meet the criteria set out in (a) or (b) above and provide to Emera Maine a written guarantee that MMWEC will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from Emera Maine.

B. If the customer does not qualify for unsecured credit under Section A, the customer will qualify for unsecured credit equivalent to two months of transmission service charges, or for interconnections, the credit equivalent of two months of the annual facilities charges and other ongoing charges, if the customer has, on a rolling basis, 12 consecutive months of payments to Emera Maine with no missed, late or defaults in payment.

4. Financial Assurance

If the customer does not meet the applicable requirements for Creditworthiness set out in Section 3 or if required by the terms of an agreement or state law or regulation, then the customer must:

- Pay in advance for service an amount equal to the lesser of the total charge for Transmission Service or the charge for three months of Transmission Service, not less than 5 days in advance of the commencement of service;

- Obtain Financial Assurance in the form of a letter of credit, performance bond, or corporate guarantee equal to the equivalent of 3 months of Transmission Service charges prior to receiving service; or

- Obtain Financial Assurance in the form of a letter of credit based on the value of any new facilities or upgrades associated with such Transmission Service.

If the customer pays for service in advance, Emera Maine will pay to the customer interest on the amounts not yet due to Emera Maine, computed in accordance with the Commission's regulations at 18 CFR § 35.19a(a)(2)(iii).

5. Credit Levels

If the Customer meets the applicable criteria outlined in Section 3, that Customer may receive unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges.

6. Contesting Creditworthiness Determination

The Transmission Customer may contest Emera Maine's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. Emera Maine will review and respond to the request within 20 calendar days.

7. Process for Changing Credit Requirements

In the event that Emera Maine plans to revise its requirements for credit levels or collateral requirements, as detailed in this Creditworthiness Guide, the following process shall be followed:

A. General Notification Process

1) Emera Maine shall submit such changes in a filing to the Federal Energy Regulatory Commission ("Commission") under Section 205 of the Federal Power Act. Emera Maine shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

2) Emera Maine shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

a) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Guide.

b) Emera Maine shall consult with interested stakeholders upon request.

3) Emera Maine shall consult with ISO-NE and the IRH Management Committee regarding any filing described above, at least 30 days in advance of such filing.

4) Following Commission acceptance of such filing and upon the effective date, Emera Maine shall revise its Creditworthiness Guide and an updated version of Schedule 21-EM shall be posted the ISO-NE website.

B. Transmission Customer Responsibility

1) When there is a change in requirements, it is the responsibility of the Transmission Customers to forward updated financial information to Emera Maine, to the address noted below, and indicate whether the change affects their ability to meet the requirements of this Creditworthiness Guide. In such cases where the customer's status has changed, the Customer must take the necessary steps to comply with the revised requirements of the Creditworthiness Guide by the effective date of the change.

2) Correspondence associated with Creditworthiness should be forwarded to the contact indicated in Emera Maine's Creditworthiness Guide.

C. Notification for Active Customers

1) Active Customers are defined as any current Transmission Customer that has reserved transmission service within the last 6 months.

2) All Active Customers will be notified via either e-mail or U.S. mail that the above posting has been

made and must follow the steps outlined in this procedure.

8. Posting Collateral Requirements

A. Changes in Customer's Financials

Each customer must inform Emera Maine, in writing, within five (5) business days of any material change in its financial condition, and, if the customer qualifies under Section 3A (c), that of its parent company. A material change in financial condition may include, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition, or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

B. Change in Creditworthiness Status

A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in item 4 if one or more of the following conditions apply:

- The customer no longer meets the applicable criteria for Creditworthiness in item 3;
- The customer exceeds the amount of unsecured credit extended by Emera Maine, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or
- The customer has missed two or more payments for any of the Services offered by Emera Maine in

the last 12 months.

9. Ongoing Financial Review

Each customer qualifying under Section 3.A of this Guide is required to submit to Emera Maine annually or when issued, as applicable:

- Current rating agency report;
- Audited financial statements from a registered independent auditor; and
- 10-Ks and 8-Ks, promptly upon their issuance.

10. Suspension of Service

Emera Maine may immediately suspend service (with notification to Commission) to a customer, and may initiate proceedings with Commission to terminate service, if the customer does not meet the terms described in items 3 through 7 at any time during the term of service or if the customer's payment obligations to Emera Maine exceed the amount of unsecured or secured credit to which it is entitled under this Guide. A customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

SCHEDULE 21-CMP

Local Service Schedule

Central Maine Power Company

I. COMMON SERVICE PROVISIONS

This Local Service Schedule, designated Schedule 21-CMP, governs the terms and conditions of service taken by Transmission Customers over Central Maine's Transmission System. In the event of a conflict between the provisions of this Schedule 21-CMP and other provisions of the Tariff, with respect to Local Service, the provisions of this Schedule 21-CMP shall control.

1 Definitions

Whenever used in this Schedule 21-CMP, in either the singular or plural, the following capitalized terms shall have the meanings specified in the Definition Section of this Part I. Terms used in this Schedule 21-CMP but not defined in this Definition Section shall have the meanings specified in Section 1 of the Tariff. Terms used in this Schedule 21-CMP that are not defined in the Tariff, shall have the meanings customarily attributed to such terms by the electric utility industry in New England. Sections, Schedules or Attachments referred to in this Schedule 21-CMP shall mean a section or schedule in or an attachment to this Schedule 21-CMP unless otherwise stated.

1.4 Annual Transmission Revenue Requirement:

The annual revenue requirements of Central Maine's Transmission System for purposes of this Schedule 21-CMP shall be the amount calculated pursuant to the formulas in Attachment G-W and Attachment G-R, as applicable, and as updated each June 1, or until amended by Central Maine or modified by the Commission.

1.6 Backyard Generation (or Behind-The-Meter Generation):

Generation which interconnects directly with a customer's facilities that will offset all or a portion of a customer's electric load requirements. Any generation used to supply any portion of Local Network Load will not qualify for demand credits associated with Backyard Generation. Such credits shall only be applicable to load not designated as Local Network Load. In such instances, the customer shall be responsible for taking and paying for an appropriate level of Local Point-To-Point Transmission Service.

Notwithstanding any other provisions of this Schedule 21-CMP or Tariff, the Local Network Load of transmission-level retail customers with Behind-The-Meter Generation shall be determined in accordance with Schedule No. 12 of this Schedule 21-CMP.

1.7 Central Maine:

The Central Maine Power Company.

1.8 CMP-Owned Interconnection Facilities:

Facilities and equipment, or portions thereof, owned by Central Maine that are necessary to interconnect a customer with Central Maine's Transmission System.

1.13 Control Area Operator:

ISO, or any successor organization or entity, responsible for the continued operation of the New England Control Area and the administration of the Tariff, subject to regulation by the Commission.

1.16 Designated Agent:

Any entity that performs actions or functions required under this Schedule 21-CMP or Tariff on behalf of Central Maine, an Eligible Customer, an Eligible Generator Customer or a Transmission Customer.

1.17 Direct Assignment Facilities:

Facilities or portions of facilities that are constructed by or for Central Maine for (1) the sole use/benefit of a particular Transmission Customer requesting service under this Schedule 21-CMP or (2) the use by a Generator Owner or developer of a generating station requesting to be interconnected to Central Maine's Transmission System. Direct Assignment Facilities shall be specified in the Service Agreement or Interconnection Agreement that in addition to the applicable terms and conditions of this Schedule 21-CMP and OATT governs service to the Transmission Customer; and shall be subject to Commission acceptance.

1.19 Eligible Generator Customer:

Any electric utility or other person generating energy for sale for resale that owns or develops a new generating unit or changes the electrical characteristics of an existing generating unit that is or will be directly interconnected with Central Maine's Transmission System. For purposes of this Schedule 21-CMP, an Eligible Generator Customer is also considered an Eligible Customer as defined in Section I.2.2 of the OATT.

1.26 Interconnection Agreement:

An agreement between Central Maine and an Eligible Customer or an Eligible Generator Customer for Interconnection Service.

1.27 Interconnection Service:

Those services required to electrically connect Transmission Customer's facilities to Central Maine's Transmission System. Interconnection Service includes, but is not limited to, the identification, design, and construction of facilities required to establish and maintain such electrical connection as identified by a completed System Impact Study and Facilities Study. The customer's and Central Maine's contractual obligations associated with Interconnection Service shall be specified in an Interconnection Agreement which shall be executed and filed with the Commission prior to the commencement of such service.

1.30 Load Ratio Share:

Ratio of a Transmission Customer's Local Network Load to Central Maine's total Local Network Load computed in accordance with Sections 21.II.8.b and 21.II.8.c of the Local Network Service under Part III of this Schedule 21-CMP.

1.35 Local Network Load:

The load that a Local Network Customer designates for Local Network Transmission Service under Part III of this Schedule 21-CMP. The Local Network Customer's Local Network Load shall include all load served by the output of any Network Resources designated by the Local Network Customer (including losses) and shall not be credited or reduced for any Backyard Generation. All Local Network Customers shall be required to have installed appropriate metering to determine such Backyard Generation, in accordance with the Network Operating Agreement. A Local Network Customer may elect to designate less than its total load as Local Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete Points of Delivery as Local Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of this Schedule 21-CMP for any Local Point-To-Point Transmission Service that may be necessary for such non-designated load.

Notwithstanding any other provisions of this Schedule 21-CMP and Tariff, the Local Network Load of transmission-level retail customers with Behind-The-Meter Generation shall be determined in accordance with Schedule No. 12 of this Schedule 21-CMP.

1.38 Local Point-To-Point Transmission Service:

Local Point-To-Point Service, including, without limitation, service over CMP-Owned Interconnection Facilities, is a service provided to (1) Eligible Customers, pursuant to Part II of this Schedule 21-CMP by Central Maine over its Local Network, and (2) Eligible Generator Customers that own and develop generating units that are directly interconnected to Central Maine's Transmission System, pursuant to an Interconnection Agreement.

1.40 Native Load Customers:

The wholesale and retail power customers of Central Maine on whose behalf Central Maine, by statute, franchise, regulatory requirement, or contract, has an obligation to construct and operate Central Maine's Transmission System to meet the reliable electric needs of such customers, including but not limited to customers taking service under Schedule No. 12 of this Schedule 21-CMP.

1.45 Network Operating Agreement:

An executed agreement that contains the terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Part II of Schedule 21 and Part III of this Schedule 21-CMP.

1.50 Part I:

The sections of this Schedule 21-CMP containing the definitions and common service provisions.

1.51 Part II:

The sections of this Schedule 21-CMP pertaining to Local Point-To-Point Transmission Service in conjunction with Schedule 21 and the applicable common service provisions of Part I and appropriate Schedules and Attachments.

1.52 Part III:

The sections of this Schedule 21-CMP pertaining to Local Network Transmission Service in conjunction with Schedule 21 and the applicable common service provisions of Part I and appropriate Schedules and Attachments.

1.61 Regional Application:

A request by an Eligible Generator Customer for Interconnection Service submitted to the Control Area Operator pursuant to the provisions of the OATT.

1.71 Transmission Customer:

Any Eligible Customer or Eligible Generator Customer (or its Designated Agent) that (i) executes a Service Agreement or an Interconnection Agreement, or (ii) requests in writing the filing of a proposed unexecuted Service Agreement to receive Transmission Service under Part II of this Schedule 21-CMP. This term is used in the Part I common service provisions to include customers receiving Transmission Service under Part II and Part III of this Schedule 21-CMP.

1.73 Transmission Service:

Transmission service provided over Central Maine's Local Network, designated as Local Network Service or Local Point-To-Point Service that is provided pursuant to Schedule 21 and this Schedule 21-CMP.

1.74 Transmission System:

The facilities owned, controlled or operated by Central Maine that are used to provide Transmission Service under the OATT, Schedule 21 and Part II and Part III of this Schedule 21-CMP. Central Maine's Transmission System consists of two parts: (1) those transmission facilities which qualify as PTF in accordance with section 49 of the OATT and (2) those remaining transmission facilities which constitute Central Maine's Local Network.

2 Purpose of This Schedule 21-CMP

This Schedule 21-CMP is intended to provide Transmission Service as a compliment to the regional service to be provided under the OATT which is a two-tier transmission arrangement integrating regional service which is provided under the OATT, and Local Network Service and Point-To-Point Service, including, without limitation, service over CMP-Owned Interconnection Facilities as provided under Schedule 21 and this Schedule 21-CMP.

In addition, this Schedule 21-CMP is designed to implement services related to retail access in the State of Maine. Accordingly, the rate schedules and associated service agreements allow Central Maine to act as the agent for its distribution-level customers for the purpose of arranging and obtaining Regional Network Service pursuant to the OATT. Similarly, Central Maine can act as the agent for a transmission-level customer, if such a customer so requests, and certain designated conditions are fulfilled. To the extent any of the provisions in Schedule 12 of this Schedule 21-CMP contradict any of the terms located elsewhere in this Tariff, the provisions in Schedule 12 shall govern for service to retail customers.

3 Reserved:

4 Ancillary Services

Ancillary Services are needed with Transmission Service to maintain reliability within the New England Control Area.

4.1 Ancillary Services supporting Transmission Service over PTF:

Ancillary Services to support Transmission Service over PTF are provided pursuant to the OATT.

4.2 Ancillary Services supporting Transmission Service over Central Maine's Local Network:

Pursuant to this Schedule 21-CMP, Central Maine will provide and the Transmission Customer is required to purchase from Central Maine, for all Transmission Services provided over its Local Network: Scheduling, System Control and Dispatch Service.

4.3 Unauthorized Use, Pricing and Discounts:

In the event of an unauthorized use of any Ancillary Service by the Transmission Customer, the Transmission Customer will be required to pay the charge, excluding any discount offered, which would otherwise be applicable. Such charge shall apply for the period of unreserved use.

The specific Ancillary Services, prices and/or compensation methods are described in the OATT and in this Schedule 21-CMP on the Schedules that are attached to and made part of this Schedule 21-CMP and OATT. Three principle requirements apply to discounts for Ancillary Services provided by Central Maine in conjunction with its provision of Transmission Service as follows: (1) any offer of a discount made by the Central Maine must be announced to all Eligible Customers and Eligible Generator Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by Central Maine's wholesale merchant or an Affiliate's use, if any) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an

Ancillary Service must be offered for the same period to all Eligible Customers and Eligible Generator Customers on Central Maine's Local Network.

4.4 Descriptions and Rate Schedules for Ancillary Services:

Sections 4.4.1 below lists the Ancillary Services that Central Maine provides.

4.4.1 Scheduling, System Control and Dispatch Service:

The rates and/or methodology are described in Schedule 1 of this Schedule 21-CMP when provided by Central Maine.

8 Billing and Payment

8.1 Billing Procedure:

Within a reasonable time after the first day of each month, Central Maine shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Schedule 21-CMP during the preceding month. The invoice shall be paid by the Transmission Customer within ten (10) days of receipt. All payments shall be made, in accordance with the procedure specified by Central Maine in immediately available funds payable to Central Maine, or by wire transfer to a bank named by Central Maine.

8.3 Customer Default:

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to Central Maine on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after Central Maine notifies the Transmission Customer to cure such failure, or if the Transmission Customer violates any provision of its Service Agreement, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, Central Maine may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between Central Maine and the Transmission Customer, Central Maine will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then Central Maine may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with applicable Commission rules and regulations, and may proceed with such suspension.

10 Regulatory Filings

10.2 Informational Filings

By June 30 of each year, Central Maine shall submit to FERC an informational filing which identifies: (a) the data used to update any formula rates that year, with specific references to Central Maine's FERC Form 1 when applicable; (b) the calculations performed using that data; (c) the results of such calculations; and (d) the basis for any adjustment to the CCS Charge described in Schedule No. 1. When the data used in the formula rates is not identical to data found in FERC Form 1, Central Maine shall include supporting materials. Copies of the informational filing shall be served on FERC Staff, the Maine Public Utilities Commission, and any other party that sends a written request for a copy of the informational filing, such request to be sent no earlier than May 1 of the year in which the informational filing is being requested, and to include the name and address where the copy of the informational filing is to be sent. Copies of the informational filing shall be sent by first class mail.

Within 45 days of the date on which Central Maine submits the informational filing to FERC, the FERC Staff, the Maine Public Utilities Commission, and any party that has requested the informational filing for that year, may submit discovery requests to Central Maine. Central Maine shall make a good faith effort to respond within 10 days of the date on which each particular request is sent. However, such discovery requests are to be limited in scope to the accuracy of the data inputs used in the formula rates, the accuracy of the calculations done using those data inputs, whether Central Maine has properly applied the formula rate, and the accuracy of the data and calculation underlying the adjustment to the CCS Charge. Central Maine shall not be required to respond to discovery requests addressing any other matters. Within 60 days of the date on which Central Maine submits its informational filing to FERC, the FERC Staff, the Maine Public Utilities Commission, and any other party that has requested Central Maine's informational filing, may contest: (1) the accuracy of the data inputs used in the formula rates; (2) the accuracy of the calculations performed using those data inputs; (3) whether Central Maine has properly applied the formula rate; and (4) the accuracy of the data and calculations underlying the adjustment to the CCS Charge. Central Maine and the contesting party shall attempt to resolve any such issues informally. Central Maine shall not be required to respond to any matters raised that are beyond the scope described in (1), (2) (3) or (4). Nor shall Central Maine be required to respond to any matters that are raised more the 60 days after the date on which Central Maine submitted its informational filing to FERC, whether within the scope of (1), (2) (3) and (4), or not. Nothing in this Section 10.2 shall limit the rights of FERC and the Maine Public Utilities Commission to investigate and rule on Central Maine's rates under applicable law. Nor shall this Section 10.2 limit the rights of any party to contest the prudence of any additional costs included in the informational filing under Section 206 of the Federal Power Act.

11 Force Majeure and Indemnification

11.1 Force Majeure:

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, any order, regulation or restriction imposed by a court or governmental military or lawfully established civilian authorities, or any other cause beyond a party's control. Neither Central Maine nor the Transmission Customer will be considered in default as to any obligation under or related to this Schedule 21-CMP if prevented from fulfilling the obligation due to an event of Force Majeure; provided that no event of Force Majeure shall excuse any payment obligation hereunder or under a Service Agreement. However, a party whose performance under or related to this Schedule 21-CMP is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under or related to this Schedule 21-CMP, and shall promptly notify Central Maine or the Transmission Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure

11.2 Indemnification:

The Transmission Customer shall at all times indemnify, defend, and save Central Maine harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from Central Maine's performance of its obligations under or related to this Schedule 21-CMP on behalf of the Transmission Customer or resulting from the Transmission Customer's acts or omissions under or related to this Schedule 21-CMP, except to the extent that Central Maine is found liable for gross negligence or intentional wrongdoing. For the purposes of this Section 11.2, the term "third parties” includes without limitation, customers under the Tariff, ISO and any other Transmission Owners.

11.3 Limitations of Liability

Central Maine shall not be liable (whether based on contract, indemnification, warranty, tort, strict liability or otherwise) for money damages or other compensation to the Transmission Customer for actions or omissions by Central Maine in performing its obligations under or related to Schedule 21-CMP, or any Service Agreement hereunder, except to the extent that Central Maine is found liable for gross negligence or intentional misconduct and in which case Central Maine shall be liable for only actual direct damages. To the extent the Transmission Customer has claims against Central Maine, the Transmission Customer may only look to the assets of Central Maine for the enforcement of such claims and may not seek to enforce any claims against the Affiliates of Central Maine or the respective directors, members, officers, employees or agents of Central Maine or any of its Affiliates who the Transmission Customer acknowledges and agrees have no personal or other liability for obligations of Central Maine by reason of their status as Affiliates or directors, members, officers, employees or agents of Central Maine or any of its Affiliates. In no event shall Central Maine be liable for any incidental, consequential, multiple, punitive, special, exemplary, or indirect damages, or loss of revenues or profits, attorneys fees or costs arising out of, or connected in any way with the performance or non-performance of this Schedule 21-CMP or any Service Agreement hereunder, even if such damages are foreseeable or the damaged party has advised Central Maine of the possibility of such damages and regardless of whether any such damages are deemed to result from the failure or inadequacy of any exclusive or other remedy.

11.4 Survival:

The provisions of this Section 11 survive termination or expiration of this Schedule 21 or a Service Agreement hereunder.

12 Creditworthiness

For the purpose of determining the ability of the Transmission Customer, or the Eligible Generator Customer taking Interconnection Service, to meet its obligations related to service hereunder, Central Maine may require reasonable credit review procedures in accordance with Attachment L of Schedule 21-CMP.

13 Dispute Resolution Procedures

13.1 Internal Dispute Resolution Procedures:

Any dispute between a Transmission Customer and Central Maine involving Transmission Service under this Schedule 21-CMP (excluding applications for rate changes or other changes to this Schedule 21-CMP, or to any Service Agreement entered into under this Schedule 21-CMP, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of Central Maine and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days or such other period as the parties may agree upon by mutual agreement, such dispute may be submitted to mediation and/or arbitration and resolved in accordance with the arbitration procedures set forth in Section I.6 of the Tariff.

13.2 Rights Under The Federal Power Act:

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission, or seek any other available remedy, under relevant provisions of the Federal Power Act.

II. LOCAL POINT-TO POINT TRANSMISSION SERVICE

Preamble

Firm and Non-Firm Local Point-To-Point Transmission Service over Central Maine's Local Network will be provided pursuant to the applicable terms and conditions of Schedule 21 and this Schedule 21-CMP. Local Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

Central Maine will provide Interconnection Service to owners and developers of generating units directly interconnected to Central Maine's Transmission System in accordance with an Interconnection Agreement between Central Maine and the Eligible Customer or Eligible Generator Customer.

21.I.1 Nature of Firm Local Point-To-Point Transmission Service

21.I.1.d Service Agreements:

A standard form Firm Local Point-To-Point Transmission Service Agreement shall be offered to: (1) an Eligible Generator Customer upon completion of a System Impact Study when no new transmission facilities are required; or (2) an Eligible Generator Customer upon the completion of a Facilities Study or prior to the commencement of construction when new transmission facilities are required. Service Agreements for daily and weekly reservations may be treated as blanket service agreements (i.e., covering more than a single transaction) so long as the Transmission Customer deposits an amount, as described in Section 21.I.5.c, equal to the monthly cost of Transmission Service associated with the Transmission Customer's anticipated maximum transmission reservation request (MWs). If the Transmission Customer exceeds that anticipated maximum, the Transmission Customer shall increase its deposit.

21.I.1.g Classification of Firm Local Transmission Service:

(i) The Transmission Customer taking Firm Local Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 10.a of Schedule 21 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 10.b of Schedule 21 provided that if Central Maine or another entity has constructed new facilities or upgraded facilities to accommodate the original firm service, Central Maine shall continue to be compensated for its facility costs by the Transmission Customer.

(iii) The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7 of this Schedule 21-CMP. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 10 of Schedule 21.

(iv) In the event that a Transmission Customer exceeds its firm Reserved Capacity in any single hour at any Point of Receipt or Point of Delivery, Central Maine shall require that Transmission Customer to apply for additional Firm Local Point-to-Point Transmission Service under this Schedule 21-CMP. The additional Transmission Service shall be for an amount equal to the greatest amount of such excess over its firm Reserved Capacity for the remainder of the term of the Service Agreement. Charges for such additional service will relate back to the first day of the month following the month in which Central Maine notifies such Transmission Customer that it is subject to the provisions of this paragraph. This charge shall apply until either:

(a) the Transmission Customer applies for and receives Local Network Transmission Service under Part III to replace the service provided by Local Point-to-Point Transmission Service; or

(b) the Transmission Customer modifies its facilities in such a way, at customer's expense, to ensure that the Transmission Customer will not exceed its firm Reserved Capacity during the remaining term of the Service Agreement.

21.I.2 Nature of Non-Firm Local Point-To-Point Transmission Service

21.I.2.d Service Agreements:

Service Agreements for daily and weekly reservation may be treated as blanket service agreements (i.e., covering more than a single transaction).

21.I.2.e Classification of Non-Firm Local Point-To-Point Transmission Service:

(i) Reserved

(ii) In the event that a Transmission Customer exceeds its non-firm Reserved Capacity in any single hour at any Point of Receipt or Point of Delivery, Central Maine shall require that Transmission Customer to apply for additional non-firm Local Point-to-Point Transmission Service under Schedule 21 and this Schedule 21-CMP. The additional Transmission Service shall be for an amount equal to the greatest amount of such excess over its Non-Firm Reserved Capacity for the remainder of the term of the Service Agreement. Charges for such additional service will relate back to the first day of the month following the month in which Central Maine notifies such Transmission Customer that it is subject to the provisions of this paragraph. This charge shall apply until either:

(a) the Transmission Customer applies for and receives Local Network Transmission Service under Part III to replace the service provided by Local Point-to-Point Transmission Service; or

(b) the Transmission Customer modifies its facilities in such a way, at customer's expense, to ensure that the Transmission Customer will not exceed its non-firm Reserved Capacity during the remaining term of the Service Agreement.

21.I.3 Service Availability

21.I.3.b Determination of Available Transfer Capability:

A description of the specific methodology for assessing available transfer capability (ATC) over PTF that is posted on the OASIS is contained in the OATT. Central Maine's specific methodology for assessing ATC over its Local Network which is posted on the OASIS is contained in Attachment C of this Schedule 21-CMP. In the event sufficient Local Network transfer capability may not exist to accommodate a service request, Central Maine will, at the request of an Eligible Customer or an Eligible Generator Customer, respond by performing a System Impact Study.

21.I.3.c Initiating Service in the Absence of an Executed Service Agreement:

If the Transmission Customer refuses, or otherwise does not provide written notice to Central Maine and/or the ISO, as applicable, directing Central Maine and/or the ISO, as applicable, to file an unexecuted Local Service Agreement, the ISO and/or Central Maine, as applicable, may make such a filing prior to the commencement of service. Transmission Service shall commence and the Transmission Customer shall be obligated to (i) compensate Central Maine at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of this Tariff including posting appropriate security deposits in accordance with the terms of Section 21.I.5.c.

21.I.3.g Real Power Losses:

Real Power Losses are associated with all Transmission Service. Neither the ISO nor Central Maine are obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all Transmission Service as calculated by Central Maine or the Control Area Operator. In cases where Central Maine or the Control Area Operator does not determine and allocate the actual losses, such losses shall be set at 1.5 percent for demand and 0.9 percent for energy.

21.I.3.h Load Shedding:

To the extent that system contingency exists on Central Maine's Transmission System, and Central Maine determines shedding of load is necessary, the parties shall shed load in accordance with procedures under the Tariff and the rules adopted thereunder, or in accordance with other mutually agreed to provisions.

21.I.4 Transmission Customer Responsibilities

21.I.4.a Conditions Required of Transmission Customers:

Local Point-To-Point Transmission Service and Interconnection Service shall be provided only if the following conditions are satisfied by the Transmission Customer:

(i) The Transmission Customer has pending a Completed Application for Local Service or a Completed Application for regional service, as applicable;

(ii) The Transmission Customer or Eligible Generator Customer meets the creditworthiness criteria set forth in Section 12;

(iii) The Transmission Customer or Eligible Generator Customer will have arrangements in place for any other Transmission Service necessary to effect the delivery from the generating source to Central Maine prior to the time service under Schedule 21 and Part II of this Schedule 21-CMP commences;

(iv) The Transmission Customer or Eligible Generator Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer or Eligible Generator Customer under Schedule 21 and Part II of this Schedule 21-CMP, whether or not the Transmission Customer or Eligible Generator Customer takes service for the full term of its reservation; and

(v) The Transmission Customer or Eligible Generator Customer has executed a Local Point-To-Point Transmission Service Agreement or has agreed to receive service pursuant to Section 21.I.3.c.

21.I.5 Procedures for Arranging Firm Local Point-To-Point Transmission Service

21.I.5.a Application:

All Eligible Generator Customers requesting Interconnection Service shall be required to submit a Regional Application for service to the Control Area Operator in accordance with the relevant provisions of the OATT. Upon notification by the Control Area Operator of its receipt of a Regional Application, Central Maine shall determine whether any Transmission or Ancillary

Services provided under Schedule 21 and this Schedule 21-CMP will be applicable to the Eligible Generator Customer. To the extent such services provided under Schedule 21 and this Schedule 21-CMP are applicable, the customer will be notified by tendering a Transmission Service Agreement which shall be executed and filed with the Commission, or filed with the Commission unexecuted as provided for in Schedule 21 and Section 21.I.3.c of this Schedule 21-CMP.

21.I.5.c Deposit:

A Completed Application for Firm Local Point-To-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or, if the Application is for a specific Short-Term Firm Local Point-To-Point Transmission Service, the full charge for Reserved Capacity for service requests of less than one month, including charges for Transmission Service and all applicable Ancillary Services. In the alternative, a Transmission Customer may pay in advance the total expected charge for all services requested.

If the Transmission Customer subsequently enters into a System Impact Study Agreement, which may result in a modification to or an upgrade of Central Maine's Transmission System, or construction of Direct Assignment Facilities to provide the requested service, the deposit shall be based on the average monthly rate for Firm Local Point-To-Point Transmission Service as stated in Schedule 7. Once the Transmission Customer's monthly financial obligation is determined at the conclusion of the Facilities Study, the Transmission Customer's deposit shall be adjusted accordingly.

If the local Application is for "umbrella" Short-Term Firm Local Point-To-Point Transmission Service, the Transmission Customer must specify in the local Application the maximum capacity and maximum duration expected to be requested which shall be the basis for the deposit required, subject to this Section 21.I.5.c. The deposit shall be based on that maximum capacity and duration, and shall equal the lesser of (a) three (3) months full charges or (b) charges associated with the maximum duration. In the alternative, a Transmission Customer may pay, at least 24 hours before the requested service is to commence, the total expected charge for each request for such Short-Term Firm Local Point-To-Point Transmission Service. In lieu of a cash deposit, Central Maine will accept an irrevocable letter of credit of equal value from a financial institution acceptable to Central Maine. A letter of credit in a form that Central Maine would find generally acceptable is appended as Attachment J to this Schedule 21-CMP.

21.I.5.d Notice of Deficient Application:

If the Control Area Operator, independently or in conjunction with Central Maine, determines that a Regional Application for Interconnection Service fails to satisfy the relevant requirements, the process described in the applicable provisions of the OATT shall apply.

21.I.5.e Response to a Completed Application:

Following submission to the Control Area Operator of a Regional Application by an Eligible Generator Customer, Central Maine will not take any action until it receives a System Impact Study Agreement from the Control Area Operator.

21.I.5.f Execution of Service Agreement:

For service requested by an Eligible Generator Customer, whenever Central Maine determines that a System Impact Study is not required and that the service can be provided, it shall notify the Control Area Operator and the Eligible Generator Customer as soon as practicable but no later than thirty (30) days after receiving notice from the Control Area Operator of the Completed Regional Application. Failure of an Eligible Generator Customer to execute and return the Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section 21.I.3.c, within fifteen (15) days after it is tendered will be deemed a withdrawal and termination of the Regional Application and any deposit submitted shall be refunded with Interest. Nothing herein limits the right of an Eligible Generator Customer to file another Regional Application after such withdrawal and termination. Where a System Impact Study is required, the provisions of Section 21.I.7 of Schedule 21 will govern the execution of a Service Agreement.

21.I.6. Procedures for Arranging Non-Firm Local Point-To-Point Transmission Service

21.I.6.f Determination of Available Transfer Capability:

Following receipt of a tendered schedule Central Maine will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 21.I.3.b of this Schedule 21-CMP. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.

21.I.7 Additional Study Procedures For Firm Local Point-To-Point Transmission Service Requests

21.I.7.a Notice of Need for System Impact Study:

If the request for service has been made pursuant to a Regional Application and Central Maine determines that a System Impact Study is necessary to accommodate the requested service, Central Maine shall so inform the Control Area Operator and the Eligible Generator Customer as soon as practicable. In such cases, Central Maine shall enter into a System Impact Study Agreement with the Control Area Operator or the Eligible Generator Customer, or both, as applicable, provided that the agreement requires the Eligible Generator Customer to reimburse Central Maine for performing the required System Impact Study. Central Maine shall not engage in any activity related to the System Impact Study until the Eligible Customer executes and delivers the System Impact Study Agreement to Central Maine. If the Eligible Generator Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn.

21.I.12 Metering and Power Factor Correction at Receipt and Delivery Points(s)

21.I.12.a Transmission Customer Obligations:

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of this Tariff and to communicate the information to Central Maine. Unless otherwise agreed, such equipment shall remain the property of Central Maine.

21.I.12.c Power Factor:

Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as Central Maine pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable. Where a Transmission Customer fails to maintain a power factor within the same range as Central Maine pursuant to Good Utility Practices, Central Maine may make whatever improvements or repairs are required to restore or maintain the power factor, and charge the Transmission Customer accordingly.

21.I.13 Compensation for Local Point-To-Point Transmission Service

Rates for Firm and Non-Firm Local Point-To-Point Transmission Service are provided in the Schedules appended to this Schedule 21-CMP: Firm Local Point-To-Point Transmission Service (Schedule 7); and Non-Firm Local Point-To-Point Transmission Service (Schedule 8); Retail Access Transmission and Distribution Services (Schedule 12); Monthly Carrying Charge For Meter Services (Schedule 13); and Monthly Carrying Charge For Direct Assignment Facilities (Schedule 14).

When a generator interconnected with Central Maine's non-PTF system: (1) wheels power to a wholesale load located on New York State Electric & Gas Corporation's system or (2) wheels power through New York State Electric & Gas Corporation's system to a point in the PJM control area, and in either case is subject to the New York State Electric & Gas Corporation Transmission Service Charge pursuant to the New York Independent System Operator Open Access Transmission Tariff or (3) wheels power to a wholesale load located on Rochester Gas and Electric Corporation's system and is subject to the Rochester Gas and Electric Corporation Transmission Service Charge under the New York Independent System Operator Open Access Transmission Tariff, Central Maine will waive its Transmission Service charge for Local Point-To-Point Transmission Service, which is described in Schedule Nos. 7 and 8 of this Schedule 21-CMP, each month said Transmission Service Charge under the New York Independent System Operator Open Access Transmission Tariff exceeds the applicable Central Maine Local Point-To-Point Transmission Service charge. The Eligible Generator Customer shall provide CMP with written notice when a wheeling transaction is subject to both a charge for Local Point-To-Point Transmission Service on CMP's system and a New York State Electric & Gas Corporation or Rochester Gas and Electric Corporation Transmission Service Charge under the New York Independent System Operator Open Access Transmission Tariff. Upon receipt of such notice, Central Maine will coordinate with New York State Electric & Gas Corporation or Rochester Gas and Electric Corporation to identify charges so that Central Maine can determine when to waive its Transmission Service charge pursuant to this paragraph.

When a generator interconnected with Central Maine's Non-PTF system wheels power to a retail load located on New York State Electric & Gas Corporation's system or Rochester Gas and Electric Corporation's system pursuant to the applicable retail access program approved by the New York Public Service Commission, Central Maine will waive its Transmission Service charge for Local Point-To-Point Transmission Service. As used in this paragraph, the terms "Transmission Service charge" under the Schedule 21-CMP and the New York State Electric & Gas Corporation or Rochester Gas and Electric Corporation "Transmission Service Charge" under the New York Independent System Operator Open Access Transmission Tariff include only the embedded cost charge defined in the applicable tariff and no other charges. For example, the calculation and waiver of charges discussed in this paragraph do not include calculations or waivers of Ancillary Service charges, Congestion charges, losses, contributions in aid of construction, or Direct Assignment Facilities charges, the application of which will remain unchanged by this paragraph.

21.I.15 Interconnection Service

Any entity proposing to interconnect with Central Maine's transmission facilities, that is not party to an agreement executed on or before July 9, 1996, in which Interconnection Service is addressed, that (1) proposes to site a new generating unit and directly interconnect to Central Maine's Transmission System, or (2) proposes to materially change electrical characteristics or increase the capacity of an existing generating unit and remain connected to Central Maine's Transmission System, shall submit an Application for Interconnection Service to the Control Area Operator and shall comply with applicable provisions of this Schedule 21-CMP, the OATT, and the Interconnection Agreement. The Transmission Customer shall enter into an Interconnection Agreement or an interim construction agreement with Central Maine, at Central Maine's discretion, prior to the construction of any facilities required to provide the requested service as identified in the System Impact Study and Facilities Study.

III. LOCAL NETWORK SERVICE

21.II.2.f Real Power Losses:

Real Power Losses are associated with all Transmission Service. The ISO or Central Maine is not obligated to provide Real Power Losses. The Local Network Customer is responsible for replacing losses associated with all Transmission Service as calculated by Central Maine or the Control Area Operator. The applicable Real Power Losses will be calculated according to procedures set by Central Maine or the Control Area Operator. In cases where Central Maine or the Control Area Operator does not determine and allocate the actual losses, such losses shall be set at 1.5 percent for demand and 0.9 percent for energy.

21.II.3 Initiating Service

21.II.3.a Condition Precedent for Receiving Service:

Local Network Transmission Service will be provided only if the Eligible Customer satisfies the conditions in Section 3.a of Schedule 21 and executes a Local Network Operating Agreement with Central Maine pursuant to Attachment F to this Schedule 21-CMP. Central Maine shall serve as the Designated Agent for all of its distribution-level retail customers participating in Maine's retail access program. As their agent, Central Maine shall assume all responsibilities under Schedule 21.II, Sections 3 and 4, including all associated subsections of this Schedule 21-CMP on their behalf. All of Central Maine's retail transmission-level customers may either take unbundled service directly under the terms of this OATT or may designate Central Maine to serve as their agent to arrange and maintain network service under the terms of the OATT.

21.II.3.b Application Procedures:

The applicable deposit related to the provisions described in Section 3.b of Schedule 21.II for Part III of this Schedule 21-CMP is a deposit approximating the charge for one month of service.

21.II.4 Network Resources

21.II.4.d Operation of Network Resources:

The Local Network Customer shall not operate its designated Network Resources, which are not subject to central dispatch by the Control Area Operator, such that the output of those facilities exceeds it's designated Local Network Load, plus non-firm sales delivered pursuant to Part II of this Schedule 21-CMP, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of Central Maine to respond to an emergency or other unforeseen condition that may impair or degrade the reliability of the Transmission System.

21.II.4.f Transmission Arrangements for Network Resources Not Physically Interconnected With Central Maine's Local Network:

The customer shall be obligated to reimburse Central Maine for all costs Central Maine incurs in assisting the customer in obtaining such arrangements. Upon the customer's request, Central Maine shall provide the Transmission Customer an estimate of such costs before they are incurred. Upon the customer's request, Central Maine shall provide reasonable itemization of such costs along with any invoice related to those costs.

21.II.4.i Use of Interface Capacity by the Local Network Customer:

There is no limitation upon a Local Network Customer's use of Central Maine's Local Network Transmission System at any particular interface to integrate the Local Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, a

Local Network Customer's use of the Central Maine's total interface capacity with other Transmission Systems may not exceed the Customer's Local Network Load.

21.II.5 Designation of Load

21.II.5.c Network Load Not Physically Interconnected with Central Maine's Local Network:

Central Maine shall include such load as part of a Transmission Customer's Local Network Load only if a scheduling and Interconnection Agreement acceptable to Central Maine is in effect with the Control Area in which the load is located.

21.II.6 Additional Study Procedures For Local Network Transmission Service Requests

21.II.6.d Facilities Study Procedures:

If a System Impact Study indicates that additions or upgrades to the Local Network Transmission System are needed to supply the Eligible Generator Customer's request for Interconnection Service, Central Maine shall execute a Facilities Study Agreement, as directed by the Control Area Operator, with the Eligible Generator Customer. For a service request to remain a Completed Regional Application, the Eligible Generator Customer shall execute the Facilities Study Agreement in a timely manner. If the Eligible Generator Customer elects not to execute the Facilities Study Agreement, its Regional Application shall be deemed withdrawn and its deposit (less reasonable Administrative Costs incurred by Central Maine) shall be returned with Interest.

21.II.7 Load Shedding and Curtailments

21.II.7.a Procedures:

Prior to the Service Commencement Date, Central Maine and the Local Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Local Network Operating Agreement with the objective of responding to contingencies on the Local Network Transmission System. The parties will implement such programs during any period when Central Maine determines that a system contingency exists and such procedures are necessary to alleviate such contingency. Central Maine will notify all affected Local Network Customers in a timely manner of any scheduled Curtailment.

21.II.7.b Transmission Constraints:

During any period when Central Maine determines that a transmission constraint exists on the Local Network Transmission System, and such constraint may impair the reliability of Central Maine's system, Central Maine will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of Central Maine's system. To the extent either Central Maine or the Control Area Operator determine that the reliability of the Transmission System can be maintained by redispatching resources, Central Maine can initiate procedures pursuant to the Local Network Operating Agreement, the Tariff, and other Control Area Operator rules and procedures including, without limitation, Market Rule 1. Any redispatch under this Section may not unduly discriminate between Central Maine's use of the Local Network Transmission System on behalf of its Native Load Customers and any Local Network Customer's use of the Local Network Transmission System to serve its designated Local Network Load.

21.II.7.d Curtailments of Scheduled Deliveries:

If a transmission constraint on Central Maine's Local Network Transmission System cannot be relieved through the implementation of redispatch procedures and the Control Area Operator or Central Maine, under the Control Area Operator's direction, determines that it is necessary to curtail scheduled deliveries, the parties shall curtail such schedules in accordance with any applicable provisions of the Local Network Operating Agreement, the Tariff and any Control Area Operator rules and procedures including, without limitation, Market Rule 1.

21.II.7.f Load Shedding:

To the extent that a system contingency exists on Central Maine's or the New England Transmission System and Central Maine or the ISO determines that it is necessary for Central Maine and the Local Network Customer to shed load, the parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement, or in accordance with other mutually agreed to provisions.

21.II.7.g System Reliability:

Notwithstanding any other provisions of this Tariff, Central Maine and the Control Area Operator reserve the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to curtail Local Network Transmission Service without liability on Central Maine's or the Control Area Operator's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Local Network

Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on Central Maine's Transmission System or on any other system(s) directly or indirectly interconnected with Central Maine's Transmission System, including without limitation all PTF, Central Maine or the Control Area Operator, consistent with Good Utility Practice, also may curtail Local Network Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. Central Maine or the Control Area Operator shall give the Local Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Transmission Service will be not unduly discriminatory relative to Central Maine's use of the Local Network Transmission System on behalf of its Native Load Customers. Central Maine shall specify the rate treatment and all related terms and conditions applicable in the event that the Local Network Customer fails to respond to established Load Shedding and Curtailment procedures.

21.II.8 Rates and Charges

Retail customers taking unbundled Transmission Service do so pursuant to the rates described in Schedule 12 of this Schedule 21-CMP. Otherwise, The Local Network Customer shall pay Central Maine for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

21.II.8.a Monthly Demand Charge:

The Local Network Customer shall pay a monthly demand dharge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of Central Maine's Annual Transmission Revenue Requirement. The Annual Transmission Revenue Requirement is calculated pursuant to Attachment G-R or Attachment G-W as applicable.

21.II.8.b Determination of Local Network Customer's Monthly Local Network Load:

The Local Network Customer's monthly Local Network Load is its hourly load (including its designated Local Network Load not physically interconnected with Central Maine's Local Network under Section 21.II.5.c) coincident with Central Maine's Monthly Local Network Transmission System peak.

21.II.8.c Determination of Central Maine's Monthly Local Network Transmission System Load:

Central Maine's monthly Local Network Transmission System load is Central Maine's Monthly Local Network Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Transmission Service customers pursuant to Schedule 21 and Part II of this Schedule 21-CMP plus the Reserved Capacity of all Firm Local Point-To-Point Transmission Service Customers.

21.II.8.d Redispatch Charge:

All costs associated with redispatch of resources shall be charged and allocated in accordance with the Tariff and any Control Area Operator rules and procedures including, without limitation, Market Rule 1.

21.II.8.e Stranded Cost Recovery:

Central Maine may seek to recover stranded costs from the Local Network Customer pursuant to this Schedule 21 in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, Central Maine must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

21.II.10 Operating Arrangements

21.II.10.a Operation under The Local Network Operating Agreement:

The Local Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement. If Central Maine and the Local Network Customer agree in the Interconnection Agreement, the Interconnection Agreement can serve as a Local Network Operating Agreement.

21.II.10.b Local Network Operating Agreement:

The terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Schedule 21 and Part III of this Schedule 21-CMP shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the parties to (i) operate and maintain equipment necessary for integrating the Local Network Customer within Central Maine's Local Network Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between Central Maine and the Local Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside Central Maine's Local Network Transmission System, interchange schedules, unit outputs for redispatch required under Section21.II.7, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Schedule 21 and Part III of this Schedule 21-CMP, including scheduling protocols. The Local Network Operating Agreement will recognize that the Local Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with Central Maine for Ancillary Service No. 1 and contracting with the Control Area Operator for Ancillary Service Nos. 2 through 6 or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services which may be provided by another entity, by contracting with another entity, consistent with Good Utility Practice, which satisfies any applicable requirements imposed by NERC, the NPCC, Central Maine or the Control Area Operator. For those Ancillary Services that may be provided by another entity, Central Maine shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Local Network Operating Agreement is included in Attachment F.

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into Central Maine's Local Network Control Area. Central Maine or its designee responsible for operating the Local Network can only provide this service, and the Transmission Customer must purchase this service from Central Maine or its designee. As set forth in Section 4, the Transmission Customer is required to purchase this Ancillary Service from Central Maine. The charges for Scheduling, System Control and Dispatch Service are to be based on the formula rate set forth below.

This formula sets forth the details for determining the annual revenue requirement for Scheduling, System Control and Dispatch Service. The revenue requirement reflects the cost of owning, operating and maintaining Central Maine's Local Control Center used for providing Scheduling, System Control and Dispatch Service to customers under this Schedule 21. The term "Local Control Center" used throughout this formula refers to Central Maine's entire system dispatch control center operation. Central Maine's system dispatch control center is comprised of the system dispatch center, which provides services at the regional or PTF level, and the local area dispatch center for services over Central Maine's Local Network.

The Revenue Requirement will be an annual formula rate calculation, effective for an initial term commencing on March 1, 2000 and ending on May 31, 2000, based on 1998 test year data, and updated thereafter each June 1, based on the previous calendar year's FERC Form 1 data, as shown below, using end-of-year balances for each rate base item, as further set forth below.

I. DEFINITIONS

Capitalized terms not otherwise defined in the OATT and in Section 1 of Schedule 21-CMP have the following definitions:

A. ALLOCATION FACTORS

1. <u>Wages and Salaries Allocation Factor</u> shall equal the ratio of the Local Control Center Direct Wages and Salaries to total direct wages and salaries excluding administrative and general wages and salaries.

2. Local Control Center Wages and Salaries Allocation Factor shall equal the ratio of the Transmission Local Control Center Direct Wages and Salaries to total Local Control Center Direct Wages and Salaries.

3. Local Control Center Plant Allocation Factor shall equal the ratio of the total Investment in Local Control Center Related Plant to Total Plant in service.

B. TERMS

Administrative and General Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928, and 930.1.

Amortization of Investment Tax Credits shall equal Central Maine's credits as recorded in FERC Account No. 411.4

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of Central Maine's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in Central Maine's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of Central Maine's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Central Maine's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in Central Maine's FERC Account Nos. 408.1.

Prepayments shall equal Central Maine's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Central Maine's expenses as recorded in FERC Account No. 924.

Local Control Center Direct Wages and Salaries shall equal Central Maine's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account Nos. 556, 561-561.4, and 581.

Local Control Center Operation and Maintenance Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 556, 561-561.4, and 581.

Local Control Center Plant Depreciation Reserve shall equal Central Maine's depreciation reserve balance for Local Control Center Related Plant as recorded in FERC Account Nos. 108 and 111.

Local Control Center Plant Materials and Supplies shall equal Central Maine's balance as recorded in FERC Account No. 154.

Local Control Center Related Depreciation Expense shall equal Central Maine's depreciation and amortization expense for Local Control Center Related Plant as recorded in FERC Account Nos. 403 and 404.

Local Control Center Related Plant shall equal Central Maine's gross plant balances used for system control and dispatch purposes and the Local Control Center related portion of intangible and general plant as recorded in FERC Account Nos. 301-399. To the extent that such plant includes any amounts recorded as transmission investment in FERC Account Nos. 350-359, such amounts will be excluded for purposes of determining Annual Transmission Revenue Requirements pursuant the formula in Attachment G to this Schedule 21-CMP. Local Control Center Related intangible and general plant shall equal the sum of Central Maine's balances in FERC Account Nos. 301-303 and 389-399, not otherwise directly assigned under this Schedule 21-CMP, multiplied by the Wages and Salaries Allocation Factor.

Local Control Center Support Revenues shall equal the revenues received from Local Control Center supporters as recorded in FERC Account Nos. 454 and 456, excluding any revenues received under Schedule 1 of this Schedule 21-CMP or Schedule 1 of the OATT.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and 190.

Total Municipal Tax Expense shall equal Central Maine's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal Central Maine's total gross plant balance as recorded in FERC Account Nos. 301-399.

Transmission Local Control Center Direct Wages and Salaries shall equal Central Maine's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account Nos. 561-561.4.

II. CALCULATION OF TOTAL LOCAL CONTROL CENTER REVENUE REQUIREMENTS

The Local Control Center Revenue Requirement shall equal the sum of the Local Control Center related (A) Return and Associated Income Taxes, (B) Depreciation Expense, (C) Amortization of Investment Tax Credits, (D) Municipal Tax Expense, (E) Payroll Tax Expense, (F) Operations and Maintenance Expense, (G) Administrative and General, minus (H) Support Revenues.

A. Return and Associated Income Taxes shall equal the product of the Local Control Center Investment Base and the Cost of Capital Rate.

1. Local Control Center Investment Base

The Local Control Center Investment Base will be the year end balances of Local Control Center related: (a) Plant, less (b) Depreciation Reserve, less (c) Accumulated Deferred Taxes, plus (d) Other Regulatory Assets/Liabilities, plus (e) prepayments, plus (f) Materials and Supplies, plus (g) Cash Working Capital.

(a) Local Control Center Related Plant shall equal the balance of Central Maine's Investment in Local Control Center plant and the balance of unassigned intangible and general plant multiplied by the Wages and Salaries Allocation Factor.

(b) Local Control Center Related Depreciation Reserve shall equal the Depreciation Reserve and Accumulated Amortization for Central Maine's investment in Local Control Center Related Plant.

(c) Local Control Center Related Accumulated Deferred Taxes shall equal Central Maine's electric balance of Accumulated Deferred Income Taxes multiplied by the Local Control Center Plant Allocation Factor.

(d) Local Control Center Related Other Regulatory Assets/Liabilities shall equal Central Maine's electric balance of any deferred recovery of FAS 106 expenses multiplied by the Wages and Salaries Allocation Factor, plus Central Maine's electric balance of FAS 109 multiplied by the Local Control Center Plant Allocation Factor.

(e) Local Control Center Related Prepayments shall equal Central Maine's electric balance of prepayments multiplied by the Local Control Center Plant Allocation Factor.

(f) Local Control Center Related Materials and Supplies shall equal Central Maine's electric balance of Plant Materials and Supplies, multiplied by the Local Control Center Plant Allocation Factor.

(g) Local Control Center Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Local Control Center Operation and Maintenance Expense and Local Control Center Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Central Maine's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of Central Maine's long-term debt then outstanding, including any unamortized discounts and premiums, and any unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to Central Maine's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Central Maine's preferred stock then outstanding and the ratio that preferred stock is to Central Maine's total capital.

(iii) the return on equity component, which equals the product of Central Maine's Return on Equity of 11.14% and the ratio that common equity is to Central Maine's total capital.

(b) Federal Income Tax shall equal

$$\underline{(A+[(C+B)/D]) \times FT}$$

$$1 - FT$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.C. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., and D is Local Control Center Investment Base, as determined in II.A.1., above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.C. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., D is the Local Control Center Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.1.(b) above.

B. <u>Local Control Center Depreciation Expense</u> shall equal the Local Control Center Related Depreciation and Amortization Expense.

C. <u>Local Control Center Related Amortization of Investment Tax Credits</u> shall equal Central Maine's electric Amortization of Investment Tax Credits multiplied by the Local Control Center Plant Allocation Factor.

D. <u>Local Control Center Related Municipal Tax Expense</u> shall equal Central Maine's total electric municipal tax expense multiplied by the Local Control Center Plant Allocation Factor.

E. <u>Local Control Center Related Payroll Tax Expense</u> shall equal Central Maine's total electric payroll tax expense, multiplied by the Wages and Salaries Allocation Factor.

F. Local Control Center Operation and Maintenance Expense shall equal Central Maine's Operation and Maintenance Expenses recorded in FERC Account Nos. 556, 561-561.4, and 581.

G. Local Control Center Related Administrative and General Expenses shall equal the sum of (1) Central Maine's Administrative and General Expenses multiplied by the Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Local Control Center Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments, not otherwise directly assigned to transmission, multiplied by the Local Control Center Plant Allocation Factor, plus any other Federal and State Local Control Center related expenses or assessments, plus specific Local Control Center related expenses included in Account 930.1.

H. Local Control Center Support Revenues shall equal Central Maine's revenue received from providing system control and dispatch service other than under Schedule 1 of the OATT or Schedule 21-CMP.

III. CALCULATION OF LOCAL SCHEDULE 1 REVENUE REQUIREMENTS

The total Local Control Center Revenue Requirements derived in Section II, above, are further multiplied by the Local Control Center Wages and Salaries Allocation Factor defined in Section I. A. 2., above, to determine the transmission related Revenue Requirement. The transmission related Revenue Requirement is then reduced by the revenues recorded in FERC Account No. 456 that Central Maine receives: (1) under Schedule 1 of the OATT, except that such revenues shall exclude any incremental revenues associated with FERC-approved ROE adders for RTO participation and new transmission investment,(2) for short-term service, non-firm service, or any penalties associated with the provision of Scheduling, System Control and Dispatch service under this Schedule 21-CMP, (3) for Control Center Service ("CCS") Charges received from generators who have elected such arrangements, (4) for Schedule 1 related revenues received pursuant to wheeling out transactions whether such services are provided under this Schedule 21-CMP or pursuant to an Interconnection Agreement, and for (5) Schedule 1 related revenues received by Central Maine pursuant to Transmission Service Agreements that pre-dated Order No. 888, to the extent that such transactions are treated as a revenue credit rather than in the determination of Load Ratio Share. The Schedule 1 related revenues associated with such pre-dated contacts will be prorated between Attachment G and Schedule 1 of this Schedule 21-CMP based on gross investment in plant for the services at issue. The credits for wheeling out revenues and for the CCS Charge shall change from month to month based on the actual amounts received by Central Maine for the prior month or for the most recent month that the data is available. The Revenue Requirement in this Schedule shall be revised each month to reflect the annualized amount of such credits.

IV. SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE CHARGES:

The charge for Scheduling, System Control and Dispatch service will be re-determined annually on June 1 of each year, and shall be in effect for the succeeding twelve months. The rate per kilowatt for each month is one-twelfth of the annual rate determined by dividing the annual Revenue Requirement calculated in III. above, by Central Maine's average monthly Local Network Transmission System load (as defined in Section 21.II.8.c) for the prior calendar year. Each Local Network Customer shall pay the Schedule 1 rate on the basis of the number of kilowatts of Monthly Local Network Load. (as defined in Section21.II.8.b).

Each Transmission Customer taking Local Point to Point Transmission Service shall pay the Schedule 1 rate on the basis of the highest amount of Reserved Capacity for each Local Point-To-Point Transmission Service transaction as follows:

For Monthly Service - Annual rate divided by 12 months
For Weekly Service - Annual rate divided by 52 weeks
For Daily Service - Weekly rate divided by 7 days
For Hourly Service – Daily rate divided by 24 hours

Exceeding Capacity Reservations: As set forth in Section 4.3, in the event the Transmission Customer exceeds the Capacity Reservation specified in the customer's Transmission Service Agreement as determined by Central Maine, the Transmission Customer shall be retroactively charged the rates specified above without any discount, if one is in place at the time, for any capacity exceeding the amount reserved. Such charge shall apply for the period of unreserved use.

Control Center Services Charge

In lieu of taking Scheduling, System Control and Dispatch Service directly under the terms of this Schedule, a generator interconnected to Central Maine's PTF via Direct Assignment Facilities may elect to compensate Central Maine for the cost incurred in providing Control Center Services to such generators via: (a) a Scheduling, System Control and Dispatch Service Charge, incorporated into the generator's Interconnection Agreement, which reflects exactly the same charges and terms described in this Schedule; or (b) a Control Center Service ("CCS") Charge, the terms of which are incorporated into the generator's Interconnection Agreement. If the generator elects (a) or (b), it must incorporate a provision into its

Interconnection Agreement in which it agrees to pay charges identical to those described in Schedule Nos. 13 and 14 of this Schedule 21-CMP, however, the generator shall not be required to pay any capital carrying charge in Schedule Nos. 13 and 14 if its has paid a contribution in aid of construction ("CIAC") or made any other payment that reflects all of the capital costs associated with such facilities for which the generator is ultimately responsible.

The CCS Charge shall be based on the following two-part rate:

For Generators less than or equal to 500 MW:

Fixed Charge:	$11,304.00 per year, plus
Variable Charge:	$0.25 per kw-year.

For Generators greater than 500 MW:

Fixed Charge:	$11,304.00 per year, plus
Variable Charge:	$0.19 per kw-year.

The maximum level of capacity (kw) for which the generator's interconnection was designed shall be used to establish the billing demand determinants in the calculation of the CCS Charge.
These charges shall be increased or decreased in direct proportion to the amount that the cost of owning, operating and maintaining the control center increases or decreases, as determined each June 1.

A generator may elect to switch its payment method for Scheduling, System Control and Dispatch Service, once per year, to be effective June 1, provided that the generator sends written notice of its desire to switch, between May 1 and May 15 of that year, to the Manager of Transmission Services at Central Maine. Once Central Maine receives such notice, the generator shall not be permitted to switch again until the next year.

If a generator is paying for Scheduling, System Control and Dispatch Service directly under the terms of this Schedule, or pursuant to provisions in its Interconnection Agreement that mirror the exact terms of this Schedule, Central Maine shall reduce the generator's bill each month to reflect the amounts paid for service under this Schedule for the same month by load that the generator is serving, provided that the load is located in Central Maine's service territory, and the generator has been designated a Network Resource by the load. There is no reduction to a generator's bill, regardless of where the load is located and whether the generator is designated a Network Resource, when the generator is paying the CCS Charge.

SCHEDULE 7

Long and Short Term Firm Local Point-To-Point Transmission Service

Each Transmission Customer who takes Firm Local Point-to-Point Transmission Service shall pay Central Maine each month on the basis of the highest amount of Reserved Capacity for each transaction reserved as Firm Local Point to Point Transmission Service. Except as provided otherwise below, the charges will be re-determined annually on June 1 of each year, and shall be in effect for the succeeding twelve months. The rate per kilowatt for each month is one-twelfth of the annual rate determined by dividing the Annual Transmission Revenue Requirement calculated pursuant to the Attachment G formula, by Central Maine's average monthly Local Network Transmission System load (as defined in Section21.II.8.c) for the prior calendar year.

Each Transmission Customer taking Firm Local Point to Point Transmission Service shall pay the firm local point-to-point rate on the basis of the highest amount of Reserved Capacity for each transaction reserved as Firm Local Point-To-Point Transmission Service as follows:

1) **Yearly reservation**: one-twelfth of the annual rate per kilowatt of Reserved Capacity per year.

2) **Monthly reservation**: one-twelfth of the annual rate per kilowatt of Reserved Capacity per month.

3) **Weekly reservation**: 1/52nd of the annual rate per kilowatt of Reserved Capacity per week.

4) **Daily reservation**: 1/5th of the weekly rate per kilowatt of Reserved Capacity per day.

Provided that the total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

Notwithstanding the rates described above, through February 28, 2003, each generator that is interconnected with Central Maine's integrated non-PTF system and taking Firm Local Point to Point Transmission Service shall for each transaction pay at a rate of $3.00 per kW-year multiplied by the highest amount of Reserved Capacity for that transaction. The charges for reservations of less than one year shall be determined as described above. If in a given month, a generator is serving load in Central Maine's service territory, Central Maine shall reduce the amount billed to the generator for that month's service to account for any amounts paid by such load, except that for short-term transactions where it has not been demonstrated to Central Maine's satisfaction that the generator is serving load in Central Maine's service territory, Central Maine shall bill the generator the total amount owed without any reduction, and issue a refund once it has not been demonstrated to Central Maine's satisfaction that load in its service territory is being served via such transaction. Satisfactory methods of demonstrating that load is being served in Central Maine's service territory include: (a) an affidavit executed by the generator and an affidavit executed by the load, each stating that the generator is serving the load and identifying how much service is being provided; (b) a copy of the executed contract between the generator and the load; or (c) any other method that Central Maine agrees is satisfactory. If, for any reason, the load being served in Central Maine's territory is overstated, the generator shall immediately reimburse Central Maine for all monies that would have been collected based on the correct amount of load, with interest calculated at a rate equal to Central Maine's overall rate of return. If, for any reason, the amount of load served by the generator is understated, Central Maine shall reimburse the generator for all monies that were paid in excess of the amount that should have been paid based on the correct load with interest calculated pursuant to Section 35.19a of FERC's regulations. A generator shall not receive any reduction to the amount it is billed, nor any refund, as described herein, to the extent it is wheeling power out of Central Maine's service territory. Generators are not permitted to purchase transmission on behalf of load at the $3.00 rate. Load must pay for transmission at the full rates described in this OATT. On March 1, 2003, and subsequently, the $3.00 rate and the reduction for service to load in Central Maine's service territory shall expire and be considered void.

The charges described in this schedule are subject to waiver under the circumstances and pursuant to the conditions described in Section 21.I.13 of this Schedule 21-CMP.

5) **Discounts**: Three principal requirements apply to discounts for Transmission Service as follows: (1) any offer of a discount made by Central Maine must be announced to all Eligible Customers solely by posting on the OASIS; (2) any customer-initiated requests for discounts (including requests for use by Central Maine's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, Central Maine must offer the same discounted Transmission Service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same Point(s) of Delivery on the Transmission System.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to the resales of Transmission Service, compensation for which shall be governed by Schedule 21 § 11 (a).

SCHEDULE 8

Non-Firm Local Point-To-Point Transmission Service

Each Transmission Customer who takes Non-Firm Local Point-to-Point Transmission Service shall pay Central Maine each month on the basis of the highest amount of Reserved Capacity for each transaction reserved as Non-Firm Local Point to Point Transmission Service. The charges will be re-determined annually on June 1 of each year, and shall be in effect for the succeeding twelve months. The rate per kilowatt for each month is one-twelfth of the annual rate determined by dividing the Annual Transmission Revenue Requirement calculated pursuant to the Attachment G formula, by Central Maine's average monthly Local Network Transmission System load (as defined in Section21.II.8.c) for the prior calendar year.

Each Transmission Customer taking Non-Firm Local Point to Point Transmission Service shall pay the non-firm local point-to-point rate on the basis of the highest amount of Reserved Capacity for each transaction scheduled as Non-Firm Local Point to Point Transmission Service as follows:

1) **Yearly reservation**: one-twelfth of the annual rate per kilowatt of Reserved Capacity per year.

2) **Monthly reservation**: one-twelfth of the annual rate per kilowatt of Reserved Capacity per month.

3) **Weekly reservation**: 1/52nd of the annual rate per kilowatt of Reserved Capacity per week.

4) **Daily reservation**: 1/7th of the weekly rate per kilowatt of Reserved Capacity per day.

5) **Hourly reservation**: 1/24th of the daily rate per kilowatt of Reserved Capacity per hour.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (4) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week The charges described in this schedule are subject to waiver under the circumstances and pursuant to the conditions described in Section 21.I.13 of this Schedule 21-CMP.

6) **Discounts**: Three principal requirements apply to discounts for Transmission Service as follows: (1) any offer of a discount made by Central Maine must be announced to all Eligible Customers solely by posting on the OASIS; (2) any customer-initiated requests for discounts (including requests for use by Central Maine's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, Central Maine must offer the same discounted Transmission Service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same Point(s) of Delivery on the Transmission System.

7) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to the resales of Transmission Service, compensation for which shall be governed by Schedule 21 § 11 (a).

SCHEDULE 12

Retail Access Transmission and Distribution Services

A. EXCEPTIONS TO OPEN ACCESS TRANSMISSION TARIFF:

The following applies only to Retail Network Transmission Service for both transmission-level and distribution level retail customers and Point-To-Point Transmission Service for transmission-level retail customers. For each unbundled retail Transmission Service, Central Maine specifies below the modifications to the ("OATT") terms and conditions necessary for retail access transmission and distribution services. The exceptions to the OATT specified below will apply to all customers that take service either directly under the following rate designations or pursuant to a targeted rate, Tariff or contract,[1] but for that targeted rate, Tariff or contract, the customer otherwise would take service under the following designations:

<u>Transmission-Level</u> [2] (1) LGS-ST-TOU; (2) LGS-T-TOU; (3) SB-LGS-T; and (4) SB-LGS-ST.

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1 Central Maine may change the price for distribution service that it charges customers pursuant to guidelines established by the Maine Public Utilities Commission. These price changes are normally done with targeted groups of customers or with one customer in order to retain sales or grow sales. The price changes are in the form of a rate or tariff or an individual contract

2 Transmission-level customers taking service under the specified rate schedules are required to purchase Transmission Services directly under this Schedule 21-CMP and the Tariff, except that transmission-level customers may designate CMP to act as their agent for arranging and obtaining service under the Tariff

Distribution-Level[3] : (1) A; (2) A-LM; (3) A-TOU; (4); AL (5); IGS-P-TOU; (6) IGS-S-TOU (7) LGS-P-TOU; (8) LGS-S-TOU; (9) MGS-P; (10) MGS-P-TOU; (11) MGS-S; (12) MGS-S-TOU; (13) N (14) R; (15) R-TOU; (16) SB-IGS-P; (17) SB-IGS-S; (18) SB-LGS-P; (19) SB-LGS-S; (20) SL; (21) SGS; and (22) SGS-TOU.

1. Central Maine shall be the sole Designated Agent for arranging network service for its distribution-level retail customers. Central Maine shall be allowed to bill such retail customers directly for combined transmission and distribution services. Distribution-level retail customers shall take Local Network Transmission Service from Central Maine, acting as their agent under an Umbrella Service Agreement for Retail Local Network Transmission Service ("Umbrella Agreement"). Distribution-level retail customers also agree under the Umbrella Agreement that Central Maine will act as their Designated Agent for arranging and obtaining Regional Network Service and transmission related services on their behalf pursuant to the Tariff. Such individual distribution-level retail customers are not required to sign separate Transmission Service Agreements. Distribution-level retail customers agree to take Ancillary Services for Scheduling, System Control & Dispatch Service and Reactive Power & Voltage Support From Generating Resources Service from or through Central Maine, which Central Maine will procure on behalf of such customers. Central Maine agrees to perform services under the umbrella Agreement for an initial term of one year (commencing on March 1, 2000), that will continue from year-to-year unless terminated by Central Maine through a unilateral filing with FERC under section 205 of the FPA. Accordingly, Central Maine will transmit capacity and energy sufficient to serve all of its distribution-level retail customers as determined by the Maine Public Utilities Commission.

2. Transmission-level retail customers must sign a Local Point-To-Point Service Agreement or a Local Network Service Agreement and Network Operating Agreement for Retail Local Network Transmission Service ("Service Agreement"). Local Network Service will be supplied by Central Maine to these transmission-level retail customers for an initial term established pursuant to the Service Agreement. Transmission-level retail customers must also purchase Regional Network Service and transmission-related services under the Tariff or, at their discretion, designate Central Maine to act as their agent for obtaining and arranging Regional Network Service and transmission related services under the Tariff.

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3 Distribution-level customers taking service under the specified rate schedules will purchase Transmission Services from CMP as their Designated Agent in a combined transmission and distribution rate.

3. If specifically requested by Central Maine's transmission-level retail customers in the Service Agreement, Central Maine will also arrange and obtain Regional Network Service and related services under the Tariff, and arrange and obtain Ancillary Services for Scheduling, System Control & Dispatch Service and Reactive Power & Voltage Support From Generating Resources Service as provided under the OATT and will bill these retail transmission-level customers directly for Regional Network Service and applicable Ancillary Services. Central Maine shall charge transmission-level retail Customers, designating Central Maine as their agent, an administrative fee of $200 per month for arranging such services. The initial minimum term for such designation shall be 15 months from March 1, 2000 or the term of the Service Agreement, and thereafter shall be one (1) year. Transmission-level retail customers electing to change such designation must notify the manager of transmission services, in writing by May 1 of each year to be effective on the annual June 1 of that year, when the formula rates are updated pursuant to this Schedule 21-CMP.

4. Transmission-level retail customers designating Central Maine as the sole agent to arrange and obtain Regional Network Service and related services pursuant to the Tariff agree to pay in full to Central Maine any and all costs of such services, including costs incurred to arrange such services under the Tariff and for applicable Ancillary Services (including the $200 per month administrative fee (see A.3)).

5. An additional deposit beyond that required to obtain retail distribution service will not be required to accompany an Application for Transmission Service under this Schedule 21. Nevertheless, Central Maine will reserve the right to implement "commercially reasonable" deposit practices should market conditions or individual customer conditions warrant.

6. The reservation priority for existing firm service customers is modified to give retail customers the right to continue to take service.

7. [RESERVED]

8. Unless otherwise specified in their State of Maine Tariffs or in an agreement with Central Maine, the minimum term of service for retail transmission-level customers is one year. The minimum term for retail distribution-level customers will be Central Maine's monthly billing cycle. Thereafter, such retail distribution-level customers will continue to be responsible for transmission charges from typical monthly billing cycle to typical monthly billing cycle.

9. Retail customers taking Transmission Service under the aforementioned rate designations will abide by the MPUC 's deposit, late payment, interest, and disconnection rules associated with the retail distribution service and will not be assessed additional charges covering these issues for Transmission Service under this Schedule 21.

B. TRANSMISSION RATE COMPONENTS OF CENTRAL MAINE'S DISTRIBUTION-LEVEL CUSTOMER RETAIL RATES:

The transmission rate components of Central Maine's distribution-level retail rates are determined as follows:

1. Allocate the transmission related charges[4] under the Tariff and the revenue requirement calculated pursuant to the Attachment G-R formula of this Schedule 21-CMP, including charges for system control and dispatch, to appropriate retail rate classes based upon historical test year 12 month average coincident peak data adjusted to reflect Behind-The-Meter Generation of transmission-level retail and wholesale customers, in accordance with Sections 21.II.7, 21.II.8.b and 21.II.8.c of this Schedule 21-CMP.

2. Divide the results of the allocation described in "1" above by the appropriate retail billing determinants for the same test year (kWh for customers that are not billed for demand, or kW for customers that are billed for demand) to determine the transmission prices for distribution-level customers associated with "1" above.

3. Beginning March 2000, Central Maine shall recover in distribution-level retail rates, the difference between actual Congestion costs billed pursuant to the Tariff, to the extent such Congestion costs are assessed on the basis of transmission reservations or load, and the level of Congestion costs reflected in transmission prices paid by Central Maine's distribution-level retail customers. Any difference between Congestion costs incurred and those in distribution level retail rates, whether positive or negative, will be accrued with interest calculated pursuant to Section 35.19a of the Commission's regulations, and shall be recovered or credited beginning with the next rate change for these customers.

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4 Charges incurred by Central Maine pursuant to the Tariff, including but not limited to congestion uplift costs, are considered transmission-related except for power supply related costs incurred under these regional arrangements. As a general rule, Central Maine defines transmission related charges as those regional charges allocated to Transmission Customers (or transmission owners taking Transmission Service under the Tariff as an agent for retail Transmission Customers) based on transmission billing determinants while power supply related charges are those regional charges associated with the Tariff that are allocated based on energy billing determinants.

Central Maine shall continue to be able to recover any differences (positive or negative) that exist between actual Congestion costs and that included in rates for recovery of current Congestion costs in subsequent transmission prices. Once recovery of past costs is complete, the amounts shall be removed from Central Maine's transmission prices.

Central Maine shall allocate such congestion costs to each rate class based on the same historical test year 12 month average coincident peak data used to allocate transmission-related charges under the Tariff, as described in "1" and "2" above. The amounts allocated to each rate class shall then be divided by the appropriate retail billing determinants as described in "2" above to determine the transmission prices associated with Congestion costs for distribution-level retail customers, and shall be in addition to the transmission prices for distribution-level retail customers determined in "1" and "2" above.

C. TIMING OF TRANSMISSION RATE CHANGES FOR DISTRIBUTION-LEVEL RETAIL CUSTOMERS:

1. To accommodate the timing difference between transmission price changes and distribution price changes, the retail transmission price changes for distribution-level retail customers will take effect contemporaneously with the annual changes to distribution rates. The transmission revenue effect of any difference (positive or negative) between when transmission price changes would normally occur (i.e. June 1) and when they actually occur will be accrued with interest, calculated pursuant to Section 35.19a of FERC's regulations and included in the next determination of transmission prices for distribution-level retail customers.

2. Transmission prices for distribution-level retail customers will not change each month to account for the crediting of wheeling out revenues that Central Maine receives from generators. Nor will transmission prices for distribution-level retail customers change each month to account for any revenue credits received from generators taking point-to-point service. Rather, Central Maine shall accrue with interest (calculated pursuant to Section 35.19a of FERC's regulations) the difference between the revenue credits properly assigned to distribution-level retail customers and that included in distribution-level transmission rates, and include such accrued amounts in the next determination of distribution-level retail transmission prices.

3. The rates for Scheduling, System Control and Dispatch Service shall not change each month for distribution-level retail customers. To the extent such rates should change each month to reflect revenues

associated with the Scheduling, System Control and Dispatch charges paid by generators, and CCS Charges paid by generators, Central Maine shall accrue with interest (calculated pursuant to Section 35.19a of FERC's regulations) the difference between the revenue credits properly assigned each month and the revenue credits actually used, such accrued amount to be incorporated into the next determination of rates under Schedule No. 1 for distribution-level retail customers.

D. TRANSMISSION RATES FOR CENTRAL MAINE'S TRANSMISSION-LEVEL CUSTOMERS:

1. Whether or not Central Maine's retail transmission-level customers designate Central Maine as their sole agent, Central Maine's retail transmission-level customers will be charged the applicable rate for Local Network Service pursuant to the formula in Attachment G-R of Schedule 21-CMP and Section (B) of this Schedule No. 12, and will be charged the applicable rate for Regional Network Service and applicable Ancillary Services in instances where the transmission-level customers designate Central Maine as their agent for acquiring services under the Tariff on their behalf pursuant to Section (B) of this Schedule No. 12.

2. The Local Network Load for each transmission-level retail customer with Behind-The-Meter Generation (not including those customers taking service over a Direct Assignment Facility that interconnects with PTF) shall be determined pursuant to Sections 21.II.7 and 21.II.8.b of this Schedule 21-CMP, except that Central Maine shall account for such Behind-the-Meter Generation in its calculations of Load Ratio Share using one of the following two methods: (a) by adding to the facility's monthly coincident peak demand (when the Behind-The-Meter Generation is in service), 22.5 percent of the additional load that would be placed on Central Maine's system when the Behind-The-Meter Generation is out of service; or (b) by using the monthly maximum 15 minute measured demand, occurring at any time during the month.

Customers taking service over a Direct Assignment Facility that interconnects with PTF shall pay the applicable charges for service over such Direct Assignment Facilities rather than the charge for Local Network Service under this Schedule 21-CMP. The Load Ratio Share for such Customers shall be calculated using one of the following two methods: (a) by adding to the facility's monthly coincident peak demand (when the Behind-The-Meter Generation is in service), 22.5 percent of the additional load that would be placed on Central Maine's system when the Behind-the-Meter Generation is out of service; or (b) by using the monthly maximum 15 minute measured demand, occurring at any time during the month.

3. The treatment of behind-the-meter load, as described in this Schedule 21-CMP, shall not impact the manner in which Central Maine reports load to ISO, nor shall it impact any regional charges or rates assessed by ISO. Customers who do not designate Central Maine as their agent shall be billed or credited the difference between the amount billed directly by ISO for services and the allocation of costs that result from Central Maine's apportioning of the total charges under the Tariff using the Load Ratio Shares adjusted for Behind-The-Meter Generation pursuant to this Schedule 21-CMP. In the event ISO adopts any position on behind-the-meter load, any party shall be permitted to make a filing at FERC(under Section 205 of the FPA for Central Maine; under Section 206 of the FPA for all others), proposing a change to the treatment of behind-the-meter load in this Schedule 21-CMP to be consistent with ISO's treatment. Any party responding to such a filing is permitted to argue for no change to the terms of Central Maine's Schedule 21-CMP regarding behind-the-meter load.

4. Each load with Behind-The-Meter Generation shall select one of the two methods described in 2(a) or 2(b) above. Load is permitted to change its selection only once per year by sending written notice of such change to the Manager of Transmission Operations at Central Maine no earlier than May 1 of that year and no later than May 15 of that year. Upon proper notice, the requested change shall take effect on June 1 of that year.

5. Notwithstanding any other provision in this Schedule, the Local Network Load of a customer taking non-firm service under Rate O in any month shall be the load placed on the system by the customer at the time of Central Maine's monthly system peak for the load taken under Rate O, without regard for Behind-The-Meter Generation.

6. Nothing herein shall make a Behind-The-Meter Generator a designated Network Resource or prevent such generation from being designated by the generator itself as a Network Resource.

SCHEDULE 13
METER SERVICES

This formula sets forth the details for determining the annual revenue requirement related to providing Meter Services. The revenue requirement reflects the cost of owning, operating and maintaining Central Maine's Meters. The Revenue Requirement will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31, 2000, based on 1998 test year data, and updated thereafter each June 1, based on the previous calendar year's FERC Form 1 data, as shown below, using end-of-year balances for each rate base item, as further set forth below.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section 1 of Schedule 21-CMP and used in this formula have the following definitions:

A. ALLOCATION FACTORS

1. <u>Wages and Salaries Allocation Factor</u> shall equal the ratio of the Meter Direct Wages and Salaries to Total Direct Wages and Salaries excluding Administrative and General Wages and Salaries.

2. <u>Meter Plant Allocation Factor</u> shall equal the ratio of the sum of Total Investment in Meter Plant and Meter Related General Plant to Total Plant in service.

B. TERMS

<u>Administrative and General Expense</u> shall equal Central Maine's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928, and 930.1.

<u>Amortization of Investment Tax Credits</u> shall equal Central Maine's credits as recorded in FERC Account No. 411.4.

<u>Materials and Supplies</u> shall equal Central Maine's balance as recorded in FERC Account No. 154.

<u>Meter Depreciation Expense</u> shall equal Central Maine's depreciation expense for Meter Plant as recorded in FERC Account No. 403.

Meter Direct Wages and Salaries shall equal Central Maine's direct wages and salaries related to providing meter services as recorded in FERC Account Nos. 586 and 597.

Meter Operation and Maintenance Expense shall equal Central Maine's expenses recorded in FERC Account Nos. 586 and 597.

Meter Plant shall equal Central Maine's gross plant balances used for metering purposes as recorded in FERC Account No. 370.

Meter Plant Depreciation Reserve shall equal Central Maine's depreciation reserve balance for Meter Plant as recorded in FERC Account No. 403.

General Plant shall equal Central Maine's balance in FERC Account No. 389 – 399.

General Plant Depreciation Expense shall equal Central Maine's depreciation expense for General Plant as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal Central Maine's depreciation and amortization reserve balance for General Plant as recorded in FERC Account No. 108.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of Central Maine's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in Central Maine's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of Central Maine's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Central Maine's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in Central Maine's FERC Account Nos. 408.1.

Prepayments shall equal Central Maine's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Central Maine's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and 190.

Total Municipal Tax Expense shall equal Central Maine's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal Central Maine's total gross plant balance as recorded in FERC Account Nos. 301-399.

II. CALCULATION OF TOTAL METER REVENUE REQUIREMENTS

The Meter Revenue Requirement shall equal the sum of the Meter related (A) Return and Associated Income Taxes, (B) Depreciation Expense, (C) Amortization of Investment Tax Credits, (D) Municipal Tax Expense, (E) Payroll Tax Expense, (F) Operations and Maintenance Expense, (G) Administrative and General.

A. **Return and Associated Income Taxes** shall equal the product of the Meter Investment Base and the Cost of Capital Rate reflected in Attachment G of Schedule 21-CMP.

1. **Meter Investment Base**

The Meter Investment Base will be the year end balances of Meter related: (a) Plant, plus (b) General Plant, less (c) Depreciation Reserve, less (d) Accumulated Deferred Taxes, plus (e) Other Regulatory Assets/Liabilities, plus (f) prepayments, plus (g) Materials and Supplies, plus (h) Cash Working Capital.

(a) Meter Related Plant shall equal the balance of Central Maine's Investment in Meter Plant.

(b) Meter Related General Plant shall equal the balance of Central Maine's General Plant multiplied by the Meter Wages and Salaries Allocation Factor.

(c) Meter Related Depreciation Reserve shall equal Central Maine's Meter Plant Depreciation Reserve plus the General Plant Depreciation Reserve multiplied by the Meter Wages and Salaries Allocation Factor.

(d) Meter Related Accumulated Deferred Taxes shall equal Central Maine's electric balance of Accumulated Deferred Income Taxes multiplied by the Meter Plant Allocation Factor.

(e) Meter Related Other Regulatory Assets/Liabilities shall equal Central Maine's electric balance of any deferred recovery of FAS 106 expenses multiplied by the Meter Wages and Salaries Allocation Factor, plus Central Maine's electric balance of FAS 109 multiplied by the Meter Plant Allocation Factor.

(f) Meter Related Prepayments shall equal Central Maine's electric balance of prepayments multiplied by the Meter Wages and Salaries Allocation Factor.

(g) Meter Related Materials and Supplies shall equal Central Maine's electric balance of Plant Materials and Supplies, multiplied by the Meter Plant Allocation Factor.

(h) Meter Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Meter Operation and Maintenance Expense and Meter Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Central Maine's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of:

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity, including unamortized discounts and premiums, and unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to Central Maine's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Central Maine's preferred stock then outstanding and the ratio that preferred stock is to Central Maine's total capital.

(iii) the return on equity component, which equals the product of Central Maine's Return on Equity of 11.14% and the ratio that common equity is to Central Maine's total capital.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Meter Depreciation Expense, as defined in II.B., and D is Meter Investment Base, as determined in II.A.1., above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Meter Depreciation Expense, as defined in II.B., D is the Meter Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.1.(b) above.

B. **Meter Related Depreciation Expense** shall equal the sum of the Meter Plant Depreciation Expense and the Meter Related General Plant Depreciation Expense multiplied by the Meter Wages and Salaries Allocation Factor.

C. **Meter Related Amortization of Investment Tax Credits** shall equal Central Maine's electric Amortization of Investment Tax Credits multiplied by the Meter Plant Allocation Factor.

D. **<u>Meter Related Municipal Tax Expense</u>** shall equal Central Maine's total electric municipal tax expense multiplied by the Meter Plant Allocation Factor**.**

E. **<u>Meter Related Payroll Tax Expense</u>** shall equal Central Maine's total electric payroll tax expense multiplied by the Meter Wages and Salaries Allocation Factor.

F. **<u>Meter Operation and Maintenance Expense</u>** shall equal Central Maine's Operation and Maintenance Expenses recorded in FERC Account Nos. 586 and 597.

G. **<u>Meter-Related Administrative and General Expenses</u>** shall equal the sum of (1) Central Maine's Administrative and General Expenses multiplied by the Meter Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Meter Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments not otherwise directly assigned under Attachment G of this Schedule 21-CMP, multiplied by the Meter Plant Allocation Factor, plus any other Federal and State meter related expenses or assessments, plus specific meter related expenses included in Account 930.1**.**

III. CALCULATION OF THE MONTHLY METERING CARRYING CHARGE:

Each of the Schedule 13 Meter Investment Base and Meter Revenue Requirement formula components, II.A.1.(a) through II.A.1.(h), and II (A) through II (G), respectively, will be classified as either capital related or O&M related or related to both capital and O&M. Formula components related to both capital and O&M will be assigned based on the amount of gross plant classified to each category except for II.A.1.(a) Return and Associated Taxes. The capital related portion of Return and Associated Taxes shall equal the product of the sum of the capital related meter investment base components and the Cost of Capital Rate. The O&M related portion of Return and Associated Taxes shall equal the product of the sum of the O&M related meter investment base components and the Cost of Capital Rate.

Meter Investment Base formula components II.A.1.(a) and II.A.1.(c) excluding depreciation reserve associated with general plant are capital related, while II.A.1.(b), II.A.1.(c) less meter plant depreciation reserve, the FAS106 portion of II.A.1.(e), and components II.A.1.(f) through II.A.1.(h) are O&M related. Meter Investment Base components II.A.1.(d) and the FAS 109 portion of II.A.1.(e), relate both to capital and O&M.

Meter Revenue Requirement component II.(B) excluding meter plant depreciation expense and components II(D) through II(G) are O&M related, while II(C), Amortization of Investment Tax Credits is related both to capital and O&M. The meter depreciation expense portion of II.(B) is excluded from the determination of the capital related carrying charge. Actual depreciation will be tracked for each Direct Assignment Facility and charged separately each month pursuant to this Schedule.

The annual capital related carrying charge is the sum of the capital related revenue requirement components expressed as a percentage of Central Maine's total net investment in Meter Plant. The monthly capital related carrying charge will be one-twelfth of the annual capital related carrying charge. The monthly capital related carrying charge will be applied to the net investment in Meter Plant directly assigned to the Transmission Customer to determine the monthly capital related charge. The monthly capital related charge plus the actual monthly depreciation for the Transmission Customers' Direct Assignment Facilities represents the total monthly charge for this service, and shall be in addition to any other applicable charges under this Schedule 21, including Ancillary Services.

The annual O&M related carrying charge is the sum of the O&M related revenue requirement components expressed as a percentage of Central Maine's total gross investment in Meter Plant. Gross investment in Meter Plant for purposes of this Schedule, shall reflect the investment in meter facilities for which Central Maine has received a contribution to capital or a contribution in aid of construction. Only the O&M related carrying charge is applicable in cases where the Transmission Customer has paid Central Maine for the capitalized cost of the meter plant.

The monthly O&M related carrying charge will be one-twelfth of the annual O&M related carrying charge. The monthly O&M related carrying charge will be applied to the gross investment in meter plant directly assigned to the Transmission Customer to determine the monthly charge for this service, and shall be in addition to any other applicable charges under this Schedule 21, including Ancillary Services.

SCHEDULE 14

MONTHLY CARRYING CHARGE FOR DIRECT ASSIGNMENT FACILITIES

Each of the Attachment G Transmission Investment Base and Transmission Revenue Requirement formula components, II.A.1.(a) through II.A.1.(i), and II (A) through II (G), respectively, will be classified as either capital related or O&M related or related to both capital and O&M. Formula components related to both capital and O&M will be assigned based on the amount of gross plant classified to each category except for II.A.1.(a) Investment Return and Associated Taxes. The capital related portion of Investment Return and Associated Taxes shall equal the product of the sum of the capital related investment base components and the Cost of Capital Rate. The O&M related portion of Investment Return and Associated Taxes shall equal the product of the sum of the O&M related investment base components and the Cost of Capital Rate.

Transmission Investment Base formula components II.A.1.(a), II.A.1.(c), and II.A.1.(d) excluding depreciation reserve and accumulated amortization associated with general and intangible plant are capital related, while II.A.1.(b), II.A.1.(d) less transmission plant depreciation reserve, the FAS106 portion of II.A.1.(f), and components II.A.1.(g) through II.A.1.(i) are O&M related. Transmission Investment Base components II.A.1.(e) and the FAS 109 portion of II.A.1.(f), relate both to capital and O&M.

Transmission Revenue Requirement component II.(B) excluding transmission depreciation expense and components II(D) through II(G) are O&M related, while II(C), Amortization of Investment Tax Credits is related both to capital and O&M. The transmission plant depreciation portion of II.(B) is excluded from the determination of the capital related carrying charge. Actual depreciation will be tracked for each Direct Assignment Facility and charged separately each month pursuant to this Schedule.

The annual capital related carrying charge is the sum of the capital related revenue requirement components expressed as a percentage of Central Maine's total net investment in Transmission plant, excluding the balance associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts for test periods beginning with the calendar year 1999 and thereafter. The monthly capital related carrying charge will be one-twelfth of the annual capital related carrying charge. The monthly capital related carrying charge will be applied to the net investment in transmission plant directly assigned to the Transmission Customer to determine the monthly capital related charge. The monthly capital related charge plus the actual monthly depreciation for the Transmission Customers' Direct Assignment Facilities represents the total monthly charge for this service, and shall be in addition to any other applicable charges under this Schedule 21, including Ancillary Services.

The annual O&M related carrying charge is the sum of the O&M related revenue requirement components expressed as a percentage of Central Maine's total gross investment in Transmission Plant, excluding the balance associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts for test periods beginning with the calendar year 1999 and thereafter. Gross investment in transmission plant for purposes of this Schedule, shall reflect the investment in transmission facilities for which Central Maine has received a contribution to capital or a contribution in aid of construction. Only the O&M related carrying charge is applicable in cases where the Transmission Customer has paid Central Maine for the capitalized cost of the transmission plant.

The monthly O&M related carrying charge will be one-twelfth of the annual O&M related carrying charge. The monthly O&M related carrying charge will be applied to the gross investment in transmission plant directly assigned to the Transmission Customer to determine the monthly charge for this service, and shall be in addition to any other applicable charges under this Schedule 21, including Ancillary Services.

When applicable, wholesale Transmission Customers will pay the carrying charge calculated as described above based on the Attachment G-W formula. The carrying charge for retail Transmission Customers will be calculated as described above based on the Attachment G-R formula, and, in addition to the O&M related revenue requirement components described above, will include Attachment G-R revenue requirement component II. (M) to reflect transmission related Customer Service and Informational Expenses and Sales Expenses.

ATTACHMENT C-CMP

Methodology To Assess Available Transfer Capability

1 Introduction

ISO is the regional transmission organization ("RTO"), serving the New England Control Area. ISO is responsible for the development, oversight, and fair administration of New England's wholesale market, management of the bulk electric power system and wholesale markets planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is comprised of PTF, Non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Provider of RNS and Through or Out Service over PTF, certain Participating Transmission Owners ("PTOs") also provide local Transmission Service over Non-PTF within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Service provided under Schedule 21. CMP is a Transmission Provider of Local Service under Schedule 21-CMP in accordance with the Transmission Operating Agreement ("TOA"). Pursuant to CFR§37.6(b) of the FERC Regulations which states the available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path. The Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path accordingly.

As stated in §37.6(b)(1)(i) Posted Path means any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.

Non-PTF facilities are primarily radial paths that provide Transmission Service directly to interconnected generators. It is possible, in the future that a particular path may interconnect more nameplate capacity generation than the path's TTC. However, for CMP's Non-PTF modeled by the ISO or the Local Control Center ("LCC"), the ISO or the LCC will only dispatch an amount of generation interconnected to such path so as not to incur a reliability violation on the subject path consistent with ISO's economic, security constrained dispatch methodology.

CMP does not currently have a Posted Path based on the above definition. However, should CMP have any Posted Path(s) in the future, CMP will calculate TTC using NERC MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to the following functions performed by CMP as the Transmission Provider of Local Point-to Point Transmission Service over Non-PTF pursuant to this Schedule 21-CMP, the TOA, and the ISO OATT:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)
- Use of Rollover Rights (ROR) in the calculation of ETC

As explained in Section 2, TTC and ATC are required to be calculated only for certain Non-PTF internal Posted Paths over which Local Point-to-Point Transmission Service is provided under Schedule 21-CMP. TTC and ATC is not calculated by CMP for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and advanced reservations are not required for network service.

2 Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point Transmission Service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the New England Control Area, out of the New England Control Area or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region. This process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF local facilities utilized for Local Network Service by generation or load. However, CMP provides service over Non-PTF over which advance Transmission Service reservations for firm or non-firm Transmission Service may be required. On those local facilities, the market participant must obtain a Transmission Service reservation under Schedule 21-CMP prior to delivery of energy into the New England Wholesale Market. This document addresses the calculation of ATC and TTC for the non-PTF internal paths.

3 Total Transfer Capability (TTC)

The Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected Transmission Systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule

21-CMP is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on the CMP OASIS site.

CMP will calculate and post TTC on OASIS for all Non-PTF Posted Paths that are eligible for Local Point-to-Point Transmission Service reservations. The TTC on CMP's Non-PTF eligible for Local Point-to-Point Transmission Service reservations are relatively static values. CMP thus calculates the TTC for Non-PTF Posted Paths equal to the rating of the particular transmission path.

4 Capacity Benefit Margin (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the load serving entities. The ISO does not set aside any CBM for use by the load serving entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load serving entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load serving entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of CMP's ATC calculation and because CBM for the New England Control Area is set to zero (0), CMP utilizes a zero (0) CBM value.

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservation (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

5 Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. CMP does not have any external interfaces, and therefore TRM for CMP's Non-PTF is zero.

6 Calculation of ATC for CMP's Local Facilities - General Description

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a Transmission Provider's ATC methodology. As a practical matter, the ratings of the Non-PTF radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, Transmission Services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for CMP's Non-PTF described above, as ATC is positive and listed as 9999. Transmission Customers are not restricted from reserving firm or non-firm Transmission Service on CMP's Non-PTF.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the Non-PTF in the New England market is almost always positive. With this simplified version of ATC, there is no detailed algorithm to be described or posted. Thus, for those Non-PTF facilities that serve as a path for the CMP Schedule 21-CMP Local Point-to-Point Transmission Customers, CMP has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Firm ATC (ATC_F)

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F , $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service over Schedule 21-CMP that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-CMP transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F.

6.1.2 Calculation of ATC_F in the Operating Horizon (OH)

For purposes of this Attachment C OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F , CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service over Schedule 21-CMP is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-CMP transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Firm Transmission Service is not offered in the Scheduling Horizon (SH) therefore ATC_F in the SH is zero.

6.2 Calculation of Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-CMP are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-CMP transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-CMP are zero. TRM_U, $counterflows_{NF}$ and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus $ETC_{F,}$ and ETC_{NF} plus postbacks $Postbacks_{NF}$.

6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, Transmission Services over these posted paths are considered to be always available. The Non-PTF facilities are primarily radial paths that provide Transmission Service to directly interconnected generators.

It is possible, in the future that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, for CMP's Non-PTF modeled by ISO or the LCC, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path consistent with ISO's economic, security constrained dispatch methodology. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

7 Posting of ATC

7.1 Location of ATC Posting

ATC values are posted on CMPs OASIS site in accordance with NAESB Standards.

7.2 Updates To ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

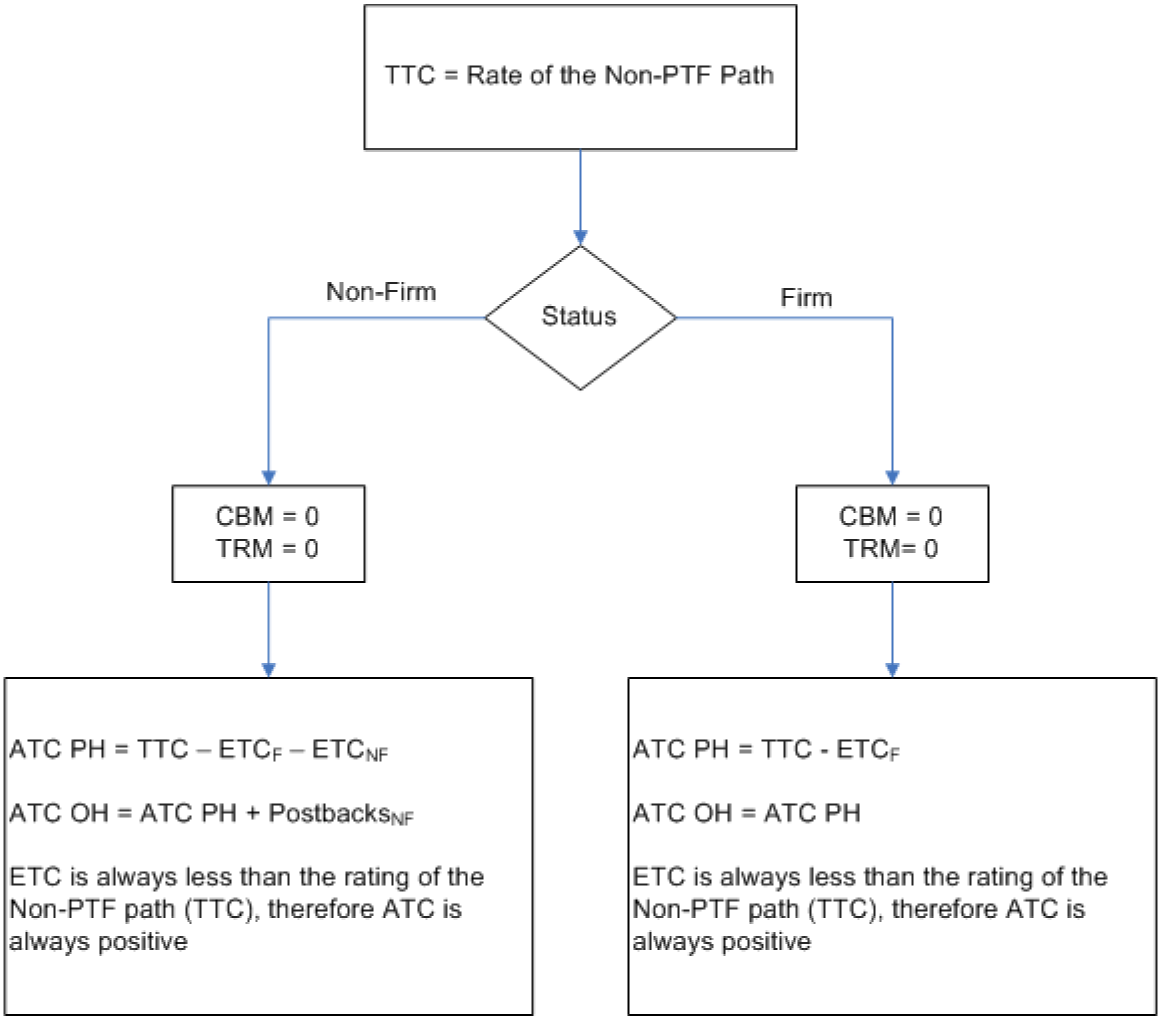
7.3 Coordination of ATC Calculations

Schedule 21-CMP non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms A link to the actual mathematical algorithm for the calculation of ATC for CMP's non-PTF internal interfaces is located on CMP's website at

http//www/cmpco.com/SuppliersAndPartners/TransmissionServices/CMPTransmissionSvc/CMPDownloads.html

Non-PTF Transmission Path ATC Process Flow Diagram



ATTACHMENT D

Methodology for Completing a System Impact Study

Central Maine (or its Designated Agent) may require System Impact Studies for the purpose of determining the feasibility of providing Transmission Service under this Schedule 21. All System Impact Studies will be coordinated with the Control Area Operator and completed using the same method employed by Central Maine to provide Transmission Service to its Affiliate customers. System Impact Studies associated with a request from an Eligible Generator Customer for Interconnection Service shall be performed at the direction of the Control Area Operator. Specifically, System Impact Studies will be performed by applying NPCC Criteria and the "Reliability Standards of ISO," or its successor, while assuring that Central Maine's Native Load Customers and those loads directly interconnected to the Central Maine Transmission System that are receiving Transmission Service can be served economically and reliably. All of the criteria, standards, and guidelines referenced above are included as part of the annual FERC Form 715 filing of Central Maine.

ATTACHMENT F

Local Network Operating Agreement

This Local Network Operating Agreement is part of Schedule 21 and is subject to and in accordance with all provisions of said Schedule 21. All definitions and terms and conditions of this Schedule 21-CMP are incorporated herein by reference.

1.0 General Terms and Conditions

Central Maine agrees to provide Local Network Transmission Service to the Transmission Customer subject to the Transmission Customer operating its facilities in accordance with applicable Central Maine, or its Affiliates, Control Area Operator, NERC and NPCC criteria, rules, standards, procedures or guidelines as they may be changed from time to time. In addition, service to the Transmission Customer is provided subject to the terms and conditions contained herein.

1.1 Character of Service

All Local Network Transmission Service shall be in the form of three-phase sixty (60) hertz alternating current at a delivery voltage agreed to by both parties.

1.2 Maintenance Scheduling

Central Maine shall consult the Transmission Customer regarding the timing of any scheduled maintenance of the Transmission System that would affect service to the Transmission Customer.

1.3 Information Requirements

The Transmission Customer shall be responsible for providing all information required by the Control Area Operator and Central Maine necessary for planning, operations, maintenance and regulatory filings. This information may include, but not be limited to:

Load related data:

- Ten (10) year forecast of Local Network Load at each delivery point.
- Power factor performance.
- Amount of interruptible load under contract, including interruption terms.
- Load shedding capability by delivery point.
- Capability to shift load between delivery points.

- Disturbance reports.
- Results of periodic metering and protection equipment tests and calibration.
- Planned changes to interconnection equipment.
- Voltage reduction capability.

Network Resources and interconnected generation:

- Resource operating characteristics, including ramp rate limits, minimum run times, etc.
- Ten year forecast of resource additions, retirements and capability changes.
- Generator reactive capability.
- Results of periodic metering and protection equipment tests and calibration.

Failure of the Transmission Customer to respond promptly and completely to Central Maine's reasonable request for information shall result in a fine of $100 per day payable to Central Maine. Continued failure to respond shall constitute default.

In addition to the types of information shown above, the Transmission Customer shall supply accurate and reliable operating information to Central Maine. Such information might include, but not be limited to, metered values for kWh, kW, KVAR, voltage, current, frequency, breaker status data and all other data necessary for reliable operation. Central Maine can require such information to be provided electronically using a method such as Supervisory Control And Data Acquisition (SCADA), Remote Terminal Units (RTU), remote access metering or be capable of interfacing directly with Central Maine's dispatch computer system. All equipment used for such purposes must be approved by Central Maine.

1.4 Operating Requirements

The Transmission Customer shall not conduct any switching or other activity likely to affect Central Maine's system without first contacting and receiving permission from Central Maine.

The Transmission Customer shall carry out all switching orders from Central Maine, the Control Area Operator, or a Designated Agent of either, in a timely manner.

The Transmission Customer shall operate all of its equipment and facilities connected to Central Maine's Transmission System, either directly or indirectly, in a safe, reliable and efficient manner. Such operations shall also conform to Good Utility Practice and all requirements and guidelines of Central Maine, the Control Area Operator, NERC and NPCC.

1.5 Discontinuance of Service

If at any point in time, it is Central Maine's judgment that the Transmission Customer is operating its equipment in a manner that would adversely impact the quality of service, reliability or safe operation of Central Maine's system, it may discontinue Transmission Service until the condition has been corrected.

If it is Central Maine's or the Control Area Operator's judgment that an emergency exists or that significant adverse impact is imminent, service to the Transmission Customer may be discontinued without notice. Otherwise, Central Maine or the Control Area Operator shall provide the Transmission Customer with reasonable notice of any intent to discontinue service. When practical, Central Maine will also allow suitable time for the Transmission Customer to correct the problem.

1.6 Required Equipment

The Transmission Customer will install, maintain and repair all interconnection equipment at its expense.

1.7 Emergency Operations

The Transmission Customer shall be subject to all applicable emergency operation standards and practices required of Central Maine to operate in an interconnected regional power pool. For Local Network Customers that are not members of ISO, Central Maine reserves the right to require such customers to provide their fair share of actions required under ISO Operating Procedure No 4: Action During a Capacity Deficiency, ISO Operating Procedure No. 7: Action in an Emergency and ISO Operating Procedure No. 14: Action During Extremely Light Load Conditions.

These actions might include, but are not limited to, running generation at maximum or minimum capability, voltage reduction, load shedding, transferring load between Points of Delivery, public appeals for load reduction, implementation of interruptible load programs and starting stand-by and idle generation.

2.0 Metering

Central Maine will provide Local Network Service to each Point of Delivery specified in the Transmission Customer's Service Agreement. Each Point of Delivery shall have a unique identifier, meter location and meter number.

2.1 Equipment

All metering equipment and installations used to measure energy and capacity delivered to the Transmission Customer must be approved by Central Maine. All Local Network Customers shall be required to have installed appropriate metering to determine such Backyard Generation. Central Maine may require the installation of telemetering equipment for the purposes of billing, power factor measurements and to allow Central Maine to operate its system reliably and efficiently. All such equipment will be installed and maintained at the Transmission Customer's expense.

All meters shall be capable of measuring the instantaneous kW within each hour, net flow in kWh and reactive power flow.

2.2 Seals

All meters shall be sealed, and the seals shall not be broken without prior approval by Central Maine.

2.3 Access

The Transmission Customer shall provide access, including telecommunications access, for a representative of Central Maine, to the meters at reasonable times for the purposes of reading, inspecting, and testing. Central Maine shall use its best efforts not to interfere with normal business operations.

2.4 Calibration and Maintenance

Unless otherwise mutually agreed, the meters shall not be tested or recalibrated or any of the connections, including those of the transformers, disturbed or changed except in the presence of duly authorized representatives of Central Maine and the Transmission Customer or under Emergency Conditions or unless either party, after reasonable notice fails or refuses to have its representatives present.

2.5 Testing

Central Maine will make tests of the metering equipment using Central Maine's standards of accuracy and procedures. Central Maine shall notify the Transmission Customer prior to conducting any metering tests, and the Customer may observe the test. If the meter is found to be inaccurate or otherwise defective, it shall be repaired, adjusted, or replaced at the Transmission Customer's expense.

3.0 Interconnection Equipment

The Transmission Customer's interconnection equipment shall meet all standards of Good Utility Practice.

3.1 Cost

Central Maine will not bear any costs of the interconnection, including any changes as required by this Agreement. The cost of Direct Assignment Facilities will be paid in accordance with this Schedule 21 and the Service Agreement. In the event that Central Maine would incur any expense in connection with the Direct Assignment Facilities, prior to Central Maine incurring any such expense, the Transmission Customer shall be responsible for forwarding to Central Maine funds sufficient to cover that expense, as estimated by Central Maine, including any tax liability for contribution in aid of construction. Central Maine will provide the customer with the actual expenses associated with the funding of Direct Assignment Facilities within sixty (60) days of completion of construction. Adjustments will be made within thirty (30) days thereafter.

3.2 Inspection

Central Maine may inspect the Transmission Customer's interconnection equipment to determine if all standards of Good Utility Practice are met. Central Maine shall not be required to deliver to, or receive electricity from, the Transmission Customer until those requirements are met.

3.3 New Resources

The Transmission Customer shall not connect any generators after the execution of this agreement without first informing Central Maine in writing one-hundred-twenty (120) days in advance of any such connection, except that any such generation not requiring approval the RTO-NE, shall not be connected without sixty (60) days prior notice in writing. Any third party generating facilities connected after the date of the execution of this agreement shall comply with Central Maine's then-existing Technical Interconnection Requirements for Non-Utility Generation as it applies to generation connected directly to the Central Maine system. The Transmission Customer shall be responsible to ensure compliance with these requirements.

In the event that the Transmission Customer or any third party generating facilities incorporate a synchronous generator after the date of the execution of this Local Network Operating Agreement, the Transmission Customer shall furnish, install and maintain equipment necessary to establish and maintain synchronism with Central Maine's system.

3.4 Protection Equipment

In order to protect Central Maine's system from damage, to minimize the likelihood of injury to operating personnel and third parties, and to allow Central Maine to maintain service to its non-generating customers in the event the Transmission Customer's system encounters operating difficulties, the Transmission

Customer shall at its expense, provide, install, and maintain the following equipment insofar as required by Good Utility Practice and, after consultation with Central Maine:

A. A three-phase, gang-operated, load-break, lockable main disconnect switch that allows isolation of the Transmission Customer's facilities from Central Maine's system.

B. An automatic circuit breaker activated by a D.C. power source independent of both Central Maine's and the Transmission Customer's A.C. voltage source which can be tripped by the protective relay system under all system conditions. The circuit breaker must also be suitable for use in synchronizing generation on the Transmission Customer system to Central Maine's system.

C. Under-frequency and over-frequency protective relays to be used in conjunction with the required automatic circuit breaker.

D. Under-voltage and over-voltage protective relays to be used in conjunction with the required automatic circuit breaker.

E. Over-current protective relays to be used in conjunction with the required automatic circuit breaker.

F. Potential and current transformers to be used for the above relaying, sized and connected as approved by Central Maine.

G. Such other equipment as may be reasonably required by Good Utility Practice, as recommended by Central Maine.

H. The Transmission Customer shall provide to Central Maine complete documentation of the Transmission Customer's interconnection equipment, including, but not limited to, power one-line diagrams, relaying diagrams, plans, sectional and elevation views, grading plans, conduit plans, foundation plans, fence and grounding plans and detailed steel erection diagrams. In addition, the Transmission Customer agrees to provide to Central Maine complete documentation of any changes to the Transmission Customer's Interconnection equipment.

I. The protective relay system required to detect faults on Central Maine's system and the breaker required to disconnect the Transmission Customer's generation to protect the general public and Central Maine's personnel must be approved by Central Maine. Central Maine shall provide relay settings and recommendations for design, equipment selection, and routine maintenance. The Transmission Customer shall purchase, install, and maintain the protective relay system, and maintain and make available to Central Maine all maintenance and test records. Central Maine shall perform functional test(s), at reasonable intervals, of the protective relay system to determine whether the system functions in a manner acceptable to Central Maine and shall notify the Transmission Customer in writing of the test results. The Transmission Customer shall bear the cost of this testing and any other assistance that may be requested of Central Maine before and after the system is made operational.

J. The Transmission Customer shall, at its own expense, repair and maintain its protective relay system and any other equipment owned or operated by the Transmission Customer.

3.5 Maintenance and Modifications To The Interconnection

A. The Transmission Customer shall repair and maintain during the term hereof all of the Transmission Customer's interconnection equipment on the Transmission Customer's side of the visible disconnect that isolates the Transmission Customer's facilities from Central Maine's system, in accordance with established practices and standards for the operation and maintenance of power system equipment.

B. The Transmission Customer shall maintain its own generation in accordance with Good Utility Practice. The Transmission Customer shall ensure that all third party generation facilities connected to the Transmission Customer system is maintained in accordance with Central Maine's Technical Interconnection Requirements for Non-Utility Generation.

C. The Transmission Customer shall arrange with Central Maine an initial functional testing and inter-tie inspection, to be completed prior to the effective date of this agreement. In addition, the Transmission Customer shall arrange with Central Maine for an annual, visual inspection of all interconnection facilities and associated maintenance records. Every two years, the Transmission Customer shall arrange a relay calibration test and operational test of the Transmission Customer's interconnection equipment. The relay calibration test must be performed by a qualified contractor approved by Central Maine and acceptable to the Transmission Customer or by Central Maine itself. After the relay calibration tests are completed, Central Maine may perform a relay system functional test. The

Transmission Customer shall bear the cost of any relay testing and any other assistance that may be requested by Central Maine before and after the system is made operational.

D. Before May 1 of each year, Central Maine shall provide the Transmission Customer with recommended dates for scheduling maintenance of the Transmission Customer's generating facilities and third party generating facilities greater than 5 MW and the Transmission Customer transmission facilities operating at 34.5 Kv or greater. The Transmission Customer shall provide to Central Maine on or before June 1 of each year a list of periods, in order of preference and in accordance with Central Maine's recommended dates, during which the Transmission Customer prefers to schedule maintenance during the subsequent calendar year. If Central Maine does not provide the Transmission Customer with recommended dates before May 1 of any year, the Transmission Customer shall nonetheless provide Central Maine on or before June 1 of that year, a list of periods, in order of preference, in which the Transmission Customer prefers to schedule maintenance during the subsequent calendar year, and Central Maine will attempt to accommodate the Transmission Customer's proposed schedule of maintenance periods if Central Maine can do so without adverse operational or economic effect on ISO, Central Maine or its customers. By July 1 of each year, the Transmission Customer and Central Maine will agree on maintenance periods for the interconnection equipment.

E. If Central Maine in its reasonable judgment determines that the Transmission Customer's interconnection equipment is, in any substantial respect, being maintained otherwise than in accordance with Good Utility Practice, Central Maine may so notify the Transmission Customer in writing. Within thirty (30) days of the date of notification, the Transmission Customer shall conform its maintenance practices to the requirements of Good Utility Practice and of this agreement. In the event that the Transmission Customer fails to bring its maintenance practices into conformance with the requirements of Good Utility Practice within that thirty (30) day period, Central Maine may de-energize the interconnection between the Transmission Customer and Central Maine until the Transmission Customer has conformed its maintenance practices as provided herein.

F. The Transmission Customer shall give Central Maine adequate written notice of any modification or replacement of the Transmission Customer's interconnection equipment. All additions, modifications or replacements must meet the requirements of this agreement and all standards of Good Utility Practice. If the Transmission Customer makes changes without notice to Central Maine, and if Central Maine has reasonable cause to believe that the changes may create dangerous conditions, Central Maine may de-energize the interconnection between the Transmission Customer and Central Maine.

G. The Transmission Customer, at its expense, shall change the Transmission Customer's interconnection equipment as may be reasonably required by Central Maine or as may otherwise be required to conform to Good Utility Practice to meet changing requirements of Central Maine's system.

H. In the event that de-energization of the interconnection is required by the provisions of this agreement, Central Maine will only de-energize the interconnection at the affected Point or Points of Delivery.

4.0 Power Factor

To prevent degradation of voltage to Central Maine's customers, to prevent unnecessary system losses, and to maintain Central Maine voltage levels and area reactive support, the Transmission Customer shall maintain a 97% or higher power factor. Should Central Maine be required to maintain a higher level than 97%, the Transmission Customer shall be required to do so as well. Failure by the Transmission Customer to maintain acceptable power factor may result in additional Direct Assigned Facilities charges associated with installing any equipment needed to maintain the designated power factor.

5.0 Voltage Control

The Transmission Customer's automatic voltage control equipment shall ensure that no more than a 3% instantaneous variation in voltage shall occur at the interconnection during connection or disconnection of a synchronous generator, an induction generator, or any motor load or capacitor.

6.0 Harmonics

The Transmission Customer must operate and maintain its system in a manner that avoids the generation of harmonic frequencies exceeding the limits established by the latest revision of IEEE-519 Recommended Practices and Requirements for Harmonics Control in Electrical Power Systems.

7.0 Default

The Transmission Customer's failure to meet the terms and conditions of the agreement shall be deemed to be a default resulting in Central Maine seeking, consistent with FERC rules and regulations, immediate termination of service.

ATTACHMENT G-R

FORMULA FOR CALCULATING ANNUAL RETAIL TRANSMISSION REVENUE REQUIREMENTS
UNDER THE CENTRAL MAINE POWER COMPANY
LOCAL SERVICE SCHEDULE, Schedule 21-CMP

This formula sets forth the details for determining each year's Annual Transmission Revenue Requirement for Central Maine Power Company (Central Maine). The Transmission Revenue Requirement reflects Central Maine's cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to retail Transmission Customers under this Schedule 21-CMP. The Transmission Revenue Requirement will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31, 2000, based on 1998 test year data, and updated thereafter each June 1, based on the previous calendar year's FERC Form 1 data, and based on actual data in lieu of allocated data, if specifically identified in FERC Form 1, as shown below, using end-of-year balances for each rate base item, as further set forth below. The Annual Transmission Revenue Requirement calculated pursuant to this Attachment G-R shall include a Forecasted Transmission Revenue Requirement and Annual True-up as further set forth below and calculated in accordance with Attachment K to this Schedule 21-CMP. The Annual Transmission Revenue Requirement shall include an Incremental Return and Associated Income Taxes and shall incorporate the 125 basis point incentive ROE adder granted by the FERC in Docket No. EL08-74-000 for the Maine Power Reliability Program ("MPRP") on MPRP CWIP or any other MPRP transmission investments not otherwise recoverable as Pool-Supported PTF under Attachment F of this OATT. The data used in determining the Incremental Return and Associated Taxes shall be based on actual data specifically identified in Central Maine's accounting records.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section 1 of the Central Maine Schedule 21-CMP have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct wages and salaries not otherwise assigned under this Schedule

21-CMP, including those of Affiliate companies, and the wages and salaries associated with the Transmission Related Customer Service and Information Expenses and Sales Expenses to Central Maine's total direct wages and salaries excluding administrative and general wages and salaries. The wages and salaries associated with the Transmission Related Customer Service and Informational Expenses and Sales Expenses shall exclude any wages and salaries associated with state-mandated programs, activities, and services.

2. Transmission Network Allocation Factor shall equal the ratio of Total Investment in Transmission Plant excluding the balance associated with generator leads and generator step up transformers in Central Maine's Transmission Plant for test periods beginning with calendar year 1999 and thereafter to Total Investment in Transmission Plant.

3. Transmission Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Transmission Plant excluding the balance associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts for test period beginning with calendar year 1999 and thereafter, and Transmission Related General Intangible Plant to Total Plant in service.

4. Customer Service and Informational Expenses and Sales Expenses Allocation Factor shall initially equal the ratio of transmission revenue requirements (excluding such expenses) to the total company revenue requirements (excluding such expenses) Beginning with the 2001 test year, the allocation factor shall be the ratio of actual transmission revenues to total actual transmission and distribution revenues, including stranded costs.

B. TERMS

Administrative and General Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

Amortization of Investment Tax Credits shall equal Central Maine's credits as recorded in FERC Account No. 411.4.

Customer Service and Information Expenses and Sales Expenses shall equal Central Maine's expenses as recorded in FERC Account Nos. 901-916 reduced by the revenues that Central Maine receives for providing such services to energy service providers as recorded in FERC Account No. 456.

Depreciation Expense for Transmission Plant shall equal Central Maine's transmission depreciation expense as recorded in FERC Account No. 403 and shall not include any depreciation expense associated with generator leads and generator step-up transformers after March 31, 1999.

Intangible and General Plant shall equal Central Maine's gross plant balance as recorded in FERC Account Nos. 301-303 and 389-399.

Intangible and General Plant Depreciation Expense shall equal Central Maine's intangible and general expenses as recorded in FERC Account Nos. 403 and 404.

Intangible and General Plant Depreciation Reserve shall equal Central Maine's intangible and general reserve balance as recorded in FERC Account Nos. 108 and 111.

Maine Power Reliability Program Construction Work In Progress ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of Central Maine's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in Central Maine's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of Central Maine's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Central Maine's FERC Account No. 254.

Plant Held for Future Use shall equal Central Maine's balance in FERC Account No.105.

Prepayments shall equal Central Maine's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Central Maine's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and the deferred tax balance as recorded in FERC Account No. 190.

Total Municipal Tax Expense shall equal Central Maine's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal Central Maine's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal Central Maine's transmission reserve balance as recorded in FERC Account 108, and for test years beginning with 1999 and thereafter, shall exclude any reserve balance associated with generator leads and generator step-up transformers.

Transmission Operation and Maintenance Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564, the transmission-related portion of the Bolt Hill wheeling agreement as recorded in Account No. 565, and 566-573, excluding any HQ HVDC expenses booked to accounts 560 through 573 and any other expenses in support of other utilities' transmission facilities which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal Central Maine's Gross Plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal Central Maine's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of Central Maine's (A) Investment Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for MPRP), (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Investment Tax Credits, (D) Transmission Related Municipal Tax Expense, (E) Transmission Operation and Maintenance Expense, (F) Transmission Related Administrative and General Expenses, (G) Transmission Related Taxes and Fees, (H) Transmission Support Expense, minus (I) Transmission Support Revenue, minus (J) ISO Transmission Revenue, minus (K) Other Wheeling Revenue, minus (L) Transmission Rents Received from

Electric Property, plus (M) Transmission Related Customer Service and Informational Expenses and Sales Expenses, plus (N) Forecasted Transmission Revenue Requirement and Annual True-up. The Incremental Return and Associated Income Taxes for MPRP shall be calculated using the Transmission Investment Base components specifically identified in Section A.1 of the formula below.

A. Investment Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Investment Return and Associated Income Taxes for MPRP, Transmission Investment Base will only include Sections II.A.1.(a), (d), (e), and (j) in the manner indicated.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Other Regulatory Assets/Liabilities, plus (g) Transmission Prepayments, plus (h) Transmission Materials and Supplies, plus (i) Transmission Related Cash Working Capital, plus (j) MPRP CWIP.

(a) Transmission Plant will equal the balance of Central Maine's Investment in Transmission Plant multiplied by the Transmission Network Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, MPRP Transmission Plant will be separately identified.

(b) Transmission Related Intangible and General Plant shall equal the sum of Central Maine's investment in Intangible and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation.

(c) Transmission Plant Held for Future Use shall equal the balance of Transmission-related Plant Held for Future Use.

(d) Transmission Related Depreciation Reserve shall equal the balance of Total Transmission Depreciation Reserve, plus the sum of the balance of Transmission Related Intangible and General Plant Depreciation Reserve. Transmission Related Intangible and General Plant Depreciation Reserve shall equal the product of Intangible and General Plant Depreciation Reserve and the

Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, Transmission Depreciation Reserve associated with MPRP will be separately identified.

(e) Transmission Related Accumulated Deferred Taxes shall equal Central Maine's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, Transmission Related Accumulated Deferred Income Taxes associated with MPRP will be separately identified.

(f) Other Regulatory Assets/Liabilities shall equal Central Maine's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor, plus Central Maine's electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(g) Transmission Prepayments shall equal Central Maine's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

(h) Transmission Materials and Supplies shall equal Central Maine's electric balance of Plant Materials and Supplies, multiplied by the Plant Allocation Factor.

(i) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph J of the formula.

(j) MPRP CWIP shall equal Central Maine's balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and not otherwise recoverable as Pool-Supported PTF under Attachment F of this OATT. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, MPRP CWIP will be separately identified.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Central Maine's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity, including any unamortized discounts and premiums, and unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to Central Maine's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Central Maine's preferred stock then outstanding and the ratio that preferred stock is to Central Maine's total capital.

(iii) the return on equity component, which equals the product of Central Maine's Return on Equity of 11.14% and the ratio that common equity is to Central Maine's total capital. In order to calculate the Incremental Investment Return and Associated Income Taxes for MPRP, the incremental return on equity shall be the product of the MPRP incremental return on equity of 1.25% and the ratio that common equity is to Central Maine's total capital.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.C., below, C is the Equity AFUDC component of Transmission Depreciation Expense , as defined in Section II.B., and D is Transmission Investment Base, as determined in II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 - FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.C. below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., D is the Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. <u>Transmission Depreciation Expense</u> shall equal the sum of Depreciation Expense for Transmission Plant, plus an allocation of Intangible and General Plant Depreciation Expense calculated by multiplying Intangible and General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

C. <u>Transmission Related Amortization of Investment Tax Credits</u> shall equal Central Maine's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

D. Transmission Related Municipal Tax Expense shall equal Central Maine's total electric municipal tax expense multiplied by the Plant Allocation Factor.

E. Transmission Operation and Maintenance Expense shall equal Central Maine's Transmission Operation and Maintenance Expenses, multiplied by the Transmission Network Allocation Factor.

F. Transmission Related Administrative and General Expenses shall equal the sum of (1) Central Maine's Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments multiplied by Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments, and beginning June 1, 2007, minus the amortization of RTO formation and associated carrying costs included in Account 928, plus a pro forma amount of such costs expected to be amortized to Account 928 from June 1 through May 31 of the current rate year, plus specific transmission related expenses included in Account 930.1. The pro forma amount described above shall continue through May 31, 2011 and shall not be subject to the Annual True-up described in Attachment K of this Schedule 21-CMP.

G. Transmission Related Regulatory Assessments shall include any FERC assessments associated with Transmission Service provided under the OATT and Schedule 21, based on the FERC regulations in 18 C.F.R. § 382.201, and as recorded in FERC Account No. 408.1.

H. Transmission Support Expense shall equal Central Maine's electric expense for transmission support, excluding any support expenses associated with the non-PTF facilities as the Millstone power plant.

I. Transmission Support Revenues shall equal Central Maine's revenue received for transmission support, excluding, for test periods beginning in calendar year 1999 and thereafter, and support revenues associated with generator leads and step-up transformers in Central Maine's Transmission Plant accounts. To the extent that a customer had pre-paid Central Maine for O&M service performed during the test period associated with Direct Assignment Facilities, interconnection facilities, or grid upgrades, such prepayment shall not be credited to the revenue requirement described in this Attachment G-R. Rather, an annual amount of O&M service revenue shall be imputed to such service in accordance with Schedule No. 14 and credited for each test year during which such O&M service obligation continues.

J. ISO Transmission Revenues shall equal the revenues distributed to Central Maine, from ISO, for network, and through and out Transmission Service provided under the OATT excluding any incremental revenues associated with FERC-approved incentives for MPRP CWIP and the ROE adders for RTO participation and new transmission investment. These revenues will be based on historical test year data, except that for the duration of the transition period, Central Maine will use a pro forma amount for network service revenues expected to be received in the rate year.

K. Other Wheeling Revenues shall equal any revenues received by Central Maine for providing wheeling out services to Generators as well as any other short-term, non-firm, or penalty revenues received by Central Maine associated with the provision of Transmission Services under this Schedule 21-CMP, not otherwise reflected in Section II. J above. The credit for wheeling out revenues shall change from month to month based on the actual amounts received by Central Maine for the most recent month that data is available. The revenue requirement described in this Attachment G-R shall be revised each month to reflect the annualized amount of the credit. Revenues received by Central Maine pursuant to Transmission Service agreements that pre-dated Order No. 888, to the extent that the such transactions are treated as a revenue credit rather than in the determination of Load Ratio Share, will be prorated between this Attachment G-R and Schedule 1 of this Schedule 21-CMP on the basis of gross investment in plant for the services at issue.

L. Transmission Rents Received from Electric Property shall equal any Rents from electric property, associated with Transmission Plant as defined in Section II.A.1.(a) above, excluding, for test periods beginning in calendar year 1999 and thereafter, any rents associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts, but not otherwise reflected in Section II. I. above as Transmission Support Revenues.

M. Transmission-Related Customer Service and Informational Expenses and Sales Expenses shall equal Central Maine's expenses in FERC Account Nos. 901-916 less any State-mandated programs, activities and services multiplied by the Customer Service and Informational Expenses and Sales Expenses Allocation Factor.

N. Forecasted Transmission Revenue Requirement and Annual True-up shall equal Central Maine's estimated revenue requirements for forecasted transmission plant additions and any associated Annual

True-up. The Forecasted Transmission Revenue Requirement and Annual True-up shall be calculated in accordance with Attachment K to this Schedule 21-CMP.

ATTACHMENT G -W
FORMULA FOR CALCULATING
ANNUAL WHOLESALE TRANSMISSION REVENUE REQUIREMENTS
UNDER THE CENTRAL MAINE POWER COMPANY
LOCAL SERVICE SCHEDULE
SCHEDULE 21-CMP

This formula sets forth the details for determining each year's Annual Transmission Revenue Requirement for Central Maine Power Company (Central Maine). The Transmission Revenue Requirement reflects Central Maine's cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to wholesale Transmission Customers under this Schedule 21-CMP. The Transmission Revenue Requirement will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31, 2000, based on 1998 test year data, and updated thereafter each June 1, based on the previous calendar year's FERC Form 1 data, and based on actual data in lieu of allocated data, if specifically identified in FERC Form 1, as shown below, using end-of-year balances for each rate base item, as further set forth below. The Annual Transmission Revenue Requirement calculated pursuant to this Attachment G-W shall include a Forecasted Transmission Revenue Requirement and Annual True-up as further set forth below and calculated in accordance with Attachment K to this Schedule 21-CMP. The Annual Transmission Revenue Requirement shall include an Incremental Return and Associated Income Taxes and shall incorporate the 125 basis point incentive ROE adder granted by the FERC in Docket No. EL08-74-000 for the Maine Power Reliability Program ("MPRP") on MPRP CWIP and on any MPRP transmission investments not otherwise recoverable as Pool-Supported PTF under Attachment F of this OATT. The data used in determining the Incremental Return and Associated Taxes shall be based on actual data specifically identified in Central Maine's accounting records.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section 1 of the Schedule 21-CMP have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct wages and salaries not otherwise assigned under this Schedule 21-CMP, including those of Affiliate Companies to Central Maine's total direct wages and salaries

including those of the Affiliate Companies and excluding administrative and general wages and salaries.

2. Transmission Network Allocation Factor shall equal the ratio of Total Investment in Transmission Plant excluding the balance associated with generator leads and generator step up transformers in Central Maine's Transmission Plant for test periods beginning with calendar year 1999 and thereafter to Total Investment in Transmission Plant.

3. Transmission Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Transmission Plant, excluding the balance associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts for test periods beginning with calendar year 1999 and thereafter, and Transmission Related General and Intangible Plant to Total Plant in service.

B. TERMS

Administrative and General Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

Amortization of Investment Tax Credits shall equal Central Maine's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal Central Maine's transmission depreciation expense as recorded in FERC Account No. 403 and shall not include any depreciation expense associated with generator leads or generator step up transformers for test years beginning with 1999 and thereafter.

Intangible and General Plant shall equal Central Maine's gross plant balance as recorded in FERC Account Nos. 301-303 and 389-399.

Intangible and General Plant Amortization and Depreciation Expense shall equal Central Maine's intangible and general expenses as recorded in FERC Account Nos. 404 and 403.

Intangible and General Plant Depreciation Reserve shall equal Central Maine's intangible and general reserve balance as recorded in FERC Account Nos. 111 and 108.

Maine Power Reliability Program Construction Work In Progress ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of Central Maine's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in Central Maine's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of Central Maine's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Central Maine's FERC Account No. 254.

Plant Held for Future Use shall equal Central Maine's balance in FERC Account No.105.

Prepayments shall equal Central Maine's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Central Maine's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and the deferred tax balance as recorded in FERC Account No. 190.

Total Municipal Tax Expense shall equal Central Maine's municipal tax expenses as recorded in FERC Account No. 408.1.

Total Plant in Service shall equal Central Maine's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal Central Maine's transmission reserve balance as recorded in FERC Account 108, and for test years beginning with 1999 and thereafter, shall exclude any reserve balance associated with generator leads and generator step-up transformers.

Transmission Operation and Maintenance Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564 and 566-573, excluding any HQ HVDC expenses booked to accounts 560 through 573 and any other expenses in support of other utilities' transmission facilities which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal Central Maine's Gross Plant balance as recorded in FERC Account Nos. 350-359 and for test years beginning with 1999 and thereafter, shall exclude any investment in generator leads and generator step up transformers.

Transmission Plant Materials and Supplies shall equal Central Maine's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of Central Maine's (A) Investment Return and Associated Income Taxes (including the Incremental Investment Return and Associated Income Taxes for MPRP), (B) Transmission Depreciation Expense, (C), Transmission Related Amortization of Investment Tax Credits, (D) Transmission Related Municipal Tax Expense, (E) Transmission Operation and Maintenance Expense, (F) Transmission Related Administrative and General Expenses, (G) Transmission Related Regulatory Assessments, (H) Transmission Support Expense, minus (I) Transmission Support Revenue, minus (J) ISO Transmission Revenue, minus (K) Other Wheeling Revenue, minus (L) Transmission Rents Received from Electric Property, and (M) Forecasted Transmission Revenue Requirement and Annual True-up. The Incremental Return and Associated Income Taxes for MPRP shall be calculated using the Transmission Investment Base components specifically identified in Section A.1 of the formula below.

A. Investment Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Investment Return and Associated Income Taxes for MPRP, Transmission Investment Base will only include Sections II.A.1.(a), (d), (e), and (j) in the manner indicated.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Other Regulatory Assets/Liabilities, plus (g) Transmission Prepayments, plus (h) Transmission Materials and Supplies, plus (i) Transmission Related Cash Working Capital, plus (j) MPRP CWIP.

(a) Transmission Plant will equal the balance of Central Maine's Investment in Transmission Plant multiplied by the Transmission Network Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, MPRP Transmission Plant will be separately identified.

(b) Transmission Related Intangible and General Plant shall equal the sum of Central Maine's investment in Intangible and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the balance of Transmission-related Plant Held for Future Use.

(d) Transmission Related Depreciation Reserve shall equal the balance of Total Transmission Depreciation Reserve, plus the sum of the balance of Transmission Related Intangible and General Plant Depreciation Reserve. Transmission Related Intangible and General Plant Depreciation Reserve shall equal the product Intangible and General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, Transmission Depreciation Reserve associated with MPRP will be separately identified.

(e) Transmission Related Accumulated Deferred Taxes shall equal Central Maine's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, Transmission Related Accumulated Deferred Income Taxes associated with MPRP will be separately identified.

(f) Other Regulatory Assets/Liabilities shall equal Central Maine's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor, plus Central Maine's electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(g) Transmission Prepayments shall equal Central Maine's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

(h) Transmission Materials and Supplies shall equal Central Maine's electric balance of Plant Materials and Supplies, multiplied by the Plant Allocation Factor.

(i) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph J of the formula.

(j) MPRP CWIP shall equal Central Maine's balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and not otherwise recoverable as Pool-Supported PTF under Attachment F of this OATT. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, MPRP CWIP will be separately identified.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Central Maine's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity, including any unamortized discounts and premiums, and unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to Central Maine's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Central Maine's preferred stock then outstanding and the ratio that preferred stock is to Central Maine's total capital.

(iii) the return on equity component, which equals the product of Central Maine's Return on Equity of 11.14% and the ratio that common equity is to Central Maine's total capital. In order to calculate the Incremental Investment Return and Associated Income Taxes for MPRP, the incremental return on equity shall be the product of the MPRP incremental return on equity of 1.25% and the ratio that common equity is to Central Maine's total capital.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.C., below, C is the Equity AFUDC component of Transmission Depreciation Expense , as defined in Section II.B., and D is Transmission Investment Base, as determined in II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 – FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.C. below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., D is the Transmission Investment

Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Transmission Plant, plus an allocation of Intangible and General Plant Depreciation Expense calculated by multiplying Intangible and General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

C. Transmission Related Amortization of Investment Tax Credits shall equal Central Maine's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

D. Transmission Related Municipal Tax Expense shall equal Central Maine's total electric municipal tax expense multiplied by the Plant Allocation Factor.

E. Transmission Operation and Maintenance Expense shall equal Central Maine's Transmission Operation and Maintenance Expenses, multiplied by the Transmission Network Allocation Factor.

F. Transmission Related Administrative and General Expenses shall equal the sum of (1) Central Maine's Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Transmission Network Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments multiplied by Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments, and beginning June 1, 2007, minus the amortization of RTO formation and associated carrying costs included in Account 928, plus a pro forma amount of such costs expected to be amortized to Account 928 from June 1 through May 31 of the current rate year, plus specific transmission related expenses included in Account 930.1. The pro forma amount described above shall continue through May 31, 2011 and shall not be subject to the Annual True-up described in Attachment K of this Schedule 21-CMP.

G. Transmission Related Regulatory Assessments shall include any FERC assessments associated with Transmission Service provided under the OATT and Schedule 21, based on the FERC regulations in 18 C.F.R. § 382.201, and as recorded in FERC Account No 408.1.

H. Transmission Support Expense shall equal Central Maine's electric expense for transmission support, excluding any support expenses associated with the non-PTF portion of Millstone.

I. Transmission Support Revenues shall equal Central Maine's revenue received for transmission support, excluding, for test periods beginning in calendar year 1999 and thereafter, and support revenues associated with generator leads and step-up transformers in Central Maine's Transmission Plant accounts. To the extent that a customer had pre-paid Central Maine for O&M service performed during the test period associated with Direct Assignment Facilities, interconnection facilities, or grid upgrades, such prepayment shall not be credited to the revenue requirement described in this Attachment G-W. Rather, an annual amount of O&M service revenue shall be imputed to such service in accordance with Schedule No. 14 and credited for each test year during which such O&M service obligation continues.

J. ISO Transmission Revenues shall equal the revenues distributed to Central Maine, from ISO, for network, and through and out Transmission Service provided under the OATT excluding any incremental revenues associated with FERC-approved incentives for MPRP CWIP and the ROE adders for RTO participation and new transmission investment. These revenues will be based on historical test year data, except that for the duration of the transition period, Central Maine will use a pro forma amount for network service revenues expected to be received in the rate year.

K. Other Wheeling Revenues shall equal any revenues received by Central Maine for providing wheeling out services to generators as well as any other short-term, non-firm, or penalty revenues received by Central Maine associated with the provision of Transmission Services under this Schedule 21-CMP, not otherwise reflected in Section II . J above. The credit for wheeling out revenues shall change from month to month based on the actual amounts received by Central Maine for the most recent month that data is available, and this Attachment G-W revenue requirement will be revised each month to reflect the annualized amount of such monthly value, to account for the updated credit. Revenues received by Central Maine pursuant to Transmission Service agreements that pre-dated Order No. 888, to the extent that the such transactions are treated as a revenue credit rather than in the determination of Load Ratio Share, will be prorated between this Attachment G-W and Schedule 1 of this Schedule 21-CMP on the basis of gross investment in plant for the services at issue.

L. Transmission Rents Received from Electric Property shall equal any Rents from electric property, associated with Transmission Plant as defined in Section II.A.1.(a) above, excluding, for test periods beginning in calendar year 1999 and thereafter, any rents associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts, but not otherwise reflected in Section II. I. above as Transmission Support Revenues.

M. Forecasted Transmission Revenue Requirement and Annual True-up shall equal Central Maine's estimated revenue requirements for forecasted transmission plant additions and any associated Annual True-up. The Forecasted Transmission Revenue Requirement and Annual True-up shall be calculated in accordance with Attachment K to this Schedule 21-CMP.

ATTACHMENT H

Umbrella Service Agreement For Retail

Local Network Transmission Service

1.0 This Service Agreement, dated as of March 1, 2000 is entered into, by and between Central Maine Power Company, and Central Maine Power Company, as the Designated Agent for its distribution level retail access customers as determine by the Maine Public Utility Commission ("Transmission Customer"). Such retail customers are not required to sign a Service Agreement, but have designated the Central Maine as their agent to arrange and maintain Local Network Transmission Service under the Central Maine Power Company Local Service Schedule 21 and Regional Network Service under the OATT on their behalf.

2.0 Service under this agreement shall commence on March 1, 2000. The Service Agreement shall be effective for an initial term of one year. Thereafter, it will continue from year-to-year unless terminated by Central Maine through a unilateral filing with FERC under section 205 of the FPA. Unless otherwise specified in their State of Maine Tariffs or in their contract with Central Maine, retail distribution level customers taking service under this Service Agreement shall be responsible for transmission charges for the initial term of one of Central Maine's typical monthly billing cycles for retail customers. Thereafter, such customers will continue to be responsible for transmission charges from typical monthly billing cycle to typical monthly billing cycle.

3.0 Central Maine agrees to provide and the Transmission Customer agrees to take and pay for Local Network Service in accordance with the provisions of Part III of this Schedule 21-CMP, Schedule 12 and this Service Agreement. Retail customers shall continue to pay Maine Public Utility Commission ordered rates, including without limitation, stranded costs and other distribution-related costs, as applicable.

4.0 This Schedule 21 is incorporated herein and made a part hereof.

Specifications for Retail Local Network Transmission Service

1.0 Term of Transaction: The Service Agreement shall be effective for an initial term of one year. Thereafter, it will continue from year-to-year.

Start Date: March 1, 2000

2.0 General description of capacity and energy to be transmitted by Central Maine including the electric Control Area in which the transaction originates.

Central Maine will transmit capacity and energy sufficient to serve all of it retail distribution level customers as determined by the Maine Public Utility Commission.

3.0 Retail Local Network Service Customers agree to take the following Ancillary Services from Central Maine under the terms and conditions of the OATT and Central Maine's Local Service Schedule 21.

1. Scheduling, System Control and Dispatch.

Retail Local Network Customers agree to take the following Ancillary Services under the terms and conditions of the OATT and applicable ISO Market Rules through Central Maine or another entity acting as their Designated Agent.

1. Scheduling, System Control and Dispatch
2. Reactive Supply and Voltage Control Service
3. Regulation and Frequency Response Service (Automatic Generation Control)
4. Energy Imbalance Service
5. Ten Minute Spinning Reserve Service
6. Ten Minute Non-Spinning Reserve Service
7. Thirty Minute Operating Reserve Service

ATTACHMENT I

Service Agreement For Retail Local Network Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between Central Maine Power Company ("Central Maine"), and ____________________ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Central Maine to have a Completed Application for Local Network Transmission Service under Schedule 21.

3.0 By checking here , the Transmission Customer agrees to designate Central Maine as its sole agent, pursuant to Schedule 12, for arranging and obtaining Regional Network Service under the Tariff. The Transmission Provider agrees to bill the Transmission Customer directly for such services, and the Transmission Customer agrees to pay in full such bill for PTF service.

3.1 The Transmission Customer agrees to pay Central Maine any and all charges associated with the distribution component of the network service even if there is a dispute over charges associated with the transmission component of the network service. Central Maine reserves the right to terminate service for non-payment of charges for distribution service. Disputes concerning charges for distribution service will be subject to the rules of the Maine Public Utilities Commission. Disputes concerning Transmission Service will be subject to Federal Energy Regulatory Commission ("FERC") rules. Any partial payment by the Transmission Customer to Central Maine will applied first to any outstanding charges associated with Transmission Services provided by Central Maine to the Transmission Customer under the Tariff. Thereafter, any partial payment by the Transmission Customer to Central Maine will be applied to the outstanding charges associated with distribution services provided under Central Maine's Local Service Schedule.

4.0 Service under this agreement shall commence on the later of (1) __________________, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility additions or upgrades are completed, or (3) the date on which a Local Network Operating Agreement is executed and all requirements of said Agreement have been completed or (4) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on _____________________.

5.0 Central Maine agrees to arrange and to provide and the Transmission Customer agrees to take and pay for Local Network Service in accordance with the provisions of Part III of this Schedule 21-CMP and this Service Agreement.

6.0 Any notice or request made to or by either party regarding this Service Agreement shall be made to the representative of the other party as indicated below.

<u>Central Maine</u>:

____
____
____

<u>Transmission Customer</u>:

____
____
____

7.0 This Local Service Schedule is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Central Maine:

By:__________________________ ______________________ __________

Name Title Date

Transmission Customer:

By:__________________________ ______________________ __________

Name Title Date

Specifications For Local Network Transmission Service

1.0 Term of Transaction: ____

Start Date: ____

Termination Date: ____

2.0 General description of capacity and energy to be transmitted by Central Maine including the electric Control Area in which the transaction originates.

____

3.0 Detailed description and forecast of Local Network Load at each delivery point:

____

____

____

4.0 Detailed description of each Network Resource, including any operating restrictions:____

____

____

5.0 Detailed description of the Transmission Customer's anticipated use of Central Maine's interfaces:

____

____

____

6.0 Description of any Transmission System owned or controlled by the Transmission Customer:____

____

____

____

7.0 Names(s) of any intervening Transmission Owners:

____

____

____

8.0 The Local Network Service Customer agrees to take the following Ancillary Services from Central Maine.

1. Scheduling, System Control and Dispatch _____Yes\No

The Local Network Customer agrees to take the following Ancillary Services from the ISO, a third party or agrees to self provide them.

		Yes/No	Source
1.	Reactive Supply and Voltage Control	____	* __________
2.	Regulation and Frequency Response	____	* __________
3.	Energy Imbalance	____	* __________
4.	Spinning Reserve	____	* __________
5.	Supplemental Reserve	____	* __________

9.0 Description of required Direct Assignment Facilities:

____

____

____

10.0 In addition to the charge for Transmission Service and charges for Ancillary Services as set forth in this Schedule 21, the customer will be subject to the following charges:

10.1 System Impact and/or Facilities Study Charge(s):

____

____

10.2 Direct Assignment Facilities Charges:______________________________________

____

____

10.3 Redispatch Charges:

____

____

10.4 Facility Additions or Upgrade Charges:

____

ATTACHMENT J

Form Letter of Credit

[BANK LETTERHEAD]

IRREVOCABLE LETTER OF CREDIT

[Date]

Irrevocable Letter of Credit No.

Central Maine Power Co.
Manager, Transmission Services
83 Edison Drive
Augusta, ME 04336

Dear Sirs:

At the request and on the instructions of our customer _________________________________ we hereby establish our irrevocable letter of credit No. _____________________ in your favor for the account of ____and authorize you to draw on ____ Bank an amount not to exceed _______________________Dollars ($______________________).

Funds under this letter of credit are available to you against a sight draft on us, which must be marked "Drawn under ____ Bank Irrevocable Letter of Credit No. _________________ dated _____________________ ".

Each draft must be accompanied by: (1) a written statement by your duly authorized officer that there is then payable to you from ____________________________ an amount equal to the amount of such draft and specifying the section of the Power Purchase Agreement under which the amount is payable; and (2) the original of this letter of credit, which will be returned to you following notation hereon by the Bank of the amount of such draft, except that, if the amount of the draft is in the full amount of this letter of credit, then the letter of credit will be retained by the Bank.

Drafts so drawn and accompanied will be honored by this Bank if presented to our main office in ________________________, prior to the close of business on the expiration date. The expiration date of this letter of credit is ______________________________.

Upon the payment to you of any amount demanded hereunder, we shall be fully discharged on our obligation under this letter of credit with respect to such amount, and we shall not thereafter be obligated to make any further payments under this letter of credit in respect of such amount to you or to any other person.

If at any time prior to presentation for payment hereunder, we receive a certificate signed by an authorized officer of Central Maine stating that this Letter of Credit has been lost, stolen, mutilated or destroyed, we will, upon receipt of (i) the mutilated Letter of Credit, in the case of mutilation of the Letter of Credit, or (ii) in other cases, such proof of loss as we shall reasonably specify, issue to Central Maine a replacement Letter of Credit dated the same date, bearing the same number, in the same amount, and in all other respects identical to this Letter of Credit, as it may have been amended or reduced, except that the replacement Letter of Credit shall be marked "Duplicate" and shall contain a provision stating, "This duplicate Letter of Credit is issued to replace Letter of Credit No. _________; the beneficiary herein agrees to return promptly this duplicate Letter of Credit to [Bank]_________________ in the event the original Letter of Credit is recovered."

This letter of credit sets forth in full our understanding and such understanding shall not in any way be modified, amended, amplified or limited by reference to any document, instrument or agreement referred to herein.

This letter of credit is subject to the Uniform Customs and Practice for Documentary Credits, 1983 Revision, ICC Publication No. 400 (the "Uniform Customs"). This letter of credit shall be deemed to be a contract made under the laws of the State of Maine and shall, as to matters not governed by the Uniform Customs, be governed by and construed in accordance with the laws of said State.

Very truly yours,

BANK

By:

Its:

ATTACHMENT K

FORECASTED TRANSMISSION REVENUE REQUIREMENTS FOR ATTACHMENT G-R AND ATTACHMENT G-W

I. DEFINITIONS

(i) **<u>Annual True-up (ATU)</u>**: shall be the difference between Central Maine's actual Annual Transmission Revenue Requirements for the most recently concluded calendar year and Central Maine's actual Annual Transmission Revenue Requirements for the calendar year prior to the most recently concluded calendar year (i.e., the revenue requirements used to calculate LNS rates effective June 1 of the most recently concluded calendar year), as adjusted to include interest pursuant to Part II below.

(ii) **<u>Forecast Period</u>**: The calendar year immediately following the calendar year for which the most recent FERC Form I data is available.

(iii) **<u>Forecasted Transmission Plant Additions (FTPA)</u>**: shall equal an estimate of Central Maine's transmission plant additions for the Forecast Period.

(iv) **<u>Forecasted MPRP CWIP (FCWIP)</u>**: shall equal CMP's estimated incremental change in MPRP CWIP for the Forecast Period.

(v) **<u>Adjusted Carrying Charge Factor (ACCF)</u>**: shall equal the sum of the Carrying Charge Factor and the quotient of (i) the Cost of Capital Rate multiplied by Central Maine's Transmission Related Accumulated Deferred Taxes associated with Post-1996 PTF Transmission Plant for the most recently concluded calendar year, and (ii) PTF Transmission Plant for the most recently concluded calendar year, as shown:

ACCF = CCF + [(COC * Transmission Related Accumulated Deferred Taxes associated with Post-1996 PTF Transmission Plant) ÷ PTF Transmission Plant]

(vi) **<u>Carrying Charge Factor (CCF)</u>**: shall reflect the most recent calendar year data used in determining Central Maine's Annual Transmission Revenue Requirements and shall equal the sum of Attachment G-R Sections II.A, excluding MPRP CWIP, through II.H plus II.M divided by Attachment G-R

Section II.A.1.(a) for Central Maine's retail Transmission Customers. The CCF for Central Maine's wholesale Customers shall equal the sum of Attachment G-W Sections II.A, excluding MPRP CWIP, through II.H divided by Attachment G-W Section II.A.1.(a).

(vii) **Forecasted ADIT (FADIT)**: shall equal Central Maine's projected change in Accumulated Deferred Income Taxes from the most recently concluded calendar year related to accelerated depreciation for the Forecast Period calculated in accordance with Treasury regulation Section 1.167(l)-1(h)(6).

(viii) **Cost of Capital Rate (COC)**: shall be determined in accordance with Attachment G-R Section II.A.2 and Attachment G-W Section II.A.2.

(ix) **MPRP Cost of Capital Rate (MCOC)**: shall be determined in accordance with Attachment G Section II.A.2.

(x) **Forecasted Transmission Revenue Requirement (FTRR)**: shall equal FTPA multiplied by the ACCF, less FADIT multiplied by the COC, plus FWCIP multiplied by the MCOC, as shown:

FTRR = (FTPA * ACCF) - (FADIT * COC) + (FCWIP * MCOC)

II. INTEREST ON ANNUAL TRUE-UPS

Interest on the Annual True-up amounts (i.e., interest applicable to any over or under collection) shall be calculated pursuant to the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii).

III. INFORMATIONAL FILINGS

Supporting documentation for the derivation and calculation of Section I (i) through (vii) of this Attachment K will be included as part of the Annual Informational Filing required pursuant to Section 10.2 of Schedule 21-CMP.

Schedule 21 – CMP

Attachment L
Creditworthiness Procedure

I. General Information

This Attachment L details the specific requirements for creditworthiness procedures of Schedule 21-CMP of the OATT for Central Maine Power Company ("CMP"). Any customer taking (i) any service under Schedule 21-CMP, the Local Service Schedule ("LSS") for CMP under the OATT or (ii) any Federal Energy Regulatory Commission ("Commission") regulated Interconnection Service from CMP (such a customer is referred to herein as a "Customer" and such services are referred to individually herein as a "Service" and collectively as "Services") must meet the terms of this Attachment L. The creditworthiness of each Customer must be established prior to receiving Service from CMP. A Customer will be evaluated at the time it's Application for such Service is provided to CMP or to ISO. A credit review shall be conducted for each Transmission Customer at least annually or upon reasonable request by the Transmission Customer. CMP may conduct a credit review any time there is a material change in a Customer's financial conditions as set forth in Section VIII.A. Any change in this Attachment L will be made in accordance with Section 10 and posted on CMP's OASIS.

All Customers must comply with the terms of this Attachment L. The Customer should refer to the Company's web site at www.cmpco.com or the Company's OASIS site, for the applicable contact representative at CMP.

Upon receipt of a Customer's Financial Information, CMP will review it for completeness and will notify the Customer if additional information is required. Upon completion of a credit evaluation of a Customer, CMP will notify the Customer of the results as well as of any Financial Assurance requirements. CMP will provide a written report of the credit evaluation, upon written or email request by the Customer.

II. Financial Information

- Customers requesting Service are required, at the sole discretion of CMP, to submit, if available, all current rating agency reports from Standard and Poor's ("S&P"), Moody's
- and/or Fitch of the Customer, its direct or indirect parent ("Parent"), or other credit provider, or
- Audited financial statements provided by a registered independent auditor for the two most recent years, or the period of its existence, if shorter, for the Customer, its Parent, or credit provider.

III. <u>Creditworthiness Requirements</u>

A. The Customer must meet at least one of the following quantitative criteria:

a) If rated, the Customer must have either for itself or for its outstanding debt the following:

- S&P's or Fitch rating of at least a **BBB-**, or
- Moody's rating of at least a **Baa3**.

Not withstanding any other provision of this Schedule L, a Customers credit will be limited as follows:

Rating (S&P / Moody's)	Credit Limit
A/A2	$30,000,000
A-/A3	$20,000,000
BBB+/Baa1	$15,000,000
BBB/Baa2	$10,000,000
BBB-/Baa3	$5,000,000

If ratings by different agencies are inconsistent, CMP will use the lowest rating.

b) If unrated or if rated below BBB-/Baa3, as stated in a), the Customer must meet all of the following:

- A Current Ratio of at least 1.0 times (current assets divided by all current liabilities);
- A Total Capitalization Ratio of less than 60% debt: total debt (including all short-term borrowing) divided by total shareholders' equity plus total debt:

c) If the Customer relies on the creditworthiness of a parent company; the Customer's parent company must meet the criteria set out in (a) or (b) above, and must provide to CMP a written guarantee, to CMP's satisfaction, that it will be unconditionally responsible for all financial obligations associated with the Customer's receipt of Transmission Service from CMP.

B. If the Customer does not meet the quantitative criteria in Section A of this Section III, the Customer will qualify for unsecured credit equivalent to two month Transmission Service charges, or for Interconnection Service, the credit equivalent of two months of the annual facilities charges and other ongoing charges, if the following qualitative criteria are met:

- The Customer has, on a rolling basis, 12 consecutive months of payments to CMP with no missed, late or defaults in payment.

IV. Financial Assurance

If the Customer does not meet the creditworthiness set out in Section III, then the Customer must either:

- Pay in advance for service an amount equal to the lesser of the total charge for Services or the charge for three months of Services not less than five (5) business days in advance of the commencement of service; or,
- Subject to prior approval by CMP, for Transmission Service of three (3) months or longer, prepay each month not less than (5) business days before the beginning of the month. Notwithstanding any other provision of this Attachment L, CMP will not pay interest for prepayment of the current month's service.
- For Interconnection Service, prepayment of three (3) months of the anticipated facilities construction and all construction related costs including but not limited to project planning, management and overheads, as specified and updated from time to time by CMP, not less than five (5) business days in advance of commencing work; or prepayment of all construction related costs according to a schedule to be included in the Interconnection Agreement or E&P Agreement. If a conflict arises between the Terms of this Schedule L and an Interconnection or E&P Agreement, the terms of Interconnection or E&P Agreement shall apply.
- Obtain Financial Assurance, to CMP's satisfaction in the form of (a) letter of credit, (b) performance bond, (c) a cash deposit, or (d) corporate guarantee equal to the equivalent of three (3) months of Transmission Service changes prior to receiving service.

If the Customer pays for service more than one month in advance or posts a cash deposit, CMP will pay the Customer interest on the amounts not yet due to CMP, computed in accordance with the Commission's regulations at 18 CRF 35.19a(a)(2)(iii).

V. Credit Levels

If the Customer meets the applicable criteria outlined in Section III, that Customer may receive unsecured credit equivalent to three (3) months of transmission charges or, for interconnections, the credit equivalent of three (3) months of the annual facilities charges and other ongoing charges.

VI. Contesting Creditworthiness Determination

The Customer may submit a written request for reconsideration within twenty (20) calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for reconsideration. CMP will review and respond to the request within twenty (20) calendar days.

VII. Process for Changing Credit Requirements

In the event that CMP plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, CMP shall submit such changes in a filing to the Commission under Section 205 of the Federal Power Act. CMP shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

A. General Notification Process

a) CMP shall provide written notification to ISO and stakeholders of any filing described above, at least thirty (30) days in advance of such filing.

b) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s).

c) CMP shall consult with interested stakeholders upon request.

d) Following Commission acceptance of such filing and upon the effective date,
CMP shall revise its Attachment L Creditworthiness Procedures and an updated version of Schedule 21-CMP shall be posted on the ISO website.

B. Transmission Customer Responsibility

When there is a change in requirements, it is the responsibility of the Transmission Customers to forward updated financial information to the Company, to the address noted on CMP's OASIS site and indicate whether the change affects their ability to meet the requirements of Attachment L. In such cases where the Customer's status has changed, the Customer must take the necessary steps to comply with the revised requirements of Attachment L by the effective date of the change. Failure to meet the requirements of this Section VII (B) shall, at CMP's sole discretion, result in the requirement to post Financial Assurance immediately upon written or email notice by CMP.

VIII. Posting Collateral Requirements

A. Changes in Customer's Financial:

Each Customer must inform CMP in writing, within five (5) business days of any material change in its financial condition, and, if the Customer qualifies under Section IIIA. (c), that of its Parent. A material change in financial conditions may include, but not limited to, the following:

- Change in ownership direct or indirect, by way of merger, acquisition or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

Failure to meet the requirements of this Section VIII (A) shall, at CMP's sole discretion, result in the requirement to post Financial Assurance immediately upon written or email notice by CMP.

B. Change in Creditworthiness Status

A Customer who has been extended unsecured credit under this policy must provide Financial Assurance as set forth in Section IV, within three (3) business days, if one or more of the following conditions apply:

- The Customer no longer meets the applicable criteria for creditworthiness in item III;
- The Customer exceeds the amount of unsecured credit extended by CMP, in which case Financial Assurance equal to the amount of excess must be provided within three (3) business days; or

- The Customer has missed two or more payments for any of the Services offered by the Company's in the last 12 months.
- The Customer fails to meet the requirements of Sections VII (B) or VIII (A).

In the event that CMP determines that there is a change in the credit level or collateral requirements, the Customer may request a written explanation of the basis for this change. Such notification should be sent, in writing or via email, to the CMP contact indicated on the CMP OASIS site. CMP shall respond to such request within twenty (20) days of receipt of such notification.

Customers must post additional collateral within three (3) business days, from the date they are notified of the need for additional requirements.

IX. <u>Ongoing Financial Review</u>

Each Customer is required to submit to CMP annually or when issued, as applicable:

- Current rating agency report covering the Customer or its Parent;
- Audited financial statements of the Customer or its Parent from a registered independent auditor; and
- 10-Ks and 8-Ks, promptly upon their issuance.

X. <u>Suspension of Service</u>

CMP may, at its sole discretion, immediately suspend service (with notification to Commission) to a Customer, and may initiate proceedings with Commission to terminate service, if the Customer does not meet the terms described in items III through VII at any time during the term of service or if the customer's payment obligations to CMP exceed the amount of unsecured or secured credit to which it is entitled under this Attachment L. A Customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

SCHEDULE 21 - FG&E

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY
LOCAL SERVICE SCHEDULE

SCHEDULE 21-FG&E

Fitchburg Gas and Electric Light Company Local Service Schedule

I. COMMON SERVICE PROVISIONS

Fitchburg Gas and Electric Light Company ("FG&E") is a participant in the New England Control Area and has agreed to provide transmission and ancillary services over PTF pursuant to the Tariff. The services provided under this Schedule 21-FG&E apply only to Non-PTF, except in the case of service to Network Customers that have all or part of their Network Load directly connected to the PTF in the Local Network. These Network Customers shall pay for Local Network Service pursuant to Attachment H to this Schedule 21-FG&E. Provisions of this Schedule 21-FG&E shall have priority over any conflicting provisions in the Tariff.

1 Definitions

1.0 Annual Transmission Costs: The total annual cost of the Local Network for purposes of Local Network Service shall be the amount specified in Attachment H until amended by FG&E or modified by the Commission.

1.1 Curtailment: A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

1.2 Load Ratio Share: Ratio of a Transmission Customer's Non-PTF Network Load to FG&E's total load computed in accordance with Sections II.10 and II.10(a) of this Schedule under Sections Supplementing Section 21 of the OATT and calculated on a rolling twelve month basis.

1.3.1 Local Network: The transmission facilities owned, controlled, or operated by FG&E that are used to provide transmission service under Schedule 21 of the OATT.

1.4 Local Network Service: The transmission service provided under Schedule 21 of the OATT and this Schedule.

1.5 Network Load: The load directly interconnected to the PTF or Non-PTF facilities of FG&E. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Schedule 21 of the OATT for any Local Point-to-Point Service that may be necessary for such non-designated load. For purposes of establishing rates and charges under this Tariff, the Network Load will be subdivided into one of two categories:

A. PTF Network Load shall be the load over FG&E's PTF facilities and shall equal the load of Network Customers directly interconnected with FG&E's PTF or indirectly utilizing FG&E's PTF through Non-PTF facilities of FG&E.

B. Non-PTF Network Load shall be the load over FG&E's Non-PTF directly interconnected with FG&E's Non-PTF facilities.

1.6 **Network Upgrades**: Modifications or additions to transmission-related facilities that are integrated with and support FG&E's overall Local Network for the general benefit of all users of such Local Network.

1.7 **Parties**: FG&E and the Transmission Customer receiving service under this Schedule and the OATT.

SECTIONS SUPPLEMENTING THE BODY OF THE TARIFF

Preamble

The following provisions supplement the provisions of the Tariff. Provisions of this Schedule 21-FG&E shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-FG&E correspond to or are consecutive to the section numbers in the body of the Tariff that are affected by the additional provisions herein.

Sections Supplementing Section 1: General Terms and Conditions

1.7 **Creditworthiness**: For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, FG&E may require reasonable credit review procedures in accordance with Attachment L to Schedule 21-FG&E.

Sections Supplementing Section II of the Tariff: Open Access Transmission Tariff (OATT)

II.A. COMMON SERVICE PROVISIONS

II.4 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. FG&E is required to provide (or offer to arrange with the ISO as discussed below), and the Transmission Customer is required to purchase Scheduling, System Control and Dispatch Service.

The following Ancillary Services are available pursuant to Section II.4 of the Tariff only to the Transmission Customer serving load within the New England Control Area: (i) Reactive Supply and Voltage Control Service, (ii) Regulation and Frequency Response , (iii) Energy Imbalance, (iv) Ten-Minute Spinning Reserve Service, (v) Ten-Minute Non-Spinning Reserve Service and (vi) Thirty-Minute Operating Reserve Service.

II.8 Billing and Invoicing; Accounting

8.2 Invoicing: Within a reasonable time after the first day of each month, FG&E shall submit an invoice to the Transmission Customer for the charges for all services furnished under the OATT during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to FG&E, or by wire transfer to a bank named by FG&E.

8.4 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to FG&E on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after FG&E notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, FG&E may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between FG&E and the Transmission Customer, FG&E will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then FG&E may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

II.10.2 Stranded Cost Recovery

FG&E may seek to recover stranded costs from the Transmission Customer pursuant to this OATT in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, FG&E must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

SECTIONS SUPPLEMENTING SCHEDULE 21 OF THE OATT

I. Local Point-to-Point Service Over the Local Network Owned by FG&E

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-FG&E shall govern Local Point-To-Point transactions using the Local Network owned by FG&E. Provisions of this Schedule 21-FG&E shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-FG&E correspond to or are consecutive to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

To the extent not otherwise covered in the OATT, the then-current ISO New England Operating Documents, or the TOA, or the rules adopted thereunder, whenever FG&E implements least-cost redispatch procedures in response to a transmission constraint, FG&E and the Transmission Customer(s) taking Local Point-To-Point Service will each bear a proportionate share of the total redispatch cost.

3) Service Availability

b) Determination of Available Transfer Capability (ATC): A description of FG&E's specific methodology for assessing ATC is contained in Attachment C of this Schedule. In the event sufficient transfer capability may not exist to accommodate a service request, FG&E will respond by performing a System Impact Study.

g) Real Power Losses: Real power losses are associated with all transmission service. FG&E is not obligated to provide real power losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by FG&E. The applicable real power loss factors tabulated below will be applied to metered loads and Reserved Capacity amounts to account for losses on FG&E's system. The applicable real power loss factors are as follows:

Firm Local Point-to-Point Service = 0.72% at 69 kV subtransmission.

Non-firm Local Point-to-Point Service = 0.72% at 69 kV subtransmission.

6) Procedures for Arranging Non-Firm Local Point-To-Point Service

f) Determination of Available Transfer Capability: Following receipt of a tendered schedule FG&E will make a determination on a non-discriminatory basis of ATC pursuant to Attachment C of this Schedule. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service (during FG&E's normal business hours of 8:00 a.m. to 4:30 p.m., Monday to Friday).

11) Sale or Assignment of Local Point-to-Point Service

c) Information on Assignment or Transfer of Service: FG&E currently has waiver from the obligations of FERC Order No. 889 to maintain an OASIS. In the future, upon implementation of any FG&E OASIS site, resellers may use FG&E's OASIS site to post transmission capacity available for resale.

II. Local Network Service using Non-PTF Owned by FG&E

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-FG&E shall govern Local Network Service using Non-PTF owned by FG&E. Provisions of this Schedule 21-FG&E shall have priority over any conflicting provision in the Tariff. The section numbers of this Schedule 21-FG&E correspond to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

Local Network Service allows the Network Customer to integrate, economically dispatch, and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which FG&E utilizes its Non-PTF to serve its Native Load Customers. Local Network Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Schedule 21 of the OATT.

2) Availability of Local Network Service

f) Real Power Losses: The Network Customer is responsible for replacing losses associated with all transmission service as calculated by FG&E. The applicable real power loss factors tabulated below will be applied to metered loads and Reserved Capacity amounts to account for losses on FG&E's system. The applicable real power loss factors are as follows:

Local Network Service = 0.72% at 69 kV subtransmission.

8) Load Shedding and Curtailments

a) Procedures: Prior to the Service Commencement Date, FG&E and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to Section II.20 of the Tariff, with the objective of responding to contingencies on the Non-PTF. The Parties will implement such programs during any period when the ISO, the Local Control Center or FG&E determines that a system contingency exists and such procedures are necessary to alleviate such contingency. FG&E will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

b) Transmission Constraints: During any period when FG&E determines that a transmission constraint exists on the Local Network, and such constraint may impair the reliability of FG&E’s system, FG&E will take whatever actions, consistent with then-current ISO New England Operating Documents or the TOA, and the rules adopted thereunder, and with Good Utility Practice, that are reasonably necessary to maintain the reliability of FG&E’s system. To the extent ISO determines that the reliability of the ISO New England transmission system can be maintained by redispatching resources, FG&E will initiate procedures pursuant to the OATT, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder to redispatch all Network Resources and FG&E's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between FG&E's use of the Local Network on behalf of its Native Load Customers and any Network Customer's use of the Local Network to serve its designated Network Load.

c) Cost Responsibility for Relieving Transmission Constraints: To the extent not otherwise covered in the OATT, the then-current ISO New England Operating Documents, or the TOA, or the rules adopted thereunder, whenever FG&E implements least-cost redispatch procedures in response to a transmission constraint, FG&E and the Network Customer(s) will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

d) Curtailments of Scheduled Deliveries: If a transmission constraint on FG&E's Local Network cannot be relieved through the implementation of least-cost redispatch procedures and FG&E determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with Section II.22 of the Tariff.

e) Allocation of Curtailments: The ISO, the Local Control Center or FG&E shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by FG&E and Network Customers in proportion to their respective Load Ratio Shares. Neither the ISO, the Local Control Center, nor FG&E shall direct the Network Customer to Curtail schedules to an extent greater than either would Curtail FG&E's schedules under similar circumstances.

f) Load Shedding: To the extent that a system contingency exists on FG&E's Local Network and the ISO, the Local Control Center or FG&E determines that it is necessary for FG&E and the Network Customers to shed load, the Parties shall shed load in accordance with previously established procedures in accordance with Section II.22 of the Tariff, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder.

g) System Reliability: Notwithstanding any other provisions of this Schedule, FG&E reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on the part of FG&E for the purpose of making necessary adjustments to, changes in, or repairs on FG&E's lines, substations, and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the event of any adverse conditions or disturbances on FG&E's Local Network or on any other system(s) directly or indirectly interconnected with FG&E's Local Network, FG&E, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. FG&E will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will not be unduly discriminatory relative to FG&E's use of its Local Network on behalf of its Native Load Customers. FG&E shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

9) Rates and Charges

In addition to the above sections that correspond to sections in Schedule 21 of the OATT, the following additional provision shall apply to Local Network Service over FG&E's Local Network.

a) Monthly Demand Charge: The Network Customer shall pay a Monthly Demand Charge which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of FG&E's Annual Transmission Revenue Requirement as specified in Attachment H to this Schedule 21-FG&E.

10) Determination of Network Customer's Local Monthly Network Load: The Network Customer's local monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with FG&E under Section II.5(c) of Schedule 21 of the OATT) coincident with the FG&E's Monthly Local Network Peak. Monthly revenue requirements not otherwise paid for through charges to Eligible Customers for Local Point-to-Point Service will be allocated among FG&E's Network Customers receiving service under the tariff on the basis of their loads during the hour in the month in which the total connected load to the local network is at its maximum, without any adjustment for credits for generation.

In addition to the above sections that correspond to sections in Schedule 21 of the OATT, the following three provisions shall apply to Local Network Service over FG&E's local network.

10a) Determination of FG&E's Monthly Local Network Load: FG&E's monthly Local Network Load is FG&E's Monthly Local Network Peak minus the coincident peak usage of all firm Local Point-To-Point Service customers pursuant to Schedule 21 of the OATT plus the Reserved Capacity of all firm Local Point-To-Point Service customers.

10b) Recovery of PTF Transmission Revenue Requirements: The portion of FG&E's annual transmission revenue requirements with respect to PTF which is not recovered through the distribution of revenues from Regional Network Service or Local Point-to-Point Service shall be recovered from Eligible Customers taking Regional Network Service or Local Point-to-Point Service pursuant to Section II.12.2(b) of the Tariff.

SCHEDULE 1

Local Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into FG&E's Local Network Control Area. Local Scheduling, System Control and Dispatch Service is to be provided directly by FG&E and the ISO. The Transmission Customer must purchase this service from FG&E. The charges for FG&E's Local Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent that the ISO performs this service for FG&E, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to FG&E by the ISO.

Each firm Local Point-To-Point Service Customer under this Tariff will be charged for Local Scheduling, System Control and Dispatch Services for the total Reserved Capacity specified in each reservation for firm Local Point-To-Point Service made under the Tariff at the rates set forth in Appendix A of this Schedule 1.

Each Network Customer under this Tariff will be charged a monthly Local Scheduling, System Control and Dispatch Service Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Formula Requirements specified in Appendix B of this Schedule 1.

Each Transmission Customer with generation within the ISO's Control Area shall be required also to provide for Scheduling, System Control and Dispatch Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting with the ISO for these services on an unbundled basis. FG&E will make available Generation Scheduling, System Control and Dispatch Service at the rates set forth in Appendix C of this Schedule 1.

Each Transmission Customer with generation located outside of the ISO Control Area shall be required to provide for Scheduling, System Control and Dispatching Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting for these services from the provider of these services within the Control Area where the generation is located. FG&E shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule 1 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE 1

Appendix A

Determination Of

FG&E's Local Network Point-To-Point Formula Rate

For Local Scheduling, System Control And Dispatch Service

FG&E's Formula Rate for Point-To-Point Local Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{FORMULA RATE}_i = \frac{A_{i-1} - B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of FG&E for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule 1.

- B_{i-1} is the actual local scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual local scheduling and dispatch revenues shall be those recorded on the books of FG&E in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

- C_{i-1} is the single annual coincident peak transmission load (expressed in kilowatts) of FG&E for the calendar year prior to the Service Year, as reported in FERC Form No. 1.

Schedule 1
Appendix A
Exhibit 1

Determination of Annual Control Center Expenses

The rate formula for determination of the annual control center expenses revenue requirements for FG&E is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES = Sum of FG&E's (Account 556 System Control and Load Dispatching Expense) + (Account 557 Other Expense) X .50* for the calendar year prior to the Service Year.

* This factor reflects allocation to the transmission function of a portion (50 percent) of the costs recorded in Accounts 556 and 557 associated with dispatching transmission and generating facilities. This 50 percent allocation of control center costs is based on two functions performed by the control center (i) control of generation and (ii) control of transmission.

SCHEDULE 1

Appendix B

Determination of FG&E's
Network Formula Requirements
For Local Scheduling, System Control
And Dispatch Service

FG&E's formula requirements for Network Local Scheduling, System Control and Dispatch Service is determined from the following formula.

Formula Requirements_i = $A_{i-1} - B_{i-1}$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of FG&E for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to Appendix A of Schedule 1.

- B_{i-1} is the actual local scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual local scheduling, system control and dispatch revenues shall be those recorded on the books of FG&E in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

SCHEDULE 1

Appendix C

Determination Of FG&E's Formula Rate

For Generation Scheduling, System Control And Dispatch Service

FG&E's Formula Rate for Generation Scheduling, System Control and Dispatch Service ("Formula Rate") shall be calculated using the Formula Rate for Point-to-Point Local Scheduling, System Control and Dispatch Service in Appendix A of Schedule 21 - FG&E.

SCHEDULE 7

Long-Term Firm Local and Short-Term Firm Local Point-to-Point Service

The Transmission Customer shall compensate FG&E each month for firm Reserved Capacity at the sum of the applicable charges set forth below:

1) Yearly delivery:

The Yearly Delivery Charge per kW shall be FG&E's Annual Transmission Revenue Requirement (determined in accordance with Attachment H of this Tariff) divided by FG&E's Total Peak Load for the corresponding calendar year. Total Peak Load, calculated based on the monthly average for the year, shall be FG&E's peak load, minus the coincident peak of all firm local point-to-point customers, plus the contract demand reservation for firm local point-to-point customers.

2) Monthly delivery:

The Monthly Delivery Charge per kW shall be determined by dividing the Yearly Delivery Charge by 12.

3) Weekly delivery:

The Weekly Delivery Charge per kW shall be determined by dividing the Yearly Delivery Charge by 52.

4) Daily delivery:

The Daily Delivery Charge per kW shall be determined by dividing the Yearly Delivery Charge by 365.

The total delivery charge in any week, pursuant to a reservation for daily delivery, shall not exceed the Weekly Delivery Charge specified in section (3) above times the highest amount in kilowatts of firm Reserved Capacity in any day during such week.

5) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by FG&E must be announced to all Eligible Customers solely by posting on Unitil.com, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on Unitil.com, and (3) once a discount is negotiated, details must be immediately posted on Unitil.com. For any discount agreed upon for service on a path from point(s) of receipt to point(s) of delivery, FG&E must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on FG&E's Local Network.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section I.11 (a) of Schedule 21 of the OATT.

SCHEDULE 8

Non-Firm Local Point-to-Point Service

The Transmission Customer shall compensate FG&E for non-firm Local Point-To-Point Service for non-firm Reserved Capacity up to the sum of the applicable charges set forth below:

1) Monthly delivery:
The Monthly Delivery Charge shall be determined by multiplying the Monthly Delivery Charge as described on Schedule 7 by .75.

2) Weekly delivery:
The Weekly Delivery Charge shall be determined by multiplying the Weekly Delivery Charge as described on Schedule 7 by .75.

3) Daily delivery:
The Daily Delivery Charge shall be determined by multiplying the Daily Delivery Charge as described on Schedule 7 by .75.
The total delivery charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the Weekly Delivery Charge specified in section (2) above times the highest amount in kilowatts of non-firm Reserved Capacity in any day during such week.

4) Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the Daily Delivery Charge specified in section (3) above divided by 24. The total delivery charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Delivery Charge specified in section (3) above times the highest amount in kilowatts of non-firm Reserved Capacity in any hour during such day. In addition, the total delivery charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Delivery Charge specified in section (2) above times the highest amount in kilowatts of non-firm Reserved Capacity in any hour during such week.

5) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by FG&E must be announced to all Eligible Customers solely by posting on Unitil.com, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on Unitil.com, and (3) once a discount is negotiated, details must be immediately posted on Unitil.com. For any discount agreed upon for service on a path from point(s) of receipt to point(s) of delivery, FG&E must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on FG&E's Local Network.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section I.11 (a) of Schedule 21 of the OATT.

SCHEDULE 9
DISTRIBUTION ADDER UNDER TARIFF

In the case where distribution facilities of FG&E are employed in providing service under Schedule 21 of the OATT, the Transmission Customer shall compensate FG&E for the use of such facilities. In addition to the charges contained in this Tariff, the compensation for such distribution facilities will be determined on a case-by-case basis.

All such charges shall be subject to appropriate regulatory approval.

ATTACHMENT C

Methodology To Assess Available Transfer Capability

1. Introduction

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, but does not include the transmission system in northern Maine (i.e., Aroostook and parts of Penobscot and Washington Counties) that is radially connected to New Brunswick and administered by the Northern Maine Independent System Administrator. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"). MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Service Provider for regional transmission service ("Regional Transmission Service") associated with Pool Transmission Facilities, the Participating Transmission Owners ("PTOs") provide local transmission service over Non-Pool Transmission Facilities within the RTOP footprint and are responsible for calculating TTC and ATC associated with Local Transmission Service provided under Schedule 21 pursuant to the Transmission Operating Agreement ("TOA"). Pursuant to CFR § 37.6(b)[5] of the FERC Regulations, Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. The ISO is not responsible for the calculation of these values.

Posted Path is defined as any control area to control area interconnection; any path for which service is

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5 Section §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.[6]

FG&E does not currently have any Posted Paths based on the above definition. However, to the extent that FG&E does in the future have a Posted Path, FG&E will calculate TTC using the NERC Standard MOD-029 – Rated System Path Methodology ("MOD-029") as outlined below.

1.1 Scope of Document

The scope of this document is limited to those functions performed by FG&E as the Transmission Service Provider of Schedule 21-FG&E Point-to Point transmission service over Local Facilities pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT:

- Methodology for calculating Total Transfer Capability (TTC)
- Methodology for calculating Available Transfer Capability (ATC)
- Existing Transmission Commitment (ETC)
- Use of Transmission Reliability Margin (TRM)
- Use of Capacity Benefit Margin (CBM)
- Use of Rollover Rights (ROR) in the calculation of ETC

TTC and ATC are required to be calculated only for certain non-PTF internal Posted Paths over which Local Point-to-Point transmission service is provided under Schedule 21-FG&E. TTC and ATC is not calculated by FG&E for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and FG&E does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission pro forma OATT.

6 Section § 37.6(b)(1)(i).

The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the New England Control Area, out of the New England Control Area or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS or Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, FG&E owns Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those Local Facilities, the market participant may obtain a transmission service reservation from FG&E under Schedule 21-FG&E prior to delivery of energy into the Real-Time Energy Market.[7] This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. Schedule 21-FG&E Total Transfer Capability (TTC)

The TTC on FG&E's non-PTF Local Facilities that require Point-to-Point transmission service reservations are relatively static values and are calculated using the NERC Standard MOD-029 – Rated System Path Methodology. TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths)

7 See n - 2, 3 and 6, supra.

between those areas under specified system conditions. FG&E calculates TTC according to this definition applying the process as described below.

3.1 Guidelines and Principles

When estimating TTC, FG&E will apply the following, as amended and/or adopted from time to time

- Good Utility Practice
- NERC criteria and guidelines
- ISO New England criteria, rules and reliability standards
- Northeast Power Coordinating Council (NPCC) criteria and guidelines
- Fitchburg Gas and Electric Light Company guides

3.2 Transmission System Model Representation

FG&E will estimate TTC using transmission system load flow models developed for FG&E's system. The models may include representations of other neighboring systems. FG&E will use system models that it deems appropriate for study of the request for firm transmission service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

3.3 Contingency Analysis

FG&E will perform, if necessary, power flow and transient stability analysis to ensure that the interface's physical limits will not be violated for credible system contingencies per NERC, NPCC and ISO reliability criteria. TTC, based on contingency analysis, is the incremental transfer capability of the transmission system following the loss of the most critical element while maintaining thermal, and stability performance of the system within acceptable regional practices and consistent with guidelines of Item 3.1 of this Attachment.

3.4 Posting TTCs

When necessary, FG&E will estimate TTC as outlined above and post on its website.

4. Capacity Benefit Margin (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of ATC calculation, CBM for the New England Control Area is set to zero (0).

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed firm transmission reservations (PTP_F) plus any rollover rights for firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed non-firm transmission reservations (PTP_{NF}). There are no allowances necessary for non-firm Network Integration Transmission Service ($NITS_{NF}$), non-firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. FG&E, under Schedule 21, does not have any external interfaces, and therefore, TRM for FG&E's non-PTF facilities is zero.

6. Calculation of ATC for FG&E's Local Facilities

General Description

This section defines the ATC calculations performed by FG&E pursuant to MOD-029 for its non-PTF internal interfaces. Consistent with the NERC definition, the equation for Available Transfer Capability is: ATC = (TTC – CBM – TRM – Existing Transmission Commitments + Postbacks + counterflows). As discussed above, the CBM and TRM for the PTF interfaces for which FG&E calculates ATC are zero (0). As consistent with the ISO calculation, the equations for firm and non-firm Available Transfer Capability are:

Firm ATC = (TTC – CBM – TRM – firm ETC)
Non-firm ATC = (TTC – CBM – TRM – firm and non-firm ETC)[8]

As discussed above, the TRM and CBM for FG&E's non-PTF paths are zero. The purpose of the Existing Transmission Commitments ("ETC") component of the ATC equation is for FG&E to reduce the amount of ATC by the amount of existing firm transmission commitments that are not otherwise included in CBM or TRM. There is no requirement to purchase transmission service in advance of flowing energy in Real-Time, and there is no MW amount set aside by FG&E on any interface. One such example is point-to-point service commitments. Point-to-point service commitments sharing common transmission paths would be combined through system modeling to calculate the net existing transmission capacity (ETC) impact. This ETC value is then used in the ATC calculation shown above. Therefore there are no Existing Transmission Commitments to be applied in the ATC equation. For this reason, ETC equals zero (0) for the purposes of ATC calculation. Because Postbacks and counterflows are related to ETC and ETC is zero (0), both Postbacks and counterflows also are equal to zero (0).

As described in Section 2, under Schedule 21-FG&E, FG&E requires the purchase of transmission service in advance of delivery of energy to the New England Wholesale Market over certain non-PTF paths, and those existing transmission commitments would be applied to the ATC equation for the specific posted path. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Entities submit their bids and offers to move energy into, out of and through the Energy Market through External Transactions. As Real-Time approaches, the ISO determines which of the submitted External Transactions will be scheduled in the coming hour in accordance with the rules set forth in the ISO New England Operating Documents. Basically, the ATC of the non-PTF assets in the New England market is

8 Existing Transmission Commitments ("ETC")

almost always positive. The ATC is equal to the amount of External Transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF facilities that serve as a path for the FG&E's Schedule 21-FG&E Point-to-Point Transmission Customers, FG&E would post the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it would be posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Schedule 21-FG&E Firm ATC (ATC_F)

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C, PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-FG&E that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-FG&E transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

6.1.2 Calculation of ATC_F in the Schedule 21-FG&E Operating Horizon (OH)

For purposes of this Attachment C, OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily firm Transmission Service under Schedule 21-FG&E is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule

21-FG&E transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Because firm Schedule 21-FG&E transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

6.2 Calculation of Schedule 21-FG&E Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for non-firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), non-firm Postbacks ($Postbacks_{NF}$) and non-firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-FG&E are zero. Non-firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-FG&E transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-FG&E are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F, plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$).

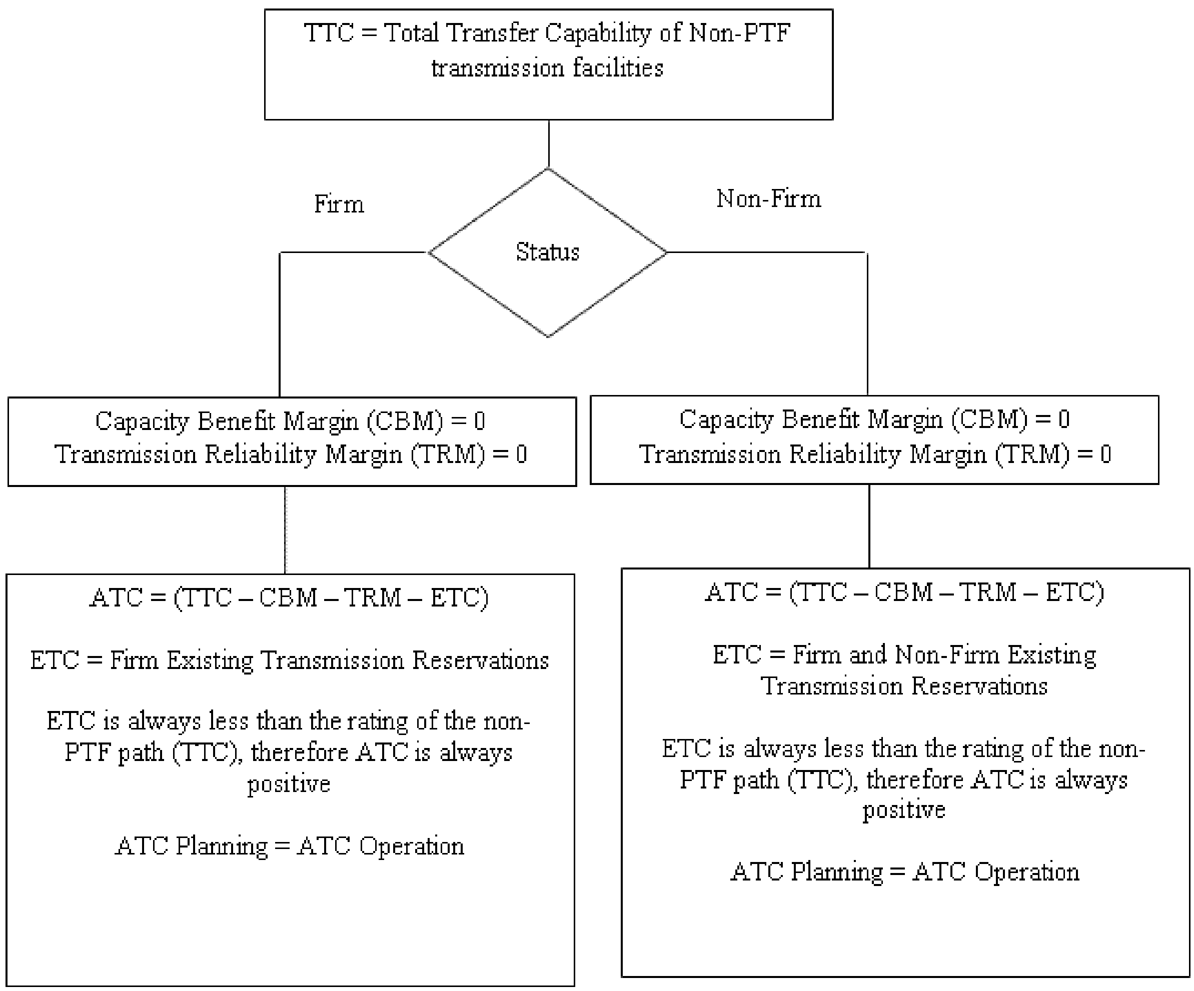
6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

As stated above, FG&E's non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators. It is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

ATC Process Flow Diagram for Non-PTF Interfaces

The process flow diagram illustrates the steps through which ATC is calculated both on an operating and planning horizon.



7. Posting of Schedule 21-FG&E ATC

7.1 Location of ATC Posting.

When necessary, FG&E will estimate ATC values for these internal paths as outlined above and post on its website, http://www.unitil.net/nepool/ma/pdf/atc_cbm_ttc_trm_fge.pdf.

7.2 Updates To ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

7.3 Coordination of ATC Calculations

Schedule 21-FG&E non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms

A link to the actual mathematical algorithm for the calculation of ATC for FG&E's non-PTF internal interfaces is located at http://www.unitil.com/sites/default/files/pdfs/fge_atc_algorithms_3_11.pdf.

ATTACHMENT D

Methodology for Completing a System Impact Study

FG&E will perform System Impact Studies for the purpose of determining the feasibility of integrating Network Load and Network Resources into FG&E's Local Network under Schedule 21 of the OATT, or for the purpose of determining the feasibility of providing Local Point-To-Point Service under this Tariff. All System Impact Studies will be completed using the same method employed by FG&E to integrate into FG&E's Local Network (i) generation resources owned or acquired to serve its Native Load Customers, and (ii) its Native Load Customers' load. Specifically, System Impact Studies will be performed by applying the applicable criteria, rules, standards and operating procedures. In addition to applying the applicable criteria, rules, standards and operating procedures, to determine the feasibility of providing service to Network Load and/or Local Point-To-Point Service, System Impact Studies will also be performed by applying Unitil Service Corp.'s "Electric System Planning Guide".

ATTACHMENT E

Index Of Local Point-To-Point Service Customers

Customer	Date of Service Agreement
Fitchburg Gas and Electric Light Company	September 10, 1996
Pinetree Power Fitchburg Inc.	March 9, 1999

ATTACHMENT H

Annual Transmission Revenue Requirement For Local Network Service

The Transmission Revenue Requirement for FG&E will reflect FG&E's costs with respect to transmission facilities not related to PTF ("Non PTF"). Except as provided below for the transitional implementation of this formula rate, the Transmission Revenue Requirement will be an annual calculation, effective June 1, based on the previous year's calendar data as reported in FG&E's FERC Form 1 report for that year, or other reasonable documentation, using end-of-year balances for each rate base item, as set forth below. The initial Transmission Revenue Requirement shall be effective October 1, 2003 through May 31, 2004 based on calendar year 2002 data as adjusted, as approved by the Commission. Further, the Transmission Revenue Requirement to be effective June 1, 2004, based on calendar year 2003 data, shall include an adjustment to annualize the impact on 2003 depreciation expense of revised depreciation rates effective October 1, 2003, as approved by the Commission. Depreciation expense shall be calculated according to Appendix A of this attachment, as approved by the Commission.

Beginning July 31, 2004, FG&E shall make an annual informational filing on or before July 31 of each year showing the Transmission Revenue Requirement in effect for the period beginning June 1 of that year through May 31 of the subsequent year. If there are corrections made to the information reflected in the informational filing after it has been submitted, FG&E will file corrections to the informational filing.

I. FORMULA

A. The Transmission Revenue Requirement for FG&E's Non-PTF shall equal the sum of the following: (A) Non-PTF Return and Associated Income Taxes, plus (B) Non-PTF Depreciation Expense, plus (C) Non-PTF Amortization of Intangible Plant and Other Regulatory Assets/Liabilities, plus (D) Non-PTF Amortization of Rate Case Expense, plus (E) Non-PTF Amortization of Loss on Reacquired Debt, minus (F) Non-PTF Amortization of Investment Tax Credits, plus (G) Non-PTF Property Tax Expense, plus (H) Non-PTF Payroll Tax Expense, plus (I) Non-PTF Transmission Operation and Maintenance Expense, plus (J) Non-PTF Customer Accounting Bad Debts Expense, plus (K) Non-PTF Administrative and General Expense, plus (L) Non-PTF Transmission Related Taxes and Fees Charge, minus (M) Non-PTF Transmission Rents Received from Electric Property, minus (N) Non-PTF Revenue for Through or Out Service.

B. Each of the components of A. above shall be calculated by subtracting the related PTF costs and revenues from the same calendar year, as included in ISO-NE's OATT, from the total transmission costs and revenues as described in Section III. Support Expense included in PTF shall only be included in this computation to the extent these costs are included in the determination of total transmission costs.

II. DEFINITIONS

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission–related direct wages and salaries to FG&E's total direct wages and salaries, excluding administrative and general wages and salaries.
2. Transmission Plant Allocation Factor shall equal the ratio of the sum of (1) Transmission Plant, (2) Transmission Related Intangible Plant, (3) Transmission Related General Plant, and (4) Transmission Related Common Plant, to Total Plant in Service.
3. Transmission Revenue Allocation Factor shall equal the ratio of Total Internal Transmission Revenue to Total Billed Revenue from Sales to Ultimate Customers.

B. TERMS

Administrative and General Expense shall equal FG&E's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

Amortization of Intangible Plant and Common Plant shall equal FG&E's expenses related to Intangible Plant and Common Plant as recorded in FERC Account No. 404.

Amortization of Investment Tax Credits shall equal FG&E's credits as recorded in FERC Account No. 411.4.

Amortization of Loss on Reacquired Debt shall equal FG&E's expenses as recorded in FERC Account No. 428.1.

Amortization of Other Regulatory Assets/Liabilities-FAS 109 shall equal FG&E's expenses related to Other Regulatory Assets/Liabilities–FAS 109 as recorded in FERC Account No. 407.

Amortization of Rate Case Expenses shall equal FG&E's expenses related to the deferred costs of regulatory rate proceedings related to transmission service as approved by FERC and as recorded in FERC Account No. 407.

Common Plant shall equal FG&E's gross balance of the plant common to both electric and gas operations as recorded in FERC Account Nos. 303, 310, 389-399, excluding capital leases.

Common Plant Amortization Reserve shall equal FG&E's Common Plant reserve balances as recorded in FERC Account No. 111.

Common Plant Depreciation Expense shall equal FG&E's Common Plant expenses as recorded in FERC Account No. 403.

Common Plant Depreciation Reserve shall equal FG&E's Common Plant reserve balance as recorded in FERC Account No. 108.

Customer Accounting Bad Debts Expense shall equal FG&E's expenses as recorded in FERC Account No. 904.

General Plant shall equal FG&E's gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation Expense shall equal FG&E's General Plant expenses as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal FG&E's General Plant reserve balance as recorded in FERC Account No. 108.

Intangible Plant shall equal FG&E's gross plant balance as recorded in FERC Account No. 303 (consisting of investments in computer systems and software).

Intangible Plant Amortization Reserve shall equal FG&E's Intangible Plant reserve balance as recorded in FERC Account No. 111.

Other Regulatory Assets/Liabilities–FAS 106 shall equal the net of FG&E's FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in FG&E's FERC Account No. 254.

Other Regulatory Assets/Liabilities–FAS 109 shall equal the net of FG&E's FAS 109 balance as recorded in FERC Account No. 182.3 and any FAS 109 balance as recorded in FG&E's FERC Account No. 254.

Payroll Tax Expense shall equal those payroll tax expenses as recorded in FG&E's FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal FG&E's balance in FERC Account No. 105.

Prepayments shall equal FG&E's electric prepayment balance as recorded in FERC Account No. 165. The electric portion shall be determined by multiplying the balance in FERC Account No. 165 by the ratio of electric utility plant to total utility plant as reported in FG&E's FERC Form 1.

Property Insurance Expense shall equal FG&E's expenses as recorded in FERC Account No. 924.

Property Tax Expense shall equal FG&E's property tax expenses as recorded in FERC Account Nos. 408.1 and 409.1.

Support Expense shall equal Transmission Support Expense as defined in the OATT Attachment F.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and FERC Account No. 190.

Total Billed Revenue from Sales to Ultimate Customers shall equal FG&E's total electric service revenues as recorded in FERC Account Nos. 440, 442, 444, 445, 446, 448, and 449.

Total Internal Transmission Revenue shall equal FG&E's internal transmission revenues as recorded in FERC Account Nos. 440, 442, 444, 445, 446, 448 and 449.

Total Loss on Reacquired Debt shall equal FG&E's expenses as recorded in FERC Account No. 189.

Total Plant in Service shall equal FG&E's total electric gross plant balance as recorded in FERC Account Nos. 301-399 (inclusive of electric Common Plant).

Transmission Operation and Maintenance Expense shall equal FG&E's electric expenses as recorded in FERC Account Nos. 560-564 and 566-576.5 and shall exclude expenses already included in PTF Transmission Support Expense, costs billed to Select Energy, Inc. under a generation related entitlement sales agreement and Account Nos. 561.4 and 575.7.

Transmission Plant shall equal FG&E's gross plant balance as recorded in FERC Account Nos. 350-359 excluding joint owned unit costs.

Transmission Plant Depreciation Expense shall equal FG&E's Transmission Plant expenses as recorded in FERC Account No. 403 less joint owned unit costs.

Transmission Plant Depreciation Reserve shall equal FG&E's Transmission Plant reserve balance as recorded in FERC Account 108 less joint owned unit reserves.

Transmission Plant Held for Future Use shall equal the transmission-related balance of electric Plant Held for Future Use.

Transmission Plant Materials and Supplies shall equal FG&E's balance as assigned to transmission, as recorded in FERC Account No. 154.

Transmission Prepayments shall equal FG&E's Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Accumulated Deferred Income Taxes shall equal FG&E's electric balance of Total Accumulated Deferred Income Taxes multiplied by the Transmission Plant Allocation Factor.

Transmission Related Administrative and General Expense shall equal the sum of (1) electric Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus (2) electric Property Insurance Expense reduced by amounts billed to Select Energy Inc. under a generation related entitlement sales agreement and multiplied by the Transmission Plant Allocation Factor, plus (3) electric expenses included in FERC Account No. 928 related to FERC fees and assessments, plus (4) any other electric transmission related expenses included in FERC Account No. 928 plus (5) specific electric transmission related expenses included in FERC Account No. 930.1 and minus (6) any Administrative and General Expense amounts billed to Select Energy Inc. and not already deducted elsewhere, multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Amortization of Intangible Plant and Other Regulatory Assets/Liabilities shall equal the sum of (1) electric Amortization of Intangible Plant and Common Plant multiplied by the Transmission Wages and Salaries Allocation Factor and (2) electric Amortization of Other Regulatory Assets/Liabilities-FAS 109 multiplied by the Transmission Plant Allocation Factor. This component shall include additional regulatory assets/liabilities as established by regulatory authority and relevant to transmission services.

Transmission Related Amortization of Investment Tax Credits shall equal FG&E's electric Amortization of Investment Tax Credits multiplied by the Transmission Plant Allocation Factor.

Transmission Related Amortization of Loss on Reacquired Debt shall equal FG&E's electric Amortization of Loss on Reacquired Debt multiplied by the Transmission Plant Allocation Factor.

Transmission Related Cash Working Capital shall be 12.5% allowance (45 days/360 days) of the sum of Transmission Operation and Maintenance Expense, plus Transmission Related Customer Accounting Bad Debts Expense and plus Transmission Related Administrative and General Expense.

Transmission Related Common Plant shall equal FG&E's electric Common Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Customer Accounting Bad Debts Expense shall equal FG&E's electric Customer Accounting Bad Debts Expense multiplied by the Transmission Revenue Allocation Factor.

Transmission Related Depreciation & Amortization Reserve shall equal the sum of (1) Transmission Plant Depreciation Reserve plus (2) electric Intangible Plant and electric Common Plant Amortization Reserves multiplied by the Transmission Wages and Salaries Allocation Factor and (3) electric General Plant and electric Common Plant Depreciation Reserves multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Depreciation Expense shall equal the sum of (1) Transmission Plant Depreciation Expense, (2) electric General Plant Depreciation Expense multiplied by the Transmission Wages and

Salaries Allocation Factor and (3) electric Common Plant Depreciation Expense multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related General Plant shall equal FG&E's electric General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Intangible Plant shall equal FG&E's electric Intangible Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Loss on Reacquired Debt shall equal FG&E's electric balance of Total Loss on Reacquired Debt multiplied by the Transmission Plant Allocation Factor.

Transmission Related Other Regulatory Assets/Liabilities shall equal the sum of (1) FG&E's electric balance of Other Regulatory Assets/Liabilities-FAS 106 multiplied by the Transmission Wages and Salaries Allocation Factor, and (2) FG&E's electric balance of Other Regulatory Assets/Liabilities-FAS 109 multiplied by the Transmission Plant Allocation Factor. This component shall include additional regulatory assets/liabilities as established by regulatory authority and relevant to transmission services.

Transmission Related Payroll Tax shall equal FG&E's electric Payroll Tax Expense multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Property Tax shall equal FG&E's electric Property Tax Expense, reduced by amounts billed to Select Energy, Inc. under a generation related entitlement sales agreement, multiplied by the Transmission Plant Allocation Factor.

III. CALCULATION OF TRANSMISSION REVENUE REQUIREMENT

This section describes the calculation of the components of the Transmission Revenue Requirement for FG&E's Non-PTF as provided in Section I.

A. Non-PTF Return and Associated Income Taxes shall equal the product of the Total Internal Transmission Investment Base and the Cost of Capital Rate, reduced by the amount recovered as PTF. For purposes of this computation, the PTF amount shall be calculated using the Cost of Capital Rate defined in III.A.2 below.

1. Total Internal Transmission Investment Base

The Total Internal Transmission Investment Base shall be the sum of the year end balances of the following items as defined in Section II.: (a) Transmission Plant, plus (b) Transmission Related Intangible Plant, plus (c) Transmission Related General Plant, plus (d) Transmission Related Common Plant, plus (e) Transmission Plant Held for Future Use, minus (f) Transmission Related Depreciation & Amortization Reserve, minus (g) Transmission Related Accumulated Deferred Income Taxes, plus (h) Transmission Related Loss on Reacquired Debt, plus (i) Transmission Related Other Regulatory Assets/Liabilities, plus (j) Transmission Prepayments, plus (k) Transmission Plant Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) FG&E's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of:

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of FG&E's long-term debt then outstanding and the ratio that long-term debt is to FG&E's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of FG&E's preferred stock then outstanding and the ratio that preferred stock is to FG&E's total capital.

(iii) the return on equity component, which equals the product of the cost of equity of 11.14% and the ratio that common equity is to FG&E's total capital.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/])\text{x FT}}{1\text{-FT}}$$

Where FT is the Federal Income Tax Rate; A is the sum of the preferred stock component and the return on equity component, as determined in Sections III.A.2.(a)(ii) and (iii) above; B is Transmission Related Amortization of Investment Tax Credits, as defined in Section II above, C is the equity AFUDC component of Transmission Related Depreciation Expense, as defined in Section II above, and D is Total Internal

Transmission Investment Base, as determined in Section III.A.1., above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax}) \times ST}{1-ST}$$

Where ST is the State Income Tax Rate; A is the sum of the preferred stock component and return on equity component as determined in Sections III.A.2. (a)(ii) and (iii) above; B is the Transmission Related Amortization of Investment Tax Credits as defined in Section II. above; C is the equity AFUDC component of Transmission Related Depreciation Expense, as defined in Section II above; D is the Total Internal Transmission Investment Base, as determined in Section III.A.1. above; and Federal Income Tax is the rate determined in Section III.A.2.(b) above.

B. Non-PTF Depreciation Expense shall equal FG&E's Transmission Related Depreciation Expense reduced by the amount recovered as PTF.

C. Non-PTF Amortization of Intangible Plant and Other Regulatory Assets/Liabilities shall equal FG&E's Transmission Related Amortization of Intangible Plant and Other Regulatory Assets/Liabilities reduced by the amount recovered as PTF.

D. Non-PTF Amortization of Rate Case Expenses shall equal the Amortization of Rate Case Expenses reduced by the amount recovered as PTF.

E. Non-PTF Amortization of Loss on Reacquired Debt shall equal FG&E's Transmission Related Amortization of Loss on Reacquired Debt reduced by the amount recovered as PTF.

F. Non-PTF Amortization of Investment Tax Credits shall equal FG&E's Transmission Related Amortization of Investment Tax Credits reduced by the amount recovered as PTF.

G. Non-PTF Property Tax Expense shall equal FG&E's Transmission Related Property Tax Expense reduced by the amount recovered as PTF.

H. Non-PTF Payroll Tax Expense shall equal FG&E's Transmission Related Payroll Tax Expense reduced by the amount recovered as PTF.

I. <u>Non-PTF Transmission Operation and Maintenance Expense</u> shall equal Transmission Operation and Maintenance Expenses reduced by the amount recovered as PTF.

J. <u>Non-PTF Customer Accounting Bad Debts Expense</u> shall equal the Transmission Related Customer Accounting Bad Debts Expense reduced by the amount recovered as PTF.

K. <u>Non-PTF Administrative and General Expenses</u> shall equal the Transmission Related Administrative and General Expenses reduced by the amount recovered as PTF.

L. <u>Non-PTF Transmission Related Taxes and Fees Charge</u> shall include any fee or assessment imposed by any governmental authority on service provided hereunder which is not specifically identified under any other section. This amount shall be reduced by the amount recovered as PTF.

M. <u>Non-PTF Transmission Rents Received from Electric Property</u> shall equal any amount in FERC Account No. 454, Rents from Electric Property, associated with Transmission Plant. This amount shall be reduced by the amount recovered as PTF.

N. <u>Non-PTF Revenue for Through or Out Service</u> shall equal distributions received by FG&E from ISO out of revenues paid for Through or Out Service (as defined in the OATT), pursuant to Section II.12.2(d) of the Tariff.

Appendix A

PTF and non-PTF Depreciation Rates

Account	Description	Depreciation Rates (%) Eff. January 1, 2011	Depreciation Rates (%) Eff. May 1, 2016
Transmission Plant			
351.00	Clearing Land and Rights of Way	1.27	1.27
352.00	Structures and Improvements	2.29	2.12
353.00	Station Equipment	4.11	3.92
355.00	Poles and Fixtures	5.38	6.13
356.00	Overhead Conductors and Devices	3.92	3.51
General Plant			
394.00	Tools, Shop and Garage Equipment	3.11	3.22
395.00	Laboratory Equipment	4.29	4.03
397.00	Communication Equipment	10.38	2.64
398.00	Miscellaneous Equipment	4.75	3.56
Common Plant			
390.00	Structures and Improvements	3.24	2.64
391.00	Office Furniture and Equipment	3.33	4.59
393.00	Stores Equipment	2.31	2.36
394.00	Tools, Shop and Garage Equipment	2.63	2.76
396.00	Power Operated Equipment	0.90	1.63
397.00	Communication Equipment	8.76	10.02
398.00	Miscellaneous Equipment	N/A	N/A

ATTACHMENT I

Index Of Local Network Service Customers

Customer	Date of Service Agreement
Fitchburg Gas and Electric Light Company	September 10, 1997
Massachusetts Bay Transportation Company	April 17, 2000

Attachment L

Creditworthiness Policy

1. Introduction

This guide establishes creditworthiness standards for transmission service and/or interconnection service customers ("Customers") entering into new or amended service agreements with Fitchburg Gas and Electric Light Company ("FG&E") under the ISO New England Open Access Transmission Tariff ("ISO-NE OATT").[9] In accordance with the Federal Energy Regulatory Commission's Policy Statement on Credit-Related Issues for Electric OATT Transmission Providers, Independent System Operators and Regional Transmission Organizations ("Policy Statement"), this Creditworthiness Policy is intended to make FG&E's credit-related practices more transparent and comprehensive. The following describes FG&E credit review procedures and the types of security that are acceptable to FG&E to protect against the risk of non-payment.

2. Creditworthiness

FG&E will evaluate the creditworthiness of Customers entering into new or amended transmission or interconnection service agreements with FG&E in order to assess a Customer's credit risk relative to the exposure of "Total Outstanding Obligation" as defined in Section 2.1 below, created by the transaction or transactions that FG&E has with the Customer. For purposes of determining the ability of a Customer to meet its obligations, FG&E may require the Customer to submit financial information for the credit review, including credit ratings, credit reports and audited financial statements for the last five years, including audited quarterly reports for the prior two years, if available. Further, the Customer will be expected to provide calculations of the following: Current Total Capitalization Ratio, Including Short-Term Debt; Tangible Net Worth for a period within sixty days of a Customer's request; Earnings Before Interest, Taxes, Depreciation and Amortization for twelve of the last fifteen consecutive months; and additional calculations and other information deemed necessary for the evaluation credit. In completing its evaluation, FG&E may consider other factors including but not limited to past billing history or the characteristics of service being requested.

2.1 Total Outstanding Obligation

The Customer's Total Outstanding Obligation to FG&E will be the sum total of the following components:

9 *See* ISO New England Inc., ISO New England Inc. Transmission, Markets and Services Tariff, Section II. This policy is applicable to transmission or interconnection service agreements established from time-to-time under Schedules 21 - FG&E of the ISO-NE OATT and to individually negotiated agreements for similar transmission or interconnection services.

2.1.1 If the Customer is making payments to FG&E for ongoing expenses (including, but not limited to, O&M expenses related to interconnections or other monthly charges such as monthly transmission charges under Schedule 21 – FG&E) the Customer will be required to provide security pursuant to Section 2.2 below, for four months' worth of the Customer's average payment obligation for such charges.

2.1.2 In accordance with the provisions of the ISO-NE OATT, a Customer will pay a Contribution in Aid of Construction ("CIAC") or transfer ownership of facilities to FG&E for transmission or interconnection facilities that are to be constructed on behalf of a Customer at the Customer's sole expense. If FG&E determines in good faith that the receipt of CIAC payments or property from the Customer are non-taxable, FG&E will require a form of security from the customer pursuant to Section 2.2 below for the amount of the potential tax liability to FG&E that would occur if such facilities were deemed taxable.

2.1.3 In accordance with the provisions of Schedule 21 – FG&E to the ISO-NE OATT, a Customer will pay a formula rate over time for return of and on the cost of capital incurred by FG&E on behalf of a Customer at the Customer's sole expense. The Customer will also be required to provide security pursuant to Section 2.2 below, for the unamortized balance of plant in service reserved for the sole use of the Customer.

2.2 Creditworthiness Requirements

A Customer will be considered creditworthy upon satisfying at least one of the following conditions or a combination of those conditions at the time that the customer enters into a transmission or interconnection service agreement and for so long as the Customer maintains satisfaction of at least one of these conditions for any outstanding obligations thereunder:

2.2.1 The Customer maintains a minimum credit rating from Standard & Poor's Long-term Issuer Credit Rating of BBB- or better or Moody's Investors Service Long-term Issuer Credit Rating of Baa3 or better so long as the Customer's Total Outstanding Obligation plus any other unsecured obligations with FG&E does not exceed the Credit Limits discussed in Section 4 below. When FG&E reviews a Customer's rating from two or more rating agencies and a split rating is present, the lower debt rating will apply. In the event that the Customer has no rating from either Standard & Poor's or Moody's Investors Service, a rating from Fitch may also be used with

acceptable ratings equivalent to those from either Standard and Poor's or Moody's Investors Service. If unrated, the Customer's financial statements will be reviewed to determine an equivalent rating based on the Customer's unsecured credit limits and/or financial statements.

If, at any time, the Customer's rating falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify FG&E within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to FG&E, as described in this Section 2.2.

2.2.2 The Customer provides and maintains in effect during the term of and until full and final payment and performance of the service agreement an unconditional and irrevocable standby letter of credit for the Total Outstanding Obligation in the form and substance and issued by a bank reasonably acceptable to FG&E. A draft, acceptable form letter of credit is attached. Any such bank must satisfy the creditworthiness criteria described in 2.2.1 above.

If, at any time, the bank's rating falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify FG&E within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to FG&E, as described in this Section 2.2.

2.2.3 If the Customer's parent or an affiliate company satisfies the creditworthiness criteria described in 2.2.1 above and, subject to the Credit Limits stated in Section 4 below, such company submits to FG&E and maintains in effect a letter of guaranty reasonably acceptable to FG&E as to amount, form and substance for the term of and until full and final payment and performance of the service agreement.

If, at any time, the credit rating of the Customer's parent or affiliate providing the guaranty falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify FG&E within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to FG&E, as described in this Section 2.

2.2.4 The Customer makes an advance payment to FG&E in immediately available funds for the Total Outstanding Obligation.

3. Customer Costs Requiring Prepayment

In accordance with the provisions of the ISO-NE OATT, a Customer will pay a Contribution in Aid of Construction ("CIAC") for transmission or interconnection facilities to be constructed by FG&E on behalf of a Customer at the Customer's sole expense. The Customer will have the option to (i) prepay the CIAC in immediately available funds to FG&E, or (ii) make periodic CIAC progress payments, as defined in the Customer's service agreement, to prepay in increments capital costs scheduled to be incurred by FG&E. If FG&E determines in good faith that such payments or property transfers made by the Customer should be reported as income subject to taxation, the Customer shall also prepay all costs associated with the cost consequences of the current tax liability imposed on FG&E by those facilities (the "Tax Gross- up").

4. Determination of Credit Limits

FG&E reserves the right to limit the total amount of unsecured credit extended to a Customer under 2.2.1 and 2.2.3 above such that the sum of all unsecured credit that such Customer has with FG&E, including the Total Outstanding Obligation, shall not exceed the Credit Limits defined below. Such limitations are based on an assessment of the Customer's or its Guarantor's credit rating and the net worth of the Customer's or its Guarantor's assets.

Standard and Poor's (or Equivalent) Rating	Unsecured Credit Limit as Percent of Customer's or Guarantor's Tangible Net Worth
A and above	1.0%
A-	0.5%
BBB+	0.3%
BBB	0.2%
BBB-	0.1%

Once FG&E has evaluated or reevaluated and determined the maximum Credit limits for each Customer, it will inform the prospective Customer of the amount of such credit limits. A customer may request in writing a reevaluation of the maximum Credit limits, within 14 days from the date that they were informed by FG&E of such limits. Justification for such a reevaluation should be contained in the request. All requests for reevaluation must be submitted directly to the FG&E Contract Administrator.

From time to time, principally due to unknown factors such as changing market, economic, banking or other financial conditions, but not solely limited to these factors, FG&E may find it necessary to modify or amend its creditworthiness policies and guidelines after a 15 day notice period and require that present and future Transmission Customers fulfill any additional conditions contained in the modified Creditworthiness Guide. Transmission Customers will have 30 days after the notice period to cure any deficiency.

FORM LETTER OF CREDIT

___________________________________ Bank

____
(address)

IRREVOCABLE STANDBY LETTER OF CREDIT

DATE: ______________________

AMOUNT U.S. $_______________

____

FOR INTERNAL IDENTIFICATION PURPOSES ONLY

____

Our Number:

Beneficiary: Applicant:

___________________________ ___________________________

___________________________ ___________________________

___________________________ ___________________________

___________________________ ___________________________

Attn: At the request of:

____

Ref:____

LADIES AND GENTLEMEN;

WE HEREBY ESTABLISH THIS IRREVOCABLE, AND UNCONDITIONAL, EXCEPT AS STATED HEREIN, LETTER OF CREDIT NUMBER _____________ (LETTER OF CREDIT), BY ORDER OF, FOR THE ACCOUNT OF, AND ON BEHALF OF [CUSTOMER NAME] (ACCOUNT PARTY) IN FAVOR OF FITCHBURG GAS AND ELECTRIC LIGHT COMPANY (BENEFICIARY) FOR DRAWINGS, IN ONE OF MORE DRAFTS, UP TO AN AGGREGATE AMOUNT NOT EXCEEDING U.S. $_______________ EFFECTIVE IMMEDIATELY. THE TERM 'BENEFICIARY' INCLUDES ANY SUCCESSOR OF THE NAMED BENEFICIARY.

THIS LETTER OF CREDIT CANNOT BE AMENDED, MODIFIED OR REVOKED WITHOUT THE PRIOR WRITTEN CONSENT OF BOTH THE BANK AND THE BENEFICIARY. THE BENEFICIARY SHALL NOT BE DEEMED TO HAVE WAIVED ANY RIGHTS UNDER THIS LETTER OF CREDIT, UNLESS AN OFFICER OF THE BENEFICIARY SHALL HAVE SIGNED A WRITTEN WAIVER EXPRESSLY REFERENCING THE RIGHT TO BE WAIVED. NO SUCH WAIVER SHALL BE EFFECTIVE AS TO ANY TRANSACTION THAT OCCURS SUBSEQUENT TO THE DATE OF THE WAIVER, NOT AS TO ANY CONTINUANCE OF A BREACH AFTER THE WAIVER.

WE HEREBY UNDERTAKE TO PROMPTLY HONOR YOUR DRAFT(S) DRAWN ON US, INDICATING OUR LETTER OF CREDIT NUMBER __________ IS ISSUED, PRESENTABLE AND PAYABLE AND WE GUARANTY TO THE DRAWERS, ENDORSERS, AND BONA FIDE HOLDERS OF THIS LETTER OF CREDIT, THAT DRAFTS UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT WILL BE HONORED. THIS LETTER OF CREDIT MAY NOT BE TRANSFERRED OR ASSIGNED BY US.

SUBJECT TO THE EXPRESS TERMS AND CONDITIONS HEREIN, FUNDS UNDER THIS LETTER OF CREDIT ARE AVAILABLE TO YOU BY PRESENTATION AT OUR OFFICES LOCATED AT [_______________] OF BENEFICIARY'S DRAWING CERTIFICATE ISSUED SUBSTANTIALLY IN THE FORM OF ANNEX 1 ATTACHED HERETO AND WHICH FORMS AN INTEGRAL PART HEREOF, DULY COMPLETED AND PURPORTEDLY BEARING THE ORIGINAL SIGNATURE OF AN OFFICER OF THE BENEFICIARY. PRRESENTATION OF ANY DRAWING CERTIFICATE UNDER THIS LETTER OF CREDIT MAY BE MADE IN PERSON TO US OR MAY BE SENT TO US

BY TELEX TO [_________________] OR BY FACSIMILE TRANSMISSION TO FACSIMILE TELEPHONE NUMBER [_______________].

ALL COMMISSIONS AND CHARGES WILL BE BORNE BY THE ACCOUNT PARTY. IF DOCUMENTS, IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT, ARE RECEIVED BEFORE 10:00 AM (EASTERN TIME) ON A BUSINESS DAY, PAYMENT WILL BE EFFECTED ON OR BEFORE 5:00 PM (EASTERN TIME) ON THE NEXT BUSINESS DAY. IF DOCUMENTS, IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT ARE RECEIVED AFTER 10:00 AM ON A BUSINESS DAY, PAYMENT WILL BE EFFECTED ON OR BEFORE 5:00 PM ON THE SECOND BUSINESS DAY FOLLOWING SUCH DATE OF RECEIPT.

EXCEPT AS EXPRESSLY STATED HEREIN, THIS UNDERTAKING IS NOT SUBJECT TO ANY AGREEMENT, CONDITION OR QUALIFICATION. THIS LETTER OF CREDIT DOES NOT INCORPORATE, AND SHALL NOT BE DEEMED MODIFIED OR AMENDED BY REFERENCE TO ANY DOCUMENT, INSTRUMENT OR AGREEMENT (A) THAT IS REFERRED TO HEREIN (EXCEPT FOR THE UNIFORM CUSTOMS, AS DEFINED BELOW), OR (B) IN WHICH THIS LETTER OF CREDIT IS REFERRED TO OR TO WHICH THIS LETTER OF CREDIT RELATES.

OUR OBLIGATION UNDER THIS LETTER OF CREDIT SHALL BE OUR INDIVIDUAL OBLIGATION AND IS IN NO WAY CONTINGENT UPON THE REIMBURSEMENT WITH RESPECT THERETO, OR UPON OUR ABILITY TO PERFECT ANY LIEN, SECURITY INTEREST OR ANY OTHER REIMBURSEMENT.

THIS LETTER OF CREDIT EXPIRES WITH OUR CLOSE OF BUSINESS ON [364 days from effective date]; HOWEVER, IT IS A CONDITION OF THIS LETTER OF CREDIT THAT IT SHALL BE DEEMED AUTOMATICALLY EXTENDED WITHOUT AMENDMENT FOR 364 DAYS FROM THE PRESENT OR ANY FUTURE EXPIRATION DATE HEREOF, UNLESS AT LEAST SIXTY (60) DAYS BEFORE ANY SUCH EXPIRATION DATE WE NOTIFY YOU BY REGISTERED MAIL ADDRESSED TO: [address of beneficiary, ATTN: _______________], THAT WE ELECT NOT TO RENEW THIS LETTER FOR SUCH ADDITIONAL PERIOD.

THIS LETTER OF CREDIT IS SUBJECT TO THE UNIFORM CUSTOMS AND PRACTICE FOR DOCUMENTARY CREDITS (1993 REVISION) INTERNATIONAL CHAMBER OF COMMERCE, PUBLICATION NO. 500. IF THIS LETTER OF CREDIT EXPIRES DURING THE INTERRUPTION

OF BUSINESS AS DESCRIBED IN ARTICLE 17 THEREOF WE HEREBY SPECIFICALLY AGREE TO EFFECT PAYMENT IF THE LETTER OF CREDIT IS DRAWN AGAINST WITHIN 30 DAYS AFTER THE RESUMPTION OF BUSINESS.

ANNEX 1 TO [BANKNAME]
IRREVOCABLE LETTER OF CREDIT NO. _____________

[INSERT DATE]

[BANK NAME]
[ATTENTION]
[BANK ADDRESS 1]
[BANK ADDRESS 2]

LADIES AND GENTLEMEN:

THE UNDERSIGNED _________________________________, A DULY ELECTED AND ACTING OFFICER OF FITCHBURG GAS AND ELECTRIC LIGHT COMPANY (THE "BENEFICIARY"), HEREBY CERTIFIES TO [INSERT BANK NAME] (THE "BANK"), WITH REFERENCE TO IRREVOCABLE LETTER OF CREDIT NO. _________ DATED ________________, ISSUED BY THE BANK IN FAVOR OF THE BENEFICIARY (THE "LETTER OF CREDIT"), AS FOLLOWS AS OF THE DATE THEREOF:

1. THE BENEFICIARY IS A PARTY TO THAT CERTAIN [INTERCONNECTION AGREEMENT], EFFECTIVE _______________, BETWEEN THE BENEFICIARY AND [CUSTOMER NAME] (THE "AGREEMENT").

2. BENEFICIARY IS MAKING A DRAWING UNDER THE LETTER OF CREDIT IN THE AMOUNT OF $___________ BECAUSE [CHECK APPLICABLE PROVISION]:

[____] (A) THERE CURRENTLY EXIST ONE OR MORE UNPAID AMOUNTS WHICH [CUSTOMER NAME] IS OBLIGATED TO PAY PURSUANT TO THE TERMS OF THE AGREEMENT.

[____] (B) THE BENEFICIARY HAS RECEIVED NOTICE FROM THE BANK OF ITS INTENTION NOT TO RENEW THE LETTER OF CREDIT BEYOND THE CURRENT EXPIRATION DATE AND [CUSTOMER NAME] HAS FAILED, PRIOR TO THE CLOSE OF BUSINESS ON ________________ [INSERT DATE WHICH IS NOT MORE THAN THIRTY (30) DAYS BEFORE THE PRESENT

EXPIRATION DATE], TO DELIVER TO BENEFICIARY A REPLACEMENT LETTER OF CREDIT SATISFYING THE REQUIREMENTS OF THE AGREEMENT.

3. BASED UPON THE FOREGOING, THE BENEFICIARY HEREBY MAKES DEMAND UNDER THE LETTER OF CREDIT FOR PAYMENT OF U.S. DOLLARS __________________ AND _____/100THS (U.S. $_______________).

4. FUNDS PAID PURSUANT TO THE PROVISIONS OF THE LETTER OF CREDIT SHALL BE WIRE TRANSFERRED TO THE BENEFICIARY IN ACCORDANCE WITH THE FOLLOWING INSTRUCTIONS:

____

____

____

UNLESS OTHERWISE PROVIDED HEREIN, CAPITALIZED TERMS WHICH ARE USED AND NOT DEFINED HEREIN SHALL HAVE THE MEANING GIVEN EACH SUCH TERM IN THE LETTER OF CREDIT.

IN WITNESS WHEREOF, THIS CERTIFICATE HAS BEEN DULY EXECUTED AND DELIVERED ON BEHALF OF THE BENEFICIARY BY ITS DULY ELECTED AND ACTING OFFICER AS OF THIS _____ DAY OF ___________, _____.

BENEFICIARY: FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

____

NAME:

____

TITLE

SCHEDULE 21 - NEP

NEW ENGLAND POWER COMPANY
LOCAL SERVICE SCHEDULE

I. COMMON SERVICE PROVISIONS

1 Definitions

Whenever used in this Schedule, in either the singular or plural number, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Schedule that are not defined in this Schedule shall have the meanings set forth in the Tariff or customarily attributed to such terms by the electric utility industry in New England.

1.0 New England Affiliate: New England Affiliate means Massachusetts Electric Company, Nantucket Electric Company, The Narragansett Electric Company and Granite State Electric Company.

1.1 Annual Peak Load: The highest Network Load of the Network Customer during a calendar year.

1.2 Contract Termination Charge (CTC): New England Power Company's stranded cost charge to certain wholesale requirements customers, as defined and described in the Stipulations and Agreements and as calculated pursuant to Appendix 1 of the Offer of Settlement filed with the Commission in Docket Nos. ER97-678-000 and ER97-680-000.

1.3 Contribution in Aid of Construction (CIAC): A contribution in aid of construction pursuant to Section 118(b) of the Internal Revenue Code of 1986.

1.4 Distribution System: Distribution System means the facilities owned or supported by NEP or its New England Affiliates that do not constitute PTF or Non-PTF and are used for Transmission Service under the Tariff for Transmission Customers other than end-use customers.

1.5 [Reserved]

1.6 IRS Notice 87-82: Internal Revenue Service Notice 87-82, Providing guidance with Respect to the Treatment of CIACs (received by regulated public utilities) After Enactment of New Section 118(b) of the Internal Revenue Code.

1.7 IRS Notice 90-60: Internal Revenue Service Notice 90-60, Contribution in Aid of Construction, issued September 10, 1990.

1.7.1 Load Interconnections: Any load facility desiring to interconnect with NEP's electrical system or modify an existing interconnection, as further set forth in the Local Service Agreement in Schedule 21-Attachment A. In addition, Attachment C, D, E, F and H of Schedule 21-NEP shall apply.

1.8 Load Power Factor: The ratio of the load measured in kW to the same load measured in kVA during a one-hour period.

1.9 Load Ratio Share: Ratio of a Transmission Customer's monthly PTF Network Load occurring coincident with NEP's Total Monthly Peak Load, to NEP's Total Monthly Peak Load, calculated on a monthly basis.

1.10 [Reserved]

1.11 Monthly Transmission Expenses: The total monthly cost of the Transmission System as specified in Attachment RR to this Schedule until amended by NEP or modified by the Commission.

1.12 NEP: NEP means New England Power Company, a Transmission Owner under the Tariff

1.13 NEPOOL Tariff: The predecessor NEPOOL Open Access Transmission Tariff as filed with the Commission on December 31, 1996 and as amended and in effect from time to time.

1.14 NERC: North American Electric Reliability Council

1.15 Network Load: The load interconnected (not reduced for any generation behind the meter) to the PTF, Non-PTF or Distribution Facilities of NEP or its New England Affiliates either directly or through Distribution Facilities or Non-PTF Facilities of other entities that a Network Customer designates to receive Local Network Service under Schedule 21 and this Schedule. For purposes of establishing rates and charges under this Schedule, the Network Load will be subdivided into one of three categories:

A. PTF Network Load shall be the load over NEP's Local Network and shall equal the load of Network Customers directly interconnected with NEP's PTF or indirectly utilizing NEP's PTF through Non-PTF or Distribution Facilities of NEP or its New England Affiliates.

B. Non-PTF Network Load shall be the load over NEP's Non-PTF either directly interconnected with NEP's Non-PTF or indirectly utilizing NEP's Non-PTF through Distribution Facilities of NEP or its New England Affiliates.

C. Distribution Facilities Network Load shall be the load interconnected to the Distribution Facilities of NEP, its New England Affiliates or other entities.

1.16 Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support NEP's overall Transmission System for the general benefit of all users of such Transmission System or to reliably integrate a generating unit with the Transmission System or to interconnect to outside control areas.

1.17 Non-PTF Load Ratio Share: Ratio of a Transmission Customer's monthly Non-PTF Network Load occurring coincident with NEP's Total Monthly Non-PTF Peak Load, to NEP's Total Monthly Non-PTF Peak Load.

1.18 NPCC: Northeast Power Coordinating Council, a regional reliability governing body.

1.19 Own Use Energy: Energy consumed by NEP's transmission facilities for purposes including but not limited to station service and sleet thawing, but excluding losses incurred on the Transmission System.

1.20 Parties: NEP and the Transmission Customer receiving service under this Schedule and the Tariff.

1.21 Payment Schedule: The payment schedule attached to a Local Service Agreement containing estimated milestones and estimated costs.

1.22 Policy and Practices for Protection Requirements for New or Modified Load Interconnections: NEP's policy concerning protection requirements for new or modified interconnections to loads, are included in the associated attachments of the Transmission Customer's Local Service Agreement.

1.23 Project: The substation and all facilities ancillary and appurtenant thereto, which the Transmission Customer requests to interconnect to the Transmission System, as more fully described in associated attachments to this Schedule 21-NEP and Attachment A to Schedule 21, Local Transmission Service.

1.24 Qualified Bidders List: A list of contractors and vendors qualified by NEP to work on interconnection facilities.

1.25 REMVEC: The Rhode Island, Eastern Massachusetts, Vermont Energy Control, which operates as a Local Control Center to the ISO.

1.26 Taxable Event: An event taxable to NEP resulting from transfers made by the Transmission Customer to NEP for services provided under this Schedule and Schedule 21 with respect to construction and installation of new Direct Assignment Facilities or improvements.

1.27 Total Monthly Peak Load: For each month, the highest hourly sum of the coincident peaks of deliveries to all PTF Network Loads under this Schedule, plus the loads of customers served under New England Power Company's (NEP) FERC Electric Tariff, Original Volume No. 1, connected directly to NEP's PTF or indirectly utilizing NEP's PTF through Non-PTF or Distribution Facilities of NEP, its New England Affiliates or other entities, including losses and NEP's Own Use Energy.

1.28 Total Monthly Non-PTF Peak Load: For each month, the highest hourly sum of the coincident peaks of deliveries to all Non-PTF Network Loads under this Schedule plus the loads of customers served under NEP's FERC Electric Tariff, Original Volume No. 1, that would otherwise qualify as Non-PTF Network Load, including losses and NEP's Own Use Energy.

1.29 Transformation Facilities: One or more transformers in a substation that step the voltage from the transmission voltage level to the distribution voltage level.

1.30 Transmission Service: Service provided under the OATT.

1.31 Transmission System: Transmission System means the facilities owned, controlled or operated by NEP that are used to provide Transmission Service.

2 Purpose of This Schedule

The OATT provides for a two-tier transmission arrangement integrating regional transmission service over PTF and Local Service over Non-PTF. The arrangement is designed and shall be operated in such a manner as to encourage and promote competition in the electric market to the benefit of ultimate users of electric energy. The OATT is intended to provide for comparable, non-discriminatory treatment of all similarly situated Transmission Owners and all Eligible Customers that are transmission users, and it shall be construed in the manner which best achieves this objective.

This Schedule functions in conjunction with the OATT to offer Transmission Services and Ancillary Services not provided pursuant to the other sections of the OATT, and to provide for the recognition of payments by and credits to NEP under the OATT. The rates, terms and conditions of this Schedule supplement and, where applicable, replace the rates, terms and conditions of the OATT and Schedule 21 with respect to Local Service; however Local PTP Service is not offered by NEP. In the event of a conflict between the terms of this Schedule and the terms of Schedule 21 with respect to Local Service, the terms of this Schedule shall govern.

Pursuant to this Schedule and to Schedules 22 and 23, NEP: (a) offers access to its Transmission Facilities for Excepted Transactions; (b) offers access to its Non-PTF in conjunction with the purchase of Transmission Service under the OATT; (c) provides rates, terms and conditions for the interconnection of new network load to the Transmission System and Distribution System for wholesale transactions; (d) reflects in the charges for Transmission Service and Ancillary Services amounts paid by NEP or credited to NEP in accordance with the OATT; and (e) provides for the recovery of costs associated with the Transmission Facilities and Ancillary Services that are not recovered pursuant to the OATT.

3 Ancillary Services

Ancillary Services are needed with Transmission Service to maintain reliability within and among the Control Areas affected by the Transmission Service. NEP is required to provide and the Network Customer or the Transmission Customer taking service in accordance with this Schedule and the OATT is required to purchase Local Scheduling, System Control and Dispatch Service in accordance with the rates and/or methodology described in Attachment S-1 and Attachment OCC to this Schedule.

4 Billing and Payment

4.1 Billing Procedure: Within a reasonable time after the first day of each month, NEP or its designee shall submit an invoice to the Transmission Customer for the charges for all services furnished by NEP under this Schedule and Schedule 21 during the preceding month. The invoice shall be paid by the Transmission Customer within twenty-five (25) days of issuance. All payments shall be made in immediately available funds payable to NEP, or by wire transfer to a bank named by NEP.

4.2 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to NEP on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after NEP notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, NEP may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between NEP and the Transmission Customer, NEP will continue to provide service under the Local Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then NEP may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

4.3 After Termination or Cancellation: The applicable provisions of the OATT, Schedule 21, this Schedule and any Local Service Agreement shall continue in effect after termination or cancellation thereof to the extent necessary to provide for final billings, billing adjustments and payments and with respect to liability and indemnification from acts or events that occurred while the Local Service Agreement was in effect. Notwithstanding the above, if the OATT, Schedule

21, this Schedule or any Local Service Agreement is terminated prior to the end of its initially contemplated term, for reasons other than breach by NEP, the Transmission Customer shall reimburse NEP for all unrecovered costs applicable to facilities installed pursuant to the provisions of the OATT, Schedule 21, this Schedule or any Local Service Agreement.

4.4 Audits of Accounts and Records: Within two (2) years following a calendar year, NEP and the Transmission Customer shall have the right to audit each other's accounts and records at the offices where such accounts and records are maintained during normal business hours; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service for said calendar year. The party being audited will be entitled to review the audit report and any supporting materials. The independent auditor performing such audit shall be subject to a confidentiality agreement between the auditor and the party being audited. To the extent that audited information includes confidential information, the auditing party shall designate an independent auditor to perform such audit. For the purpose of this provision, confidential information is proprietary information supplied by a Transmission Customer or a provider of Ancillary Services to NEP, which the Transmission Customer or a provider of Ancillary Services requests NEP not to disclose. NEP will treat such information as confidential except to the extent that disclosure of this information is required by the OATT, by regulatory or judicial order for reliability purposes pursuant to Good Utility Practice, pursuant to the Commission's Final Order 889 in Docket No. RM95-9-000, or as required under the ISO New England Information Policy. NEP will not disclose such information to its power marketing Affiliate or others.

5 Creditworthiness

For the purpose of determining the ability of a Transmission Customer to meet its obligations related to service hereunder, NEP may require reasonable credit review procedures. Applicable creditworthiness procedures are specified in Attachment L of this Schedule.

6 Dispute Resolution Procedures

6.1 Interpretation: The interpretation of and performance under this Schedule shall be according to and controlled by the laws of the Commonwealth of Massachusetts when not in conflict with or pre-empted by the Federal Power Act.

6.2 Indemnification: In cases where the Transmission Customer enjoys limitation of its liability under the Massachusetts Tort Claims Act, G.L. c. 258, §§1 and 2, as amended from time to time, NEP will have a similar limitation on its liability under the OATT, Schedule 21 and this Schedule.

II. LOCAL NETWORK SERVICE

The rates, terms and conditions set forth below supplement and, where applicable, replace the rates, terms and conditions of Local Network Service set forth in Schedule 21. In the event of a conflict between the terms of this Schedule and the terms of Schedule 21, the terms of this Schedule shall govern.

19 Real Power Losses

Real Power Losses are associated with all Transmission Service. NEP is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all Transmission Service as calculated by NEP. The applicable Real Power Loss factors tabulated in Attachment I to this Schedule will be applied to metered loads to account for losses on the Non-PTF System and/or Distribution System that are not otherwise accounted for and allocated. Determination of losses across NEP's PTF system will be according to the procedure set by the ISO. In cases where the ISO or the Tariff does not allocate PTF losses, PTF losses will be assigned at 3%. When a load interconnects to the Transmission System at a Non-PTF point, the Real Power Loss factors in Attachment I to this Schedule will be applied to metered load amounts to reflect the losses incurred between the metering point and the PTF. Application of appropriate loss compensation to the meter would negate the need to apply the Real Power Loss factors. The Real Power Loss factors vary, depending upon the system voltage level at the interconnection point. If multiple voltage levels intervene between the PTF and the interconnection point/metering point, the Real Power Loss factors for each of the intervening voltage levels are additive. Any Non-PTF losses not allocated under Attachment I to this Schedule will be allocated to Non-PTF Network Load on the basis of Non-PTF Load Ratio Share.

20 Metering and Power Factor Correction at Point(s) of Delivery

20.1 Power Factor: The Network Customer's cumulative Load Power Factor for all Point(s) of Delivery in an area as defined by the ISO shall be maintained within a range, as required by NEP, the ISO, and/or REMVEC, in accordance with Good Utility Practice. This range will be reviewed periodically and is subject to change. The Network Customer shall be notified of such changes. If the Network Customer's cumulative Load Power Factor does not fall within the required range, and NEP has existing means of providing the deficient reactive power NEP will charge the Network Customer a Power Factor Penalty in accordance with Attachment OCC to this Schedule. The Power Factor Penalty charge will be suspended if the customer corrects the Load Power Factor or, if during periods when the range may be changed, the customer's Load Power Factor is within the prescribed range. If NEP cannot provide the deficient reactive power from existing facilities, NEP will install, at the Customer's sole expense, the appropriate equipment to bring the customer's power factor within the required range. NEP will file with the Commission the cost support for such installations.

21 Network Resources

21.1 [Reserved]

21.2 Designation of New Network Resources: Each designation of a Network Resource shall be effective as of the beginning of a month, shall remain in effect for at least one full month, and shall only be terminated at the end of a month.

22 Construction of Facilities Associated with Interconnection of New Network Load

22.1 Basic Understandings: In cases in which the Transmission Customer intends to interconnect new network load to the Transmission System or Distribution System, the interconnection: (i) shall require the construction of interconnection facilities and associated equipment and (ii) may require the construction or installation of facilities and/or associated equipment in addition to the interconnection facilities on the Transmission System or Distribution System or the transmission system of another utility. These interconnection facilities and additional facilities shall be the financial responsibility of the Transmission Customer, to the extent consistent with Commission policy.

Subject to the following terms and conditions, NEP or its New England Affiliate shall, at the Transmission Customer's expense, build the facilities or make preparations so that this construction can be submitted for written bids to parties on the Qualified Bidders List. NEP shall have the right to supervise any construction undertaken by qualified outside contractors at the Transmission Customer's expense and to reject any construction work which fails to meet its requirements.

22.2 General Considerations: NEP or its New England Affiliate or another party selected pursuant to this Section shall construct the facilities at the Transmission Customer's expense. NEP or its New England Affiliate shall design, own, and maintain the facilities. NEP and the Transmission Customer shall mutually agree upon a schedule for construction and final interconnection. NEP shall use due diligence to fulfill its obligations under this Schedule in order to permit the interconnection of the Project in a timely manner. NEP reserves the exclusive right to make the final interconnection between the Project and NEP's Transmission System. NEP shall use, or specify that the Transmission Customer's selected contractor use, standard equipment customarily employed by NEP or its New England Affiliate for its own system in accordance with Good Utility Practice in making the final interconnection.

The Transmission Customer shall pay NEP for all reasonable costs and fees required to enable NEP to fulfill its obligations, including any tax liability, the costs and fees of all permits, licenses, franchises or regulatory or other approvals necessary for the construction and operation of the facilities. NEP shall consult with Transmission Customer on decisions involving substantial additional costs to be incurred by NEP in fulfillment of its obligations.

22.3 Tax Security Arrangements: The Transmission Customer shall acknowledge that under IRS Notice 87-82, transfers made by the Transmission Customer to NEP for services provided hereunder with respect to the construction and installation of new facilities or improvements may, under certain circumstances cause a Taxable Event to NEP. The Transmission Customer agrees to assure NEP recovery of all potential tax costs, both state and federal, including all interest and penalty claims, if a Taxable Event occurs.

The Transmission Customer shall expressly agree to indemnify and save NEP harmless from and against any and all federal and/or state income tax, interest or penalty claims, or liability related to any tax gross-up incurred as a result of the work performed for and the services rendered to the Transmission Customer.

22.4 Security: In addition to the security provided for in Section 5 of this Schedule, the Transmission Customer shall agree to provide NEP with security for the potential tax liability for a term and in a form acceptable to NEP. Such security shall cover an amount calculated in accordance with the terms of Section 22.5 of this Schedule. If the Transmission Customer fails to provide NEP with satisfactory security within thirty (30) days of notice by NEP, NEP may cease all work related to the Transmission Customer's request until such security is in place.

NEP reserves the right to require the Transmission Customer to increase the value of the security to reflect changed circumstances including, but not limited to, an increase in the taxable value of the Direct Assignment Facilities or changes in tax law which affect NEP's tax position vis-à-vis the construction and installation of new or modified facilities. The Transmission Customer shall provide NEP with the security as well as any periodic renewals that may be required by NEP. Such security shall have a minimum term of one (1) year and, in the case of a letter of credit, shall designate NEP as beneficiary with authority to draw drafts on the issuer for the secured amount in accordance with this Schedule. Such security shall also provide that NEP may draw the full amount of the security in the event it has not been renewed, extended or replaced on or before thirty (30) days prior to the expiration date of such security.

If at any time during the term of the Transmission Customer's Service Agreement with NEP there is a change in federal law tax which, in NEP's view, mitigates or eliminates its tax liability under applicable law or regulation, NEP shall agree, to the extent it deems appropriate, to release to the Transmission Customer any security determined to be in excess of NEP's potential tax liability.

22.5 Determination of Secured Amount: The Transmission Customer agrees that if a Taxable Event occurs, NEP's tax liability will be based upon the fair market value of the facilities constructed, installed or modified hereunder. The Transmission Customer agrees that the fair market value of the facilities is deemed to be the depreciated replacement cost of such facilities at the time of the transfer, as prescribed by IRS Notice 90-60.

The Transmission Customer shall secure an amount equal to the product of the depreciated replacement cost of the facilities times NEP's gross-up tax factor (net federal and state tax rate). NEP shall provide an initial estimate of the amount to be secured, based upon its facilities construction, installation or modification estimate. These projected figures, however, are subject to adjustment for actual construction costs when they become known.

The Transmission Customer shall agree to increase the secured amount to reflect any other adjustments as required by NEP to ensure that the existing security is sufficient to cover NEP's potential tax liability. The Transmission Customer shall agree to increase the secured amount within thirty (30) days of receipt of notice from NEP of any such adjustment to these costs. In the event that the Transmission Customer fails to do so, NEP shall have the right to seek termination of its service to the Transmission Customer until it increases the secured amount to the level specified by NEP.

22.6 Payment of Tax and Reconciliation: In the event that a Taxable Event occurs, NEP may exercise its rights under the security arrangement and draw upon all amounts necessary to pay the applicable taxes. If, in NEP's judgment, there are insufficient funds from such security to pay the applicable taxes, the Transmission Customer agrees to provide NEP with the balance of the funds needed within fifteen (15) days notice from NEP of such insufficiency. Any excess funds covered by security shall remain at NEP's disposal until NEP has received a final determination from the taxing authorities on the amounts payable as a result of the Taxable Event.

Upon such final determination, there shall be a reconciliation of the taxes payable by NEP, including any interest or penalties, and amounts provided by the Transmission Customer, in the form of security or otherwise. If the funds provided by the Transmission Customer prove insufficient to cover NEP's tax liability, the Transmission Customer shall pay NEP the amount of the underpayment within fifteen (15) days notice from NEP of the additional amount owed. If NEP receives a refund from the taxing authorities of any amounts paid due to the Taxable Event, NEP shall refund to the Transmission Customer such amount refunded to NEP. If taxes had not as yet been paid by NEP, in the form of estimated tax payments or otherwise, NEP shall refund the amount paid by the Transmission Customer in excess of NEP's actual tax liability. Interest on such amounts shall accrue, from the applicable following date: (a) the date the refund is received by NEP; (b) the date of recovery of estimated taxes previously paid by NEP (i.e., the due date of the tax payment following the determination); or (c) the date of final payment by the Transmission Customer under this Schedule, to the date NEP refunds such amount to the Transmission Customer. Once the Transmission Customer has fulfilled all of its obligations with respect to the final determination of the tax amounts payable, NEP shall release the Transmission Customer from all obligations under this Section. Interest, however, will not apply when a Letter of Credit is used as security.

22.7 IRS Private Letter Ruling. In the case of a Contribution in Aid of Construction ("CIAC") amounting to at least $100,000 and upon written request by a Transmission Customer, NEP will request a Private Letter Ruling from the Internal Revenue Service on the taxable nature of the Transmission Customer's CIAC. The Transmission Customer must submit such written request to NEP, with payment for the estimated costs of obtaining such ruling, within 30 days of the Commission's acceptance of the transmission Customer's Service Agreement (or its amendment) covering construction under this Schedule. Payment shall be sufficient to cover NEP's estimated expenses in retaining outside tax counsel with expertise in such matters, all regulatory, filing and application fees and any other reasonable expenses, including salary and overhead costs, deemed appropriate and necessary for preparing, managing and obtaining the ruling.

The Transmission Customer shall be responsible for all costs that NEP incurs in pursuing the Private Letter Ruling. If NEP's costs in pursuing the Private Letter Ruling exceed the estimated costs shown, it shall so notify the Transmission Customer and the Transmission Customer shall reimburse or pay the estimated additional cost, as the case may be, within thirty (30) days of notification. NEP shall not be responsible for pursuing or continuing to pursue the Private Letter Ruling if the Transmission Customer has not complied with these payment provisions.

The Transmission Customer agrees that the selection and retention of outside tax counsel in this regard shall be exclusively determined by NEP. Furthermore, the Transmission Customer understands that NEP cannot predict or guarantee the outcome of the Private Letter Ruling and, should the Internal Revenue Service deem the CIAC taxable to NEP, the Transmission Customer must meet its financial obligations to NEP to cover federal and state taxes.

The Transmission Customer shall cooperate in the preparation and provision of information, documents and other materials needed by NEP and its outside counsel for the Private Letter Ruling application and its supporting description and analysis. As soon as practicable after NEP's receipt of the Private Letter Ruling from the IRS, it shall provide the Transmission Customer with a copy of the document. The parties agree that the decision of the IRS as to the taxable status of the CIAC shall be binding upon the parties, their successors and/or assigns.

22.8 Land Interests: The Transmission Customer recognizes that acquisition of the land interests necessary for the interconnection facilities may require individual agreements between NEP or its New England Affiliate and the landowners. The Transmission Customer agrees to pay

NEP all its reasonable costs associated with these acquisition agreements in advance of their execution. In the event the Transmission Customer acquires the land, permits, licenses, franchises or regulatory or other approvals necessary for the construction and operation of the interconnection facilities, NEP has the right, at the Transmission Customer's expense, to approve or reject any terms and conditions related thereto prior to the acceptance of the interconnection facilities.

22.9 Construction: If the Transmission Customer does not request that the construction of the interconnection facilities be submitted for written bids as described below, NEP or its New England Affiliate shall construct the interconnection facilities and the Transmission Customer shall pay NEP the total costs associated with the construction of the interconnection facilities. The estimated costs (exclusive of any regulatory approval costs and/or fees) and the schedule for the Transmission Customer's payments to NEP will be shown the Service Agreement.

The Transmission Customer shall pay NEP following the close of the Transmission Customer's construction financing (if any) in accordance with the Payment Schedule shown in the Service Agreement. The Payment Schedule contains estimated milestones and estimated costs. NEP shall invoice the Transmission Customer for costs, on an estimated basis.

Within a reasonable period of time following completion of the interconnection facilities, NEP shall provide the Transmission Customer with a report of actual construction costs sufficient to allow identification of all major cost components. Upon completion of the interconnection facilities, the Transmission Customer and NEP agree to make a final adjustment to correct for any overpayment or underpayment of the construction costs.

22.10 Construction by Third-Party: The Transmission Customer may request that the construction of the interconnection facilities be submitted for written bids by NEP-approved contractors having the capability and skill to perform the work in accordance with the terms and conditions contained herein. The Transmission Customer shall assume all risks and consequences associated with the decision to use such bidding process.

The Transmission Customer understands that if a contractor other than NEP or its New England Affiliate constructs the interconnection facilities, the RFP process and interconnection facilities construction may require more time than if NEP or its New England Affiliate constructed the interconnection facilities. Notwithstanding the foregoing, the Transmission Customer understands and agrees that all construction work on existing facilities shall be done by NEP or its New England Affiliate. Such work shall not be included in the work submitted for bid by the Transmission Customer to outside contractors.

If the Transmission Customer requests that the construction of the interconnection facilities be submitted for written bids in accordance with the preceding paragraph, NEP shall prepare RFPs for construction of the interconnection facilities which, at a minimum, shall include construction drawings, steel structure specifications, bid drawings and specifications, materials specifications, and construction specifications. NEP shall also prepare the Qualified Bidders List. Materials, including steel structures, shall be obtained from suppliers listed in the Qualified Bidders List. The Transmission Customer shall seek NEP's prior approval with respect to any additions to the Qualified Bidders List or substitution of equal items of material from approved suppliers. The Transmission Customer shall reimburse NEP for its reasonable costs of preparing the RFPs and the Qualified Bidders List.

Upon the Transmission Customer's acceptance of the RFPs and the Qualified Bidders List, the Transmission Customer shall issue the RFPs to the contractors on the Qualified Bidders List. NEP and its New England Affiliates shall have the right to respond to the RFPs. The Transmission Customer shall review the responses to the RFPs and select a contractor to construct the interconnection facilities. Selection of the contractor shall be at the Transmission Customer's sole discretion, but subject to the limitations and criteria contained herein. The contractor selected by this process shall contract directly with the Transmission Customer for this construction. In no event shall NEP become legally or financially obligated to the selected contractor for construction of the interconnection facilities or any other related work.

If NEP or its New England Affiliate is not the successful bidder, NEP shall have the ongoing right to monitor, at the Transmission Customer's expense, and approve or reject the contractor's construction of the interconnection facilities to ensure that the contractor's performance satisfies NEP's specifications and the criteria set forth in this Schedule and all appendices, exhibits, and attachments hereto. NEP shall have the right to make a final inspection and acceptance of the completed interconnection facilities. NEP's evaluation and acceptance of the interconnection facilities shall be based on compliance with the contract specifications; Good Utility Practice; the National Electric Safety Code as in effect during the time of construction; the appropriate state rules and regulations; NEP’s Policy and Practices for Protection Requirements for New or

Modified Load Interconnections; and other practices, procedures, specifications, and applicable standards developed by NEP's New England Affiliate. Any part of the work which NEP reasonably finds unsatisfactory shall be corrected prior to its acceptance of the completed interconnection facilities.

If the Transmission Customer selects a contractor other than NEP or its New England Affiliate, within thirty days following completion of the interconnection facilities, the Transmission Customer shall provide NEP with all detailed construction cost data that NEP needs to meet construction cost unitizing requirements under the Federal Power Act and relevant regulations.

22.11 Delivery and Measurement of Electricity:

22.11.1 Voltage Level: All electricity across the interconnection point shall be the form of three-phase sixty-hertz alternating current at a voltage class determined by mutual agreement of the parties.

22.11.2 Machine Reactive Capability: The Transmission Customer will be required to provide reactive capability to regulate and maintain system voltage at the interconnection point. NEP and the ISO shall establish a scheduled range of voltages to be maintained by the Project. The reactive capability requirements shall be reviewed during the System Impact Study and Facilities Study.

22.11.3 Metering and Related Equipment: The Transmission Customer shall be responsible for the cost of installing and maintaining compatible metering and communication equipment at or distant from the Project which measures steam flow, if the Project is a generating source (as applicable and where necessary), as well as electricity flows between NEP and Transmission Customer and determines the status of switching equipment. The Transmission Customer shall be responsible for communicating to NEP accurate information on capacity and energy being transmitted. Instrument transformers shall be approved by NEP before the design is finalized. In cases where it may be appropriate for the metering equipment to be installed at the Transmission Customer's property, NEP reserves the right to inspect, commission and witness test such meters. NEP shall also have access to read such meters remotely and locally to facilitate measurements and billing.

The Transmission Customer shall provide suitable space within its facilities for installation of the metering, telemetering, environmental control, and communication equipment at no cost to NEP.

The Transmission Customer shall be responsible for providing all necessary leased telephone lines and any necessary protection for leased lines and shall furthermore be responsible for all communication required by the ISO, or its designee. The Transmission Customer shall maintain all telemetering and transducer equipment on the Project in accordance with applicable criteria, rules, standards and operating procedures. At the Transmission Customer's expense, NEP shall purchase, own and maintain all telemetering equipment located on NEP's facilities. The Transmission Customer shall be responsible for the cost of installing NEP-approved or NEP-specified test switches in the transducer circuits.

If the metering equipment, the interconnection point and the Point(s) of Receipt are not at the same location, the metering equipment shall record delivery of electricity in a manner that accounts for losses occurring between the metering point and the Point(s) of Receipt or between the metering point and the interconnection point, as appropriate. Accounting for transmission losses between the metering point and the Point(s) of Receipt or between the metering point and the interconnection point shall be pursuant to the rates, terms and conditions of this Schedule and the OATT.

All metering equipment may be routinely tested by NEP at the Transmission Customer's expense, in accordance with applicable criteria, rules, standards and operating procedures. If, at any time, any metering equipment is found to be inaccurate by a margin greater than that allowed under applicable criteria, rules, standards and operating procedures, NEP shall cause such metering equipment to be made accurate or replaced at the Transmission Customer's expense. Meter readings for one-half the period extending back to the last successful meter test shall be adjusted so far as the same can be reasonably ascertained. Each party shall comply with any reasonable request of the other concerning the sealing of meters, the presence of a representative of the other party when the seals are broken and the tests are made, and other matters affecting the accuracy of the measurement of electricity delivered from the Project. If either party believes that there has been a meter failure or stoppage, it shall immediately notify the other.

The Transmission Customer shall be responsible for the cost of purchasing and installing software, hardware and/or other technology that may be required to read billing meters.

The Transmission Customer shall be responsible for the costs of all metering and related equipment pursuant to Attachment OCC to this Schedule and/or Attachment DAF to this Schedule, as applicable.

22.12 Notice Provisions: If at any time, in the reasonable exercise of NEP's judgment, operation of the Project adversely affects the quality of service to other customers or interferes with the safe and reliable operation of the Transmission System or Distribution System, NEP may discontinue service to the Transmission Customer until the condition has been corrected. Unless an emergency exists or the risk of one is imminent, NEP shall give the Transmission Customer reasonable notice of its intention to discontinue service and, where practical, allow suitable time for the Transmission Customer to remove the interfering condition. NEP's judgment with regard to discontinuance of deliveries or disconnection of facilities under this paragraph shall be made in accordance with Good Utility Practice. In the case of such discontinuance, NEP shall immediately confer with the Transmission Customer regarding the conditions causing such discontinuance and its recommendation concerning the timely correction thereof.

22.13 Access and Control: Properly accredited representatives of NEP or its New England Affiliates shall at all reasonable times have access to the Project to make reasonable inspections and obtain information required in connection with this Schedule. At the Project, such representatives shall make themselves known to the Transmission Customer's personnel, state the object of their visit, and conduct themselves in a manner that will not interfere with the construction or operation of the Project. NEP or its New England Affiliates will have control such that it may open or close the circuit breaker or disconnect and place safety grounds at the Point(s) of Receipt, or at the station, if the Point(s) of Receipt is (are) remote from the station.

22.14 Insurance Requirements: The Transmission Customer shall be subject to the insurance requirements specified in the Local Service Agreement.

23 Load Shedding and Curtailments

23.1 Transmission Constraints: During any period when NEP determines that a transmission constraint exists on the Non-PTF, and such constraint may impair the reliability of the New England Transmission System, NEP will take whatever actions, consistent with Good Utility

Practice, that are reasonably necessary to maintain the reliability of the system. To the extent NEP determines that the reliability of the New England Transmission System can be maintained by redispatching resources, NEP will initiate procedures pursuant to contracts with owners of the identified resources to redispatch all Network Resources and NEP's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this Section may not unduly discriminate between NEP's use of the Non-PTF on behalf of its Native Load Customers and any Network Customer's use of the Non-PTF to serve its designated Network Load.

23.2 Cost Responsibility for Relieving Transmission Constraints: Whenever NEP implements least-cost redispatch procedures in response to a transmission constraint, NEP and the Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

23.3 System Reliability: A Network Customer that fails to respond to established load shedding and curtailment procedures will be deemed by NEP of making unauthorized use of the Transmission System. If unauthorized use occurs, NEP will charge and the Transmission Customer will be obligated to pay a penalty equal to twice the standard rate for such a transaction, as described more fully in Section 24.15 of this Schedule. In all cases of unauthorized use of the Transmission System, the service will be considered non-firm and NEP will be under no obligation to provide any services for such use.

24 Compensation for Local Network Service

The following rates and charges may apply to Local Network Service as specified below. Charges under this Section shall include any applicable PTF costs not otherwise recovered under the OATT. To the extent that NEP enters into an incentive rate plan(s), the incentive rate terms shall be reflected in a separate filing with the Commission under Section 205 of the Federal Power Act. Additionally, all costs and revenues under such incentive rate plan(s) shall be excluded from NEP's PTF and Non-PTF Transmission Revenue Requirement. However, liquidated damages mandated by the Commission in Docket No. RM02-1-000 shall be reflected in NEP's costs and included in its PTF and Non-PTF Transmission Revenue Requirement calculations.

24.1 Monthly Demand Charge: Any Network Customer utilizing NEP's PTF facilities either directly or indirectly shall pay a Monthly Demand Charge as calculated in accordance with Attachment OCC to this Schedule.

24.2 Monthly Non-PTF Demand Charge: Any Network Customer with Network Load qualifying as Non-PTF Network Load, shall pay a Monthly Non-PTF Demand Charge determined in accordance with Attachment OCC to this Schedule.

24.3 Transformer Surcharge: In the event that a Network Customer does not own the stepdown transformation from 69 kV or greater voltage to distribution voltage level, where it utilizes NEP's Transformation Facilities, the Network Customer will be subject to a Transformer Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.4 Meter Surcharge: If the Network Customer neither owns nor supports metering equipment necessary for provision of Local Network Service, that customer will be subject to a Meter Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.5 Power Factor Penalty: Pursuant to the requirements of Section 20.1 of this Schedule, the Network Customer may be subject to a Power Factor Penalty calculated in accordance with Attachment OCC to this Schedule.

24.6 Direct Assignment Facility Charge: The Direct Assignment Facility Charge compensates NEP for the annual costs of the facilities, expansions and upgrades that may be directly assigned by NEP or by the ISO, as appropriate, to the Transmission Customer. These costs may include, but are not limited to, the capital carrying cost, income tax, depreciation, operation and maintenance, administrative and general expenses and property tax. The Direct Assignment Facility Charge shall be calculated as specified in Attachment DAF to this Schedule. In no event shall the Direct Assignment Facilities Charge be less than $1,000.00 per year. If NEP enters into an agreement for use and support of facilities owned by other entities on behalf of a Transmission Customer, any charges incurred by NEP will be directly assigned to the Transmission Customer.

The Direct Assignment Facilities Charge in each year shall be billed based on forecast data for that year and shall be adjusted for experienced costs as soon as practicable after the close of the year. The charge so calculated shall commence on the date the facilities, expansions or upgrades are placed in service.

24.7 Distribution Service:

24.7.1 Specific Distribution Surcharge: Any Network Customer listed in Attachment OCC, VI, to this Schedule, which relies on the specific distribution facilities of NEP's New England Affiliate, Massachusetts Electric Company, as provided to NEP under the Integrated Facilities provision of NEP's FERC Electric Tariff No. 1 (Tariff No. 1), will be subject to a Specific Distribution Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.7.2 Rolled-In Distribution Surcharge: To the extent that a Network Customer listed in Attachment OCC, VI, to this Schedule, utilizes distribution facilities in addition to the specific facilities identified in NEP's Tariff No. 1 (as of February 28, 1998), the Network Customer will pay the Rolled-In Distribution Surcharge calculated in accordance with Attachment DS to this Schedule for delivery service to load. To the extent that distribution service to a new Network Customer is subject to the direct jurisdiction of the Federal Energy Regulatory Commission, the provision of distribution service to that customer on or after March 1, 1998 shall be reflected in the Network Customer's Local Service Agreement.

In the event that the integrated distribution facilities under NEP's FERC Electric Tariff No. 1 are otherwise eliminated or superseded, the customers listed in Attachment OCC, VI, to this Schedule, will take distribution service entirely under the Rolled-In Distribution Surcharge calculated in accordance with Attachment DS to this Schedule.

24.8 Ancillary Services: Any Network Customer with Network Load qualifying as PTF Network Load will be subject to the Network Load Dispatch Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.9 OASIS Charges: Identifiable usage-dependent costs of OASIS may be charged to the specific user in accordance with the Commission's Final Order 889 in Docket No. RM95-9-000, and any subsequent amendments thereto.

24.10 [Reserved]

24.11 EPRI Credit: The Network EPRI Credit, calculated in accordance with Attachment OCC to this Schedule, shall apply to any wholesale Network Customer, which is not also an Affiliate of NEP.

24.12 Pre-1997 RNS Revenue Credit: Pursuant to the compliance filing made by NEP in FERC Docket Nos. EC99-70-00 and ER99-2832-000 (Not Consolidated), Taunton Municipal Lighting Plant, Middleborough Gas and Electric Department and Pascoag Fire District will receive a credit in their monthly bill under this Schedule calculated in accordance with Attachment OCC to this Schedule.

24.13 Network Upgrade Charge: If network upgrades are required in association with a new load, the Network Customer shall be required to pay a Network Upgrade Charge. The monthly Network Upgrade charge shall be the higher of (i) the allocated Monthly Transmission Expenses for Local Network Service with the New Network Upgrades rolled-in; or (ii) an incremental monthly charge for service based upon the total costs of the Network Upgrades for which the Transmission Customer is responsible as determined by the formula in Attachment DAF to this Schedule.

24.14 Redispatch Charge: Pursuant to Section 23.2 of this Schedule, the Transmission Customer may be subject to charges for generation redispatch.

24.15 Unauthorized Use Penalty: Pursuant to Section 23.3 of this Schedule, the Transmission Customer may be subject to a penalty equal to twice the standard rate for unauthorized use of the Transmission System, based on the period of unauthorized use.

The annual standard rate per KW for unauthorized use of the Transmission System shall be derived from (i) the previous calendar year's annual transmission expenses as calculated in Attachment RR, excluding any revenue credits associated with Section 24.1 of this Schedule divided by (ii) the average of the twelve Total Monthly Peak Loads from the previous year.10

[10] The standard rate is analogous to the former Firm Local Point-To-Point Service rate that was eliminated from Schedule 21-NEP (Attachment J) effective November 1, 2007; *see Docket No. ER07-1323-000*.

The monthly standard rate per KW shall equal one-twelfth of the annual standard rate; the weekly standard rate per KW shall equal one-fifty-second of the annual standard rate; and the daily standard rate per KW shall equal one-fifth of the weekly standard rate.

The unauthorized use penalty charge for a single hour of unauthorized use shall be based on the daily standard rate, and more than one assessment for a given duration (e.g., daily) results in an increase of the penalty period to the next longest duration (e.g., weekly). The unauthorized use penalty charge for multiple instances of unauthorized use (i.e., more than one hour) within a day will be based on the daily standard rate. The unauthorized use penalty charge for multiple instances of unauthorized use isolated to one calendar week would result in a penalty based on the weekly standard rate. The unauthorized use penalty charge for multiple instances of unauthorized use during more than one week during a calendar month will be based on the monthly standard rate.

ATTACHMENT C

Form of System Impact Study Agreement

This Agreement dated __________, is entered into by ____________ (the Transmission Customer) and New England Power Company (NEP), for the purpose of setting forth the terms, conditions and costs for conducting a System Impact Study relative to _________________________________.

1. The Transmission Customer agrees to provide, in a timely and complete manner, all required information and technical data necessary for NEP to conduct the System Impact Study. The Transmission Customer understands that it must provide all such information and data prior to NEP's commencement of the Study. Such information and technical data is specified in Exhibit 1 to this Agreement.

2. All work pertaining to the System Impact Study that is the subject of this Agreement will be approved and coordinated only through designated and authorized representatives of NEP and the Transmission Customer. Each party shall inform the other in writing of its designated and authorized representative.

3. NEP will advise the Transmission Customer of any additional studies as it may in its sole discretion deem necessary. Any such additional studies shall be conducted only if required by Good Utility Practice and shall be subject to the Transmission Customer's consent to proceed, such consent not be unreasonably withheld.

4. NEP contemplates that it will require _______ to complete the System Impact Study. Upon completion of the Study by NEP, NEP will provide a report to the Transmission Customer based on the information provided and developed as a result of this effort. If, upon review of the Study results, the Transmission Customer decides to pursue ___________, NEP will, at the Transmission Customer's direction, tender a Facilities Study Agreement within thirty (30) days. The System Impact and Facilities Studies, together with any additional studies contemplated in Paragraph 3, shall form the basis for the Transmission Customer's proposed use of NEP's transmission system and shall be furthermore utilized in obtaining necessary third-party approvals of any interconnection facilities and requested transmission services. The Transmission Customer understands and acknowledges that any use of study results by the Transmission Customer or their agents, whether in preliminary or final form, prior to application approval pursuant to Section I.3.9 of the Tariff, is completely at the Transmission Customer's risk and that NEP will

not guarantee or warrant the completeness, validity or utility of study results prior to application approval pursuant to Section I.3.9 of the Tariff.

5. The estimated costs contained within this Agreement are NEP's good faith estimate of its costs to perform the System Impact Study contemplated by this Agreement. NEP’s estimates do not include any estimates for wheeling charges that may be associated with the transmission of facility output to third parties or with rates for station service. The actual costs charged to the Transmission Customer by NEP may change as set forth in this Agreement. Prepayment will be required for all study, analysis, and review work performed by NEP or its Designated Agent, all of which will be billed by NEP to the Transmission Customer in accordance with Paragraph 6 of this Agreement.

6. The payment required is $______ from the Transmission Customer to NEP for the primary system analysis, coordination, and monitoring of the System Impact Study. NEP will, in writing, advise the Transmission Customer in advance of any cost increases for work to be performed if total amount increases by 10% or more. Any such changes to NEP’s costs for the study work shall be subject to the Transmission Customer’s consent, such consent not to be unreasonably withheld. The Transmission Customer shall, within thirty (30) days of NEP’s notice of increase, either authorize such increases and make payment in the amount set forth in such notice, or NEP will suspend the System Impact Study and this Agreement will terminate if so permitted by the Federal Energy Regulatory Commission.

In the event this Agreement is terminated for any reason, NEP shall refund to the Transmission Customer the portion of the above credit or any subsequent payment to NEP by the Transmission Customer that NEP did not expend in performing its obligations under this Agreement. Any additional billings under this Agreement shall be subject to an interest charge computed in accordance with the provisions of the OATT. Payments for work performed shall not be subject to refunding except in accordance with Paragraph 7 below.

7. If the actual costs for the work exceed prepaid estimated costs, the Transmission Customer shall make payment to NEP for such actual costs within thirty (30) days of the date of NEP’s invoice for such costs. If the actual costs for the work are less than those prepaid, NEP will credit such difference toward NEP costs unbilled, or in the event there will be no additional billed expenses, the amount of the overpayment will be returned to the Transmission Customer with interest computed as stated in Paragraph 6 of this Agreement, from the date of reconciliation.

8. Nothing in this Agreement shall be interpreted to give the Transmission Customer immediate rights to wheel over or interconnect with NEP's Transmission or Distribution System. Such rights shall be provided for under separate agreement and in accordance with the OATT.

9. Within one (1) year following NEP's issuance of a final bill under this Agreement, the Transmission Customer shall have the right to audit NEP's accounts and records at the offices where such accounts and records are maintained, during normal business hours; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service under this Agreement. NEP reserves the right to assess a reasonable fee to compensate for the use of its personnel time in assisting any inspection or audit of its books, records or accounts by the Transmission Customer or their Designated Agent.

10. Each party agrees to indemnify and hold the other party and its Affiliates, including affiliated trustees, directors, officers, employees, and agents of each of them, harmless from and against any and all damages, costs (including attorney's fees), fines, penalties and liabilities, in tort, contract, or otherwise (collectively "Liabilities") resulting from claims of third parties arising, or claimed to have arisen as a result of any acts or omissions of either party under this Agreement. Each party hereby waives recourse against the other party and its Affiliates for, and releases the other party and its Affiliates from, any and all Liabilities for or arising from damage to its property due to a performance under this Agreement by such other party.

11. If either party materially breaches any of its covenants hereunder, the other party may terminate this Agreement by filing a notice of intent to terminate with the Federal Energy Regulatory Commission and serving notice of same on the other party to this Agreement.

12. This agreement shall be construed and governed in accordance with the laws of the Commonwealth of Massachusetts and with Part II of the Federal Power Act, 16 U.S.C. §§824d et seq., and with Part 35 of Title 18 of the Code of Federal Regulations, 18 C.F.R. §§35 et seq.

13. All amendments to this Agreement shall be in written form executed by both parties.

14. The terms and conditions of this Agreement shall be binding on the successors and assigns of either party.

15. This Agreement will remain in effect for a period of up to two years from its effective date as permitted by the Federal Regulatory Commission, and is subject to extension by mutual agreement. Either party may terminate this Agreement by thirty (30) days' notice except as is otherwise provided herein. If this Agreement expires by its own terms, it shall be NEP's responsibility to make such filing.

NEP:

By:______________________ _______________ ______________
Name Title Date

Transmission Customer:

By:______________________ _______________ ______________
Name Title Date

System Impact Study Agreement

EXHIBIT 1

Information to be Provided to NEP

by the Transmission Customer for System Impact Study

1.0 Facilities Identification

1.1 Requested capability in MW and MVA; summer and winter

1.2 Site location and plot plan with clear geographical references

1.3 Preliminary one-line diagram showing major equipment and extent of Transmission Customer ownership

1.4 Auxiliary power system requirements

1.5 Back-up facilities such as standby generation or alternate supply sources

2.0 Major Equipment

2.1 Power transformer(s): rated voltage, MVA and BIL of each winding, LTC and or NLTC taps and range, Z1 (positive sequence) and Z0 (zero sequence) impedances, and winding connections. Provide normal, long-time emergency and short-time emergency thermal ratings.

2.2 Generator(s): rated MVA, speed and maximum and minimum MW output, reactive capability curves, open circuit saturation curve, power factor (V) curve, response (ramp) rates, H (inertia), D (speed damping), short circuit ratio, X1 (leakage), X2 (negative sequence), and X0 (zero sequence) reactances and other data:

	Direct Axis	Quadrature Axis
saturated synchronous reactance	Xdv	Xqv

	Direct Axis	Quadrature Axis
unsaturated synchronous reactance	Xdi	Xqi
saturated transient reactance	X'dv	X'qv
unsaturated transient reactance	X'di	X'qi
saturated subtransient reactance	X"dv	X"qv
unsaturated subtransient reactance	X"di	X"qi
transient open-circuit time constant	T'do	T'qo
transient short-circuit time constant	T'd	T'q
subtransient open-circuit time constant	T"do	T"qo
subtransient short-circuit time constant	T"d	T"q

2.3 Excitation system, power system stabilizer and governor: manufacturer's data in sufficient detail to allow modeling in transient stability simulations.

2.4 Prime mover: manufacturer's data in sufficient detail to allow modeling in transient stability simulations, if determined necessary.

2.5 Busses: rated voltage and ampacity (normal, long-time emergency and short-time emergency thermal ratings), conductor type and configuration.

2.6 Transmission lines: overhead line or underground cable rated voltage and ampacity (normal, long-time emergency and short-time emergency thermal ratings), Z1 (positive sequence) and Z0 (zero sequence) impedances, conductor type, configuration, length and termination points.

2.7 Motors greater than 150 kW 3-phase or 50 kW single-phase: type (induction or synchronous), rated hp, speed, voltage and current, efficiency and power factor at ½, 3/4 and full load, stator resistance and reactance, rotor resistance and reactance, magnetizing reactance.

2.8 Circuit breakers and switches: rated voltage, interrupting time and continuous, interrupting and momentary currents. Provide normal, long-time emergency and short-time emergency thermal ratings.

2.9 Protective relays and systems: ANSI function number, quantity manufacturer's catalog number, range, descriptive bulletin, tripping diagram and three-line diagram showing AC connections to all relaying and metering.

2.10 CT's and VT's: location, quantity, rated voltage, current and ratio.

2.11 Surge protective devices: location, quantity, rated voltage and energy capability.

3.0 Other

3.1 Additional data to perform the System Impact Study will be provided by the Transmission Customer as requested by NEP.

3.2 NEP reserves the right to require specific equipment settings or characteristics necessary to meet the applicable criteria and standards.

ATTACHMENT D

Form of Facilities Study Agreement

This agreement dated __________, is entered into by ____________ (the Transmission Customer) and New England Power Company (NEP), for the purpose of setting forth the terms, conditions and costs for conducting a Facilities Study Agreement relative to ______________________________________. The Facilities Study will determine the detailed engineering, design and cost of the facilities necessary to satisfy the Transmission Customer's request for service over NEP's Transmission System.

1. The Transmission Customer agrees to provide, in a timely and complete manner, all required information and technical data necessary for NEP to conduct the Facilities Study. Where such information and technical data was provided for the System Impact Study, it should be reviewed and updated with current information, as required.

2. All work pertaining to the Facilities Study that is the subject of this Agreement will be approved and coordinated only through designated and authorized representatives of NEP and the Transmission Customer. Each party shall inform the other in writing of its designated and authorized representative.

3. NEP will advise the Transmission Customer of additional studies as may be deemed necessary by NEP. Any such additional studies shall be conducted only if required by Good Utility Practice and shall be subject to the Transmission Customer's consent to proceed, such consent not to be unreasonably withheld.

4. NEP contemplates that it will require ___ days to complete the Facilities Study. Upon completion of the study by NEP, NEP will provide a report to the Transmission Customer based on the information provided and developed as a result of this effort. If, upon review of the study results, the Transmission Customer decides to pursue its transmission service request, the Transmission Customer must sign a supplemental Service Agreement with NEP. The System Impact and Facilities Studies, together with any additional studies contemplated in Paragraph 3, shall form the basis for the Transmission Customer's proposed use of NEP's Transmission System and shall be furthermore utilized in obtaining necessary third-party approvals of any facilities and requested transmission services. The Transmission Customer understands and acknowledges that any use of the study results by the Transmission Customer or their agents, whether in preliminary or final form, prior to application approval pursuant to Section I.3.9 of the Tariff, is completely at the Transmission Customer's risk and that NEP will not guarantee or warrant the

completeness, validity or utility of the study results prior to application approval pursuant to Section I.3.9 of the Tariff.

5. The estimated costs contained within this Agreement are NEP's good faith estimate of its costs to perform the Facilities Study contemplated by this Agreement. NEP’s estimates do not include any estimates for wheeling charges that may be associated with the transmission of facility output to third parties or with rates for station service. The actual costs charged to the Transmission Customer by NEP may change as set forth in this Agreement. Prepayment will be required for all study, analysis, and review work performed by NEP’s or its Designated Agent’s personnel, all of which will be billed by NEP to the Transmission Customer in accordance with Paragraph 6 of this Agreement.

6. The payment required is $____ from the Transmission Customer to NEP for the primary system analysis, coordination, and monitoring of the Facilities Study to be performed by NEP for the Transmission Customer’s requested service. NEP will, in writing, advise the Transmission Customer in advance of any cost increases for work to be performed if the total amount increases by 10% or more. Any such changes to NEP’s costs for the study work to be performed shall be subject to the Transmission Customer’s consent, such consent not to be unreasonably withheld. The Transmission Customer shall, within thirty (30) days of NEP’s notice of increase, either authorize such increases and make payment in the amount set forth in such notice, or NEP will suspend the study and this Agreement will terminate if so permitted by the Federal Energy Regulatory Commission. In the event this Agreement is terminated for any reason, NEP shall refund to the Transmission Customer the portion of the above credit or any subsequent payment to NEP by the Transmission Customer that NEP did not expend in performing its obligations under this Agreement. Any additional billings under this Agreement shall be subject to an interest charge computed in accordance with the provisions of the OATT. Payments for work performed shall not be subject to refunding except in accordance with Paragraph 7 below.

7. If the actual costs for the work exceed prepaid estimated costs, the Transmission Customer shall make payment to NEP for such actual costs within thirty (30) days of the date of NEP’s invoice for such costs. If the actual costs for the work are less than that prepaid, NEP will credit such difference toward NEP costs unbilled, or in the event there will be no additional billed expenses, the amount of the overpayment will be returned to the Transmission Customer with interest computed in accordance with the provisions of the OATT.

8. Nothing in this Agreement shall be interpreted to give the Transmission Customer immediate rights to interconnect to or wheel over NEP's Transmission or Distribution System. Such rights shall be provided for under separate agreement.

9. Within one (1) year following NEP's issuance of a final bill under this Agreement, the Transmission Customer shall have the right to audit NEP's accounts and records at the offices where such accounts and records are maintained during normal business hours; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service under this Agreement. NEP reserves the right to assess a reasonable fee to compensate for the use of its personnel time in assisting any inspection or audit of its books, records or accounts by the Transmission Customer or their Designated Agent.

10. Each party agrees to indemnify and hold the other party and its Affiliates, including affiliated trustees, directors, officers, employees, and agents of each of them, harmless from and against any and all damages, costs (including attorney's fees), fines, penalties and liabilities, in tort, contract, or otherwise (collectively "Liabilities") resulting from claims of third parties arising, or claimed to have arisen as a result of any acts or omissions of either party under this Agreement. Each party hereby waives recourse against the other party and its Affiliates for, and releases the other party and its Affiliates from, any and all Liabilities for or arising from damage to its property due to performance under this Agreement by such other party.

11. If any party materially breaches any of its covenants hereunder, the other party may terminate this Agreement by filing a notice of intent to terminate with the Federal Energy Regulatory Commission and serving notice of same on the other party to this Agreement.

12. This agreement shall be construed and governed in accordance with the laws of the Commonwealth of Massachusetts and with Part II of the Federal Power Act, 16 U.S.C. §§824d et seq., and with Part 35 of Title 18 of the Code of Federal Regulations, 18 C.F.R. §§35 et seq.

13. All amendments to this Agreement shall be in written form executed by both parties.

14. The terms and conditions of this Agreement shall be binding on the successors and assigns of either party.

15. This Agreement will remain in effect for a period of up to two years from its effective date as permitted by the Federal Energy Regulatory Commission, and is subject to extension by mutual agreement.

Either party may terminate this Agreement by thirty (30) days' notice except as is otherwise provided herein. If this Agreement expires by its own terms, it shall be NEP’s responsibility to make such filing.
NEP:

By:______________________ _______________ ______________
Name Title Date

Transmission Customer:

By:______________________ _______________ ______________
Name Title Date

ATTACHMENT E

Local Service Agreement

Policy and Practices for Protection Requirements
For New or Modified Load Interconnections

Any load facility, hereafter called a LF, desiring to interconnect with NEP's electrical system or modify an existing interconnection must meet the technical specifications and requirements set forth in this Policy and Practices. Once interconnected, NEP, in keeping with Good Utility Practice and in its sole discretion, may disconnect the LF if the LF departs from the technical specifications and requirements of this Policy and Practices. The LF must return to full compliance with this Policy prior to reconnecting with NEP's electrical system.

If it is possible for the LF to be a significant source of current flow into NEP's lines due to generation sources within the LF system then NEP may determine the LF to be considered a Generation Facility and the Policy and Practices for Protection Requirements for Generation Interconnections shall apply as set forth in the New England ISO OATT.

This document is divided into the following sections:

1. Protection Information Required from the LF for All Interconnections
2. General Protection Requirements for All LF Interconnections
3. Protection Equipment Requirements for All LF Interconnections
4. Requirements for Protection of NEP's System
5. Requirements for Protection of NEP's System: Facilities Having Sources
6. Requirements for Emergency Load Reduction
7. Protection System Testing and Maintenance
8. Changes to the LF's Protection System

1.) PROTECTION INFORMATION REQUIRED FROM THE LF FOR ALL INTERCONNECTIONS

A. The following information must be submitted by the LF for review and acceptance by NEP prior to finalizing the LF's protection design:

- A station one-line drawing.
- A one-line drawing showing the relays and metering including current transformer (CT) and voltage transformer (VT) connections and ratios.
- A three-line drawing showing the AC connections to the relays and meters.
- The LF’s transformer nameplate information including rated voltage, rated KVA, positive and zero sequence impedances and winding connections.
- A list of protective relay equipment proposed to be furnished to conform with this Policy and Practices including: relay types, styles, manufacturer's catalog numbers, ranges and descriptive bulletins.
- Schematic drawings showing the control circuits for the interconnection breaker(s) or equivalent interrupting device(s).
- Equipment specifications for CTs and VTs relevant to the interconnection.
- Interconnection breaker or equivalent interrupting device operating time.
- Other information that may be determined by NEP as required for a specific interconnection.

B. Relay settings for all LF protective relays that affect the interconnection with NEP’s system must be submitted by the LF for review and acceptance by NEP at least four weeks prior to the scheduled date for setting the relays.

C. If, due to the interconnection of the LF to the line, the fault interrupting, continuous, momentary or other rating of any of NEP's equipment or the equipment of others connected to NEP's system is exceeded, NEP shall have the right to require the LF to pay for the purchase, installation, replacement or modification of equipment to eliminate the condition. Where such action is deemed necessary by NEP, NEP will, where possible, permit the LF to choose among two or more options for meeting NEP’s requirements as described in this Policy and Practices.

2.) GENERAL PROTECTION REQUIREMENTS FOR ALL LF INTERCONNECTIONS

A. A circuit breaker, or other fault interrupting method acceptable to NEP, shall be installed to isolate the LF from NEP's system. This will hereafter be called the "interconnection breaker". If there is more than one interconnection breaker, the requirements of this Policy and Practices apply to each one individually.

B. NEP will review the relay settings as submitted by the LF to assure adequate protection for NEP's facilities. NEP shall not be responsible for the protection of the LF's facilities. Providing the relaying is installed and maintained as reviewed, the LF shall not be responsible for the protection of NEP's facilities. The LF shall be responsible for protection of its system against possible damage resulting from interconnection with NEP.

If requested by the LF, NEP will provide system protection information for the line terminal(s) directly related to the interconnection. This protection information is provided exclusively for use by the LF in evaluating protection of the LF's facilities during parallel operation.

C. NEP shall specify whether the transformer, if any, between NEP's voltage and the LF's distribution voltage, hereafter called the "LF's transformer", is to be grounded or ungrounded at NEP's voltage.

3.) PROTECTION EQUIPMENT REQUIREMENTS FOR ALL LF INTERCONNECTIONS

A. The interconnection breaker control circuits shall be DC powered from a station battery.

B. The LF shall provide a switch at the Interconnection Point with NEP that can be opened for isolation. NEP shall have the right to open the interconnection during emergency conditions or with due notice to the LF at other times. NEP shall exercise such right in accordance with Good Utility Practice. The switch shall be gang operated, have a visible break when open, and be capable of being locked open, tagged and grounded on NEP side by NEP personnel. The switch shall be of a manufacture and type generally accepted for use by NEP.

C. Protective relaying control circuits shall be DC powered from a station battery. Solid state relays shall be self powered or DC powered from a station battery.

D. CT ratios and accuracy classes shall be chosen such that secondary current is less than 100 amperes and transformation errors are less than 10% under maximum fault conditions.

E. All protective relays required by this Policy and Practices shall meet ANSI/IEEE standard C37.90 and be of a manufacture and type generally accepted for use by NEP.

F. Protective relays provided by the LF as required per this Policy and Practices shall be sufficiently redundant and functionally separate so as to provide adequate protection, as determined by NEP, upon the failure of any one component. The use of a single all-inclusive relay package is not acceptable.

G. NEP may require the LF to provide two independent, redundant relaying systems in accordance with NPCC Criteria for the Protection of the Bulk Power System if the interconnection is to the Bulk Power System or if it is determined that delayed clearing of faults within the LF adversely affects the Bulk Power System.

H. A direct transfer tripping system, if provided, shall use equipment generally accepted for use by NEP and shall, at the option of NEP, use dual channels.

4.) REQUIREMENTS FOR PROTECTION OF THE TRANSMISSION SYSTEM

A. The LF must provide protective relays to detect any faults, whether phase-to-phase or phase-to-ground within the LF, and isolate the LF from NEP's line(s) such that the following criteria are met, as determined by NEP:

- The existing sensitivity of fault detection is not substantially degraded.
- The existing speed of fault clearing is not substantially degraded.
- The coordination margin between relays is not substantially reduced.
- The sustained unfaulted phase voltage during a line-to-ground fault is not increased beyond 1.25 times the normal phase-to-ground voltage. (This value may be further reduced if required to coordinate with existing system insulation levels and overvoltage protection.)
- Non-directional line relays will not operate for faults external to the line due to the LF's contribution.
- Proper settings for existing relays are achievable within their ranges.

NEP may perform engineering studies to evaluate the LF's protection compliance with respect to the above and may make recommendations to the LF on methods to achieve compliance.

If, due to the interconnection of the LF to NEP's system, any of the above criteria are violated for NEP's facilities or for the facilities of others connected to NEP's system, NEP shall have the right to require the LF to pay for the purchase, installation, replacement or modification of protective equipment to eliminate the violation and restore the level of protection existing prior to the interconnection. This may include the addition of pilot relaying systems involving communications between all terminals. Where such action is deemed necessary by NEP, NEP will, where possible, permit the LF to choose among two or more options for meeting NEP's requirements as described in this Policy and Practices.

B. The LF is responsible for procuring any communications channels necessary between the LF and NEP's stations and for providing protection from transients and overvoltages at all ends of these communication channels.

C. The LF may be required to use high speed protection if time-delayed protection would result in degradation in the existing sensitivity or speed of the protection systems on NEP's lines.

D. The LF may be required to provide local breaker failure protection which may include direct transfer tripping to NEP's line terminal(s) in order to detect and clear faults within the LF that cannot be detected by NEP's back-up protection.

5.) REQUIREMENTS FOR PROTECTION OF THE TRANSMISSION SYSTEM: FACILITIES HAVING SOURCES

If it is possible for the LF to be a source of current flow into NEP's system, either due to generation within the LF system or due to connections within the LF system to other sources, the LF must provide protective relays to detect any faults, whether phase-to-phase or phase-to-ground on NEP's lines or within the LF, and isolate the LF from NEP's line(s) per the requirement of Section 4 above and the following:

A. A control interlock scheme that detects voltage on NEP's line(s) shall be used to prevent an interconnection breaker from closing to energize NEP's line(s).

B. A voltage transformer shall be provided by the LF, connected to NEP side of the interconnecting breaker. The voltage from this VT shall be used in the interlock as specified in Section 5A above. If the LF's connection is ungrounded at NEP voltage, this VT shall be a single three-phase device or three single-phase devices connected from each phase to ground, rated for phase-to-phase voltage and provided with two secondary windings. One winding shall be connected in open delta, have a loading resistor to prevent ferroresonance, and be used for the relay specified in Section 5C below.

C. If the LF's connection to NEP's system is un-grounded, the LF shall provide a zero sequence overvoltage relay fed from the open delta of the three phase VT specified in Section 5B above.

D. NEP's lines generally have automatic reclosing following a trip with reclosing times as short as five seconds and without regard to whether the LF is keeping the circuit energized. The LF is responsible for protecting its equipment from being reconnected out of synchronism with NEP's system by an automatic line reclosure operation. The LF may choose to install additional equipment such as direct transfer tripping from NEP's station(s) to insure the LF is off the line prior to the line reclosing.

6.) REQUIREMENTS FOR EMERGENCY LOAD REDUCTION

A. The LF shall provide a manual load shed lockout relay to trip and block closing of selected load feeders. This relay shall be operated via a signal sent from an area dispatching center to a remote terminal unit (RTU) provided by the LF and shall be manually reset. The selection of feeders to trip shall be in conformance with NPCC Emergency Operation Criteria and determined by the area control authority. Alternatively, the LF may elect to provide compensatory load reduction through contractual arrangements with other area customers or by other means.

B. During system conditions where local area load exceeds generation, NPCC Emergency Operation Criteria requires a program of phased automatic underfrequency load shedding of up to 25% of area load to assist in arresting frequency decay and to minimize the possibility of system collapse. In conformance to these criteria, the LF shall provide an underfrequency relay with a lockout function to trip and block closing of selected load feeders. Feeders so shed shall not be re-energized without the express permission of the area control authority. If desired, the LF may use the RTU specified in Section 6A above to receive a signal sent from an area dispatching center that would reset the lockout function and permit automatic restoration of the feeders. The underfrequency settings and the selection of feeders shall be in conformance with these Criteria and determined by the area control authority. Alternatively, the LF may elect to provide compensatory load reduction to conform with the requirements of this Section through contractual arrangements with other area customers or by other means.

C. The LF shall provide a voltage reduction function to reduce the feeder voltage regulation set point by 5% for all load feeders. This function shall be operated via a signal sent from an area dispatching center to an RTU provided by the LF and shall be remotely reset from the dispatching center or self reset in 4 hours.

D. Depending on the point of connection of the LF to NEP's system, NEP may require a dead station tripping function to disconnect the LF from NEP's lines following six minutes of de-energized NEP lines in order to assist in restoration of service following an area or system wide shutdown.

7.) PROTECTION SYSTEM TESTING AND MAINTENANCE

A. NEP shall have the right to witness the testing of protective relays and control circuits required by this Policy and Practices at the completion of construction and to receive a copy of all test data. The LF shall provide NEP with at least a one week notice prior to the final scheduling of these tests. Testing shall consist of:

- CT and CT circuit polarity, ratio, insulation, excitation, continuity and burden tests.
- VT and VT circuit polarity, ratio, insulation and continuity tests.
- Relay pick-up and time delay tests.
- Functional breaker trip tests from protective relays.
- Relay in-service test to check for proper phase rotation and magnitudes of applied currents and voltages.
- Breaker closing interlock tests.
- Other relay commissioning tests typically performed for the relay types involved.

B. The protective relays shall be tested and maintained by the LF on a periodic basis but not less than once every four years or as determined by NEP. The results of these tests shall be summarized by the LF and reported in writing to NEP.

For relays installed in accordance with the NPCC Criteria for the Protection of the Bulk Power System, maintenance intervals shall be in accordance with the NPCC Maintenance Criteria for Bulk Power System Protection. The status of conformance with the NPCC Maintenance Criteria for Bulk Power System Protection shall be reported in writing to NEP annually.

8.) CHANGES TO THE LF'S PROTECTION SYSTEM

The LF must provide NEP with reasonable advance notice of any proposed changes to be made to the protective relay system, relay settings, operating procedures or equipment that affect the interconnection.

NEP will determine if such proposed changes require re-acceptance of the interconnection per the requirements of this Policy and Practices.

In the future, should NEP implement changes to the system to which the LF is interconnected, the LF will be responsible at its own expense for identifying and incorporating any necessary changes to its protection system. Those changes to the LF's protection system are subject to review and approval by NEP.

ATTACHMENT F

Local Service Agreement

Insurance Requirements

During the term of this Agreement, the interconnecting Transmission Customer, at its own cost and expense, shall procure and maintain insurance in the forms and amounts acceptable to NEP at the following minimum levels of coverage:

1) Statutory coverage for workers' compensation, and Employer's Liability Coverage with a limit no less than $500,000.00 per accident;

2) Comprehensive General Liability Coverage including Operations, Contractual Liability and Broad Form Property Damage Liability written with limits no less than $5,000,000.00 combined single limit for Bodily Injury Liability and Property Damage Liability; and

3) Automobile Liability for Bodily Injury and Property Damage to cover all vehicles used in connection with the work with limits no less than $1,000,000.00 combined single limit for Bodily Injury and Property Damage Injury.

Prior to commencing the work, the interconnecting Transmission Customer shall have its insurer furnish to NEP certificates of insurance evidencing the insurance coverage required above and the interconnecting Transmission Customer shall notify and send copies to NEP of any policies maintained hereunder written on a "claims-made" basis. NEP may at its discretion require the interconnecting Transmission Customer to maintain tail coverage for five years on all policies written on a "claims-made" basis.

Every contract of insurance providing the coverages required in this provision shall contain the following or equivalent clause: "No reduction, cancellation or expiration of the policy shall be effective until thirty (30) days from the date written notice thereof is actually received by the interconnecting Transmission Customer. Upon receipt of any notice of reduction, cancellation or expiration, the interconnecting Transmission Customer shall immediately notify NEP.

NEP and its Affiliates shall be named as additional insureds, as their interests may appear, on the Comprehensive General Liability and Automobile Liability policies described above.

The interconnecting Transmission Customer shall waive all rights of recovery against NEP for any loss or damage covered by said policies. Evidence of this requirement shall be noted on all certificates of insurance provided to NEP.

ATTACHMENT H

Methodology for Completing System Impact Study

When New England Power Company ("NEP") determines on a non-discriminatory basis that a System Impact Study is needed because its Transmission System will be inadequate to accommodate a request for service, the following outlines the study methodology that NEP will employ to estimate the transmission system impact of a request for firm Transmission Service and/or any Costs for System Redispatch, Direct Assignment Facilities or Network Upgrades that would be incurred in order to provide the requested transmission service.

1. **System Impact** will be estimated based on consideration of reliability requirements to

- meet obligations under agreements that predate the OATT;
- meet obligations of existing and pending Valid Requests under the OATT; and
- maintain thermal, voltage and stability system performance within acceptable regional practices

2. **Guidelines and Principles followed by NEP -** NEP is a Participating Transmission Owner under the TOA and the Tariff and a member of the NPCC. When performing the System Impact Study, NEP will apply the following, as amended and/or adopted from time to time.

- Good Utility Practice;
- Criteria rules and reliability standards applicable to the New England Transmission System;
- NPCC criteria and guidelines; and
- New England Power Service Company (or its successor) guides

3. **Transmission System Model Representation -** The Transmission System Model will be based on a library of loadflow cases prepared by the ISO for studies of the New England area. The models may include representations of other NPCC and neighboring systems. These loadflow cases include individual system model representations provided by members of the ISO and represent forecasted system conditions for up to ten years in to the future. This library of loadflow cases is maintained and updated as appropriate by the ISO, and is consistent with information filed under FERC Form 715. NEP will use system models that it deems appropriate for study of the Request for Service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of loadflow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

4. System Conditions - Loading of all transmission system elements shall be less than normal ratings for precontingency conditions and less than long-term emergency (LTE) ratings for post-contingency conditions. Post-contingency loading above LTE rating and less than short-term emergency (STE) rating may be allowed where demonstrated that loading can be reduced below the LTE rating within 15 minutes.

Transmission system voltages shall be within the applicable design ratings of connected equipment for normal and emergency conditions. Normal and post-contingency voltages shall be in accordance with NEP and ISO standards.

5. Short Circuits - Transmission system short circuit currents shall be within the applicable equipment design ratings.

6. Study Analysis - System impact of the integration of new generators will be evaluated to meet the requirements of design, identified in the guidelines and principles under Item 2, to provide sufficient transmission capability to maintain stability and to maintain thermal and voltage levels of lines and equipment within applicable limits. The same applies to the evaluation of transmission and delivery service under this tariff.

7. Loss Evaluation - The impact of losses on the Transmission System will be taken into account in the System Impact Study to ensure Good Utility Practice in the design and operation of its system.

8. System Protection - Protection requirements will be evaluated by NEP.

9. Approvals - NEP will conduct the System Impact Study to ensure compliance with its planning and design policies and practices. However, the actions to be taken by the Parties to implement the recommendations of the System Impact Study are subject to approval under the ISO New England Operating Procedures or Section I.3.9 of the Tariff, as amended and/or adopted from time to time.

10. Study Scope and Reporting - The study will determine the impacts and identify changes required, if any, to NEP's existing Transmission System. NEP will provide the Eligible Customer with a written report of the physical interconnection alternative(s), required NEP system additions and/or modifications, if any, associated study grade cost estimates (+/-25%) and the results of the analysis.

ATTACHMENT I

Real Power Losses Factors

Voltage Class kV	Losses as a % of Energy Delivered
Stepdown transformer*	1.00
69	1.25**
34.5	1.98
23	2.61
15	4.18
5	4.34
Dist. Secondary	0.52

*The transformer that steps the voltage from the transmission level to the delivery level.

**The loss factor for the 69 kV level applies only when the Point of Delivery is not directly interconnected with the PTF.

Note: When multiple voltage levels are present between the Point of Delivery and the metering point, the loss factors are additive.

ATTACHMENT DAF

Direct Assignment Facilities

This Attachment applies to all transactions that utilize any Direct Assignment Facilities or any other charges specifically assigned to a customer by NEP under this Schedule or the OATT. The formula set forth in this Attachment, as it may be amended from time to time, represents the Direct Assignment Facilities Charge which a Transmission Customer or Network Customer (together, "Transmission Customer") will pay in addition to the other applicable charges specified herein.

The determination of the annual Direct Assignment Facilities Charges chargeable to a specific Transmission Customer or group of Transmission Customers shall be calculated by the Annual Facility Charge formulas set forth below for transmission and distribution facilities. In no event will the Annual Facilities Charge be less than $1,000 per calendar year.

TRANSMISSION

Determination of Annual Facilities Charges for Transmission Facilities
The basis for this charge is data of NEP. The Annual Facilities Charge for NEP and its New England Affiliates shall equal the product of the year-end Gross Plant Investment associated with the facility and the average Annual Transmission Carrying Charge, for the life of the facility.

The Gross Plant Investment will be the investment from the plant accounting records associated with the facility.

The average Annual Transmission Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of total transmission plant investment determined in accordance with Attachment RR, Section I. (A) (1) (a) to this Schedule.

To the extent that the Transmission Customer provides a Contribution in Aid of Construction the average Annual Transmission Carrying Charge calculation will be modified to exclude Sections I. (A) (1) (a), I. (A) (1) (d), I. (A) (1) (e), I. (A) (1) (f), I. (B), and I. (C) of Attachment RR to this Schedule.

If the Transmission Customer permanently terminates service prior to the normal expiration of its Service Agreement, the Transmission Customer may, at its option, close out its continuing obligation to pay the Annual Facilities Charge by paying NEP a lump sum payment equal to the net present value of the Return and Depreciation Expense on the net book value of the facility at the time of termination that would have been collected over the remaining life of the facility, plus any cost of removal if applicable. The return shall be equal to that found in Attachment RR, Section I. (A)(2) to this Schedule, in the year of termination. Depreciation Expense shall be based on a straight-line method. The discount rate in the net present value calculation shall be equal to the interest rate pursuant to Section 35.19(a) of the Commission's regulations effective at the time of termination.

Billings shall initially be based upon estimates calculated based on actual costs in the preceding year, such estimates being adjusted to actual as soon as practicable after such costs become known. The source of the data shall be NEP's accounting records.

DISTRIBUTION

Determination of the Annual Facilities Charge for Distribution Facilities

The basis for this charge is data of NEP's New England Affiliate(s) or any other Affiliate that shall assume ownership over the Facilities included under this attachment.

The Annual Facilities Charge shall equal the product of the year-end Gross Plant Investment associated with the facility and the average Annual Distribution Carrying Charge, for the life of the facility.

The Gross Plant Investment will be the investment from the plant accounting records associated with the facility.

The average Annual Distribution Carrying Charge shall be the Annual Distribution Revenue Requirement as determined in Attachment RR, Exhibit 1 to this Schedule, divided by the year-end balance of total distribution plant investment determined in accordance with Attachment RR, Exhibit 1, Section I. (A) (1) (a) to this Schedule.

To the extent that the Transmission Customer provides a Contribution in Aid of Construction the average Annual Distribution Carrying Charge calculation will be modified to exclude Sections I. (A) (1) (a), I. (A) (1) (d), I. (A) (1) (e), I. (A) (1) (f), I. (B), and I. (C) of Attachment RR, Exhibit 1 to this Schedule.

If the Transmission Customer permanently terminates service in advance of the term of its Service Agreement, the Transmission Customer may, at its option, close out its continuing obligation to pay the Annual Facilities Charge by paying NEP a lump sum payment equal to the net present value of the Return and Depreciation Expense on the net book value of the facility at the time of termination that would have been collected over the remaining life of the facility, plus any cost of removal if applicable. The return shall be equal to that found in Attachment RR, Exhibit 1, Section I.(A)(2) to this Schedule, in the year of termination. Depreciation Expense shall be based on a straight-line method. The discount rate in the net present value calculation shall be equal to the interest rate pursuant to Section 35.19(a) of the Commission's regulations effective at the time of termination.

Billings in accordance with this Schedule shall initially be based upon estimates calculated based on actual costs in the preceding year, such estimates being adjusted to actual as soon as practicable after such costs become known. The source of the data shall be NEP's or its applicable New England Affiliate's accounting records.

METERS

Determination of Annual Metering Charges

The Meter Maintenance Charge shall equal the product of NEP's installed metering costs for the customer and the Meter Carrying Charge determined in Attachment OCC, Exhibit 3 to this Schedule.

In accordance with the Meter Carrying Charge referenced above, the Annual Metering Charges will be updated on May 31 each year to reflect costs from the prior calendar year.

If the customer makes a CIAC, then the carrying charge in Attachment OCC, Exhibit 3 to this Schedule, will be adjusted accordingly.

ATTACHMENT DS

Rolled-In Distribution Surcharge

The monthly Rolled-in Distribution Surcharge shall be (i) the monthly cost per kilowatt of $2.77, multiplied by (ii) the annual peak load of the Transmission Customer on the distribution system of NEP's applicable New England Affiliate(s) from the prior calendar year. Notwithstanding the foregoing, this provision will not apply to the Transmission Customer's Network Load taking service under the Specific Distribution Surcharge.

ATTACHMENT OCC

Other Charges & Credits

The following charges and credits may apply to a Transmission Customer or Network Customer, as applicable:

I. Monthly Demand Charge:

Pursuant to Section 24.1 of this Schedule, the Network Customer will pay a monthly charge determined by multiplying its Load Ratio Share by the NEP's Monthly Local Network Transmission Expense as calculated in accordance with Exhibit 2 of this Attachment.

II. Monthly Non-PTF Demand Charge:

Pursuant to Section 24.2 of this Schedule, the Network Customer will pay a monthly charge determined by multiplying its Non-PTF Load Ratio Share by the Monthly Non-PTF Transmission Expense calculated in accordance with Attachment RR to this Schedule.

III. Transformer Surcharge:

Pursuant to Section 24.3 of this Schedule, the Transmission Customer or Network Customer will pay a monthly surcharge computed in accordance with Exhibit 1 of this Attachment.

This charge shall be multiplied by the Network Customer's Annual Peak Load, from the prior calendar year (coinciding with the calendar year used to calculate the Transformer Surcharge) in Exhibit 1 of this Attachment.

IV. Meter Surcharge:

The monthly meter surcharge shall be computed in accordance with Exhibit 3 of this Attachment multiplied by the number of NEP meters necessary to measure the delivery of transmission service to the Transmission Customer or Network Customer.

V. Power Factor Penalty:

Pursuant to Section 20.1 of this Schedule, a Network Customer or Transmission Customer will pay a Monthly Power Factor Penalty of $0.62 multiplied by the customer's deficient kilovars.

VI. Specific Distribution Surcharge:

The monthly Specific Distribution Surcharge shall be available to the following Network Customers

Georgetown Municipal Light Dept.
Ipswich Municipal Light Dept.
Princeton Electric Light Dept.
Hull Municipal Lighting Plant
Granite State Electric
Green Mountain Power Corp.
Groveland Municipal Light Dept.
Merrimac Municipal Light Dept.
Rowley Municipal Light Dept.

The monthly Specific Distribution Surcharge shall equal $.70 per KW month multiplied by the customer's Annual Peak Load from the prior calendar year.

VII. Network Load Dispatch Surcharge:

The monthly Network Load Dispatch Surcharge shall equal the monthly Dispatching Expense, Account 561, as defined in Attachment RR, Section I.G. to this Schedule, less any revenue received by NEP from the ISO for load dispatching services, multiplied by the Network Customer's Load Ratio Share.

VIII. [Reserved]

IX. Network EPRI Credit:

The Network EPRI Credit shall be determined by multiplying the Monthly Transmission-Related EPRI Expenses by the customer's Non-PTF Network Load Ratio Share.

The Monthly Transmission-Related EPRI Expenses shall equal themonthly EPRI Expenses as recorded in Account 930.

X. [Reserved]

XI. Pre-1997 RNS Revenue Credit:

The Pre-1997 RNS Revenue Credit will apply in the subsequent month's billing for the period June 1, 2001 through March 1, 2008, unless the transitional arrangements for the period prior to March 1, 2008 are otherwise amended.

ATTACHMENT OCC
EXHIBIT 1

Transformer Surcharge

I. No later than May 31 of each calendar year, the Transformer Surcharge will be calculated based on the prior calendar year's annual costs. The annual costs for Transformation Facilities service shall be the year-end balance of transmission plant investment in transformers included in Attachment RR, Section I. (A)(1)(a) to this Schedule multiplied by the Average Annual Carrying Charge.

II. The Average Annual Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of total transmission plant investment included in Attachment RR, Section I. (A)(1)(a) to this Schedule.

III. To determine the monthly Transformer Surcharge rate, the annual costs for transformation service will be divided by the Annual Peak Loads of that portion of all Transmission Customers' or Network Customers' load receiving such transformation service under this Schedule, and further divided by 12.

ATTACHMENT OCC
EXHIBIT 2

Monthly Local Network Transmission Expense

I. The Monthly Local Network Transmission Expense shall be the monthly balance of PTF Transmission Plant investment included in Attachment RR, Section I. (A)(1)(a) to this Schedule multiplied by the Monthly Carrying Charge, less any revenue received from the ISO associated with transmission-related services provided under the OATT.

II. The Monthly Carrying Charge shall be the Monthly Transmission Revenue Requirement as determined in accordance with Attachment RR to this Schedule, excluding any revenue credits associated with Transmission-related revenues from the ISO and revenues under Section 24.1 of this Schedule and as specified in Attachment RR, Section I.(G) and (J) to this Schedule, divided by the monthly balance of Transmission Plant determined in accordance with Attachment RR, Section I.(A)(1)(a) to this Schedule.

ATTACHMENT OCC

EXHIBIT 3

Meter Surcharge

I. No later than May 31 of each calendar year, the Meter Surcharge will be calculated based on the prior calendar year's annual costs. The annual costs for metering service shall be the year-end balance of plant investment in meters included in Attachment RR, Section I. (A) (1) (a) to this Schedule multiplied by the Average Annual Carrying Charge.

II. The Average Annual Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of transmission plant investment included in Attachment RR, Section I.(A) (1) (a) to this Schedule.

III. To determine the monthly Meter Surcharge rate, the annual costs for meter service will be divided by the number of NEP-Owned Billing Meters and further divided by twelve. The number of NEP-Owned billing meters shall equal the total number of meters owned by NEP and used for billing purposes under NEP's tariffs for wholesale all requirements and firm and non-firm transmission services.

ATTACHMENT OCC

EXHIBIT 4

Pre-1997 RNS Revenue Credit

The respective Pre-1997 RNS Revenue Credit to Taunton Municipal Lighting Plant, Middleborough Gas and Electric Department and Pascoag Fire District will be equal to

$$\left[1- \frac{\text{EUA RNS Rate}}{\text{Combined RNS Rate}}\right] * \text{[customer's payment for RNS]}$$

Where:

EUA RNS Rate is former Montaup's 1999 Pre-1997 RNS rate as calculated under the NEPOOL Tariff.

Combined RNS Rate is equal to:

$(A*B) + (C*D) / (B+D)$

Where:

A = EUA's 1999 Pre-1997 RNS Rate as calculated under the NEPOOL Tariff.

B = EUA's 1999 12 CP Network Load (MW) as calculated under the NEPOOL Tariff.

C = NEP's 1999 Pre-1997 RNS Rate as calculated under the NEPOOL Tariff.

D = NEP's 1999 12 CP Network Load (MW) as calculated under the NEPOOL Tariff.

ATTACHMENT RR

Transmission Revenue Requirements

The Transmission Revenue Requirement will be determined based on the calculation shown below. In determining the rate for Local Network Service, the Revenue Requirement calculation as set forth below will be determined on a monthly basis.

I. The Transmission Revenue Requirement shall equal the sum of NEP's (A) Return and Associated Income Taxes, (B) Transmission Depreciation Expense, (C) Transmission-Related Amortization of Loss on Reacquired Debt, (D) Transmission-Related Amortization of Investment Tax Credits, (E) Transmission-Related Amortization of FAS 109, (F) Transmission-Related Municipal Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission-Related Administrative and General Expense, (I) Transmission-Related Integrated Facilities Credit, (J) Transmission Revenue Credit, (K) Distribution-Related Integrated Facilities Credit, and plus (L) Billing Adjustments; plus (M) Reactive Power Expense; plus (N) Bad Debt Expense.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be (a) Transmission Plant, plus (b) Transmission-Related General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) Transmission-Related Construction Work in Progress, less (e) Transmission-Related Depreciation Reserve, less (f) Transmission-Related Accumulated Deferred Taxes, plus (g) Transmission-Related Loss on Reacquired Debt, plus (h) Other Regulatory Assets, less (i) Allowance for Funds Used During Construction (AFUDC) Regulatory Liability, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission-Related Cash Working Capital.

(a) Transmission Plant will equal the balance of NEP's Total Investment in Transmission Plant, plus NEP's Total Investment in Distribution Plant excluding NEP's capital leases in the Hydro-Quebec DC facilities (HQ leases). NEP's investment in PTF transmission plant and step-down transformers beyond NEP's Point of Delivery, including associated equipment, shall be included but stated separately. NEP's investment in wholesale metering, including associated equipment, shall also be included but stated separately.

(b) **Transmission-Related General Plant** shall equal NEP's balance of investment in General Plant excluding General Plant related to NEP's generation facilities as specifically identified in NEP's CTC.

(c) **Transmission Plant Held for Future Use** shall equal the balance of investment in FERC Account 105.

(d) **Transmission-Related Construction Work In Progress** shall equal the portion of NEP's investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.

(e) **Transmission-Related Depreciation Reserve** shall equal the balance of Total Depreciation Reserve, excluding any generation-related depreciation reserve associated with assets identified in NEP's CTC.

(f) **Transmission-Related Accumulated Deferred Taxes** shall equal NEP's balance of Total Accumulated Deferred Income Taxes, excluding any Accumulated Deferred Taxes associated with non-utility assets or generation facilities as identified in the CTC.

(g) **Transmission-Related Loss on Reacquired Debt** shall equal NEP's balance of Total Loss on Reacquired Debt excluding losses associated with NEP Generation as specifically identified in the CTC, or any generation-related losses associated with pollution control bonds.

(h) **Other Regulatory Assets** shall equal NEP's balance of FAS 109 excluding FAS 109 balances associated with NEP Generation as specifically identified in the CTC.

(i) **AFUDC Regulatory Liability** shall equal the unamortized balance of the capitalized AFUDC booked on NEP's Transmission-related projects as recorded in FERC Account 254 consistent with Commission orders.

(j) **Transmission Prepayments** shall equal NEP's balance of prepayments excluding any prepayments related to NEP's ongoing generation-related activities.

(k) Transmission Materials and Supplies shall equal NEP's balance of Transmission-related Materials and Supplies.

(l) Transmission-Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense and Transmission-Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) NEP's Weighted Cost of Capital, plus (b) the Yankee Adjustments plus (c) Federal Income Tax plus (d) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each month and will equal the sum of:

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of NEP's long-term debt excluding any debt associated with pollution control bonds then outstanding and the ratio that long-term debt is to NEP's total capital less the end-of-year investment in Yankee Units.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of NEP's preferred stock then outstanding and the ratio that preferred stock is to NEP's total capital less the end-of-year investment in Yankee Units.

(iii) the return on equity component (ROE), which equals the product of the allowed based ROE of 11.14% and the ratio that common equity is to NEP's total capital less the end-of-year investment in Yankee Units.

For purposes of implementing the exclusion of the FERC-approved adders from Section J. below, the following ROEs will be applied to the corresponding investment:

post-2003 to pre-2009 PTF transmission plant investment in Regional System Plan approved by ISO-NE	12.64%

remaining PTF transmission plant investment	11.64%
remaining transmission plant investment	11.14%

plus any ROE incentive approved by the FERC under Order No. 679 for other plant investments.[11]

(b) **The Yankee Adjustment** shall be calculated in accordance with FERC Opinion Nos. 49 and 49(a) issued in NEP's R-10 rate case and FERC Opinion No. 158 issued in NEP's W-3 rate case.

(c) **Federal Income Tax** shall equal

$$\frac{A \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Section (I)(A)(2)(a)(ii), and Section (I)(A)(2)(a)(iii) above.

(d) **State Income Tax** shall equal

$$\frac{(A + \text{Federal Income Tax}) \times ST}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and Federal Income Tax is the rate determined in Section (I)(A)(2)(c) above.

B. **Transmission Depreciation Expense** shall equal the Depreciation Expense associated with the Transmission Plant, Transmission-Related General Plant and Transmission Plant Held for Future Use as described in Sections I.A.(a)(1), (b) and (c), less the amortization of AFUDC regulatory credit as recorded in FERC Account 407.4.

C. **Transmission-Related Amortization of Loss on Reacquired Debt** shall equal NEP's Amortization of the balance on Loss on Reacquired Debt as defined in Section I.A.(1)(f).

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11 FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679

D. Transmission-Related Amortization of Investment Tax Credits shall equal NEP's Amortization of Investment Tax Credits, excluding any ITC credits specifically identified as generation-related in NEP's CTC.

E. Transmission-Related Amortization of FAS 109 shall equal the Amortization of NEP's Balance of FAS 109, as identified in Section I.A.(1)(q) over a ten-year period beginning on the Divestiture Date of NEP's Generating Assets as defined in the CTC.

F. Transmission-Related Municipal Tax Expense shall equal NEP's total municipal tax expense excluding specifically identified generation-related municipal taxes or payments in lieu of such generation-related municipal taxes.

G. Transmission Operation and Maintenance Expense shall equal all expenses charged to FERC Account Numbers 560 through 598. Account Number 565, Transmission by Others, shall only include those expenses in support of facilities that are integrated with NEP's Transmission System or other transmission systems. Transmission Operation and Maintenance Expense shall include any expenses associated with transmission-related administrative services provided by the ISO and the expenses associated with providing Transmission Customers with the Pre-1997 Revenue Credit as described in Attachment OCC to this Schedule.

H. Transmission-Related Administrative and General Expenses shall equal NEP's Administrative and General Expenses, less Production-related Administrative and General Expense associated with joint-owned production units, plus Payroll Taxes,

I. Transmission-Related Integrated Facilities Credit shall equal NEP's transmission payments to its New England Affiliates for use of the integrated transmission facilities of those New England Affiliates.

J. Transmission Revenue Credit shall equal NEP's total transmission revenue, FERC Account Number 456, transmission-related sub-accounts of 447, and those revenues received from the ISO associated with the provision of transmission services under the OATT excluding the revenue received under the terms set forth in Section 24.2 of this Schedule, excluding any revenue received for the Hydro-Quebec DC facilities, excluding any revenue directly credited to Network Customers under Section 24.11 of this Schedule, excluding distribution revenues associated with expenses that have been excluded from NEP's Transmission Revenue Requirement, and excluding any incremental revenues associated with

FERC-approved adders for RTO participation and new transmission investment. To the extent that NEP's transmission-related revenue under FERC Electric Tariff No. 1 is not reflected in the above-reference accounts on or after July 9, 1996, such revenue will be imputed under the formula set forth in the OATT and included in the Transmission Revenue Credit in accordance with the above specifications. Any Transmission Revenue Credit related to Section 24.1 of this Schedule shall be stated separately. Any revenue from the ISO associated with the provision of transmission service under the OATT, shall also be included but stated separately.

K. Distribution-Related Integrated Facilities Credit shall be equal to the credit applied to the purchased power bill of Massachusetts Electric Company under NEP's Tariff No. 1 for use of its distribution facilities used in support of wholesale transactions.

L. Billing Adjustments shall be plus or minus any billing adjustments from the prior transmission billing periods, including ISO adjustments. Billing adjustments shall include, but not be limited to, adjustments due to metering errors, corrections to any value included in this Attachment RR, or the Load Ratio Share. Such adjustments may be corrected prospectively. However, if the error is substantial, or substantially affects an individual Network or Transmission Customer, NEP reserves the right to credit and rebill customers for each affected billing month in which the error occurred.

M. Reactive Power Expense shall be set at zero as of the Second Effective Date, as defined in the NEPOOL Agreement.

N. Bad Debt Expense shall be the bad debt expense as reported in Account 904 related to transmission billing.

O. Miscellaneous Provisions In the event that the FERC accounts listed above are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts.

EXHIBIT 1

Distribution Cost of Service

Pursuant to Attachment DAF to this Schedule, the Distribution Cost of Service shall be calculated as follows for the applicable New England Affiliate:

I. The Primary Distribution System Cost of Service shall equal the sum of (A) Return and Associated Income Taxes, (B) Primary Depreciation Expense, (C) Primary Related Amortization of Loss on Reacquired Debt, (D) Primary Related Amortization of Investment Tax Credits, (E) Primary Related Municipal Tax Expense, (F) Primary Operation and Maintenance Expense, (G) Primary Related Administrative and General Expense, and (H) Primary Revenue Credit.

A. Return and Associated Income Taxes shall equal the product of the Primary Investment Base and the Cost of Capital Rate.

(1) Primary Investment Base will be (a) Total Primary Distribution Plant, plus (b) Primary Related General Plant, plus (c) Primary Plant Held for Future Use, less (d) Primary Depreciation Reserve, less (e) Primary Related Accumulated Deferred Income Taxes, plus (f) Primary Related Loss on Reacquired Debt, plus (g) Other Regulatory Assets, plus (h) Primary Materials and Supplies, plus (i) Primary Related Prepayments, plus (j) Primary Related Cash Working Capital.

(a) Total Primary Distribution Plant shall equal the New England Affiliate's Plant Accounts 360 to 373 multiplied by allocation factors from the Distribution Engineering Study.

(b) Primary Related General Plant shall equal the New England Affiliate's Investment in General Plant, multiplied by the Primary Wages & Salaries Allocation Factor. The Primary Wages & Salaries Allocation Factor shall equal the ratio of Total Distribution Wages & Salaries to the Total New England Affiliate's Wages & Salaries excluding A&G, multiplied by the ratio of Primary Distribution related O&M to Total Distribution O&M (Primary O&M Allocation Factor).

(c) Primary Plant Held for Future Use shall equal the New England Affiliate's Account 105, multiplied by the Primary Land Allocation Factor from the Distribution Engineering Study.

(d) **Primary Depreciation Reserve** shall equal the New England Affiliate's Depreciation Reserve multiplied by the ratio of Primary Depreciable Distribution Plant to Total Depreciable Distribution Plant (Primary Depreciable Plant Allocation Factor), plus an allocation of average General Plant Depreciation Reserve calculated by multiplying beginning and end of year General Plant Depreciation Reserve by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

(e) **Primary Related Accumulated Deferred Income Taxes** shall equal the Total Accumulated Deferred Income Taxes, multiplied by the ratio of average Primary Plant in Service to average Total Plant in Service excluding General Plant (Primary Plant Allocation Factor).

(f) **Primary Related Loss on Reacquired Debt** shall equal the Total Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

(g) **Other Regulatory Assets** shall equal the New England Affiliate's balance of FAS 106, multiplied by the Primary Wages and Salaries Allocator described in Section (I)(A)(1)(b), plus the New England Affiliate's balance of FAS 109, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(c) above.

(h) **Primary Materials and Supplies** shall equal the New England Affiliate's Distribution Plant Materials and Supplies, multiplied by the Primary O&M Allocation Factor as described in Section (I)(A)(1)(b) above.

(i) **Primary Related Prepayments** shall equal the New England Affiliate's Prepayments, multiplied by the Primary Wages and Salaries Allocator described in Section (I)(A)(1)(b) above.

(j) **Primary Related Cash Working Capital** shall be a 45 day allowance or 12.5% of Primary Operation and Maintenance Expense and Primary Related Administrative and General Expense.

(2) **Cost of Capital Rate** will equal (a) the New England Affiliate's Weighted Cost of Capital, plus (b) Federal Income Tax, plus (c) State Income Tax.

(a) **The Weighted Cost of Capital** will be calculated based upon the capital structure at the end of each year and will equal the sum of:

i) **the long-term debt component**, which equals the product of the actual dollar weighted average embedded cost to maturity of the New England Affiliate's long-term debt then outstanding and the ratio that long-term debt is to the New England Affiliate's total capital.

ii) **the preferred stock component**, which equals the product of the actual weighted average embedded cost to maturity of the New England Affiliate's preferred stock then outstanding and the ratio that preferred stock is to the New England Affiliate's total capital.

iii) **the return on equity component**, which equals the product of 11.14% and the ratio that common equity is to the New England Affiliate's total capital.

(b) **Federal Income Tax** shall equal

$$\frac{A \times FT}{1 - FT}$$

where FT is the Federal Income Tax Rate and A the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above.

(c) **State Income Tax** shall equal

$$\frac{(A + \text{Federal Income Tax}) \times ST}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and Federal Income Tax is Federal Income Tax as determined in Section (I)(A)(2)(b) above.

B. **Primary Depreciation Expense** shall equal Depreciation Expense for Distribution Plant, multiplied by the Primary Depreciable Plant Allocation Factor as described in Section (I)(A)(1)(d) above, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant

Depreciation Expense by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

C. Primary Related Amortization of Loss on Reacquired Debt shall equal the New England Affiliate's Amortization of Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

D. Primary Related Amortization of Investment Tax Credits shall equal the New England Affiliate's Amortization of Investment Tax Credits, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

E. Primary Related Municipal Tax Expense shall equal a pro-rata share of the New England Affiliate's total municipal taxes allocated by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

F. Primary Operation and Maintenance Expense shall the sum of all expenses charged to FERC Account Numbers 580 through 598, allocated to Primary as indicated by the Distribution Engineering Study.

G. Primary Related Administrative and General Expenses shall equal the New England Affiliate's Administrative and General Expenses, plus Payroll Taxes, multiplied by the Primary Wages & Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

ATTACHMENT L

Creditworthiness Policy

1. Introduction & Applicability

This policy establishes creditworthiness standards for transmission service and/or interconnection service customers ("Customers") entering into new, amended or assigned service agreements with NEP under the ISO-NE OATT. The following describes NEP's qualitative and quantitative credit review procedures and the types of security that are acceptable to NEP to protect against the risk of default.

2. Information Requirements

For purposes of determining the ability of a Customer to meet its obligations, NEP may require the Customer to submit financial information for the credit review, including credit ratings, credit reports and audited financial statements. In addition, the following factors may be considered in evaluation of the Customer's creditworthiness: applicant's history; nature of organization and operating environment; management; contractual obligations; governance, financial / accounting policies, risk management and credit policies; market risk including price exposures, credit exposures, and operational exposures; and event risk. All information required under this Attachment should be forwarded to the NEP account manager as specified on the NEP OASIS website.

3. Creditworthiness Evaluation

NEP will evaluate the creditworthiness of Customers entering into new or amended transmission or interconnection service agreements with NEP in order to assess a Customer's credit risk relative to the exposure or "Total Outstanding Obligation" as defined in Section 3.1 below, created by the transaction or transactions that NEP has with the Customer.

3.1 Total Outstanding Obligation

The Customer's Total Outstanding Obligation to NEP will be the sum total of the following components:

3.1.1 If the Customer is making payments to NEP for ongoing expenses (including, but not limited to, O&M expenses related to interconnections or other monthly charges such as monthly transmission charges under Schedule 21-NEP of the ISO-NE OATT) the Customer will be required to provide security pursuant to Section 3.2 below, for four months' worth of the Customer's average payment obligation for such charges

3.1.2 Whenever, in accordance with the provisions of the ISO-NE OATT, a Customer pays a Contribution in Aid of Construction ("CIAC") or transfers ownership of facilities to NEP for transmission or interconnection facilities that are to be constructed on behalf of a Customer at the Customer's sole expense, and NEP determines in good faith that the receipt of CIAC payments or property from the Customer are non-taxable, NEP will require a form of security from the Customer pursuant to Section 3.2 below for the amount of the potential tax liability to NEP that would occur if such facilities were deemed taxable.

3.1.3 Whenever, in accordance with the provisions of the ISO-NE OATT, a Customer pays a formula rate over time for return of and on the cost of capital incurred by NEP on behalf of a Customer at the Customer's sole expense, the Customer will be required to provide security pursuant to Section 3.2 below, for the unamortized balance of plant in service reserved for the sole use of the Customer.

3.2 Creditworthiness Requirements

A Customer will be considered creditworthy upon satisfying at least one of the following conditions, or a combination of those conditions, at the time that the Customer enters into a transmission or interconnection service agreement and for so long as the Customer maintains satisfaction of at least one of these conditions for any outstanding obligations thereunder:

3.2.1 The Customer maintains a minimum credit rating of BBB from Standard & Poor's Long-term Issuer Credit Rating or Baa2 from Moody's Investors Service Long-term Issuer Credit Rating, so long as the Customer's Total Outstanding Obligation plus any other unsecured obligation with NEP and its Affiliates does not exceed the Credit Limits discussed in Section 5 below.[12] If unrated, the Customer's financial statements will be reviewed to determine an equivalent rating based on the Customer's unsecured credit limits and/or financial statements.

3.2.2 The Customer provides and maintains in effect during the term of and until full and final payment and performance of the service agreement an unconditional and irrevocable Letter of Credit for the Total Outstanding Obligation in the form and substance and issued by a bank acceptable to NEP. A draft, acceptable form letter of credit is posted on OASIS. Any such bank must satisfy the creditworthiness criteria described in 3.2.1 above.

3.2.3 The Customer's parent or an Affiliate company satisfies the creditworthiness criteria described in 3.2.1 above and, subject to the Credit Limits stated in Section 4 below, such company submits to NEP and maintains in effect a Letter of Guaranty acceptable to NEP as to amount, form and substance for the term of and until full and final payment and performance of the service agreement.

3.2.4 The Customer is a municipal that is a member of the Massachusetts Municipal Wholesale Electric Cooperative (MMWEC). In such instances, MMWEC must meet the criteria set out in 3.2.1 or 3.2.2 above and provide to NEP a Letter of Guaranty that MMWEC will be unconditionally responsible for all financial obligations associated with the Customer's receipt of transmission or interconnection service from NEP.

3.2.5 The Customer makes an advance payment to NEP in immediately available funds for the Total Outstanding Obligation.

If, at any time, the credit rating of the Customer, Customer's bank, or Customer's parent or Affiliate providing the Guaranty as set out in 3.2.1, 3.2.2 or 3.2.3 above falls below investment grade (BBB- from Standard and Poor's and or Baa3 from Moody's), the Customer will be required to provide (i) notification to NEP within 10 days and, (ii) another form of security acceptable to NEP, as described in this Section 3.2, within 30 days.

4. Customer Costs Requiring Prepayment

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[12] When NEP reviews a Customer's rating from two or more rating agencies and a split rating is present, the lower debt rating will apply. In the event that the Customer only has a rating from either Standard & Poor's or Moody's Investors Service, a rating from Duff & Phelps or Fitch and Weiss may also be used with acceptable ratings equivalent to those from either Standard and Poor's or Moody's Investors Service.

Whenever, in accordance with the provisions of the ISO-NE OATT, a Customer pays a CIAC for transmission or interconnection facilities to be constructed by NEP on behalf of a Customer at the Customer's sole expense, the Customer will have the option to (i) prepay the CIAC in immediately available funds to NEP, or (ii) make periodic CIAC progress payments, as defined in the Customer's service agreement, to prepay in increments capital costs scheduled to be incurred by NEP. If NEP determines in good faith that such payments or property transfers made by the Customer should be reported as income subject to taxation, the Customer shall also prepay all costs associated with the cost consequences of the current tax liability imposed on NEP by those facilities (the "Tax Gross- up").

5. Credit Limits

NEP reserves the right to limit the total amount of unsecured credit extended to a Customer under 3.2.1 and 3.2.3 above such that the sum of all unsecured credit that such Customer has with NEP and its Affiliates, including the Total Outstanding Obligation, shall not exceed the Credit Limits defined below. Such limitations are based on an assessment of the Customer's or its Guarantor's credit rating and the net worth of the Customer's or its Guarantor's assets.

Standard and Poor's (or Equivalent) Rating	Unsecured Credit Limit as Percent of Customer's or Guarantor's Tangible Net Worth
A and above	1.0%
A-	0.5%
BBB+	0.2%
BBB	0.1%
BBB-	0.0%

6. Contesting Creditworthiness Determinations

A Customer may contest NEP's determination of creditworthiness by submitting a written request to NEP for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate the Customer's creditworthiness. NEP will review and respond to the request within 20 calendar days.

7. Process for Changing Credit Requirements

In the event that NEP plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, NEP shall submit such changes in a filing to the Federal Energy Regulatory Commission ("Commission") under Section 205 of the Federal Power Act. NEP shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

7.1 General Notification Process

7.1.1 NEP shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing. Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Policy. NEP shall consult with interested stakeholders upon request.

7.1.2 Following Commission acceptance of such filing and upon the effective date, NEP shall revise its Attachment L Creditworthiness Policy and an updated version of Schedule 21-NEP shall be posted on the ISO-NE website.

7.2 Customer Responsibility

7.2.1 Upon the effective date of any revision to these creditworthiness requirements or upon the date of the Commission's order accepting such revisions, whichever is later, the Customer shall have 30 days to forward updated financial information to NEP and indicate whether the revised creditworthiness requirements impair the Customer's ability to comply with the revised requirements. In such cases, the Customer must take all reasonable steps to comply with the revised requirements of the Creditworthiness Policy within 45 days of the effective date of the change.

7.3 Notification for Active Customers

7.3.1 Active Customers are defined as any current Customer that has a Service Agreement currently in effect and has posted an irrevocable letter of credit, letter of guaranty or prepayment in accordance with Sections 3.2.2, 3.2.3, 3.2.4, or 3.2.5, above.

7.3.2 All Active Customers will be served with copies of any filing submitted to the Commission to modify the NEP's creditworthiness requirements.

8. Suspension of Service

NEP may, immediately suspend service (with notification to Commission) to a customer, and may initiate proceedings with Commission to terminate service, if the customer does not meet the terms described in this Attachment. A customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

ATTACHMENT S-1

Local Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area over Non-PTF. The Transmission Customer or Network Customer must purchase this service from NEP. The charges for Scheduling, System Control and Dispatch Service shall be based on the Local Network Load Dispatch Surcharge set forth in Attachment OCC to this Schedule. To the extent the ISO performs this service for NEP, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to NEP by the ISO.

SCHEDULE 21-NHT

Local Service Schedule

New Hampshire Transmission, LLC

I. COMMON SERVICE PROVISIONS

This Local Service Schedule, designated Schedule 21-NHT, governs the terms and conditions of service taken by Transmission Customers over the Local Network Transmission System who are not otherwise served under transmission service agreements with NHT that are still in effect. In the event of a conflict between the provisions of this Schedule 21-NHT and other provisions of the Tariff the provisions of this Schedule 21-NHT shall control.

1. Definitions

Whenever used in this Schedule 21-NHT, in either the singular or plural number, the following capitalized terms shall have the meanings specified in the Definition Sections of this Part I. Terms used in this Schedule 21-NHT but not defined in this Definition Section shall have the meanings specified in Section 1 of the Tariff. Terms used in this Schedule 21-NHT but not defined in this Definition Section shall have the meanings customarily attributed to such terms by the electric utility industry in New England. Sections or Attachments referred to in this Schedule 21-NHT shall mean a section in or attachment to this Schedule 21-NHT unless otherwise stated.

1.1 Annual Transmission Revenue Requirements (“ATRR”):

The annual revenue requirements of NHT’s Local Network Transmission System for purposes of this Schedule 21-NHT shall be the amount calculated pursuant to the formula in Attachment G to this Schedule 21-NHT as updated each June 1, or until amended by NHT or modified by the Commission.

1.2 Backyard Generation (or Behind-the-Meter Generation):

Generation which interconnects directly with a customer’s facilities that will offset all or a portion of a customer’s electric load requirements. Any generation used to supply any portion of Local Network Load will not qualify for demand credits associated with Backyard Generation. Such credits shall only be applicable to load not designated as Local Network Load. In such instances, the customer shall be responsible for taking and paying for an appropriate level of Local Point-To-Point Transmission Service pursuant to this Schedule 21-NHT.

1.3 Control Area Operator:

ISO, or any successor organization or entity, that is responsible for the continued operation of the New England Control Area and the administration of the Tariff, subject to regulation by the

Commission.

1.4 Designated Agent:

Any entity that performs actions or functions required under this Schedule 21-NHT or the Tariff on behalf of NHT, an Eligible Customer, or a Transmission Customer.

1.5 Direct Assignment Facilities:

Facilities or portions of facilities that are constructed by or for NHT for (1) the sole use/benefit of a particular Transmission Customer requesting service under this Schedule 21-NHT or (2) the use by an owner or developer of a generating station requesting to be interconnected to the Local Network Transmission System. Direct Assignment Facilities shall be specified in the Service Agreement or interconnection agreement that in addition to the applicable terms and conditions of this Schedule 21-NHT or the OATT governs service to the Transmission Customer; and shall be subject to Commission acceptance.

1.6 NHT

New Hampshire Transmission, LLC.

1.7 NHT-Owned Interconnection Facilities:

Facilities and equipment, or portions thereof, owned by NHT that are necessary to interconnect a customer with the Local Network Transmission System.

1.8 Generator or Generator Owner:

The owner, in whole or in part, of a generating unit whether located within or outside the New England Control Area.

1.9 Interconnection Agreement:

An agreement between NHT and an Eligible Customer for Interconnection Service.

1.10 Interconnection Service:

Those services required to electrically connect Transmission Customer's or Generator Owner's facilities to the Local Network Transmission System. Interconnection Service includes, but is not limited to, the identification, design, and construction of facilities required to establish and maintain such electrical connection as identified by a completed System Impact Study and

Facilities Study. The customer's and NHT's contractual obligations associated with Interconnection Service shall be specified in an Interconnection Agreement which shall be executed and filed with the Commission prior to the commencement of such service.

1.11 LNS Service:

The service provided by NHT over its Local Network pursuant to this Schedule 21-NHT.

1.12 Load Ratio Share:

Ratio of a Transmission Customer's Local Network Load to NHT's total Local Network Load computed in accordance with Sections 22.2 and 22.3 of the Local Network Service under Part III of this Schedule 21-NHT.

1.13 Local Network (Local Network Transmission System):

The transmission facilities owned or operated by NHT within the New England Control Area that are used to provide transmission service.

1.14 Local Network Load:

The load that a Local Network Customer designates for Local Network Transmission Service under Part III of this Schedule 21-NHT. The Local Network Customer's Local Network Load shall include all load served by the output of any Network Resources designated by the Local Network Customer (including losses) and shall not be credited or reduced for any Backyard Generation. All Local Network Customers shall be required to have installed appropriate metering to determine such Backyard Generation, in accordance with the Network Operating Agreement. A Local Network Customer may elect to designate less than its total load as Local Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Local Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of this Schedule 21-NHT for any Local Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.15 Network Operating Agreement:

An executed agreement that contains the terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Part III of this Schedule 21-NHT.

1.16 Part I:

The sections of this Schedule 21-NHT containing the definitions and common service provisions.

1.17 Part II:

The sections of this Schedule 21-NHT pertaining to Local Point-To-Point Transmission Service in conjunction with the applicable common service provisions of Part I and appropriate Schedules and Attachments.

1.18 Part III:

The sections of this Schedule 21-NHT pertaining to Local Network Transmission Service in conjunction with the applicable common service provisions of Part I and appropriate Schedules and Attachments.

1.19 Parties:

NHT and the Transmission Customer receiving service under this Tariff.

1.20 Transmission Service:

Transmission service provided over NHT's Local Network, designated as Local Network Service or Local Point-To-Point Service that is provided pursuant to this Schedule 21-NHT.

2. Purpose of This Schedule 21-NHT

This Schedule 21-NHT is only applicable for service over NHT's transmission facilities located within the New England Control Area. It is intended to provide Transmission Service as a complement to the regional service to be provided under the OATT and is designed to ensure cost recovery by NHT of its ATRR as determined in accordance with the formula specified in Attachment G hereto.

The OATT contemplates a two-tier transmission arrangement integrating regional service which is provided under Part B of the OATT, and LNS Service, including Local Network Service and Local Point-To-Point Transmission Service, including, without limitation, service over NHT-Owned Interconnection Facilities as provided under this Schedule 21-NHT.

3. RESERVED

4. Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within the New England Control Area.

4.1 Ancillary Services supporting transmission service over the Local Network Transmission System:

Ancillary Services to support transmission service over the Local Network Transmission System will be provided pursuant to the OATT.

5. Billing and Payment

5.1 Billing Procedure:

Within a reasonable time after the first day of each month, NHT shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Schedule 21-NHT during the preceding month. In accordance with the formula rate contained in Attachment G of this Schedule 21-NHT, such monthly invoices for transmission service shall reflect an estimate of the monthly revenues NHT expects to receive associated with NHT's share of regional transmission service revenues collected pursuant to the OATT, with such estimated monthly amounts being reconciled with interest pursuant to Section 35.19(a) of the Commission's Regulations to actual monthly revenues received in subsequent billing months when such actual amounts are known by NHT. The invoice shall be paid by the Transmission Customer within ten (10) days of receipt. All payments shall be made, in accordance with the procedure specified by NHT in immediately available funds payable to NHT, or by wire transfer to a bank named by NHT.

5.2 Interest on Unpaid Balances:

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in 18 C.F.R. § 35.19a(a)(2)(iii) of the Commission's regulations. Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by NHT.

5.3 Customer Default:

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to NHT on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after NHT notifies the Transmission Customer to cure such failure, or if the Transmission Customer violates any provision of its Service Agreement, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, NHT may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between NHT and the Transmission Customer, NHT will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then NHT may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with applicable Commission rules and regulations, and may proceed with such suspension.

6.0 Accounting for the PTO's Use of this Schedule-21-NHT.

NHT will record the following amounts, as outlined below.

6.1 Transmission Revenues:

Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Part II of this Schedule 21-NHT.

6.2 Study Costs and Revenues:

Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the PTO conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including Third-Party Sales, if any, under this Schedule 21-NHT or at the direction of the Control Area Operator; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in a Transmission Customer's billing under this Schedule 21 or at the direction of the Control Area Operator.

7. Regulatory Filings

7.1 Rights Under The Federal Power Act

Nothing contained in this Schedule 21-NHT or any Service Agreement shall be construed as affecting in any way the right of NHT unilaterally to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation.

Nothing contained in this Schedule 21-NHT or any Service Agreement shall be construed as affecting in any way the ability of a Transmission Customer receiving service under this Schedule 21-NHT or for an Excepted Transaction to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

8. Force Majeure and Indemnification

8.1 Force Majeure:

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, any order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither NHT nor the Transmission Customer will be considered in default as to any obligation under this Schedule 21-NHT if prevented from fulfilling the obligation due to an event of Force Majeure; provided that no event of Force Majeure shall excuse any payment obligation hereunder or under a Service Agreement. However, a Party whose performance under this Schedule 21-NHT is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Schedule 21-NHT, and shall promptly notify NHT or the Transmission Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure.

8.2 Indemnification:

The Transmission Customer shall at all times indemnify, defend, and save the Transmission Owner harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Owner's performance of its obligations under this Schedule 21-NHT on behalf of the Transmission Customer, except in cases of gross negligence or intentional wrongdoing by the Transmission Owner.

9. Creditworthiness

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, NHT may require reasonable credit review procedures in accordance with Attachment L of this Schedule 21- NHT. This review shall be made in accordance with standard commercial practices. In addition, NHT may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under this Schedule 21-NHT, or an alternative form of security proposed by the Transmission Customer and acceptable to NHT and consistent with commercial practices established by the Uniform Commercial Code that protects NHT against the risk of non-payment.

10. Dispute Resolution Procedures

10.1 Internal Dispute Resolution Procedures:

Any dispute between a Transmission Customer and NHT involving Transmission Service under this Schedule 21-NHT (excluding applications for rate changes or other changes to this Schedule 21-NHT, or to any Service Agreement entered into under this Schedule 21-NHT, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of NHT and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days or such other period as the Parties may agree upon by mutual agreement, such dispute may be submitted to mediation and/or arbitration and resolved in accordance with the arbitration procedures set forth in Section I.6 of the Tariff.

10.2 Rights Under The Federal Power Act:

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission, or seek any other available remedy, under relevant provisions of the Federal Power Act.

II. LOCAL POINT-TO POINT TRANSMISSION SERVICE

Preamble

NHT will provide Firm and Non-Firm Local Point-To-Point Transmission Service over its Local Network pursuant to the applicable terms and conditions of this Schedule 21-NHT. Local Point-To-Point

Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

NHT will provide Interconnection Service to owners and developers of generating units directly interconnected to the Local Network Transmission System in accordance with the provisions of Schedule 22 of the ISO Tariff for generators with generating capacity of more than 20MW, and Schedule 23 of the ISO Tariff for generators with generating capacity of 20MW or less. Transmission services provided over PTF and Interconnection Service to interconnect directly with PTF are governed by the OATT.

11. Unauthorized use of the Transmission System

Any use of the Local Network Transmission System that exceeds a) the Transmission Customer's firm Reserved Capacity at any Point of Receipt or Point of Delivery or b) the Transmission Customer's non-firm capacity reservation, will be deemed an unauthorized use of the Local Network Transmission System. In the event that a Transmission Customer exceeds its firm reserved capacity or non-firm capacity reservation at any Point of Receipt or Point of Delivery, it shall pay an amount equal to 200% of the otherwise applicable charge firm point to point transmission service for each Kilowatt of the excess, exclusive of any discounts offered to any other Eligible Customer. Such charge shall apply for the length of the reservation period, not to exceed one month. In all cases of unauthorized use of the Local Network Transmission System, the service will be considered non-firm and NHT will be under no obligation to provide any services for such use.

12. Service Availability

12.1 Determination of Available Transmission Capability:

Determinations regarding availability and capabilities of the PTF are made by the Control Area Operator. NHT's specific methodology for assessing ATC over its non-PTF is posted on the OASIS and is contained in Attachment C of this Schedule 21-NHT. In the event sufficient Local Network transmission capability may not exist to accommodate a service request, NHT will, at the request of an Eligible Customer, respond by performing a System Impact Study as described in the following sections.

12.2 Initiating Service in the Absence of an Executed Service Agreement:

If NHT and the Transmission Customer requesting Firm or Non-Firm Local Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Local Point-To-Point

Service Agreement, the ISO, acting as agent for NHT, shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification to NHT and the ISO directing the ISO acting as agent for NHT to file, an unexecuted Local Point-To-Point Service Agreement containing terms and conditions deemed appropriate by NHT for such requested Transmission Service. If the Transmission Customer refuses, or otherwise does not make such a request, the ISO acting as agent for NHT, may make such a filing prior to the commencement of service. NHT shall commence providing Transmission Service and the Transmission Customer shall be obligated to (i) compensate NHT at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of this Schedule 21-NHT including posting appropriate security deposits in accordance with the terms of Section I.5.c of the Common Provisions of Schedule 21 to the OATT.

12.3 Real Power Losses:

Real Power Losses are associated with all transmission service. NHT is not a Control Area Operator and is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by NHT or the Control Area Operator.

12.4 Load Shedding:

To the extent that system contingency exists on the Local Network Transmission System, and NHT determines shedding of load is necessary, the Parties shall shed load in accordance with procedures under the Service Agreement, the Tariff, and the rules adopted thereunder, or in accordance with other mutually agreed to provisions.

13. Transmission Customer Responsibilities

13.1 Conditions Required of Transmission Customers:

Local Point-To-Point Transmission Service and Interconnection Service shall be provided by NHT only if the following conditions are satisfied by the Transmission Customer:

(a) The Transmission Customer has pending a Completed Local Application for service with the ISO or in the case of Interconnection Service, has a Completed Application for service with the Control Area Operator and satisfied all other requirements of the Tariff or of this Schedule 21-NHT, as applicable;

(b) The Transmission Customer meets the creditworthiness criteria set forth in Section 9;

(c) The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to NHT's Local Network Transmission System prior to the time service under Part II of this Tariff commences;

(d) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of this Tariff, whether or not the Transmission Customer takes service for the full term of its reservation; and

(e) The Transmission Customer has executed a Local Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 12.2 of this Schedule 21-NHT.

14. Metering and Power Factor Correction at Receipt and Delivery Points(s)

14.1 Transmission Customer Obligations:

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of this Schedule 21-NHT and to communicate the information to NHT. Unless otherwise agreed, such equipment shall remain the property of NHT.

14.2 Power Factor:

The Transmission Customer is required to maintain a power factor within a range as specified by NHT pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable. Where a Transmission Customer fails to maintain a power factor within the specified range, NHT may make whatever improvements or repairs are required to restore or maintain the power factor, and charge the Transmission Customer accordingly.

15. Compensation for Local Point-To-Point Transmission Service

Rates for Firm and Non-Firm Local Point-To-Point Transmission Service are provided in the Schedules appended to this Schedule 21-NHT: Firm Local Point-To-Point Transmission Service (Schedule 7); and Non-Firm Local Point-To-Point Transmission Service (Schedule 8).

16. Interconnection Service

Any entity proposing to interconnect with NHT's transmission facilities, that is not party to an agreement executed on or before July 9, 1996, in which Interconnection Service is addressed, that (1) proposes to site a new generating unit and directly interconnect to the Local Network Transmission System, or (2) proposes to materially change electrical characteristics or increase the capacity of an existing generating unit and remain connected to the Local Network Transmission System, shall submit an application for Interconnection Service to the Control Area Operator and comply with all applicable requirements of the Tariff, including but not limited to Schedule 22 of the ISO Tariff for generators with generating capacity of more than 20MW, and Schedule 23 of the ISO Tariff for generators with generating capacity of 20MW or less.

III. LOCAL NETWORK SERVICE

17. Real Power Losses

Real Power Losses are associated with all transmission service. NHT is not a Control Area Operator and is not obligated to provide Real Power Losses. The Local Network Customer is responsible for replacing losses associated with all transmission service as calculated by NHT or the Control Area Operator.

18. Initiating Service

18.1 Condition Precedent for Receiving Service:

Subject to the terms and conditions of Part III of this Schedule 21-NHT, NHT will provide Local Network Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under the OATT, (ii) the Eligible Customer and NHT complete the technical arrangements for such service, (iii) the Eligible Customer executes a Service Agreement for service under Part III of this Schedule 21-NHT or requests in writing that the ISO, acting as agent for NHT, file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Local Network Operating Agreement with NHT.

18.2 Application Procedures:

An Eligible Customer requesting service under Part III of this Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the ISO acting as agent for

NHT as far as possible in advance of the month in which service is to commence in accordance with Section II. 3) a) of the common service provisions of Schedule 21 of the OATT.

18.3 Operation of Network Resources:

The Local Network Customer shall not operate its designated Network Resources, which are not subject to central dispatch by the Control Area Operator, such that the output of those facilities exceeds its designated Local Network Load, plus non-firm sales delivered pursuant to Part II of this Schedule 21-NHT, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of the ISO or NHT to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Local Network Transmission System.

18.4 Transmission Arrangements for Network Resources Not Physically Interconnected With NHT's Local Network:

The Local Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with NHT's Local Network Transmission System. NHT will undertake reasonable efforts to assist the Local Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice. The customer shall be obligated to reimburse NHT for all costs NHT incurs in assisting the customer in obtaining such arrangements. Upon the customer's request, NHT shall provide the transmission customer an estimate of such costs before they are incurred. Upon the customer's request, NHT shall provide reasonable itemization of such costs along with any invoice related to those costs.

18.5 Limitation on Designation of Network Resources:

The Local Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Local Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of this Schedule 21-NHT.

18.6 Use of Interface Capacity by the Local Network Customer:

There is no limitation upon a Local Network Customer's use of NHT's Local Network Transmission System at any particular interface to integrate the Local Network Customer's

Network Resources (or substitute economy purchases) with its Local Network Loads. However, a Local Network Customer's use of the NHT's total interface capacity with other transmission systems may not exceed the Local Network Customer's Load.

18.7 Local Network Customer Owned Transmission Facilities:
The Local Network Customer that owns existing transmission facilities that are integrated with NHT's Local Network Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Local Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of NHT to serve its power and Transmission Customers. For facilities constructed by the Local Network Customer subsequent to the Service Commencement Date under Part III of this Schedule 21-NHT, the Local Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with NHT. Calculation of the credit shall be addressed in either the Local Network Customer's Service Agreement or any other agreement between the Parties.

19. Designation of Load

19.1 Network Load Not Physically Interconnected with NHT's Local Network:
This Section applies to both initial designation and the subsequent addition of new Local Network Load not physically interconnected with NHT's Local Network. To the extent that the Local Network Customer desires to obtain Local Network transmission service for a load outside NHT's Local Network Transmission System, the Local Network Customer shall have the option of (1) electing to include the entire load as Local Network Load for all purposes under Part III of this Schedule 21-NHT and designating Local Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Transmission Service under Part II of this Schedule 21-NHT. To the extent that the Local Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this Section, the request must be made through a modification of service pursuant to a new Application. NHT shall include such load as part of a Transmission Customer's Local Network Load only if a scheduling and interconnection agreement acceptable to NHT is in effect with the Control Area in which the load is located.

20. Additional Study Procedures For Local Network Transmission Service Requests

20.1 Notice of Need for System Impact Study:

When applicable, a description of NHT's methodology for completing a System Impact Study is provided in Attachment D of this Schedule 21-NHT.

21. Load Shedding and Curtailments

21.1 Procedures:

Prior to the Service Commencement Date, NHT and the Local Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Local Network Operating Agreement with the objective of responding to contingencies on the Local Network Transmission System. The Parties will implement such programs during any period when NHT determines that a system contingency exists and such procedures are necessary to alleviate such contingency. NHT will notify all affected Local Network Customers in a timely manner of any scheduled Curtailment.

21.2 Transmission Constraints:

During any period when NHT determines that a transmission constraint exists on the Local Network Transmission System, and such constraint may impair the reliability of NHT's system, NHT will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of NHT's system. To the extent either NHT or the Control Area Operator determine that the reliability of the Transmission System can be maintained by redispatching resources, NHT can initiate procedures pursuant to the Local Network Operating Agreement, the Tariff, and other Control Area Operator rules and procedures including, without limitation, the Market Rules. Any redispatch under this Section may not unduly discriminate between NHT's use of the Local Network Transmission System on behalf of its Native Load Customers and any Local Network Customer's use of the Local Network Transmission System to serve its designated Local Network Load

21.3 Curtailments of Scheduled Deliveries:

If a transmission constraint on NHT's Local Network Transmission System cannot be relieved through the implementation of redispatch procedures and the Control Area Operator determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with any applicable provisions of the Local Network Operating Agreement, the Tariff and any Control Area Operator rules and procedures including, without limitation, the Market

Rules.

21.4 Load Shedding:

To the extent that a system contingency exists on NHT's or the New England Transmission System and NHT or the ISO determines that it is necessary for NHT and the Local Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement, or in accordance with other mutually agreed to provisions.

22. Rates and Charges

The Local Network Customer shall pay NHT for any Direct Assignment Facilities and applicable study costs, consistent with Commission policy, along with the following:

22.1 Monthly Demand Charge:

The Local Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of NHT's Annual Transmission Revenue Requirement. The Annual Transmission Revenue Requirement is calculated pursuant to Attachment G of this Schedule 21-NHT.

22.2 Determination of Local Network Customer's Monthly Local Network Load:

The Local Network Customer's monthly Local Network Load is its hourly load (including its designated Local Network Load not physically interconnected with NHT's Local Network under Section 19.1) coincident with NHT's Monthly Local Network Transmission System Peak.

22.3 Determination of NHT's Monthly Local Network Transmission System Load:

NHT's monthly Local Network Transmission System load is NHT's Monthly Local Network Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Transmission Service customers pursuant to Part II of this Schedule 21-NHT plus the Reserved Capacity of all Firm Local Point-To-Point Transmission Service customers.

22.4 Redispatch Charge:

All costs associated with redispatch of resources shall be charged and allocated in accordance with the Tariff and any Control Area Operator rules and procedures including, without limitation, the Market Rules.

22.5 Stranded Cost Recovery:

NHT may seek to recover stranded costs from the Local Network Customer pursuant to this Schedule 21-NHT in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, NHT must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

23. Operating Arrangements

23.1 Operation under The Local Network Operating Agreement:

The Local Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement. If NHT and the Local Network Customer agree in the Interconnection Agreement, the Interconnection Agreement can serve as a Local Network Operating Agreement.

23.2 Local Network Operating Agreement:

The terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of this Schedule 21-NHT shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Local Network Customer within NHT's Local Network Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between NHT and the Local Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside NHT's Local Network Transmission System, interchange schedules, unit outputs for redispatch required under Section 21, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of this Schedule 21-NHT, including scheduling protocols. The Local Network Operating Agreement will recognize that the Local Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Control Area Operator for all required Ancillary Services or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services which may be provided by another entity, by contracting with another entity, consistent with Good Utility Practice, which satisfies any applicable requirements imposed by NERC, the NPCC, NHT or the Control Area Operator. For those Ancillary Services that may be provided by another entity, NHT shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services.

SCHEDULE 7

Long and Short Term Firm Local Point-To-Point Transmission Service

Each Transmission Customer who takes Firm Local Point-to-Point Transmission Service shall pay NHT each month on the basis of the highest amount of Reserved Capacity for each transaction reserved as Firm Local Point to Point Transmission Service. Except as provided otherwise below, the charges will be re-determined annually on June 1 of each year, and shall be in effect for the succeeding twelve months. The rate per kilowatt for each month is one-twelfth of the annual rate determined by dividing the Annual Transmission Revenue Requirement calculated pursuant to the Attachment G formula, by NHT's average monthly Local Network Transmission System Load (as defined in Section 22.3) for the prior calendar year.

Each Transmission Customer taking Firm Local Point to Point Transmission Service shall pay the firm local point-to-point rate on the basis of the highest amount of Reserved Capacity for each transaction reserved as Firm Local Point to Point Transmission Service as follows:

1) Yearly reservation: one-twelfth of the annual rate per kilowatt of Reserved Capacity per year.

2) Monthly reservation: one-twelfth of the annual rate per kilowatt of Reserved Capacity per month

3) Weekly reservation: 1/52nd of the annual rate per kilowatt of Reserved Capacity per week.

4) Daily reservation: 1/7th of the weekly rate per kilowatt of Reserved Capacity per day.
Provided that the total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NHT must be announced to all Eligible Customers solely by posting on the OASIS; (2) any customer-initiated requests for discounts (including requests for use by NHT's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, NHT must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same Point(s) of Delivery on the Transmission System.

6) Exceeding Capacity Reservations and Unreserved Use: In the event the Transmission Customer exceeds the Capacity Reservation specified in the customer's transmission Service Agreement as determined by NHT, the Transmission Customer shall be retroactively charged an amount equal to 200% of the rates specified above without any discount, if one is in place at the time, for any capacity exceeding the amount reserved. Such charge shall apply for the length of the period of unreserved use of NHT's transmission system, except that: i) unreserved uses for any single hour period shall be based on 200% of the applicable rate for daily firm point-to-point transmission service, and ii) multiple unauthorized uses of any given duration (e.g., daily) occurring during any single billing month shall be subject to a penalty charge of 200% of the rate that is applicable to the next longest duration of service, (e.g. weekly).

7) Resale: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Section I.11.a of Schedule 21.

SCHEDULE 8

Non-Firm Local Point-To-Point Transmission Service

Each Transmission Customer who takes Non-Firm Local Point-to-Point Transmission Service shall pay NHT each month on the basis of the highest amount of Reserved Capacity for each transaction reserved as Non-Firm Local Point to Point Transmission Service. The charges will be re-determined annually on June 1 of each year, and shall be in effect for the succeeding twelve months. The rate per kilowatt for each month is one-twelfth of the annual rate determined by dividing the Local Network Service Annual Transmission Revenue Requirement calculated pursuant to the Attachment G formula, by NHT's average monthly Local Network Transmission System Load (as defined in Section 22.3) for the prior calendar year.

Each Transmission Customer taking Non-Firm Local Point to Point Transmission Service shall pay the non-firm local point-to-point rate on the basis of the highest amount of Reserved Capacity for each transaction scheduled as Non-Firm Local Point to Point Transmission Service as follows:

1) **Yearly reservation:** one-twelfth of the annual rate per kilowatt of Reserved Capacity per year.

2) **Monthly reservation:** one-twelfth of the annual rate per kilowatt of Reserved Capacity per month.

3) **Weekly reservation:** 1/52nd of the annual rate per kilowatt of Reserved Capacity per week.

4) **Daily reservation:** 1/7th of the weekly rate per kilowatt of Reserved Capacity per day.

5) **Hourly reservation:** 1/24th of the daily rate per kilowatt of Reserved Capacity per hour.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (4) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

6) Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NHT must be announced to all Eligible Customers solely by posting on the OASIS; (2) any customer-initiated requests for discounts (including requests for use by NHT's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, NHT must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same Point(s) of Delivery on the Transmission System.

7) Exceeding Capacity Reservations and Unreserved Use: In the event the Transmission Customer exceeds the Capacity Reservation specified in the customer's transmission Service Agreement as determined by NHT, the Transmission Customer shall be retroactively charged an amount equal to 200% of the rates specified for Long and Short Term Firm Point to Point Transmission Service as specified in Schedule 7 of this Schedule 21-NHT without any discount, if one is in place at the time, for any capacity exceeding the amount reserved.

8) Resale: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Section I.11.a of Schedule 21.

ATTACHMENT C

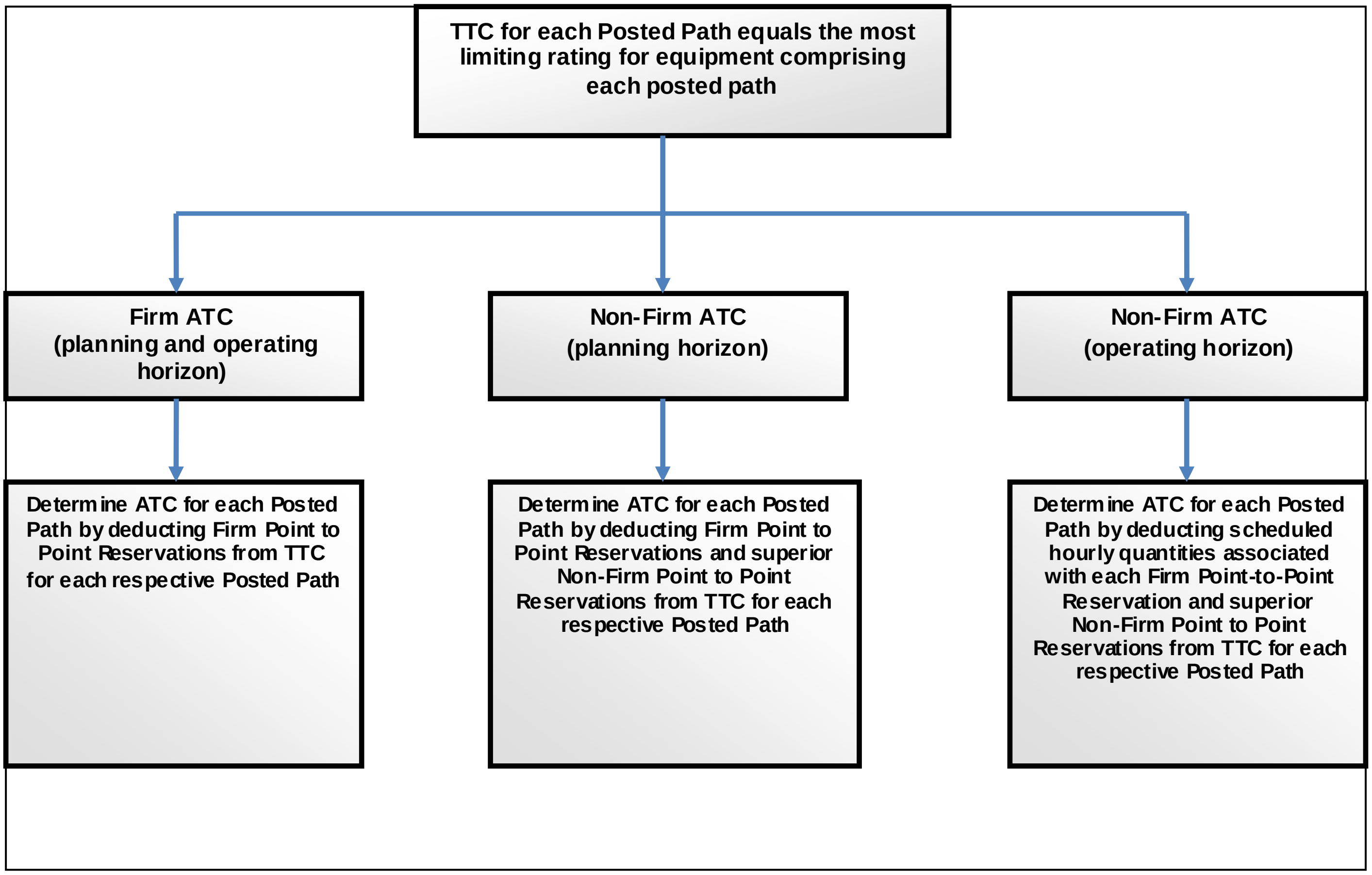
Methodology To Assess Available Transmission Capability

NHT will respond to a valid request for Local Network and Local Point-To-Point Transmission Service by determining whether sufficient transfer capability is available to grant the request. All valid requests will be assigned a priority as set forth in the OATT. The Available Transmission Capability will be calculated based on a Contract Path Methodology, taking into account Total Transfer Capability, Transmission Reliability Margin, capacity reserved by NHT to serve projected native load, existing and confirmed long-term firm transactions and all other requests consistent with the Tariff.

Total Transfer Capacity will be forecasted by NHT and/or the Control Area Operator for posted paths using system models, load flow analysis and other engineering analyses, and in accordance with the NHT Facilities Rating Methodology posted on the NHT OASIS.

In determining Available Transmission Capacity NHT will use Good Utility Practice, comply with applicable Control Area Operator criteria, rules and standards, utilize NPCC and NERC criteria and guidelines, and guidelines established by NHT. The process used by NHT to determine its Available Transmission Capacity is depicted by the following process flow diagram.

Process Used by NHT to Calculate the TCC and ATC for Posted Paths



Notes:

1. TCC and ATC are calculated in accordance with NHT's Facilities Ratings Methodology as posted on NHT's OASIS.
2. NHT has provided its Facilities Ratings Methodology and Facilities Ratings to ISO-NE.
3. TCC and ATC for Posted Paths relate to Point to Point Transmission Service taken over NHT's Non-Pool Transmission Facilities.
4. TCC and ATC are not calculated and posted over Pool Transmission Facilities because Point-to-Point Transmission Service internal to New England is part of Regional Network Service and was eliminated from the ISO-NE Tariff as a stand-along distinct service
5. ISO-NE administers transmission service over all Pool Transmission Facilities.

The algorithm used by NHT to calculate its Available Transmission Capacity is as follows:

NHT Local Service Available Transfer Capability (ATC)
Firm/Non-Firm ATC = TTC (Total Transfer Capability); minus CBM (Capacity Benefit Margin); minus TRM (Transmission Reliability Margin); minus Transmission Service Capacity Reservation(s).

Calculation of TTC shall equal: $\sqrt{3}$; times (operating voltage); times (ampere rating of the transmission facility).

No Local Service capacity reservation is set aside on any non-PTF path for CBM or TRM.

Local Service on non-Pool Transmission Facilities is currently provided for Seabrook Station Service only when there is no net generation out of the Seabrook Plant or upon failure of Generation Step Up Transformer (GSU).

Total Existing Local Service Capacity Reservations for Seabrook Station Service: 6/1/04 through current = 50 MW. Such Local Service is provided over non-PTF paths: Path 1) Seabrook 345 kV Bus No. 5 to Seabrook Station Service; and Path 2) Seabrook 345 kV Bus No. 3 to 345 kV-GSU. These non-PTF paths are not available for additional Point-to-Point Service Requests, except to meet the needs of the Seabrook Station (e.g., increase in Station Service Requirements) due to the physical limitations of access to these specific 345 kV transmission facilities.

Firm TTC (Total Transfer Capability)/Non-Firm TTC (hourly, daily, weekly, monthly, yearly) over each Path 1 and Path 2, respectively, is: 1793 MWA/1793 MW [TTC = $\sqrt{3}$ X 345 kVX 3000A]

Firm ATC/Non-Firm ATC (hourly, daily, weekly, monthly, yearly) over each Path 1 and Path 2, respectively, is: 1743 MVA/1743 MW [ATC = TTC ($\sqrt{3}$X 345 kV X 3000A); minus CBM (0); minus TRM (0); minus Transmission Service Capacity Reservations (50 MW)]

Paths available for non-PTF Point-to-Point Service are:

Path 3) Seabrook 345 kV Switch Nos. 2201-2901 to Future Unit #2; and
Path 4) Seabrook Sub. 345 kV Bus 1 to Future Tie – RAT Transformer

Firm TTC/Non-Firm TTC over each path, respectively, (3 & 4, above) (hourly, daily, weekly, monthly, yearly) is: 1793 MVA/1793 MW [TTC = $\sqrt{3}$ X 345 kV X 3000A]

Firm ATC/Non-Firm ATC (hourly, daily, weekly, monthly, yearly) over each path, respectively, (3 & 4, above) is: 1793 MVA/1793 MW [ATC = TTC ($\sqrt{3}$ X 345 kV X 3000A) – CBM (0) – TRM (0) – Transmission Service Capacity Reservations (0)]

Note: At present, there are no Transmission Service Capacity Reservations over Path 3) or Path 4).

ATTACHMENT D

Methodology for Completing a System Impact Study

NHT (or its designated agent) may require System Impact Studies for the purpose of determining the feasibility of providing Transmission Service under this Tariff. All System Impact Studies will be coordinated with the Control Area Operator and completed using the same method employed by NHT to provide Transmission Service to its affiliated customers. System Impact Studies associated with a request from an Eligible Customer for Interconnection Service shall be performed at the direction of the Control Area Operator pursuant to Schedule 22 of the ISO Tariff for generators with generating capacity of more than 20MW, and Schedule 23 of the ISO Tariff for generators with generating capacity of 20MW or less. System Impact Studies will be performed by applying NPCC Criteria and the "Reliability Standards of the New England Power Pool," or its successor, while assuring that NHT's Native Load Customers and those loads directly interconnected to the Local Network Transmission System that are receiving transmission service can be served economically and reliably. All of the criteria, standards, and guidelines referenced above are included as part of the annual FERC Form 715 filing.

ATTACHMENTS E AND F

[RESERVED FOR FUTURE USE]

ATTACHMENT G

FORMULA FOR CALCULATING ANNUAL WHOLESALE TRANSMISSION REVENUE REQUIREMENTS UNDER NEW HAMPSHIRE TRANSMISSION LLC'S SCHEDULE 21

This formula sets forth the details for determining each year's Annual Transmission Revenue Requirement for New Hampshire Transmission, LLC ("NHT"). The Transmission Revenue Requirement reflects NHT's cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to wholesale transmission customers in the New England Control Area under this Schedule 21-NHT and the OATT. The Transmission Revenue Requirement will be an annual formula rate calculation. Initially, cost data reflecting costs as incurred by NHT'S Affiliate, FPL-NED, for owning, operating and maintaining the transmission facilities located in the New England Control Area for January 1, 2009 through May 31, 2010 shall be used, and NHT's costs will be used for June 1, 2010 through December 31, 2010. Thereafter, NHT's ATRR will be updated each June 1, based on NHT's costs incurred during the previous calendar year as recorded in NHT's FERC Form 1, data, and based on actual data in lieu of allocated data, if specifically identified in FERC Form 1, using end-of-year balances for each rate base item, as further set forth below.

Notwithstanding the aforementioned, until such time as FPL-NED has completed the transfer of the transmission facilities to NHT for which this Schedule 21-NHT pertains, NHT's ATRR shall continue to be based on the cost incurred by FPL-NED for owning, operating and maintaining the transmission facilities located in the New England Control Area. As such, all references to costs, expenses and investments attributable to NHT contained in this formula, shall be deemed to refer to costs, expenses and investments attributable to NHT or FPL-NED, as applicable, to coincide with the date of such transfer. To facilitate the use of FPL-NED's costs, expenses and investments for the purpose of deriving NHT's ATRR pursuant to this Attachment G, all such FPL-NED costs used in the determination of NHT's ATRR shall be recorded in a format consistent with the FERC Uniform System of Accounts.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section 1 of this Schedule 21- NHT have the following definitions:

A. ALLOCATION FACTORS

1. **Transmission Wages and Salaries Allocation Factor** shall equal the ratio of NHT's Transmission-related direct wages and salaries not otherwise assigned under this tariff, to NHT's total direct wages and salaries excluding administrative and general wages and salaries.

2. **Transmission Plant Allocation Factor** shall be designed to ensure that no costs associated with the Seabrook Nuclear Generating Station properly functionalized as production costs or expenses are included in NHT's ATRR, and therefore, prior to the Asset Transfer Date, shall equal the ratio of the sum of (1) Total Investment in Transmission Plant attributable to NHT including the investment in the Generator Step-up Transformer, recorded in such Transmission Plant accounts, and (2) the balance of Transmission Related General and Intangible Plant attributable to NHT, to Total Plant in Service attributable to NHT, including the investment in the Generator Step-up Transformer. After the Asset Transfer Date, this Transmission Plant Allocation Factor shall be 1.00

3. **LNS Plant Allocation Factor** shall be designed to ensure that no costs associated with the Generator Step-up Transformer are included in NHT's ATRR and shall equal the ratio of the sum of Total Investment in Transmission Plant attributable to NHT, excluding the investment in the Generator Step-up Transformers, and the balance of Transmission Related General and Intangible Plant attributable to NHT, to Total Transmission Plant in Service attributable to NHT, including the investment in the Generator Step-up Transformer.

B. GENERAL TERMS

1. **Administrative and General Expense** shall equal expenses attributable to NHT as recorded in FERC Account Nos. 920-935, excluding Property Insurance recorded in FERC Account No. 924, Regulatory Commission Expense recorded in FERC Account No. 928 and General Advertising Expense recorded in FERC Account No. 930.1.

2. **Amortization of Investment Tax Credits** shall equal any credits attributable to

NHT as recorded in FERC Account No. 411.4.

3. **Asset Transfer Date** shall be the date upon which FPL-NED transfers its ownership in the Seabrook Transmission Substation to NHT.

4. **Depreciation Expense for Transmission Plant** shall equal the transmission depreciation expense attributable to NHT as recorded in FERC Account No. 403. Annual Depreciation Expense for Transmission Plant shall be based on an annual rate of 3.12 percent per year for its initial year's revenue requirements and any change shall require Commission acceptance or approval.

5. **Generator Step-up Transformers** shall equal the investment in the generator step-up transformers used to interconnect the Seabrook Nuclear Generating Station to the Local Network Transmission System. Notwithstanding the transfer of said Generator Step-up Transformers from FPL-NED to NHT reflecting that a contribution of capital was paid to FPL-NED by NextEra Energy Seabrook, LLC (formerly FPL Energy Seabrook, LLC) resulting in NHT recording such at zero cost net book basis, for purposes of deriving the Transmission Plant Allocation Factor and the LNS Plant Allocation Factor, the investment in the Generator Step-up Transformers shall be equal to the original cost of said Generator Step-up Transformers as recorded by NextEra Seabrook, LLC and shall reflect any changes in that investment (i.e. retirements, replacements, additions, etc.) on a going-forward basis. Any future additional investment in the Generator Step-up Transformers shall be paid for as a direct assignment charge to NextEra Seabrook, LLC or its successors such that the net investment basis as recorded by NHT shall continue to be zero.

6. **Intangible and General Plant** shall equal the gross plant balances attributable to NHT as recorded in FERC Account Nos. 301-303 and 389-399.

7. **Intangible and General Plant Amortization and Depreciation Expense** shall equal any intangible and general plant amortization and depreciation expenses attributable to NHT as recorded in FERC Account Nos. 404 and 403.

8. **Intangible and General Plant Depreciation Reserve** shall equal any intangible and general plant reserve balances attributable to NHT as recorded in FERC Account Nos. 111 and 108.

9. Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of FAS106 balance attributable to NHT as recorded in FERC Account 182.3 and any FAS 106 balance attributable to NHT as recorded in FERC Account No. 254.

10. Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance in FERC Account 254 attributable to NHT.

11. Payroll Taxes shall equal those payroll expenses attributable to NHT as recorded in FERC Account Nos. 408.1.

12. Plant Held for Future Use shall equal the balance recorded in FERC Account No.105 attributable to NHT.

13. Prepayments shall equal any prepayment balance attributable to NHT as recorded in FERC Account No. 165.

14. Property Insurance shall equal expenses attributable to NHT as recorded in FERC Account No. 924.

15. Total Accumulated Deferred Income Taxes shall equal the net of deferred tax balance attributable to NHT as recorded in FERC Account Nos. 281-283 and the deferred tax balance attributable to NHT as recorded in FERC Account No. 190.

16. Total Municipal Tax Expense shall equal the municipal tax expenses attributable to NHT as recorded in FERC Account No. 408.1.

17. Total Plant in Service shall equal the total gross plant balance attributable to NHT as recorded in FERC Account Nos. 301-399.

18. Total Transmission Depreciation Reserve shall equal the transmission reserve balance attributable to NHT as recorded in FERC Account 108

19. Transmission Operation and Maintenance Expense shall equal the expenses attributable to NHT as recorded in FERC Account Nos. 560 through 576.5, excluding those expenses for Load Dispatching in FERC Account 561 and excluding any amounts recorded in FERC Account No. 565 relating solely to NEPOOL & ISO Expense, and amounts recorded in FERC Account Nos. 566-576.5, excluding any expenses in support of other utilities' transmission facilities, i.e. Transmission Support Expenses, and excluding any operation and maintenance expenses associated with the Generator Step-up Transformers, which may be included in FERC Account Nos. 560-576.5.

20. **Transmission Plant** shall equal the Gross Plant balance attributable to NHT as recorded in FERC Account Nos. 350-359.

21. **Transmission Plant Materials and Supplies** shall equal the balance as assigned to transmission and that is attributable to NHT, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of the following cost components attributable to NHT: (A) Investment Return and Associated Income Taxes, plus (B) Transmission Depreciation Expense, plus (C) Transmission Related Amortization of Investment Tax Credits, plus (D) Transmission Related Municipal Tax Expense, plus (E) Transmission Related Payroll Tax Expense, plus (F) Transmission Operation and Maintenance Expense, plus (G) Transmission Related Administrative and General Expenses, plus (H) Transmission Related Regulatory Assessments, plus (I) Transmission Support Expense, plus (J) NEPOOL & ISO Expense minus (K) Transmission Support Revenue, minus (L) ISO Revenues, minus (M) Other Wheeling Revenue, and minus (N) Transmission Rents Received from Electric Property.

A. **Investment Return and Associated Income Taxes** shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. **Transmission Investment Base**

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Other Regulatory Assets/Liabilities, plus (g) Transmission Prepayments, plus (h) Transmission Materials and Supplies, plus (i) Transmission Related Cash

Working Capital.

(a) **Transmission Plant** will equal the balance of the Investment in Transmission Plant attributable to NHT less any investment in the Generator Step-up Transformers. At December 31, 2003, Transmission Plant balance is $28,195,111.

(b) **Transmission Related Intangible and General Plant** shall equal the sum of the investment in Intangible and General Plant attributable to NHT multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the LNS Plant Allocation Factor. At December 31, 2003, Transmission Related Intangibles and General Plant Balances are zero.

(c) **Transmission Plant Held for Future Use** shall equal the balance of Transmission-related Plant Held for Future Use attributable to NHT. To the extent any such amount relating to the Generator Step-up Transformers exist in said balance of Total Plant Held for Future Use, such amounts shall be excluded by further multiplying said balance by the LNS Plant Allocation Factor. At December 31, 2003, the balance of Transmission Plant Held For Future Use is zero.

(d) **Transmission Related Depreciation Reserve** shall equal the balance of Total Transmission Depreciation Reserve, plus the sum of the balance of Transmission Related Intangible and General Plant Depreciation Reserve, that are attributable to NHT. To the extent any such amount relating to the Generator Step-up Transformers exists in said balance of Total Transmission Depreciation Reserve, such amounts shall be excluded by further multiplying said balance by the LNS Plant Allocation Factor. Transmission Related Intangible and General Plant Depreciation Reserve shall equal the product of Intangible and General Plant Depreciation Reserve attributable to NHT multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the LNS Plant Allocation Factor. At December 31, 2003, Transmission Related Depreciation Reserve Balance is $8,249,858.

(e) **Transmission Related Accumulated Deferred Taxes** shall equal the balance of Total Accumulated Deferred Income Taxes attributable to NHT. To the extent any such amount relating to the Generator Step-up Transformer exist in said balance of Total Accumulated

Deferred Income Taxes, such amounts shall be excluded by further multiplying said balance of Transmission Related Accumulated Deferred Taxes by the LNS Plant Allocation Factor. At December 31, 2003, Transmission Related Accumulated Deferred Taxes is $295,398.

(f) **Other Regulatory Assets/Liabilities** shall equal the balance of any deferred rate recovery of FAS 106 expenses attributable to NHT multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the LNS Allocation Factor, plus the balance of FAS 109 attributable to NHT multiplied by the LNS Plant Allocation Factor. At December 31, 2003, Other Regulatory Assets/Liability is zero.

(g) **Transmission Prepayments** shall equal the electric balance of prepayments attributable to NHT multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the LNS Allocation Factor. At December 31, 2003, Transmission Prepayments is $1,374.

(h) **Transmission Materials and Supplies** shall equal the electric balance of Plant Materials and Supplies attributable to NHT multiplied by the Transmission Plant Allocation Factor. To the extent any such amount relating to the Generator Step-up Transformers exist in said balance of Transmission Materials and Supplies, such amounts shall be excluded by further multiplying said balance of Transmission Materials and Supplies by the LNS Plant Allocation Factor. At December 31, 2003, Transmission Materials and Supplies balance is zero.

(i) **Transmission Related Cash Working Capital** shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph K of the formula, as such expenses and revenues are attributable to NHT.

2. **Cost of Capital Rate**

The Cost of Capital Rate will equal (a) FPL's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) **The Weighted Cost of Capital** will be calculated in accordance with the methodology specified in Section 35.13(h)(22) of Part 18 of the Code of Federal Regulations, i.e. Statement AV, based upon the capital structure for FPL at the end of each year and will equal the sum of:

(i) **the long-term debt component**, which equals the product of the actual weighted average embedded cost to maturity, including any unamortized discounts and premiums, and unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to FPL's total capital.

(ii) **the preferred stock component**, which equals the product of the actual weighted average embedded cost to maturity of FPL's preferred stock then outstanding and the ratio that preferred stock is to FPL's total capital.

(iii) **the return on equity component**, which equals the product of the Return on Equity of 11.14 (10.4+.74 adder per Rehearing Order issued March 24, 2008 in Docket ER04-157-014) percent and the ratio that common equity is to FPL's total capital.

(b) **Federal Income Tax** shall equal

$$\frac{(A+[(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.C. below, C is the Equity AFUDC component of Transmission Depreciation Expense , as defined in Section II.B., and D is Transmission Investment Base, as determined in II.A.1., above.

(c) **State Income Tax** shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.C. below, C is the equity AFUDC component of Transmission

Depreciation Expense, as defined in Section II.B., D is the Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Transmission Plant attributable to NHT, plus an allocation of Intangible and General Plant Depreciation Expense attributable to NHT. To the extent any such amount relating to the Generator Step-up Transformers exist in said balance of Transmission Depreciation Expense, such amounts shall be excluded by further multiplying said balance of Transmission Depreciation Expense by the LNS Plant Allocation Factor. The allocated portion of Intangible and General Plant Depreciation Expense shall be calculated by multiplying Intangible and General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor and further multiplied by the LNS Plant Allocation Factor.

C. Transmission Related Amortization of Investment Tax Credits shall equal the electric Amortization of Investment Tax Credits attributable to NHT, multiplied by the Transmission Plant Allocation Factor. To the extent any such amount relating to the Generator Step-up Transformers exist in said balance of Transmission Related Amortization of Investment Tax Credits, such amounts shall be excluded by further multiplying said balance of Transmission Related Amortization of Investment Tax Credits by the LNS Plant Allocation Factor.

D. Transmission Related Municipal Tax Expense shall equal the total electric municipal tax expense attributable to NHT multiplied by the Transmission Plant Allocation Factor and further multiplied by the LNS Plant Allocation Factor.

E. Transmission Related Payroll Tax Expense shall equal the total payroll tax expense attributable to NHT multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the LNS Transmission Plant Allocation Factor.

F. Transmission Operation and Maintenance Expense shall equal the Transmission Operation and Maintenance Expenses attributable to NHT and excluding any operation and maintenance expenses associated with the Generator Step-up Transformers, which may be included in FERC Account Nos. 560-576.5.

G. Transmission Related Administrative and General Expenses shall equal the sum of (1) the Administrative and General Expenses attributable to NHT multiplied by the Transmission Wages and

Salaries Allocation Factor, (2) the Property Insurance attributable to NHT multiplied by the Transmission Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Regulatory Commission Expense attributable to NHT multiplied by the Transmission Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments attributable to NHT, plus specific transmission related General Advertising Expense included in Account 930.1 attributable to NHT. The sum of these components (1) through (3) shall then be multiplied by the LNS Plant Allocation Factor.

H. **Transmission Related Regulatory Assessments** shall include any FERC assessments associated with transmission service provided under the NHT Tariff, based on the FERC regulations in 18 C.F.R. § 382.201, and as recorded in FERC Account No 408.

I. **Transmission Support Expense** shall equal the expense for transmission support as incurred by NHT.

J. **NEPOOL & ISO Expense** shall equal NHT's expense associated with charges assessed NHT pursuant to the Tariff and/or the Restated NEPOOL Agreement.

K. **Transmission Support Revenues** shall equal NHT's revenue received for transmission support, excluding support revenues associated with generator step-up transformers included in Transmission Plant accounts attributable to NHT, if any.

L. **ISO Revenues** shall equal the revenues distributed to NHT from the ISO, for network integration transmission service, internal point to point transmission service, and through and out transmission service provided under the OATT, but excluding any incremental revenues associated with FERC-approved ROE adders for RTO participation and for new transmission investment. Such amounts shall be reflected as forecast amounts in each monthly billing statement and shall be reconciled to such actual monthly revenues received by NHT in the billing statement following the month in which such actual monthly revenues are received by NHT, and shall be reconciled with interest as calculated pursuant to Section 35.19(a) of the Code of Federal Regulations for any over or under estimated amounts.

M. **Other Wheeling Revenues** shall equal any revenues received by NHT for providing wheeling out services to generators as well as any other short-term, non-firm, or unauthorized use penalty revenues received by NHT associated with the provision of transmission services under this Tariff, not otherwise reflected in Section II . K above.

N. Transmission Rents Received from Electric Property shall equal any Rents from electric property associated with Transmission Plant attributable to NHT as defined in Section II.A.1.(a) above, not reflected in Section II. I. above as Transmission Support Revenues, and excluding support revenues associated with generator step-up transformers included in Transmission Plant accounts attributable to NHT, if any.

ATTACHMENT L TO SCHEDULE 21
NHT CREDITWORTHINESS GUIDE

A. Credit Review: For the purpose of determining the ability of a Transmission Customer to fulfill its financial obligations pursuant to the Tariff, the Transmission Provider shall require commercially reasonable credit review procedures. A creditworthiness review shall be conducted for each Transmission Customer upon its initial request for Transmission Service, and thereafter generally annually, or upon the anniversary of the Transmission Customer's Service Commencement Date, or upon reasonable request by the Transmission Customer. Provided, however, any time that a Transmission Customer experiences any credit downgrade that may place it below the standards specified in Section B, the Transmission Provider reserves the right to re-evaluate the Transmission Customer's creditworthiness pursuant to this Attachment L. Further, if in accordance with Section C.3, the Transmission Provider determines that financial assurances that a Transmission Customer has previously provided pursuant to this Attachment L have become insufficient to protect the Transmission Provider against the risk of non-payment, Transmission Provider can require the Transmission Customer to increase such financial assurances.

B. Creditworthiness: Both new and existing Transmission Customers that, upon their application for Transmission Service and throughout the term of their Service Agreements, satisfy the criteria delineated in this Section B will be considered creditworthy by the Transmission Provider. Such Transmission Customers will not be required to submit financial assurances (including, with respect to new customers, the application deposits that would otherwise be required pursuant to either Sections 17.3 or 29.2 of the Tariff) in order to protect the Transmission Provider from the risk of non-payment. Pursuant to this Section B, if applicable, a Transmission Customer is creditworthy if it has not, pursuant to Section 7.3, Defaulted more than once in the last twelve (12) months and:

B.1. has a Standard and Poor's ("S&P") Long-Term Issuer Credit Rating of BBB- (or better); or a Moody's Investor Service, Inc. ("Moody's") Long-Term Issuer Credit Rating of Baa3 (or better). In the event that a Transmission Customer or its guarantor is rated by both S&P and Moody's, then the Transmission Provider will use the lower of the two ratings; or

B.2. is a borrower from the Rural Utilities Service ("RUS") and has a "Times Interest Earned Ratio" of 1.05 (or better) and a "Debt Service Coverage Ratio" of 1.00 (or better) in the most recent calendar year, or is maintaining the Times Interest Earned Ratio and Debt Service Coverage Ratio as established in the Transmission Customer's RUS Mortgage. The Transmission Customer must provide appropriate documentation annually, or as agreed-upon by both parties; or

B.3. is a federal agency and its financial obligations under the Tariff are backed by the full faith and credit of the United States; or

B.4. is a municipal or state agency, or a rural electric cooperative (without RUS Debt) that:

B.4.i. if applicable, has been taking Transmission Service for one (1) year and has provided documentation that its financial obligations under the Tariff are backed by the full faith and credit of the municipality or state in which it is established; or

B.4.ii. has provided documentation that under the applicable laws of the state in which it is established, that its financial obligations under the Tariff are deemed to be operating expenses and that the agency or the electric cooperative is required by such applicable laws to devote its revenues first to the payment of its operating and maintenance expenses and the principal and interest of its outstanding obligations prior to payment of all other obligations; or

B.5. the Transmission Customer provides a letter of unconditional and continuing guaranty from its parent company. Such letter of guaranty must be acceptable to the Transmission Provider as to form and substance and can be used only if the guarantor meets, at the time of execution and maintains during the life of the applicable Service Agreement, a minimum credit rating as stated in Section B1. However, to the extent that the guarantor is placed on watch for possible downgrade and has: i) a S&P Long-Term Issuer Credit Rating of BBB (or below); or ii) a Moody's Long- Term Issuer Credit Rating of Baa2 (or below), then the Transmission Customer will be required to provide additional financial assurances as provided in this Attachment L. A draft, acceptable form of a continuing guaranty shall be posted on OASIS; or

B.6. the Transmission Customer has been in business for at least one (1) year and provides its most recent audited financial statements to the Transmission Provider which demonstrate that the Transmission Customer meets standards that are at least equivalent to the standards underlying a S&P Long-Term Issuer Credit Rating of BBB- (or better) or a Moody's Long-Term Issuer Credit Rating Baa3 (or better); provided that if the Transmission Customer is not found to be creditworthy pursuant to this Section B.6, then pursuant to Section C.5, the Transmission Provider will inform the Transmission Customer of the reasons for that determination.

C. Creditworthiness Procedures: The Transmission Provider shall require financial assurances in accordance with the procedures set forth below:

C.1. New Transmission Service: Upon its execution of a Transmission Service Agreement, a new Transmission Customer (or an existing Transmission Customer requesting new service) that does not meet the creditworthiness requirements established in Section B shall either:

C.1.i. provide an unconditional and irrevocable standby letter of credit, or an alternative form of security identified in Section E, in an amount equal to two (2) times the estimated charges for transmission and ancillary services including losses (rounded to the nearest thousand dollar increment) for an average month for that type of service.

C.1.i.a. Provided, however, uncreditworthy customers applying for Non-Firm Point-to-Point Transmission Service shall provide an unconditional and irrevocable standby letter of credit, or an alternative form of security identified in Section E, in an amount equal to three (3) times the estimated charges for transmission and ancillary services including losses (rounded to the nearest thousand dollar increment) for an average month for that type of service.

C.1.i.b. The estimated average monthly charge for Long-Term Firm Point-to-Point and Network Integration Transmission Service shall be based on the Long-Term Firm Point-to-Point Transmission Service rate for the reserved capacity or the load being served, respectively. Any letter of credit provided by a Transmission Customer must be acceptable to the Transmission Provider and consistent with the Commercial practices established by the Uniform Commercial Code. All costs associated with the issuance and maintenance of a letter of credit shall be paid by the Transmission Customer. A draft, acceptable form of a letter of credit shall be posted on OASIS; or

C.1.ii. arrange to prepay for Transmission Service as follows:

C.1.ii.a. For requests with a term greater than one month, the prepayment for the first month must be made when the Transmission Customer makes its reservation for that Transmission Service request, and no later than five (5) business days before the commencement of service. Prepayments for the subsequent months of service must be made no later than five (5) business days prior to the beginning of each month;

C.1.ii.b. For service for one (1) month or less, the Transmission Customer shall pay the total charge for service when it makes the request, and no later than five (5) business days prior to the commencement of service. For Network Integration Transmission Service customers, the advance payment for each month shall be based on a reasonable estimate by the Transmission Provider of the charge for that month. The Transmission Provider shall pay interest on any prepayments made pursuant to this Section C.1(ii) at the rates established in 18 C.F.R.§ 35.19a(2)(iii).

Where applicable, all uncreditworthy customers applying for new service that fail to meet Section B's creditworthiness criteria shall also pay the application deposits required by either Sections 17.3 or 29.2 of the Tariff.

C.2. Existing Transmission Customers: Any Transmission Customer that originally meets the creditworthiness requirements of Section B and subsequently fails to meet those requirements after it requests Transmission Service but before termination of that service shall:

C.2.i. Within five (5) business days of receipt of a notice from the Transmission Provider, provide the Transmission Provider an acceptable form of financial assurance permitted by this Attachment L that is equal to the Transmission Customer's average monthly Transmission Services charge for the applicable Transmission Service; and

C.2.ii. Within thirty-five (35) calendar days of such notification, provide the Transmission Provider either: (a) an unconditional and irrevocable letter of credit that is equal to two (2) times the Transmission Customer's average monthly Transmission Services charge for the applicable Transmission Service, including losses; or (b) an equivalent alternate form of financial assurance pursuant to Section E; or

C.2.iii. arrange to prepay for Transmission Service in accordance with the procedures set forth in Section C.1(ii). Provided, however, the Transmission Customer must provide the Transmission Provider payment for all outstanding Transmission Service charges no later than five (5) business days prior to the beginning of the next month.

C.3. The average monthly Transmission Service charge for Sections C.2 (i) and (ii) will be based on the Transmission Customer's charges during the preceding twelve (12) months for the applicable Transmission Service. If the Transmission Customer has not yet been purchasing service for twelve (12) months, then the average will be the higher of either: (a) the average of the monthly cost of service to date; or (b) the average value specified in Section C.1.

C.4. Right to Protect Against Additional Risk of Non-payment: All financial assurances calculated and collected pursuant to Sections C.1 and C.2 must be sufficient to protect the Transmission Provider from the risk of non-payment with respect to an uncreditworthy Transmission Customer during the entire term of such customer's Transmission Service Agreement. Accordingly, after an uncreditworthy customer has provided the Transmission Provider financial assurances pursuant to Sections C.1 or C.2, the Transmission Provider will monitor the amount of such customer's Transmission Services charges to ensure that it has provided a sufficient amount of security to protect the Transmission Provider against the risk of non-payment. If a Transmission Customer is not in Default pursuant to Section 7.3, then the Transmission Customer shall provide the adjusted amount of financial assurances required pursuant to this Section C.3 within thirty-five (35) calendar days of receipt of a notice from the Transmission Provider. A Transmission Customer will not be required to adjust its financial assurances pursuant to this Section C.3 more than twice every twelve (12) months.

C.4.i. Adjustment of Financial Assurances Provided Pursuant to Section C.1: If a Transmission Customer provided security when initially applying for service pursuant to Section C.1 and the Transmission Provider determines that the Transmission Customer's actual average monthly Transmission Services charges over any subsequent twelve (12) month period exceed the original average estimated charges for transmission and ancillary services upon which a financial assurance initially was based, then the Transmission Customer must increase its financial assurance to be equal to three (3) times its current actual average monthly purchases of Transmission Service. The value of the actual average monthly purchases of Transmission Services evaluated pursuant to this Section C.3.i will be based on the preceding twelve (12) month period as measured from the date immediately prior to the Transmission Provider's credit re-evaluation. Pursuant to Section C.1, the sum of any required security will include, where applicable, any application deposits required pursuant to Sections 17.3 or 29.2.

C.4.ii. Adjustment of Financial Assurances Provided Pursuant to Section C.2: If a

Transmission Customer provided security pursuant to Section C.2 and the Transmission Provider determines that the customer's actual average monthly purchases of Transmission Services over a subsequent twelve (12) month period exceed the original monthly average for charges for transmission and ancillary services upon which the amount of a financial assurance initially was based, then the Transmission Customer must increase the amount of its financial assurance to be equal to three (3) times its actual average purchases of Transmission Service. The value of the actual average monthly purchases of Transmission Services evaluated pursuant to this Section C.3.ii will be based on the preceding twelve (12) month period as measured from the date immediately prior to the Transmission Provider's credit reevaluation.

C.4.iii. Transmission Customer Right To Request A Credit Reevaluation: Transmission Customers may make reasonable requests for the Transmission Provider to re-evaluate their creditworthiness pursuant to the relevant standard established in either Section C.4.i or C.4.ii. Based on such a re-evaluation, if appropriate, the Transmission Provider will reduce the amount of financial security requested from a Transmission Customer if an analysis of its transmission usage over the preceding twelve (12) month period indicates that the customer has provided security in excess of that required by this Attachment L.

C.4.iv. Right to Draw Upon Financial Assurances Upon Default: The Transmission Provider has the right to liquidate, or draw upon, all or a portion of a Transmission Customer's form of financial assurance(s) in order to satisfy a Transmission Customer's total net obligations to the Transmission Provider upon a Default pursuant to Section 7.3 of the Tariff. A Transmission Customer shall replace any liquidated, or drawn-upon, financial assurances pursuant to the timeframe delineated in Section C.2.

C.5. Notice: The Transmission Provider's notification to a Transmission Customer will inform the Transmission Customer:

C.5.i. that it is not creditworthy pursuant to this Attachment L, or in accordance with Section C.3, that it must adjust previously provided financial assurances;

C.5.ii. why it is not creditworthy or why it must adjust previously provided financial assurances;

C.5.iii. that it must provide any required financial assurances by the deadlines specified in the notice; and

C.5.iv. that the Transmission Provider may take corrective actions, including suspension of service pursuant to Section D, if the Transmission Customer fails to provide the required financial assurances by the specified deadlines.

All notices sent to a Transmission Customer pursuant to this Section C.5 shall be in writing and shall be sent to the Transmission Customer by telefax or overnight courier at the respective telephone number or courier address specified in the Transmission Customer's application for Transmission Service (or such other address as the Transmission Customer may have designated in writing to the Transmission Provider) and shall become effective upon actual receipt as evidenced by telefax confirmation sheet or tracking information provided by the overnight courier, as the case may be.

D. **Suspension of Service:** The Transmission Provider may suspend Transmission Service if:

D.1. a Transmission Customer that is not in Default pursuant to Section 7.3 of this Tariff fails to provide the entirety of three (3) months of required financial assurances (or the entirety of any additional financial assurances required pursuant to Section C.3 or C.4) within thirty-five (35) calendar days after Transmission Provider's notification to such Transmission Customer pursuant to Section C.3. Transmission Provider will provide at least thirty (30) calendar days written notice to the Commission before suspending Transmission Service; or

D.2. a Transmission Customer that is in Default pursuant to Section 7.3 of this Tariff fails to provide the entirety of the one month's requested financial assurance within five (5) business days after the Transmission Provider's notification to such Transmission Customer pursuant to Section C. Transmission Provider will provide five (5) calendar days written notice to the Commission before suspending Transmission Service. Any notices sent to the Transmission Customer and to the Commission pursuant to this Section D may be telefaxed/mailed concurrently. The suspension of service shall continue only for as long as the circumstances that entitle the Transmission Provider to suspend service continue. A Transmission Customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

E. **Alternative Forms of Financial Assurance:** Transmission Customer may provide the following as acceptable alternative forms of financial assurance in the amounts specified in Sections C.1 or C.2:

E.1. Cash Deposit: The Transmission Customer may provide a cash deposit that will be retained during the term of (and until full and final payment and performance of) any relevant Service Agreement. If a Transmission Customer has submitted multiple requests for Transmission Service, then the Transmission Provider may require a cash deposit for each Service Agreement. Cash deposits submitted as a form of financial assurance will be held by the Transmission Provider and the Transmission Customer will be paid an interest rate that is equal to the interest rate earned on the escrow account in which the cash deposit is held. The cash deposit can be made by wiring immediately available funds to the Transmission Provider's account.

E.2. Surety Bond: The Transmission Customer may provide, and maintain in effect during the term of (and until full and final payment and performance of) the applicable Service Agreement, a surety bond issued by a financial institution acceptable to Transmission Provider. If a Transmission Customer has submitted multiple requests for Transmission Service, then the Transmission Provider may require a surety bond for each Service Agreement. All costs associated with the issuance and maintenance of a surety bond shall be paid by the Transmission Customer. A draft, acceptable form of a surety bond shall be posted on OASIS.

F. Return of Financial Assurances upon Re-establishment of Creditworthiness: If a Transmission Customer re-establishes creditworthiness pursuant to Section B, then upon verification by Transmission Provider, all financial assurances will be returned (or terminated, if applicable) to the Transmission Customer with interest (if applicable), upon payment of all past due balances to the Transmission Provider pursuant to the Tariff.

SCHEDULE 21 - NSTAR

NSTAR ELECTRIC COMPANY

LOCAL SERVICE SCHEDULE

I COMMON SERVICE PROVISIONS

1.0 DEFINITIONS

Whenever used in this Local Service Schedule, in either the singular or plural number, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Local Service Schedule that are not defined in this Local Service Schedule shall have the meanings set forth in the Tariff or customarily attributed to such terms by the electric utility industry in New England. Where there is a conflict between this Local Service Schedule and the Tariff, the terms here shall apply.

1.1 Annual Transmission Revenue Requirements

The total annual cost of the Transmission System shall be the amount specified in Attachment D until amended by NSTAR or modified by the Commission.

1.2 Annual True-Up

The reconciliation to actual costs of the estimated costs used for billing purposes under Section 4.0 of this Local Service Schedule for any Service Year.

1.3 Designated Agent

Any entity that performs actions or functions on behalf of NSTAR, an Eligible Customer, or the Transmission Customer required under the Local Service Schedule.

1.4 Firm Local Point-To-Point Service

Transmission service under this Local Service Schedule that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to this Local Service Schedule.

1.5 Load Ratio Share

Ratio of a Transmission Customer's most recently reported Monthly Network Load in the case of Network Customers and including, where applicable, the Reserved Capacity of Transmission Customers taking Firm Local Point-To-Point Service, to the total load of Network Customers and the Reserved Capacity of Transmission Customers taking Firm Local Point-To-Point Service.

1.6 Local Network

All transmission facilities constituting NSTAR's non-Pool Transmission Facilities (Non-PTF), excluding the Phase I/II HVDC-TF, which is defined in Schedule 20A of this OATT.

1.7 Local Network Load

The load that a Network Customer designates for Local Network Service under this Local Service Schedule. The Network Customer's Local Network Load shall include all load designated by the Network Customer, (including losses). A Network Customer may elect to designate less than its total load as Local Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete Points of Delivery as Local Network Load, the Eligible Customer is responsible for making separate arrangements under this Local Service Schedule for any Local Point-To-Point Service that may be necessary for such non-designated load.

1.8 Local Network Service

The transmission service provided under this Local Service Schedule over NSTAR's Local Network.

1.9 Local Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support NSTAR's overall Transmission System for the general benefit of all users of such Transmission System.

1.10 Local Point-To-Point Service

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under this Local Service Schedule over NSTAR's Local Network.

1.11 Long-Term Firm Local Point-To-Point Service

Firm Local Point-To-Point Service provided under this Local Service Schedule with a term of one year or more.

1.12 Monthly Network Load

A Network Customer's hourly load (including its designated Local Network Load not physically interconnected with NSTAR under Section 15.2 of this Local Service Schedule) coincident with NSTAR's Monthly Transmission System Peak.

1.13 Native Load Customers

The wholesale and retail power customers of NSTAR on whose behalf NSTAR, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate NSTAR's system to meet the reliable electric needs of such customers.

1.14 NERC

North American Electric Reliability Council, the Electric Reliability Organization of the United States.

1.15 Non-Firm Local Point-To-Point Service

Local Point-To-Point Service under this Local Service Schedule that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in this Local Service Schedule. Non-Firm Local Point-To-Point Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.16 NPCC

Northeast Power Coordinating Council, a regional reliability council of NERC.

1.17 NSTAR

NSTAR Electric Company, a Massachusetts Corporation with offices located at 800 Boylston Street, Boston, Massachusetts 02199. NSTAR owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides service pursuant to the rates, terms and conditions of this Local Service Schedule and the applicable terms and conditions of this Local Service Schedule.

1.18 NSTAR's Monthly Transmission System Load

NSTAR's Monthly Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Service customers pursuant to Part II of this Local Service Schedule plus the

Reserved Capacity of all Firm Local Point-To-Point Service customers.

1.19 NSTAR's Monthly Transmission System Peak

The maximum firm usage of NSTAR's Transmission System in a calendar month.

1.20 Parties

NSTAR and the Transmission Customer receiving service under this Local Service Schedule.

1.21 Point(s) of Delivery

Point(s) on NSTAR's Transmission System where capacity and energy transmitted by NSTAR will be made available to the Receiving Party under this Local Service Schedule. The Point(s) of Delivery shall be specified in the Transmission Service Agreement.

1.22 Point(s) of Receipt

Point(s) of interconnection on NSTAR's Transmission System where capacity and energy will be made available to NSTAR by the Delivering Party under this Local Service Schedule. The Point(s) of Receipt shall be specified in the Transmission Service Agreement.

1.23 Service Year

The calendar year in which the Transmission Customer is receiving service under this Local Service Schedule.

1.24 Short-Term Firm Local Point-To-Point Service

Firm Local Point-To-Point Service under this Local Service Schedule with a term of less than one year.

1.25 Transmission System

The facilities owned, controlled or operated by NSTAR that are used to provide transmission service under this Local Service Schedule.

2.0 ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the

Control Areas affected by the transmission service. NSTAR is required to provide and the Transmission Customer is required to purchase the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Supplemental End-Use Reactive Support Service.

In addition, the Transmission Customer is required to purchase additional Ancillary Services under the terms and conditions of the Tariff. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve. NSTAR shall also assess a penalty for any unauthorized use of Ancillary Services by the Transmission Customer, based on the amount of transmission service it used but did not reserve, using the rate shown for such Ancillary Service.

The prices and/or compensation methods for Local System Control and Dispatch Services and Supplemental End-Use Reactive Support Service are described in Attachment D and Schedule 2, respectively, attached to and made a part of this Local Service Schedule. Three principal requirements apply to discounts for Ancillary Services provided by NSTAR in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on NSTAR's system.

3.0 <u>CREDITWORTHINESS</u>

NSTAR's creditworthiness procedures are specified in Attachment L to this Local Service Schedule.

4.0 <u>BILLING AND PAYMENT</u>

4.1 Billing Procedure

Within a reasonable time after the first day of each month, NSTAR shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Local Service Schedule during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to NSTAR, or by wire transfer to a bank named by NSTAR.

Billings hereunder shall be based on cost estimates made by NSTAR subject to Annual True-up when actual costs for the Service Year are known. Such Annual True-up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-up relates. To the extent bill adjustments are required pursuant to the Annual True-up, such adjustments shall bear interest calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

(i) The Annual True-Up shall be performed by recalculation of the costs for the Service Year based on actual cost and load information as reported in the FERC Form 1 for that Service Year and shall develop thereby an Embedded Cost Charge, defined in Section 16.1, to be used in the said Annual True-Up. The Annual True-Up shall also include the CWIP Supplement referred to in clause (ix).

(ii) The Annual True-Up will be filed with FERC by NSTAR in an informational filing on or before May 31 of the year following the Service Year and posted on NSTAR's website. The Annual True-Up so filed and posted shall include the actual report showing the basis for the computation of the Postretirement Benefits Other Than Pensions ("PBOP") component of "Administrative and General Expense" and shall also show the basis for the allocation of the PBOP expense to the service provided under this Local Service Schedule; provided that the information so filed and posted shall not include confidential information. The informational filing shall include a Benefits Labor Loader showing the basis for such allocation of both PBOP and prepaid pension costs. On request, NSTAR shall provide any Network Customer the Annual True-Up by May 31 of the year following the Service Year. Any difference between the estimated Embedded Cost Charge and the actual Embedded Cost Charge shall be collected from or refunded to the Network

Customer in the month of June of the calendar year following the Service Year.

(iii) The Annual True-Up provided pursuant to Section 4.1(ii) shall include an attestation by a Company officer that "to the best of the affiant's knowledge, information and belief the data employed in the Annual True-Up reflect NSTAR's per book costs for the Service Year, conform to NSTAR's FERC Form 1 Report for the Service Year, conform in all material respects to the FERC Uniform System of Accounts, and have been developed in accordance with the provisions of this rate schedule."

(iv) The Annual True-Up shall also be accompanied by supplementary information which shall (i) detail any data used in the Annual True-Up not directly taken from NSTAR's FERC Form 1 Report and (ii) identify any FERC Form 1 Account used to record expenses during the Service Year that was not used in the preceding Service Year. The supplementary information shall be certified by an officer of NSTAR.

(v) There shall be an "Audit Period" that will extend from July 1 through September 30 of the year following the Service Year; provided that NSTAR and the Network Customer may agree to extend the Audit Period beyond September 30 by their mutual written agreement. During the Audit Period, any Network Customer shall have the right to conduct an audit or other inspection of the actual data used in the Annual True-Up and/or request additional information not included with the Annual True-Up. NSTAR shall not withhold information, including PBOP information, on grounds of confidentiality, but is entitled to make such information available pursuant to a confidentiality agreement and to restrict access to non-competitive duty personnel and to other personnel whose receipt of the information would not be in violation of the Standards and/or Code of Conduct as prescribed by FERC. During the Audit Period, NSTAR shall exercise all commercially reasonable efforts to provide the Network Customer, within 10 business days, such additional information as the Network Customer may request in order to understand the Annual True-Up. To the extent requested, NSTAR shall meet with any Network Customer to provide such additional information, explanation, and/or clarification regarding the Annual True-Up as the Network Customer may request.

(vi) During the Audit Period, the Network Customer shall have the right to request NSTAR to adjust the Annual True-Up, and any refunds it received or payments it made, pursuant to the Annual True-Up to the extent of any discrepancy between the data employed by NSTAR in performing the Annual True-Up and the actual data for the Service Year or in the event NSTAR developed the Annual True-Up in a manner that is inconsistent with this rate schedule.

(vii) If NSTAR does not agree to the Network Customer's request, as set forth in subparagraph (vi), and if NSTAR and the Network Customer are in disagreement as to any component of the Annual True-Up, the Network Customer within thirty days following the conclusion of the Audit Period may request and NSTAR shall agree to non-binding dispute resolution either conducted with the FERC Staff or otherwise at the Network Customer's choice. The Network Customer may file a complaint with the Commission within thirty days following completion of the audit period or the dispute resolution process and shall specify in that complaint the component or components of the Annual True Up that the Network Customer disputes. In the event such a complaint is filed, the disputed component or components of the Annual True Up shall be subject to refund as of the first day of the Service Year pending the results of the Commission investigation instituted as a result of such complaint. If the Network Customer fails to object to the Annual True-Up within thirty days following conclusion of the Audit Period, NSTAR's costs for the Service Year shall be deemed final, and its revenues from the Network Customer for the Service Year shall not be subject to refund; provided that the deadline for such an objection shall (i) be extended for ninety days following the date NSTAR makes any subsequent change to its Form 1 data for the Service Year that affects the Annual True-Up and (ii) shall not apply if the Commission prior to December 31st of the calendar year following the Service Year institutes its own investigation of NSTAR's Service Year costs.

(viii) Subject to the limitation that the Massachusetts Attorney General does not make or receive transmission payments or refunds, the Massachusetts Attorney General shall have the same procedural rights under this Section 4.0 as a Network Customer. This in no way obligates the Massachusetts Attorney General to the dispute resolution or arbitration procedures outlined in Sections 5.1 and 5.2.

(ix) The Annual True-Up shall include a CWIP Supplement, which shall apply to the Service Year, shall be filed with FERC by NSTAR in an informational filing on or before June 30 of the year following the Service Year and posted on NSTAR's website to the extent it does not include critical energy infrastructure information or other confidential information. The CWIP Supplement shall include NSTAR Electric's most recent annual construction forecast. The CWIP Supplement shall provide for each project included in rate base during the Service Year the actual amounts of CWIP recorded for each project, the related accounts, such as AFUDC and regulatory liability, inclusive of all subaccounts, and the resulting effect on the CWIP revenue requirement in line item detail. The CWIP Supplement shall also identify any changes in NSTAR's accounting practices related to the accrual of AFUDC and the inclusion of CWIP in rate base or related to ensuring that AFUDC is not accrued on CWIP balances that have been included in rate base.

For each "new project" (a project that is estimated to enter rate base for the first time in the Service Year), the CWIP Supplement shall provide, to the extent not included in the construction forecast, a detailed statement of the reasons for undertaking the project, the benefits to be derived from the project, and the alternatives to or consequences of not undertaking the project. For each "pre-existing project" (a project that entered rate base prior to the Service Year), the CWIP Supplement shall include an update on the status of the project including any material change regarding the estimated cost of the project, the estimated in-service date and/or project timelines, and whether there is any change in the need for the project or in alternatives to the project. CWIP associated with a project cannot be included in the rate base for a Service Year unless it is included in the CWIP Supplement applicable to the Service Year.

The CWIP Supplement applicable to a Service Year shall include a CWIP Work Order/Project Reference Aid ("Reference Aid") that distinguishes between new projects and pre-existing projects and that provides for each project, whether new or pre-existing, ISO information, to the extent such information is available and applies to a project, and NSTAR information. The ISO information shall include a short description of the project, the year the project was approved through the ISO process, and the project identification number for ISO purposes. The NSTAR information shall include reference to the most recent NSTAR construction planning forecast in which the project appeared, the page of the plan at which the project description begins, the NSTAR numeric project designation, the NSTAR description of the project, the work order or work orders associated with the project, and a description of each work order. The Reference Aid shall present this information in a format so that the ISO information related to a project can be correlated with the

NSTAR information related to a project. The Reference Aid, as described above, is based on current ISO and NSTAR tracking systems for projects under or proposed for construction and is to be modified to present equivalent information if and to the extent the ISO and/or NSTAR tracking system is modified.

The 50% of transmission-related CWIP included in rate base is subject to the Annual True-Up and dispute resolution provisions of this Section 4.1 regarding differences between actual and estimated costs. In addition, the CWIP included in rate base for a project shall be subject to refund as provided below to the extent the Commission makes a finding that the inclusion of such CWIP in rate base is unjust and unreasonable. In the case of a new project, the refund amount shall be the CWIP actually recovered from customers from the date of collection to the date of refund. In any proceeding regarding a new project, NSTAR shall bear the burden of proving that inclusion of CWIP related to the new project in rate base is just and reasonable. In the case of a pre-existing project, the refund amount shall be for the CWIP actually recovered from customers from the prospective refund effective date specified by the Commission pursuant to the provisions of Section 206 of the Federal Power Act to the date of refund. All refunds shall include interest at the rate specified in 18 C.F.R. § 35.19a(a)(2)(iii). Any customer and/or the Massachusetts Attorney General can request that the Commission institute an investigation into the justness and reasonableness of including CWIP for any project in rate base and the Commission may institute such an investigation sua sponte.

Nothing in this Clause (ix) authorizes the inclusion in rate base of more than 50% of the CWIP balance attributable to a project. Absent a Commission finding of imprudence, NSTAR shall be entitled to accrue AFUDC as to any CWIP that is excluded from rate base. The Commission's institution of an investigation as to the justness and reasonableness of including CWIP associated with a project in rate base does not affect the timing or the finality of other components of the Annual True-Up as established by clause (vii) hereof.

With the exception of curtailment penalty charges pursuant to Section 16.2 and Schedule 3, paragraph 5 and Schedule 4, paragraph 6, any Annual True-Up rendered under this Local Service Schedule and any other monthly bill to which the Annual True-Up relates shall be binding on both Parties one (1) year from the date of NSTAR's Annual True-Up, unless previously disputed pursuant to this section or Section 4.3 of this Local Service Schedule.

4.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by NSTAR.

4.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to NSTAR on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after NSTAR notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, NSTAR may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request.

In the event of a billing dispute between NSTAR and the Transmission Customer, NSTAR will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then NSTAR may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5.0 DISPUTE RESOLUTION PROCEDURES

5.1 Internal Dispute Resolution Procedures

Any dispute between a Transmission Customer and NSTAR involving transmission service under this Local Service Schedule (excluding applications for rate changes or other changes to this Local Service Schedule, or to any Service Agreement entered into under this Local Service Schedule, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of NSTAR and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

5.2 External Arbitration Procedures

Any arbitration initiated under this Local Service Schedule shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or ISO rules.

5.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Local Service Schedule and any Service Agreement entered into under this Local Service Schedule and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

5.4 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(a) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(b) one half the cost of the single arbitrator jointly chosen by the Parties.

5.5 Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

II LOCAL POINT-TO-POINT SERVICE

6.0 NATURE OF FIRM LOCAL POINT-TO-POINT SERVICE

6.1 Curtailment of Firm Local Point-To-Point Service

In the event a Transmission Customer (including Third-Party Sales by NSTAR) fails to curtail a transaction when requested to do so by NSTAR, the Local Control Center and/or ISO, as appropriate and pursuant to this Section, NSTAR shall assess a penalty charge to the Transmission Customer. Said penalty charge will be determined in accordance with this Local Service Schedule.

In the event NSTAR, the Local Control Center or ISO exercises their rights to effect a Curtailment, in whole or in part, of Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the Transmission Customer.

6.2 Classification of Firm Local Point-To-Point Service

(a) The Transmission Customer taking Firm Local Point-To-Point Service may, (1) change its Points of Receipt and Delivery to obtain service on a non-firm basis consistent with the terms of Part I, Section 10(a) of Schedule 21 of the OATT or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Part I, Section 10(b) of Schedule 21 of the OATT; provided that NSTAR continues to be compensated for any costs associated with the construction or upgrading of facilities associated with the original firm service.

(b) In the event that a Transmission Customer's use of the Transmission System (including Third-Party Sales by NSTAR) exceeds that Transmission Customer's Reserved Capacity at any Point of Receipt or Point of Delivery in any hour, NSTAR will charge the Transmission Customer a penalty charge in accordance with Section 10 and Schedule 3 of this Local Service Schedule.

(c) Under no circumstance will NSTAR be obligated to provide Control Area Ancillary Services to the Transmission Customer in support of any excess capacity (i.e., capacity in excess of Transmission Customer's Reserved Capacity).

7.0 NATURE OF NON-FIRM LOCAL POINT-TO-POINT SERVICE

7.1 Classification of Non-Firm Local Point-To-Point Service

In the event that a Transmission Customer's use of the Transmission System (including Third-Party Sales by NSTAR) exceeds that Transmission Customer's non-firm Reserved Capacity at any Point of Receipt or Point of Delivery, NSTAR will charge the Transmission Customer a penalty charge in accordance with Section 10 and Schedule 4 of this Local Service Schedule for such excess. Under no circumstance will NSTAR be obligated to provide Control Area Ancillary Services to the Transmission Customer in support of any excess capacity (i.e., capacity in excess of Transmission Customer's Reserved Capacity).

7.2 Curtailment or Interruption of Service

In the event a Transmission Customer (including Third-Party Sales by NSTAR) fails to implement a Curtailment or Interruption when requested to do so by NSTAR, the Local Control Center and/or ISO, as appropriate and pursuant to this Section, NSTAR shall assess a penalty charge. Said penalty charge will be determined in accordance with Section 10 and Schedule 4 of this Local

Service Schedule.

In the event NSTAR, the Local Control Center and/or ISO exercises its rights to effect a Curtailment, in whole or part, of Non-Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the Transmission Customer.

In the event NSTAR, the Local Control Center and/or ISO exercises its rights to effect an Interruption, in whole or part, of Non-Firm Local Point-To-Point Service, the charge payable by the Transmission Customer shall be computed as if the term of service actually rendered were the term of service reserved; provided that an adjustment of the charge shall be made only when the Interruption is initiated by NSTAR, the Local Control Center and/or ISO, not when the customer fails to deliver energy to NSTAR.

8.0 SERVICE AVAILABILITY

8.1 Real Power Losses

Real power losses associated with transactions on NSTAR's Local Network shall be determined based on estimated average system losses for metering points on NSTAR's Local Network; the loss factor will be three and one tenth percent (3.1%).

8.2 Load Shedding

To the extent that a system contingency exists on the NSTAR Transmission System or the New England Transmission System and NSTAR, the Local Control Center or ISO, as appropriate, determines that it is necessary to shed load, the Parties shall shed load in accordance with the procedures specified by NSTAR, the Local Control Center and/or ISO.

9.0 METERING

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under the Local Service Schedule and to communicate the information to NSTAR. However, NSTAR reserves the right to determine and approve any and all metering equipment and the metering installation design, such approval not to be unreasonably withheld.

All meters, including any recording devices or telemetry equipment must be operated and maintained in accordance with ISO Operating Procedures. Unless otherwise agreed, such equipment shall remain the property of NSTAR.

If at any time any metering equipment owned by NSTAR (or the Transmission Customer, if so agreed) is found to be inaccurate in excess of two percent (2%), up or down, the owner of the metering equipment shall cause it to be made accurate or replaced and the meter readings and rate computation for the period of inaccuracy shall be adjusted to correct such inaccuracy so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the next preceding month shall be made except by agreement of the Parties. In addition to an annual routine test, the owner of the metering equipment shall cause such equipment to be tested at any time upon written request of the other Party. If such equipment proves accurate within two percent (2%), up or down, the expense of the test shall be borne by the Party requesting the test. The determination of percent accuracy shall be in accordance with the weighted average percent registration as described in ANSI C12.1-1988, Section 6.1.8.1. The owner of the metering equipment shall comply with any reasonable request of the other Party concerning the sealing of meters, the presence of a representative when the seals are broken and tests are made, and other matters affecting the accuracy of the measurement of electricity hereunder.

10.0 COMPENSATION FOR LOCAL POINT-TO-POINT SERVICE

Rates for Firm and Non-Firm Local Point-To-Point Service shall be determined as set forth in the Schedules appended to this Local Service Schedule: Firm Local Point-To-Point Service (Schedule 3) and Non-Firm Local Point-To-Point Service (Schedule 4). Such rates shall be determined on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 4 of this Local Service Schedule.

NSTAR shall use this Local Service Schedule to make its Third-Party Sales to be transmitted as Local Point-To-Point Service. NSTAR shall account for such use at the applicable rates, pursuant to Section II.8.5 of the Tariff.

11.0 STRANDED COST RECOVERY

NSTAR may seek to recover stranded costs from the Transmission Customer pursuant to this Local Service Schedule in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, NSTAR must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

III LOCAL NETWORK SERVICE

12.0 NATURE OF LOCAL NETWORK SERVICE

12.1 Real Power Losses

Real power losses associated with transactions on Non-PTF shall be determined based on estimated average system losses for metering points on NSTAR's Local Network; the loss factor will be three and one tenth percent (3.1%).

12.2 Metering

Unless agreed otherwise, all meters, including any recording devices or telemetry equipment shall be owned, operated, maintained and tested by NSTAR or its Designated Agent in accordance with ISO Operating Procedures at the Transmission Customer's expense. NSTAR shall provide access to metering data, including telephone line access, which may reasonably be required to facilitate measurement and billing under a Service Agreement at the requesting Party's expense.

NSTAR reserves the sole right to determine appropriate metering installations. When new metering equipment is required, it shall be supplied by NSTAR, at the Transmission Customer's expense, including applicable taxes, and overhead costs, in conformity with ISO Operating Procedures.

If at any time any metering equipment owned by NSTAR (or Transmission Customer, if so agreed) is found to be inaccurate in excess of two percent (2%), up or down, the owner of the metering equipment shall cause it to be made accurate or replaced and the meter readings and rate computation for the period of inaccuracy shall be adjusted to correct such inaccuracy so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the next preceding month shall be made except by agreement of the Parties. In addition to an annual routine test, the owner of the metering equipment shall cause such equipment to be tested at any time upon written request of the other Party.

If such equipment proves accurate within two percent (2%), up or down, the expense of the test shall be borne by the Party requesting the test. The determination of percent accuracy shall be in accordance with the weighted average percent registration as described in ANSI C12.1-1988, Section 6.1.8.1. The owner of the metering equipment shall comply with any reasonable request of the other Party concerning the sealing of meters, the presence of a representative when the seals are broken and tests are made, and other matters affecting the accuracy of the measurement of electricity hereunder.

13.0 NETWORK RESOURCES

13.1 Operation of Network Resources

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or NSTAR's Control Area such that the output of those facilities exceeds its designated Local Network Load, plus Non-Firm Sales delivered pursuant to Part II of this Local Service Schedule, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of NSTAR to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System.

13.2 Transmission Arrangements for Network Resources Not Physically Interconnected With NSTAR

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with NSTAR's Transmission System. NSTAR will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

13.3 Use of Interface Capacity by the Network Customer

Unless otherwise provided under the Tariff, there is no limitation upon a Network Customer's use of NSTAR's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, unless otherwise provided by the Tariff, a Network Customer's use of NSTAR's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

13.4 Network Customer Owned Transmission Facilities

The Network Customer that owns existing transmission facilities that are integrated with NSTAR's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of NSTAR to serve its power and transmission customers. For facilities constructed by the Network Customer subsequent to the Service Commencement Date under this Local Service Schedule, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with NSTAR. Calculation of the credit shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

14.0 DESIGNATION OF LOCAL NETWORK LOAD

14.1 Local Network Load

The Network Customer must designate the individual Local Network Loads on whose behalf NSTAR will provide Local Network Service. The Local Network Loads shall be specified in the Service Agreement.

14.2 Local Network Load Not Physically Interconnected with NSTAR

This section applies to both initial designation pursuant to Section 15.1 and the subsequent addition of new Local Network Load not physically interconnected with NSTAR. To the extent that the Network Customer desires to obtain transmission service for a load outside NSTAR's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Local Network Load for all purposes under this Local Service Schedule and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Service under this Local Service Schedule.

To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this section, the request must be made through a modification of service pursuant to a new Application.

15.0 LOAD SHEDDING AND CURTAILMENTS

15.1 Procedures

Prior to the Service Commencement Date, NSTAR and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the OATT with the objective of responding to contingencies on the Transmission System. The Parties will implement such programs during any period when NSTAR, the Local Control Center or ISO, as appropriate, determines that a system contingency exists and such procedures are necessary to alleviate such contingency. NSTAR will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

15.2 Allocation of Curtailments

NSTAR shall, on a non-discriminatory basis, effect a Curtailment of the transaction(s) that effectively relieves the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by NSTAR and Network Customer in proportion to their respective Load Ratio Shares. NSTAR shall not direct the Network Customer to effect a Curtailment of schedules to an extent greater than NSTAR would effect a Curtailment of NSTAR's schedules under similar circumstances.

15.3 Load Shedding

To the extent that a system contingency exists on NSTAR's Transmission System and ISO, the Local Control Center or NSTAR, as appropriate, determines that it is necessary for NSTAR, Local Point-to-Point Customers and Network Customers to shed load, the Parties shall shed load in accordance with the OATT.

15.4 System Reliability

Any Curtailment of Local Network Service will be not unduly discriminatory relative to NSTAR's use of the Transmission System on behalf of its Native Load Customers. In the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures, NSTAR shall assess a penalty charge. Said penalty charge will be determined in accordance with Section 16.2.

16.0 RATES AND CHARGES

Rates for Local Network Service shall be determined as set forth in this Section 16 on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and all appropriate billing adjustments shall be made pursuant to Section 4 of this Local Service Schedule.

The Network Customer shall pay NSTAR for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

16.1 Monthly Demand Charge

The Network Customer shall pay a Monthly Demand Charge which shall be the Embedded Cost Charge. The Embedded Cost Charge shall be determined by multiplying the Network Customer's Load Ratio Share by one twelfth (1/12) of NSTAR's Annual Transmission Revenue Requirements, as determined in accordance with Attachment D of this Local Service Schedule and as subject to an Annual True-up pursuant to Section 4. The Embedded Cost Charge is based on NSTAR's system average embedded cost. In the event NSTAR seeks to apply a rate based on a methodology other than average embedded cost to all or any part of a Network Customer's service, either already being provided or proposed to be provided, NSTAR shall provide the affected Network Customer thirty days advance written notice of any filing with the Commission seeking to implement such a rate and shall comply with all applicable requirements of the Commission and the Tariff. Any dispute as to NSTAR's position concerning proposed cost allocation shall be addressed as provided in Section II.7(g) of Schedule 21-Local Service to Section II of the Tariff; provided that nothing in this provision prevents NSTAR from filing with the Commission at any time to establish new rates pursuant to the provisions of Section 205 of the FPA or a Network Customer from opposing such a filing, and nothing in this provision is intended to reflect a Network Customer's agreement that

NSTAR has the rights set out in this Section 16.1 or is intended to prevent the affected Network Customer from filing a complaint with the Commission at any time pursuant to the provisions of Section 206 of the FPA or NSTAR from opposing such a filing.

16.2 Curtailment Penalty Charge

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the transmission system, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the Monthly Demand Charge for Local Network Service, as calculated in accordance with Section 16.1 of this Local Service Schedule, for the month in which such service was not curtailed or interrupted.

16.3 [Reserved]

16.4 Taxes and Fees Charge

16.4.1 If NSTAR incurs tax liability currently for which it will in subsequent years receive tax benefits (for example, a taxable contribution in aid of construction) then Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years. Sections 16.4.1 and 16.4.2 are intended to apply to those Transmission Customers for whom Direct Assignment Facilities are constructed pursuant to this Local Service Schedule and to any Transmission Customer's appropriate share of the cost of any required Local Network Upgrades to the extent that any such Local Network Upgrade is identified pursuant to the study procedures outlined in Schedule 21-Local Service, Section II.7(d) and permitted or required by Commission ruling to be paid as a contribution in aid of construction.

16.4.2 If NSTAR takes a position that any particular transaction under any section of the Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above, but additionally taking into account any interest assessment required to be paid by NSTAR.

16.4.3 At its effective date, this Section 16.4 applies only to contributions in aid of construction ("CIAC"). NSTAR reserves the right to file under Section 205 of the FPA to modify this provision to apply to items other than CIAC and the Network Customer reserves the right to oppose any such filing.

17.0 OPERATING ARRANGEMENTS

17.1 Operating Requirements

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of this Local Service Schedule shall be specified in the OATT. The OATT shall provide for the Parties to:

(i) operate and maintain equipment necessary for integrating the Network Customer within NSTAR's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment),

(ii) transfer data between NSTAR and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside NSTAR's Transmission System, interchange schedules, unit outputs for redispatch required under Section 15, voltage schedules, loss factors and other real time data),

(iii) use software programs required for data links and constraint dispatching,

(iv) exchange data on forecasted loads and resources necessary for long-term planning, and

(v) address any other technical and operational considerations required for implementation of this Local Service Schedule, including scheduling protocols.

The OATT will recognize that the Network Customer shall either:

(i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO), as defined in 18 CFR 38.1, and ISO,

(ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with NSTAR, or

(iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO and ISO. NSTAR shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services.

17.2 Network Operating Committee

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the OATT. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 2

SUPPLEMENTAL END-USE REACTIVE SUPPORT SERVICE

In the event that power factor levels and reactive supply requirements set forth in the service agreement or other associated operating or interconnect agreement are not maintained by the Delivering Party (or, as appropriate, the Receiving Party), in accordance with applicable ISO standards and practices then NSTAR shall charge the Transmission Customer to take corrective action. The Transmission customer shall compensate NSTAR for installing the necessary equipment, whether in the form of generating units or other non-generating resources, such as demand resources, to correct the incremental difference between the Transmission Customer's lowest (or highest) power factor level and that which is an acceptable level in accordance with ISO standards and practices. The charges will be based upon the necessary level of reactive power supply required to correct the deficiency in the power factor level.

For the KVAR demand supplied to the Transmission Customer, the charge shall be the greater of a) the market price of installing leading reactive power supply expressed in terms of $/KVAR or b) $50/KVAR of installed (leading) reactive power reflecting current NSTAR cost.

For the KVAR demand absorbed by NSTAR the charge shall be the greater of a) the market price of installing lagging reactive power supply expressed in terms of $/KVAR or b) $22.5/KVAR of installed (lagging) reactive power reflecting current NSTAR cost.

SCHEDULE 3

LONG-TERM FIRM AND SHORT-TERM FIRM

LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall compensate NSTAR for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following charges as applicable:

1) Annual Rate

The Annual Rate for Firm Local Point-To-Point Service shall consist of the higher of (i) the Embedded Cost Charge or (ii) the Incremental Cost Charge, as set forth below:

(i) The Embedded Cost Charge shall be determined by dividing NSTAR's Annual Transmission Revenue Requirements (determined in accordance with Attachment D of this Local Service Schedule) by the maximum amount of NSTAR's Monthly Transmission System Load during such Service Year.

(ii) The Incremental Cost Charge shall be determined from the total costs of all Local Network Upgrades plus other incremental costs incurred provided for in the Service Agreement application to a transaction. If the Incremental Cost Charge is higher, the Transmission Customer shall pay for the facilities necessary to provide it with service during an amortization period, with the Transmission Customer paying the Embedded Cost Charge upon completion of the amortization. Such amortization period shall be coterminous with the Service Agreement.

2) Firm Local Point-To-Point Service for Monthly Transactions or Longer Term Transactions

The charge for each month applicable to a monthly transaction or longer term transaction (the "Monthly Rate") shall be determined as the product of: (a) NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Service Agreement for such month, expressed in kilowatts.

3) Firm Local Point-To-Point Service for Less Than One Month

NSTAR's Weekly Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by fifty-two (52) weeks. NSTAR's Daily Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by three hundred and sixty-five (365) days. NSTAR's Hourly Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by eight thousand seven hundred and sixty (8,760) hours.

The Transmission Customer shall pay the Weekly, Daily or Hourly Rate, as applicable, times the Reserved Capacity set forth in the Transmission Customer's Applicable Service Agreement.

4) <u>Penalty</u>

When the Transmission Customer exceeds its Reserved Capacity or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved (Excess Incident), NSTAR will charge the Transmission Customer 200% of the rate determined as follows for each kilowatt of the Excess Incident:

- The unreserved use penalty for a single hour of unreserved use shall be based on the rate for daily Firm Point-to Point Transmission Service.

- If there is more than one assessment for a given duration (e.g., daily) for the Transmission Customer, the penalty shall be based on the next longest duration (e.g., weekly).

- The unreserved penalty charge for multiple instances of unreserved use (i.e., more than one hour) within a day shall be based on the daily rate for Firm Point-To-Point Transmission Service.

- The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week shall be based on the charge for weekly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month shall be based on the charge for monthly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one month during a calendar year shall be based on the charge for yearly Firm Point-To-Point Transmission Service.

All Excess Incidents will be recorded by NSTAR, and if in any calendar year more than ten (10) Excess Incidents occur in connection with service for the Transmission Customer, then NSTAR may require the Transmission Customer to apply for additional Firm Local Point-To-Point Service under this Local Service Schedule in the amount equal to the highest Excess Incident during that Service Year. Charges for such additional transmission service will relate back to the first day of the month following the month of NSTAR's notice.

5) Curtailment Penalty Charge

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the Transmission System, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the Monthly Rate for Firm Local Point-To-Point Service for the month in which such service was not curtailed or interrupted.

6) Taxes and Fees Charge

A) If any governmental authority requires the payment of any fee or assessment not specifically provided for in any of the charge or rate provisions under this Local Service Schedule or imposes a sales, gross revenue, or other form of tax with respect to payments made for service provided under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. NSTAR will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's Regulations.

B) If NSTAR incurs tax liability currently for which it will, in subsequent years, receive tax benefits (for example, a taxable contribution in aid of construction), the Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years.

C) If NSTAR takes a position that any particular transaction under any section of this Local Service

Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation, or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above but additionally taking into account any interest assessment required to be paid by NSTAR.

7) Regulatory Expense Charge

NSTAR shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreement(s).

8) Customer-Related Expense Charge

NSTAR shall charge the Transmission Customer, in addition to the other charges assessed pursuant to this Local Service Schedule, and as set forth in its Service Agreement for those costs attributable to the billing, meter reading, record keeping, (all from FERC Uniform System of Accounts Nos. 901-905) and an allocation of administrative and general expenses (FERC Uniform System of Accounts Nos. 920-935) associated with each of these costs, all of which are related to the Transmission Customer's Local Point-To-Point Service and allocated on the basis of the total number of customers served by NSTAR.

9) Exchanges

With respect to any transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a transmission charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

10) Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, NSTAR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

11) Resales

The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

SCHEDULE 4

NON-FIRM LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall compensate NSTAR for any Ancillary Services and for Non-Firm Local Point-To-Point Service up to the sum of the applicable charges set forth below:

1) The Annual Rate for Non-Firm Local Point-To-Point Service shall be NSTAR's Annual Transmission Revenue Requirements (determined in accordance with Attachment D of this Local Service Schedule) for the Service Year divided by NSTAR's Monthly Transmission System Load during such Service Year.

2) Non-Firm Local Point-To-Point Service for Monthly Transactions or Longer Term Transactions
The charge for each month applicable to a monthly transaction or longer term transaction (the "Monthly Rate") shall be determined as the product of: (a) NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Service Agreement for such month, expressed in kilowatts.

3) Non-Firm Local Point-To-Point Service for Less Than One Month
NSTAR's Weekly Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by fifty-two (52) weeks.

NSTAR's Daily Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by three hundred and sixty-five (365) days. NSTAR's Hourly Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by eight thousand seven hundred and sixty (8,760) hours.

The Transmission Customer shall pay the Weekly, Daily or Hourly Rate, as applicable, time the Reserved Capacity set forth in the Transmission Customer's Applicable Service Agreement.

4) Credit to the Transmission Charge
Whenever service provided hereunder is interrupted or curtailed by NSTAR, or its Designated Agent including ISO, the Transmission Charges to the Transmission Customer calculated pursuant to Sections 2

and 3 of this Schedule 4 shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service. The credit to the Transmission Customer for each hour of interruption or curtailment shall be calculated as the product of (a) NSTAR's Hourly Rate and (b) the kilowatts of service interruption or curtailment during such hour.

5) Penalty

When the Transmission Customer exceeds its Reserved Capacity or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved (Excess Incident), NSTAR will charge the Transmission Customer 200% of the rate determined as follows for each kilowatt of the Excess Incident:

- The unreserved use penalty for a single hour of unreserved use shall be based on the rate for daily Firm Point-to Point Transmission Service.

- If there is more than one assessment for a given duration (e.g., daily) for the Transmission Customer, the penalty shall be based on the next longest duration (e.g., weekly).

- The unreserved penalty charge for multiple instances of unreserved use (i.e., more than one hour) within a day shall be based on the daily rate for Firm Point-To-Point Transmission Service.

- The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week shall be based on the charge for weekly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month shall be based on the charge for monthly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one month during a calendar year shall be based on the charge for yearly Firm Point-To-Point Transmission Service.

All Excess Incidents will be recorded by NSTAR, and if in any calendar year more than ten (10) Excess Incidents occur in connection with service for the Transmission Customer, then NSTAR may require the

Transmission Customer to apply for additional Non-Firm Local Point-To-Point Service under this Local Service Schedule in the amount equal to the highest Excess Incident during that Service Year. Charges for such additional Non-Firm Local Point-To-Point Service will relate back to the first day of the month following the month of NSTAR's notice.

6) Curtailment Penalty Charge.

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the Transmission System, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the monthly demand charge for Non-Firm Local Point-To-Point Service for the month in which such service was not curtailed or interrupted.

7) Taxes and Fees Charge

A) If any governmental authority requires the payment of any fee or assessment not specifically provided for in any of the charge or rate provisions under this Local Service Schedule or imposes a sales, gross revenue, or other form of tax with respect to payments made for service provided under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. NSTAR will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's Regulations.

B) If NSTAR incurs tax liability currently for which it will, in subsequent years, receive tax benefits (for example, a taxable contribution in aid of construction), the Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years.

C) If NSTAR takes a position that any particular transaction under any section of this Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation, or court action, then the

Transmission Customer shall pay to NSTAR an amount calculated as described above but additionally taking into account any interest assessment required to be paid by NSTAR.

8) Regulatory Expense Charge

NSTAR shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreement(s).

9) Customer-Related Transaction Charge

NSTAR shall charge the Transmission Customer, in addition to the other charges assessed pursuant to this Local Service Schedule, and as set forth in its Service Agreement for those costs attributable to the billing, meter reading, record keeping, (from FERC Uniform System of Accounts Nos. 901-905) and an allocation of administrative and general expenses (Nos. 920-935) associated with each of these costs, all of which are related to the Transmission Customer's Local Point-To-Point Service and allocated on the basis of the total number of customers served by NSTAR.

10) Exchanges

With respect to any transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a transmission charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

11) Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, NSTAR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

12) Resales

The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

ATTACHMENT A

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

1. Introduction

ISO is the regional transmission organization ("RTO"), serving the New England Control Area. ISO is responsible for development, oversight, and fair administration of New England's wholesale market and management of bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is interconnected to three neighboring Balancing Authority Areas: New Brunswick System Operator Area ("NBSO Area"), New York Independent System Operator Area ("NYISO Area"), and Hydro-Québec TransÉnergie Area ("HQTÉ Area").

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission-approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the transmission provider for transmission service associated with PTF, the Participating Transmission Owners (PTOs) under the Transmission Operating Agreement, such as NSTAR, provide local transmission service over Non-Pool Transmission Facilities within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Service provided under Schedule 21. Pursuant to CFR § 37.6(b)[1] of the Commission's regulations, NSTAR as a Transmission Provider is obligated to calculate and post ATC and TTC for certain local facilities over which Point-to-Point transmission service is provided under Schedule 21-NSTAR. These are primarily radial paths that provide transmission service to directly interconnected generators.

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[1] §37.6(b) Posting transfer capability. The available transfer capability (ATC) on the Transmission Provider's system and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set forth in this section.

Posted Path is defined as any control area-to-control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which serviced was denied, curtailed or interrupted. §37.6(b)(1)(i).

NSTAR does not currently have any Posted Paths based on the above definition. However, to the extent that NSTAR does in the future have any Posted Path(s), NSTAR will calculate ATC and TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to the following functions which are performed or utilized by NSTAR in order to provide Local Point-to Point Service under Schedule 21-NSTAR: Total Transfer Capability (TTC) methodology; Available Transfer Capability (ATC) methodology; Existing Transmission Commitment (ETC); Use of Transmission Reliability Margin (TRM); Use of Capacity Benefit Margin (CBM); and Use of Rollover Rights (ROR) in the calculation of ETC.

TTC and ATC are required to be calculated only for certain non-PTF internal paths over which Local Point-to-Point Service is provided under Schedule 21-NSTAR. TTC and ATC are not calculated by NSTAR for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and NSTAR does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the open access transmission tariff for New England, the process by which generation located inside New England supplies energy and/or capacity to the bulk electric system has differed from the Commission's pro forma open access transmission tariff. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit energy transactions that move into the New England Control Area, out of the New England Control Area or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast LMPs and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of economic External Transactions is greater than the transfer capability of the associated external interface, the ExternalTransactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through-or-Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the New England Control Area, and non-PTF where utilized for Local Network Service by generation or load. However, NSTAR owns local transmission facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those facilities, Market Participants may obtain a transmission service reservation from NSTAR under Schedule 21-NSTAR prior to delivery of energy and/or capacity into the New England markets pursuant to Schedule 18, 20A or 20B of the Tariff. This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. NSTAR Total Transfer Capability (TTC)

TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21-NSTAR is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on the NSTAR OASIS site.

The TTC on NSTAR's Non-PTF that requires Local Point-to-Point Service reservations are relatively static values. NSTAR calculates the TTC for Posted Paths as the rating of the particular radial transmission path.NSTAR will calculate and post TTC on its OASIS site for all non-PTF Posted Paths that are eligible for Local Point-to-Point Service reservations. TTC is calculated as the transfer capability rating of the particular radial transmission path less the most limiting element within the PostedPath.

4. Capacity Benefit Margin (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a Transmission Provider for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents, and in any event, ISO's determination of CBM does not apply directly to the determination of ATC for Local Service. Load Serving Entities operating with the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with the Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of NSTAR's ATC calculation and because CBM for the New England Control Area is set to zero (0), NSTAR utilizes a zero (0) CBM value.

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. As NSTAR does not have any external interfaces, TRM for its non-PTF facilities is presently set to zero.

6. Existing Transmission Commitments

6.1 Existing Transmission Commitments, Firm (ETC_F)

ETC_F are confirmed Firm Local Point-To-Point Transmission Service reservations (PTP_F) plus any exercised rollover rights for Firm Point-To-Point Transmission Service reservations (ROR_F). There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F), and other services, contracts or agreements

(OS_F) to be considered in the ETC_Fcalculation.

6.2 Existing Transmission Commitments, Non-Firm (ETC_{NF})

ETC_{NF} are confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}), or other services, contracts or agreements (OS_{NF}).

7. Calculation of ATC for NSTAR's Transmission System

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a Transmission Provider's ATC methodology. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the Non-PTF assets, as ATC is positive and listed as 9999. Transmission Customers are not restricted from reserving Firm or Non-Firm Point-to-Point Service on Non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time Energy Market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of net energy and/or capacity transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF that serve as a path for NSTAR's Transmission Customers taking Local Point-to-Point Service, NSTAR has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

7.1 Calculation of Schedule 21-NSTAR Firm ATC (ATC_F)

7.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment A, PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$. As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-NSTAR that is available in the PH includes: Yearly, Monthly, Weekly and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NSTAR transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F.

7.1.2 Calculation of ATC_F in the Operating Horizon (OH)

For purposes of this Attachment A, OH begins noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses, the total hours remaining in the OH decrease until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$. As discussed above, TRM and CBM are zero. Daily Firm Transmission Service under Schedule 21-NSTAR is the only firm service offered in the OH. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NSTAR transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

7.1.3 Calculation of ATC_F in the Scheduling Horizon (SH)

Because Firm Schedule 21-NSTAR transmission service is not offered in the SH, ATC_F in the SH is zero.

7.2 Calculation of Schedule 21-NSTAR Non-Firm ATC (ATC_{NF})

7.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$). As discussed above, the TRM and CBM for Schedule 21-NSTAR are zero. ATC_{NF} available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-NSTAR transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

7.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly. As discussed above, the TRM and CBM for Schedule 21-NSTAR are zero. TRM_U, $counterflows_{NF}$ and ETC_{NF} of Schedule 21-NSTAR transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F plus postbacks of PTP_F in the OH as PTP_{NF} ($Postbacks_{NF}$).

7.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available. As also stated above, NSTAR's Non-PTF are primarily radial paths that provide transmission service to directly interconnected generators. It is possible that in the future a particular radial path may interconnect more nameplate capacity generation than the path's TTC. For the local facilities modeled by ISO, and consistent with ISO's economic, security-constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH could become zero, but will never be negative.

8. Posting of Schedule 21-NSTAR ATC

8.1 Location of ATC Posting

ATC values are posted on the NSTAR OASIS site.

8.2 Updates to ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

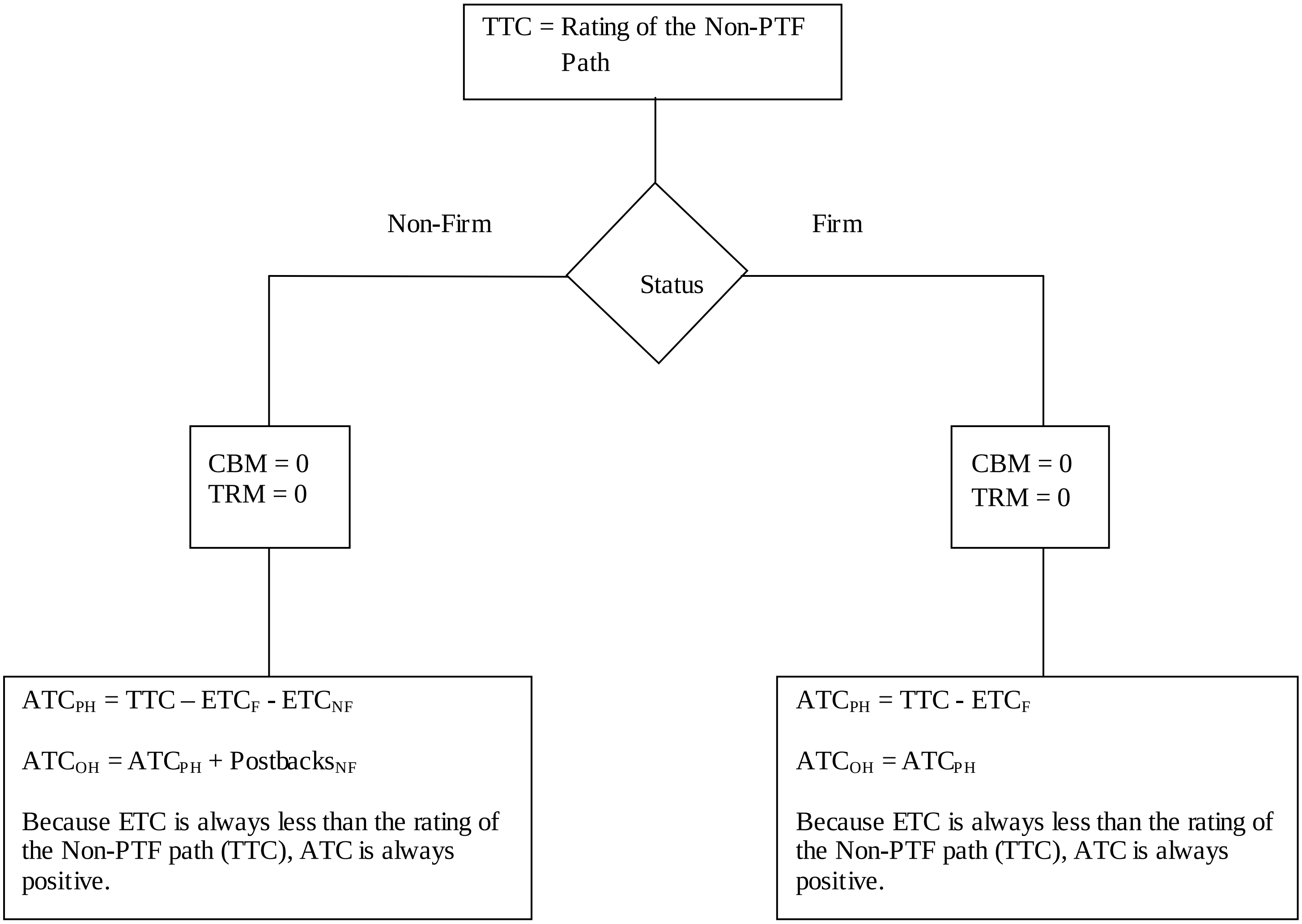
8.3 Coordination of ATC Calculations

NSTAR's Non-PTF has no external interfaces. Therefore, it is not necessary to coordinate the values.

8.4 Mathematical Algorithms

The mathematical algorithms for the calculation of ATC can be found on NSTAR's web site at http://www.nstar.com/business/rates_tariffs/open_access/docs/ATC_Algorithm-Sch_21.pdf

Non-PTF Transmission Path ATC Process Flow Diagram



ATTACHMENT B

METHODOLOGY FOR COMPLETING A SYSTEM IMPACT STUDY

When NSTAR determines on a non-discriminatory basis that a System Impact Study is needed because its Transmission System will be inadequate to accommodate a Completed Application for service, the following outlines the study methodology that NSTAR will employ to estimate the Transmission System impact of a Completed Application for Firm Local Point-To-Point Service, Network Integration Service and/or any costs associated with Direct Assignment Facilities and/or Local Network Upgrades that would be incurred in order to accommodate the service requested in the Completed Application.

1. System Impact will be estimated based on consideration of reliability requirements to:

- meet obligations under agreements that predate this Local Service Schedule;
- meet obligations of existing and pending Completed Application under this Local Service Schedule;
- maintain thermal, voltage and stability system performance within acceptable regional practices.

2. Guidelines and Principles followed by NSTAR: When performing the System Impact Study, NSTAR will apply the following, as amended and/or adopted from time to time.

- Good Utility Practice;
- Criteria, rules and reliability standards applicable to the New England Transmission System;
- NPCC criteria and guidelines; and
- NSTAR criteria and guidelines.

3. Transmission System Model Representation: The Transmission System model will be based on a library of load flow cases prepared by ISO for studies of the New England area. The models may include representations of other NPCC and neighboring systems. These load flow cases include individual system model representations provided by Transmission Owners and represent forecasted system conditions for up to ten (10) years into the future. This library of load flow cases is maintained and updated as appropriate by ISO, and is consistent with information filed under FERC Form 715. NSTAR will use system models that it deems appropriate for study of the Completed Application for service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for

conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

4. System Conditions: Loading of all Transmission System elements shall be less than normal ratings for pre-contingency conditions and less than long-term emergency (LTE) ratings for post-contingency conditions. Post-contingency loading above LTE rating and less than short-term emergency (STE) rating may be allowed where demonstrated that loading can be reduced below the LTE rating within fifteen (15) minutes. Transmission System voltage shall be within the applicable design ratings of connected equipment for normal and emergency conditions. Normal and post-contingency voltages shall be in accordance with NSTAR and ISO standards.

5. Short Circuits: Transmission System short circuit currents shall be within the applicable equipment design ratings.

6. Study Analysis: System impact of the integration of new load will be evaluated to meet the requirements of design, identified in the guidelines and principles under Item 2 above, to provide sufficient transmission capability to maintain stability and to maintain thermal and voltage levels of lines and equipment within applicable limits. The same applies to the evaluation of Firm Point-To-Point Service when it has been determined that insufficient transfer capability is available and the Eligible Customer requests a System Impact Study be conducted.

7. Loss Evaluation: The impact of losses on the Transmission System will be taken into account in the System Impact Study to ensure Good Utility Practice in the design and operation of its system.

8. System Protection: Protection requirements will be evaluated by NSTAR in accordance with ISO, NPCC, and NSTAR criteria.

9. Approvals: NSTAR will conduct the System Impact Study to ensure compliance with its planning and design policies and practices. However, the actions to be taken by the Parties to implement the recommendations of the System Impact Study are subject to approval under the Tariff.

10. Study Scope and Reporting: The study will determine the impacts and identify changes required, if any, to NSTAR's existing Transmission System. NSTAR will provide the Eligible Customer with a written report of the physical interconnection alternative(s), required NSTAR system additions and/or modifications, if any, associated study grade cost estimates (+/- 25%) and the results of the analysis.

ATTACHMENT C

INDEX OF LOCAL POINT-TO-POINT SERVICE CUSTOMERS

Customer	Date of Service Agreement
AIG Trading Corporation	October 29, 1996
Altresco Pittsfield Light Plant	December 26, 1996
Aquila Power Company	February 26, 1997
Axia Energy, LP	June 20, 2001
Baltimore Gas & Electric Co.	January 14, 1997
Bangor Hydro-Electric Co.	October 1, 1996
Belmont Municipal Light Dept.	December 11, 1996
Central Vermont Public Service	January 3, 1997
Chicopee Municipal Light Dept.	October 2, 1996
CINERGY Capital and Trading, Inc.	January 1, 1998
CINERGY Operating Companies	December 1, 1997
Citizens Lehman Power Sales	November 6, 1996
Constellation Power Source, Inc.	July 11, 1997
Duke Energy Solutions, Inc.	March 19, 1999
DukeSolutions, Inc.	May 18, 1999
Edison Source	June 9, 1997
Electric Clearinghouse, Inc.	October 7, 1996
Entergy Nuclear Generation Company	April 10, 2003
Equitable Power Services Company	October 29, 1996
Green Mountain Power Corporation	January 10, 1997
HQ Energy Services (US) Inc.	February 8, 1999
LG&E Power Marketing, Inc.	October 8, 1996
Maine Public Service Company	September 30, 1996
Massachusetts Bay Transportation Authority	May 1, 1999
Massachusetts Municipal Wholesale Electric Co.	September 6, 1996
Merchant Energy Group of the Americas, Inc.	August 16, 1998
Mirant Canal, LLC	July 6, 1998

Mirant Americas Energy Marketing, LP	April 28, 2004
Montaup Electric Co.	October 15, 1996
Morgan Stanley Capital Group, Inc.	October 29, 1996
NEPOOL on Behalf of NEPOOL Participants	June 1, 1997
New England Power Company	December 30, 1996
New York State Gas & Electric Corp.	December 16, 1997
NorAm Energy Services	November 14, 1997
Northeast Energy Services, Inc.	June 17, 1997
NP Energy, Inc.	August 1, 1997
NRG Power Marketing, Inc.	January 1, 2001
NSTAR Electric Company	December 24, 1996
PECO Energy Power Team	January 3, 1997
Rainbow Energy Power Marketing	November 7, 1996
Reading Municipal Light Department	September 6, 1996
Sithe New England Holdings, LLC	January 3, 1998
Sonat Power Marketing, Inc.	November 14, 1997
Southern Energy Trading and Marketing, Inc.	March 10, 1997
Strategic Energy Ltd.	May 11, 1999
The Power Company of America	November 18, 1996
Town of Braintree Electric Light Dept.	September 6, 1996
Town of Hingham Municipal Light Plant	September 9, 1996
Town of Hull Municipal Light Plant	December 11, 1996
Trans Alta Energy Marketing	November 24, 1998
Trans Canada Power Corporation	January 27, 1997
Western Power Services, Inc.	December 24, 1996
Williams Energy Services Company	July 17, 1997
VTEC Energy, Inc.	March 24, 1998

ATTACHMENT D
ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirements for NSTAR ("the Company") will reflect the costs for its Transmission System, including costs attributable to those incurred by the Company in owning, leasing, maintaining and supporting the Transmission System net of revenues for transmission services provided under any other FERC accepted tariff or under any contract with other parties that provides reimbursement to the Company for transmission related services. Under no circumstances shall the Company's Local Network Service rates include costs that are charged through any other rate or tariff. The Transmission Revenue Requirements will be an annual calculation based on the estimated costs for its Transmission System during the Service Year.

The Company shall make an annual informational filing with the FERC on or before May 31 of each year which shall include a True-up of estimated costs and revenues, and actual costs and revenues for the preceding Service Year. Actual costs will be determined using data required to be reported annually in the FERC Form 1 and recorded on the Company's books in accordance with FERC's Uniform System of Accounts; unless the use of other data, such as subaccount balances, is specifically required by the provisions below, in which case an officer of the Company, shall certify that the development, accuracy and application of such other data is in accordance with the provisions of this Local Service Schedule. Such certification will be included with the annual informational filing along with adequate detail that supports the values contained within the True-up calculation. References to specific FERC Form 1 pages, line numbers and columns included in this Local Service Schedule are based on the 2006 Form 1 of the Company's predecessor entities. Subsequent FERC changes to Form 1 may be adopted to the extent they are consistent with the provisions and terms of this Local Service Schedule and not otherwise prohibited by FERC.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section II.1 of the OATT or the Local Service Schedule and as used herein have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of transmission-related direct wages and salaries including those of affiliated companies as reported in the Company's annual FERC Form 1, page 354, line 21, column (b) to the Company's total direct wages and salaries including those of the affiliated companies as reported in the Company's FERC Form 1, page 354, line 28, column (b), and excluding administrative and general wages and salaries as reported in the Company's FERC Form 1, page 354, line 27, column (b).

2. Plant Allocation Factor shall equal the ratio of the sum of Transmission Plant, excluding HQ leases, plus Transmission Related Intangible and General Plant to Total Plant in Service excluding HQ Leases.

B. TERMS

Administrative and General Expense shall equal the expenses as reported in the Company's FERC Form 1, page 323, line 197, column (b), excluding Property Insurance included in FERC Account No. 924, Regulatory Commission Expense included in FERC Account No. 928, and Advertising Expense included in FERC Account No. 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded). The amount of Postretirement Benefits Other Than Pensions ("PBOP") expense in FERC Account No. 926 shall be separately stated as a footnote to the Company's FERC Form 1, page 323, line 187, column (b): Current Year and column (c): Previous Year.

Amortization of Gain on Reacquired Debt shall equal the amortization amount recorded in FERC Account No. 429.1.

Amortization of Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal the transmission expenses as recorded in FERC

Account No. 403 as reported in the Company's annual FERC Form 1 page 336, line 7, column (f).

General Plant shall equal the gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation and Amortization Expense shall equal the general plant expenses as recorded in FERC Account Nos. 403 for depreciable items and 404 for items subject to amortization as reported in the Company's annual FERC Form 1, page 336, line 10, column (f).

General Plant Depreciation Reserve shall equal the general reserve balance as recorded in FERC Account No. 108 and reported in the Company's annual FERC Form 1, page 219, line 28, column (b).

General Plant Amortization Reserve shall equal the general reserve balance as recorded in FERC Account No. 111 and reported in the Company's annual FERC Form 1, page 200 in a footnote to line 14.

Hydro-Quebec DC Facilities (HQ Leases) shall equal the balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

Intangible Plant shall equal the gross plant balance as recorded in FERC Account No. 303 as reported in the Company's annual FERC Form 1, page 205, line 4, column (g). The only allowable Intangible Plant for inclusion in the Local Service Schedule are software, patent or rights costs.

Intangible Plant Amortization Expense shall equal amortization expenses as recorded in FERC Account Nos. 404-405 as reported in the Company's annual FERC Form 1, page 336, line 1, column (f). The only allowable Intangible Plant Amortization Expense for inclusion in the Local Service Schedule is the amortization of software, patent or rights costs.

Intangible Plant Amortization Reserve shall equal the amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion in the Local Service Schedule is that related to the amortization of software, patent or rights costs.

Merger-Related Costs shall equal NSTAR Electric's amortized merger-related costs as authorized by FERC or by state regulatory order.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in the FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the FAS 109 asset and any FAS 109 balance liability.

Payroll Taxes shall equal those payroll expenses as recorded in the FERC Account No. 408.1.

Plant Held for Future Use shall equal the balance in FERC Account No. 105 that relates to land and land rights which have been purchased for future transmission use, or transmission related projects that were included in this account before January 1, 2007.

Prepayments shall equal the prepayment balance as recorded in FERC Account No. 165, plus any prepayment specifically related to the Company's Pension plans related to electric company operations recorded in FERC Account No. 182.3, Other Regulatory Assets.

Property Insurance shall equal the expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and 190 for those balances that are directly related to transmission, excluding those directly related to distribution or other businesses.

Total Gain on Reacquired Debt shall equal the gain as recorded in FERC Account No. 257.

Total Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 189.

Total Municipal Tax Expense shall equal the municipal tax expenses as recorded in FERC Account No. 408.1 as reported in the Company's annual FERC Form 1, page 263, line 10, column (i).

Total Plant in Service shall equal the total gross plant balance as recorded in FERC Account Nos. 301-399 excluding HQ Leases recorded in those accounts.

Total Transmission Depreciation Reserve shall equal the transmission reserve balance as recorded in FERC Account No. 108 as reported in the Company's annual FERC Form 1, page 219, line 25, column (b), excluding HQ-related amounts recorded in that account.

Transmission Depreciation Expense shall be the annual depreciation expense for transmission accounts computed using the following rates, as approved by FERC in Docket No. ER03-1274:

Account	Description	Rate
352	Structures and Improvements	2.19%
353	Station Equipment	2.53%
354	Towers and Fixtures	2.03%
355	Poles and Fixtures	2.25%
356	Overhead Conductors and Devices	2.19%
357	Underground Conduit	2.06%
358	Underground Conductors and Devices	2.15%
359	Roads and Trails	1.63%

Transmission Merger-Related Costs shall equal NSTAR Electric's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal all transmission-related expenses as recorded in FERC Account Nos. 560-564 and 566-576.5, and shall exclude; (i) all HQ HVDC expenses recorded in those accounts, and (ii) expenses billed to the Company by ISO-NE for Scheduling and Dispatch Service.

Transmission Plant shall equal the balance as recorded in FERC Account Nos. 350-359.1, adjusted to exclude the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

Transmission Plant Materials and Supplies shall equal the balance as assigned to transmission, as recorded in FERC Account No. 154 as reported in the Company's annual FERC Form 1, page 227, lines 5 and 8, column (c).

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Gain/Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from Generators, minus (M) Transmission Rents Received from Electric Property, minus (N) Short-Term and Non-Firm Point-To-Point Service Revenues, minus (O) Regional Network Services (RNS) Revenues, minus (P) Through or Out Revenues, minus (Q) ISO-NE Scheduling and Dispatch Revenues.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) 50 percent of Transmission Related Construction Work In Progress (CWIP), less (e) Transmission Related Depreciation and Amortization Reserve, less (f) Transmission Related Accumulated Deferred Taxes, less, (g) AFUDC Regulatory Liability, plus (h) Transmission Related Gain/Loss on Reacquired Debt, plus (i) Other Regulatory Assets/Liabilities, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

(a) Transmission Plant will equal the balance of the investment in Transmission Plant. This value excludes the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

(b) Transmission Related Intangible and General Plant shall equal the sum of the balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the land and land rights portion of the balance of Transmission-related Plant Held for Future Use (FERC Account No. 105) plus the non-land Plant Held for Future Use related to projects that were included in Account No. 105 prior to January 1, 2007 to the extent such non-land plant has not been closed to Plant In Service; such balances to be provided in conformance with the FERC Uniform System of Accounts, Instruction E, Account No. 105 which requires that "…property included in this account shall be classified according to detail accounts (301-399)…and shall be maintained in such detail as though the property were in service."

(d) 50 Percent of Transmission Related Construction Work in Process (CWIP) shall equal the balance of Transmission related investment in FERC Account 107 multiplied by 50%, subject to any exclusions pursuant to the provisions of Section 4.1 of this Local Service Schedule.

(e) Transmission Related Depreciation and Amortization Reserve shall equal the balance of Total Transmission Depreciation Reserve as reported in the Company's annual FERC Form 1, page 219 line 25, column (b), plus the balance of Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve. Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve shall equal the product of (i) the sum of the Intangible Plant Amortization Reserve, General Plant Depreciation Reserve and General Plant Amortization Reserve and (ii) the Transmission Wages and Salaries Allocation Factor. The Total Transmission Depreciation Reserve balance excludes any amounts related to the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

(f) Transmission Related Accumulated Deferred Taxes shall equal the electric balance of Total Accumulated Deferred Income Taxes (for those balances that are directly related to transmission, plus the balances not directly related to other businesses), with the remaining accumulated deferred taxes not directly related to other businesses being allocated on the same basis used for the related rate base assets.

(g) AFUDC Regulatory Liability shall equal 50% of the capitalized AFUDC booked on transmission projects as recorded in FERC Account No. 254.

(h) Transmission Related Gain/Loss on Reacquired Debt shall equal the electric balance of Total Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

(i) Other Transmission Related Regulatory Assets/Liabilities shall equal the electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(j) Transmission Prepayments shall equal the electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

(k) Transmission Materials and Supplies shall equal the electric balance of Transmission Plant Materials and Supplies.

(l) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the Transmission Operation and Maintenance Expense included in Section II.G, Transmission Related Administrative and General Expenses included in Section II.H, and Transmission Support Expenses included in Section II.K.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital for Service Years ending before January 1, 2013 will be calculated based 70% upon the capital structure at the end of each year and 30% upon a pro-forma capital structure consisting of 50% debt, 0% preferred, and 50% common equity; thereafter the pro-forma capital structure will be the same as the actual capital structure, and will equal the sum of (i), (ii) and (iii) below. Notwithstanding the foregoing, for Service Years ending before January 1, 2013, NSTAR's Weighted Cost of Capital will be the lower of the blended rate as calculated herein or the actual rate.

(i) the long-term debt component, which equals the product of: the actual weighted average embedded cost to maturity of the long-term debt then outstanding; and the sum of (a) the ratio that long-term debt is to the total capital multiplied by 70%, plus (b) 50% pro-forma capital structure multiplied by 30%.

(ii) the preferred component shall be the product of: the embedded cost of preferred stock outstanding at the end of each year; and the sum of (a) the ratio that preferred stock is to the total capital multiplied by 70%, plus (b) 0% pro-forma capital structure multiplied by 30%.

(iii) the return on equity component shall be the product of: the allowed ROE of the common equity; and the sum of (a) the ratio that common equity is to the total capital multiplied by 70%, plus (b) 50% pro-forma capital structure multiplied by 30%. The allowed ROE shall be 11.14%, plus any additional incentive ROE adders as may be applied to specific investment approved by the Commission pursuant to Order No. 679. The allowed ROE shall be subject to revision at any time by unilateral filing by NSTAR under Section 205 of the FPA or by such Section 205 filing by NSTAR on a joint basis with other New England transmission owners. In either case, the revised ROE shall become effective no later than sixty days after the filing in accordance with the provisions of the FPA and also subject to any suspension or refund condition which the Commission may order pursuant to its authority under that Section. Any filing made by NSTAR to revise the ROE in compliance with a Commission order shall become effective as of the date specified in such order and shall raise no issue regarding this Local Service Schedule other than the compliance with the Commission order. The allowed ROE is also subject to revision pursuant to the authority of the Commission under Sections 205 and 206 of the FPA.

(b) Federal Income Tax shall equal

$$\underline{(A+[(C+B)/D])(FT)}$$

$$1 - FT$$

where FT is the Federal Income Tax Rate and A is the weighted return on equity component, including preferred, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D below, C is the equity AFUDC component of Transmission Depreciation and Amortization Expense, as defined in Section II.B below, and D is Transmission Investment Base, as determined in Section II.A.1 above.

(c) <u>State Income Tax</u> shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1 - ST}$$

where ST is the State Income Tax Rate, A is the weighted return on equity component, including preferred, determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D below, C is the equity AFUDC component of Transmission Depreciation and Amortization Expense, as defined in Section II.B below, D is the Transmission Investment Base, as determined in II.A.1 above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. <u>Transmission Depreciation and Amortization Expense</u> shall equal the sum of (i) the Depreciation Expense for Transmission Plant and (ii) an allocation of Intangible Plant Amortization Expense and General Plant Depreciation Expense, which is calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation Expenses by the Transmission Wages and Salaries Allocation Factor; less the Amortization of AFUDC Regulatory Credit as recorded in FERC Account No. 407.4.

C. <u>Transmission Related Amortization of Gain/Loss on Reacquired Debt</u> shall equal the electric Amortization of Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

D. <u>Transmission Related Amortization of Investment Tax Credits</u> shall equal the electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal the total electric municipal tax expense reported in the Company's FERC Form 1, page 263, Local Real Estate and Personal Property Taxes, column (i), multiplied by the Plant Allocation Factor.

F. Transmission Related Payroll Tax Expense shall equal the total electric payroll tax expense reported in the Company's FERC Form 1, page 263, Service Company Allocations and Capitalization, column (i), multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal the Transmission Operation and Maintenance Expenses in Section I.B above.

H. Transmission Related Administrative and General Expenses shall equal the sum of the (1) Administrative and General Expense multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance included in FERC Account No. 924, line 156 multiplied by the Transmission Plant Allocation Factor, (3) expenses included in Account No. 928(excluding Merger-Related Costs included in Account No. 928), line 160 related to (i) transmission related FERC Assessments, plus (ii) any other Federal and State transmission related expenses or assessments, plus (iii) the cost of any independent audit requested by the Mass AG as the representative for NSTAR's retail customers and (4) Transmission Merger-Related Costs. The amount of PBOP expense shall be separately stated. NSTAR commits to adhere to: (i) the Commission's PBOP policy as expressed in the Commission's December 17, 1992, Statement of Policy in Docket No. PL93-1-000, as the Commission may amend that policy from time to time in the future; and (ii) the provisions of Financial Accounting Statement 106, Employers' Accounting for Postretirement Benefits Other Than Pensions.

I. Transmission Related Integrated Facilities Charges shall equal the transmission payments to Affiliates for use of the integrated transmission facilities of those Affiliates included in FERC Account No. 565.

J. Transmission Support Revenues shall equal the revenue received for transmission support included or includable in FERC Account Nos. 454 and 456 but excluding any revenue received for use of the

Company's entitlement in the Hydro-Quebec Facilities.

K. Transmission Support Expense shall equal the expense paid by the Company for transmission support included in FERC Account No. 565, but excluding expenses for the Hydro-Quebec DC Facilities.

L. Transmission-Related Expense from Generators shall equal the expenses from generators that are reflected in a filing made by the Company with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the Local Service Schedule and included or includable in FERC Account No. 565.

M. Transmission Rents Received from Electric Property shall equal any FERC Account Nos. 454 and 456 Rents from Electric Property, associated with Transmission Plant but not reflected as a credit in Transmission Support Revenues in Section II.J.

N. Short-Term and Non-Firm Point-to-Point Service Revenues shall equal the applicable wheeling revenues received for Local Point-To-Point Service provided under this Local Service Schedule, including the transmission component of the Company's Third-Party Sales, as recorded in FERC Account Nos. 447 and 456.1.

O. Regional Network Services (RNS) Revenues shall equal the Company's RNS revenues pursuant to the Tariff, as included or includable in FERC Account Nos. 454, 456 and 456.1 but excluding any incremental revenues associated with FERC-approved adders for RTO participation and new investment.

P. Through or Out Revenues shall equal the distribution of revenues received by the Company for Through or Out Service pursuant to the Tariff as included or includable in FERC Account Nos. 454 and 456.1.

Q. ISO-NE Scheduling and Dispatch Revenues shall be the amount of revenues received by the Company from ISO-NE for scheduling and dispatch services pursuant to the Tariff as included or includable in FERC Account Nos. 454, 456 and 456.1.

ATTACHMENT E

INDEX OF LOCAL NETWORK SERVICE CUSTOMERS

Customer	Date of Service Agreement
ANP Blackstone Energy Company	October 1, 2000
Entergy Nuclear Generation Company	September 1, 1999
New England Power Company	September 6, 1996
NSTAR Electric Company	December 24, 1996
Sithe New Boston LLC	September 1, 1998
Sithe Framingham LLC	September 1, 1998
Sithe Mystic LLC	September 1, 1998
Sithe Edgar LLC	September 1, 1998
Sithe West Medway LLC	September 1, 1998
Town of Braintree Municipal Light Dept.	March 1, 1997
Town of Concord Municipal Light Plant	June 21, 2002
Town of Hingham Municipal Light Plant	March 1, 1997
Town of Hull Municipal Light Plant	March 1, 1997
Town of Norwood Municipal Light Dept.	September 6, 1996
Town of Reading Municipal Light Plant	March 1, 1997
Town of Wellesley Municipal Light Plant	June 21, 2002

ATTACHMENT F

<u>FORMULA RATE TEMPLATE</u>

NSTAR Electric Company
Annual Local Network Service Revenue Requirement
Service Year Ended December 31, xxxx

This template does not change the other provisions of this Schedule 21. The template is not a substitute for Schedule 21 language. If an inconsistency between the Schedule 21 language and the template arises, the Schedule 21 language is controlling. The template is illustrative and the actual true-up filing as made from time to time may include format changes or reflect non-material changes required by the Uniform System of Accounts.

Sheet 1

	(a)	(b)	(c)	(d)
Line	Description	Section	Amount	Reference
1	**Investment Base**	II.A.1		
2	Transmission Plant	II.A.1.a	$ -	Sheet 3, Line 1, Col (f)
3	Transmission Related Intangible & General Plant	II.A.1.b	-	Sheet 3, Line 4, Col (f)
4	Transmission Plant Held for Future Use	II.A.1.c	-	Sheet 3, Line 5, Col (f)
5	Transmission Related Construction Work in Progress	II.A.1.d	-	Sheet 3, Line 6, Col (f)
6	Total Plant		-	Sum Lines 2 thru 5
7	Trans Related Depreciation and Amortization Reserve	II.A.1.e	-	Sheet 3, Line 12, Col (f)
8	Transmission Related Accumulated Deferred Taxes	II.A.1.f	-	Sheet 3, Line 20, Col (f)
9	AFUDC Regulatory Liability	II.A.1.g	-	Sheet 3, Line 21, Col (f)
10	Total Net Plant		-	Sum Lines 6 thru 9
11	Transmission Related Gain/Loss on Reacquired Debt	II.A.1.h	-	Sheet 3, Line 22, Col (f)
12	Other Trans Related Regulatory Assets/Liabilities	II.A.1.i	-	Sheet 3, Line 28, Col (f)
13	Transmission Prepayments	II.A.1.j	-	Sheet 3, Line 29, Col (f)
14	Transmission Materials & Supplies	II.A.1.k	-	Sheet 3, Line 30, Col (f)
15	Transmission Related Cash Working Capital	II.A.1.l	-	Sheet 3, Line 35, Col (f)
16	**Total Investment Base**		$ -	Sum Lines 10 thru 15
17	**Revenue Requirement**			
18	Investment Return and Income Taxes	II.A.2	$ -	Sheet 2, Line 39, Col (c)
19	Transmission Depreciation and Amortization Expense	II.B	-	Sheet 4, Line 7, Col (f)
20	Amortization of Gain/Loss on Reacquired Debt	II.C	-	Sheet 4, Line 8, Col (f)
21	Transmission Related Amort. of Investment Tax Credits	II.D	-	Sheet 4, Line 9, Col (f)

22	Transmission Related Municipal Tax Expense	II.E	-	Sheet 4, Line 10, Col (f)
23	Transmission Related Payroll Tax Expense	II.F	-	Sheet 4, Line 11, Col (f)
24	Transmission Operation & Maintenance Expense	II.G	-	Sheet 4, Line 30, Col (f)
25	Trans Related Administrative and General Expense	II.H	-	Sheet 4, Line 44, Col (f)
26	Transmission Related Integrated Facilities Charges	II.I	-	Sheet 5, Line 10, Col (e)
27	Transmission Support Revenues	II.J	-	Sheet 5, Line 15, Col (e)
28	Transmission Support Expense	II.K	-	Sheet 5, Line 20, Col (e)
29	Transmission Related Expense from Generators	II.L	-	Sheet 5, Line 23, Col (e)
30	Transmission Rents Received from Electric Property	II.M	-	Sheet 5, Line 28, Col (e)
31	Short-Term and Non-Firm P-T-P Service Revenues	II.N	-	Sheet 5, Line 31, Col (e)
32	Regional Network Services (RNS) Revenues	II.O	-	Sheet 5, Line 36, Col (e)
33	Through or Out Revenues	II.P	-	Sheet 5, Line 39, Col (e)
34	ISO-NE Scheduling and Dispatch Revenues	II.Q	-	Sheet 5, Line 43, Col (e)
35	**Total LNS Revenue Requirement**		$ -	Sum Lines 18 thru 34
36	Wholesale LNS Revenues Received:			
37	Item # 1		-	
38	Item #2		-	
39	Last Item		-	
40	Total Wholesale LNS Revenue		$ -	Sum Lines 37 thru 39
41	**Total Retail LNS Revenue Requirement**		$ -	Line 35 - Line 40
42	Average 12 CP			
43	Sum of Monthly Peaks (kw)		-	FF1: 400.17(b)
44	Average Peak		-	Line 43 / 12
45	Annual Rate per kw		$ -	Line 35 / Line 44
46	Monthly Rate per kw		$ -	Line 45 / 12
47	Daily Rate per kw		$	Line 45 / 365

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NSTAR Electric Company

Investment Return and Income Taxes

Service Year Ended December 31, xxxx

Sheet 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line	**Description**	**Tariff Section**	**Balance**	**Capitalization Ratio ***	**Cost ***	**Weighted Cost ***	**Equity Cost**	**Reference**
1	**Weighted Cost of Capital**	II.A.2.a						
2	Long Term Debt	II.A.2.a.i	$ -		0.0000%	0.0000%		FF1: Page 112.24(c)
3	Preferred Stock	II.A.2.a.ii	-		0.0000%	0.0000%	0.0000%	FF1: Page 112.3(c)
4	Common Equity	II.A.2.a.iii	-		0.0000%	0.0000%	0.0000%	FF1: Page 112.16(c) - Line 3(c)
5	Total		$ -			0.0000%	0.0000%	Sum Lines 2 thru 4
6	**Investment Return**	II.A.2						
7	Total Investment Base		$ -					Sheet 1, Line 16, Col (c)
8	Weighted Cost of Capital		0.0000%					Line 5, Col (f)
9	Total Return on Investment		$ -					Line 7 * Line 8
10	**Federal Income Tax**	II.A.2.b						
11	A = Equity Cost		0.0000%					Line 5, Col (g)
12	B = Transmission Amortization of ITC		$ -					Sheet 1, Line 21, Col (c)
13	C = Equity AFUDC		-					FF1: Page 117.38
14	Total B + C		-					Line 12 + Line 13
15	D = Investment Base		-					Line 7
16	(B + C) / D		0.00%					Line 14 / Line 15
17	(A + [(C + B) / D]		0.00%					Line 11 + Line 16
18	FT = Federal Income Tax Rate		35.00%					Federal corporate tax rate
19	1 - FT		65.00%					1 - Line 18
20	Federal Tax Factor		0.00000%					Line 17 * Line 18 / Line 19
21	Total Federal Income Taxes		$ -					Line 15 * Line 20
22	**State Income Tax**	II.A.2.c						
23	A = Equity Cost		0.0000%					Line 5, Col (g)
24	B = Transmission Amortization of ITC		$ -					Sheet 1, Line 21, Col (c)
25	C = Equity AFUDC		-					
26	Total B + C		-					Line 24 + Line 25
27	D = Investment Base		-					Line 7
28	(B + C) / D		0.00%					Line 26 / Line 27

29	(A + [(C + B) / D]		0.00%	Line 23 + Line 28
30	ST = State Income Tax Rate		6.50%	Massachusetts corporate tax rate
31	1 - ST		93.50%	1 - Line 30
32	Federal Tax Factor		0.00000%	Line 23
33	State Tax Factor		0.00000%	(Line 29 + Line 32) * Line 30 / Line 31
34	Total State Income Taxes		$ -	Line 27 * Line 33
35	**Investment Return and Income Taxes**	II.A.2		
36	Return on Investment		$ -	Line 9
37	Federal Income Taxes		-	Line 21
38	State Income Taxes		-	Line 34
39	**Total Return and Income Taxes**		$ -	Sum Lines 36 thru 38

* Note that weighting and cost are determined on Sheet 7

NSTAR Electric Company

Investment Base

Service Year Ended December 31, xxxx

Sheet 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Tariff			**Allocations**		
					LNS		
Line	**Description**	**Section**	**Total**	**Allocator**	**Factor**	**Amount**	**Reference**
			$				
1	**Transmission Plant**	II.A.1.a	-	Direct	100.0000%	-	FF1: Page 207.58(g)
2	General Plant		-	W&S	0.0000%	-	FF1: Page 207.99(g)
3	Intangible Plant		-	W&S	0.0000%	-	FF1: Page 205.5(g)
4	**Total Intangible & General Plant**	II.A.1.b	-			-	Sum Lines 2 thru 3
5	**Transmission Plant Held for Future Use**	II.A.1.c	-	Direct	100.0000%	-	FF1: Page 214.10&.23(d)
6	**Transmission Related CWIP**	II.A.1.d	-	CWIP	50.0000%	-	FF1: Page 216(b) Trans only
7	**Transmission Related Dep & Amort Reserve**	II.A.1.e					
8	Transmission Accumulated Depreciation		-	Direct	100.0000%	-	FF1: Page 219.25(b)
9	General Plant Accumulated Depreciation		-	W&S	0.0000%	-	FF1: Page 219.28(b)
10	General Plant Accumulated Amortization		-	W&S	0.0000%	-	FF1: Page 200.21(c) Footnote
11	Intangible Plant Accumulated Amortization		-	W&S	0.0000%	-	FF1: Page 200.21(c) Footnote
12	Total Transmission Related Depreciation Reserve		-			-	Sum Lines 8 thru 11
13	**Transmission Accumulated Deferred Taxes**	II.A.1.f					
14	Accumulated Deferred Taxes (190)		-		0.0000%	-	Sheet 8, Line 5, col (d)
15	Accumulated Deferred Income Taxes (281)		-			-	FF1: Page 113.62(c)
16	Accumulated Deferred Taxes - Property (282)		-				FF1: Page 275.9(k)
17	Less Transition Property		-				FF1: Page 275.4(k)
18	Net Acc. Def. Income Taxes - Other Property (282)		-	Plant	0.0000%	-	Sum Lines 16 thru 17
19	Accumulated Deferred Income Taxes - Other (283)		-		0.0000%	-	Sheet 8, Line 10, col (d)
20	Total					-	Sum Lines 17 thru 19

21	**AFUDC Regulatory Liability**	II.A.1.g	-	Direct	100.00%	-	FF1: Page 278.6(f)
22	**Gain/Loss on Reacquired Debt**	II.A.1.h	-	Plant	0.0000%	-	FF1: Page 111.81(c)+113.61(c)
23	**Other Regulatory Assets**	II.A.1.i					
24	FAS 106 (182.3 & 254)		-	W&S	0.0000%	-	FF1: Page 232.1.39(f)+278.(f)
25	FAS 109 (182.3 & 254)		-				FF1: Page 232.1.29(f)
26	Less FAS 109 - Liability (182.3 & 254)		-				FF1: Page 278.2(f)
27	Net FAS 109 (182.3 & 254)		-	Plant	0.0000%	-	Sum Lines 25 thru 26
28	Total Other Regulatory Assets		-			-	Line 24 + line 27
29	**Prepayments**	II.A.1.j	-	W&S	0.0000%	-	FF1: Page 111.57(c)+ 232.2.8(f)
30	**Transmission Materials & Supplies**	II.A.1.k	-	Direct	100.0000%	-	FF1: Page 227.8(c)+227.5(c) Trans
31	**Cash Working Capital**	II.A.1.l					
32	Operation & Maintenance Expense		-	WC	12.50%	-	Sheet 1, Line 24, col (c)
33	Administrative & General Expense		-	WC	12.50%	-	Sheet 1, Line 25, col (c)
34	Transmission Support Expenses		-	WC	12.50%	-	Sheet 1, Line 28, col (c)
35	Total Cash Working Capital		-			-	Sum Lines 32 thru 33

36	**Description**	**Allocation Factor**	**Reference**
37	Direct Allocation (Direct)	100.0000%	
38	Wages & Salary (W&S)	0.0000%	Sheet 6, Line 6(c)
39	Plant Allocation (Plant)	0.0000%	Sheet 6, Line 14(c)
40	Construction Work in Progress Allocation (CWIP)	50.0000%	Sheet 6, Line 15(c)
41	Cash Working Capital (WC)	12.50%	Tariff Section II.A.1.l

NSTAR Electric Company
Transmission Expenses
Service Year Ended December 31, xxxx
Sheet 4

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
					Allocations		
Line	**Description**	**Tariff Section**	**Total**	**Allocator**	**Factor**	**LNS Amount**	**Reference**
1	**Transmission Depreciation Expense**	II.B					
2	Transmission Depreciation	II.B.i		Direct	100.00%	$ -	FF1: Page 336.7(f)
3	General Plant Depreciation and Amortization	II.B.ii		W&S	0.00%	-	FF1: Page 336.10(f)
4	Amortization of Transmission Related Intangible Plant			W&S	0.00%	-	FF1: Page 336.1(f)
5	Amortization of AFUDC Regulatory Credit		-			-	FF1: Page 278.6(d) (amort)
6	Net Amortization of Transmission Related Intangible Plant		-			-	Sum Lines 4 and 5
7	Total Transmission Depreciation Expense		$ -			$ -	Sum Lines 2, 3 and 6
8	**Amortization of Gain/Loss on Reacquired Debt**	II.C		Plant	0.00%	$ -	FF1: Page 117.64c
9	**Transmission Related Amortization of ITC**	II.D		Plant	0.00%	$ -	FF1: Page 114.19(c)
10	**Transmission Related Municipal Tax Expense**	II.E		Plant	0.00%	$ -	FF1: Page 263.5(i)

11	**Transmission Related Payroll Tax Expense**	II.F		W&S	0.00%	$ -	FF1: Page 263.8i
12	**Transmission Operation and Maintenance Expense**	II.G					
13	Operation Supervision & Engineering (560)			Direct	100.00%	$ -	FF1: Page 321.83(b)
14	Load Dispatching (561)		-	Internal Costs		-	FF1: Page 321.83(b)
15	Load Dispatch - Reliability (561.1)		-	Internal Costs		-	FF1: Page 321.85(b) footnote
16	Load Dispatch-Mon and Oper Trans System (561.2)		-	Internal Costs		-	FF1: Page 321.86(b) footnote
17	Load Dispatch-Trans Service and Scheduling (561.3)		-	Internal Costs		-	FF1: Page 321.87(b) footnote
18	Scheduling, System Control and Dispatch Services (561.4)		-	Internal Costs		-	FF1: Page 321.88(b) footnote
19	Reliability, Planning and Standards Development (561.5)		-	Internal Costs		-	FF1: Page 321.89(b)
20	Transmission Service Studies (561.6)		-	Internal Costs		-	FF1: Page 321.90(b)
21	Generation Interconnection Studies (561.7)		-	Internal Costs		-	FF1: Page 321.91(b)
22	Reliability, Planning and Standards Development (561.8)		-	Internal Costs		-	FF1: Page 321.92(b) footnote
23	Station Expenses (562)		-	Direct	100.00%	-	FF1: Page 321.93(b)
24	Overhead Lines Expenses (563)		-	Direct	100.00%	-	FF1: Page 321.94(b)
25	Underground Lines Expenses (564)		-	Direct	100.00%	-	FF1: Page 321.95(b)
26	Miscellaneous Transmission Expenses (566)		-	Direct	100.00%		FF1: Page 321.97(b)

						-	
27	Rents (567)		-	Direct	0.00%	-	Sheet 5, Line 7, col (d)
28	Transmission Maintenance (568 - 573)		-	Direct	100.00%	-	FF1: Ppage 321.111(b)
29	Regional Market Expense (575)		-	Internal Costs	0.00%	-	FF1: Ppage 322.131(b)
30	Total Transmission O&M Expense		$ -			$ -	Sum Lines 13 thru 28
31	**Transmission Related A&G Expenses**	II.H					
32	Administrative and General Expenses		$0				FF1: Page 323.197(b)
33	Property Insurance (924)		-				FF1: Page 323.185(b)
34	Employee Pension and Benefits (926)		-				FF1: Page 323.187(b)
35	Regulatory Commission Expense (928)		-				FF1: Page 323.189(b)
36	General Advertising Expense (930.1)		-				FF1: Page 323.191(b)
37	Merger Related Costs		-				FF1: Page 320 FN
38	Sub-Total		-	W&S	0.00%	-	Sum Lines 32 thru 37
39	Property Insurance (924)	II.H.2	-	Plant	0.00%	-	Line 33
40	Employee Pension and Benefits (926) - Note 1	II.H.1	-	W&S	0.00%	-	Line 34
41	Regulatory Commission Expense (928)	II.H.3	-	Footnote	0.00%	-	Line 59
42	General Advertising Expense (930.1)	II.H	-		0.00%	-	Line 36
43	Transmission Merger Related Costs		-	Direct	100.00%	-	FF1: Page 320 FN
44	Total Transmission Related A&G Expenses		$ -			$ -	Sum Lines 39 thru 43

45	Regulatory Commission Expense (928)	II.H.3					
						$	
46	DPU - General Assessment		$ -		0.00%	-	FF1: Page 350.1 (d)
47	DPU - Appropriation Account		-		0.00%	-	FF1: Page 350.2 (d)
48	DPU - AGO Assessment #1		-		0.00%	-	FF1: Page 350.3 (d)
49	DPU - AGO Assessment #2		-		0.00%	-	FF1: Page 350.4 (d)
50	DPU - Outage Reporting Assessment		-		0.00%	-	FF1: Page 350.5 (d)
51	DPU - Manhole Cover Assessment		-		0.00%	-	FF1: Page 350.6 (d)
52	DPU - Stray Voltage Assessment		-		0.00%	-	FF1: Page 350.7 (d)
53	MA Emergency Management Agency		-		0.00%	-	FF1: Page 350.8 (d)
54	FERC Assessment		-	Direct	100.00%	-	FF1: Page 350.9 (d)
55	FER LICAP Docket		-	Direct	100.00%	-	FF1: Page 350.10 (d)
56	FERC RMR Docket		-	Direct	100.00%	-	FF1: Page 350.11 (d)
57	FERC Docket ER07-549, Including cost of audit		-	Direct	100.00%	-	FF1: Page 350.12 (d)
58	DPU Regulatory Proceeding Costs 05-85		-		0.00%	-	FF1: Page 350.13 (d)
59	Total Regulatory Commission Expenses	II.H.3	-		0.00%	-	Sum Lines 46 thru 58

Description	Allocation Factor	Reference

60	Direct Allocation (Direct)	100.0000%	
61	Wages & Salaries Allocation (W&S)	0.0000%	Sheet 6, Line 6(c)
62	Plant Allocation (Plant)	0.0000%	Sheet 6, Line 14(c)

63 **Note 1**

64 Included in the Employee Pension and Benefits Expenses are costs related to Post Retirement Benefits other than Pension (PBOP). PBOP costs are determined

65 by an independent actuary as required by FASB 106. The PBOP expense included in Account 926 for 20xx was $xx,xxx,xxx as compared to $xx,xxx,xxx in the prior year;

66 as shown

67 on the FF1, Page 323, footnote. Applying the labor allocator to the total PBOP expense results in $x,xxx,xxx of PBOP expense being recovered through the LNS Tariff

68 in 20xx as compared to $x,xxx,xxx in the prior year.

NSTAR Electric Company

Support Expense & Revenue Detail

Service Year Ended December 31, xxxx

Sheet 5

	(a)	(b)	(c)	(d)	(e)
Line	Description	Tariff Section	Amount	Includable Amount	Reference
1	Transmission Rents (Account 567)	II.G			
2	Hydro Quebec DC Phase I Support			-	FF1: Page 320.98 (b) Footnote
3	Hydro Quebec DC Phase II Support			-	FF1: Page 320.98 (b) Footnote
4	New England Power Support			-	FF1: Page 320.98 (b) Footnote
5	Hydro Quebec Phase II NEP AC, Chester SVC			-	FF1: Page 320.98 (b) Footnote
6	Transmission Line Rents		-	-	FF1: Page 320.98 (b) Footnote
7	Total Transmission Rents Received		-	-	Sum Lines 2 thru 6
	Transmission Related Integrated Facilities				
8	Charges	II.I	-	-	
9	- none -		-	-	
10	Total Trans Related Integrated Facilities Charges		-	-	Sum Lines 9 thru 9
11	Transmission Support Revenues 456 & 456.1	II.J			
12	Item #1			$ -	FF1: Page 300.21(b) Footnote
13	Item # 2			-	FF1: Page 300.21(b) Footnote
14	Last Item		-	-	FF1: Page 300.22(b) Footnote
15	Total Short Term & Non-Firm PTP Revenues		$ -	$ -	Sum Lines 12 thru 14
16	Transmission Support Expense (565)	II.K			
17	Item #1			-	FF1 Q2: Page 332.2(h)
18	Item # 2			-	FF1 Q3: Page 332.2(h)
19	Last Item		-	-	FF1: Page 332.2(h)
20	Total Transmission Support Expense		-	-	Sum Lines 17 thru 19
21	Transmission Related Expense from Generators	II.L			N/A
22	- none -		-	-	
23	Total Trans Related Expense from Generators		-	-	Sum Lines 22 thru 22
24	Rents Received from Electric Property (454)	II.M			
25	Item #1			-	FF1: Page 300.19(b) Footnote
26	Item # 2			-	FF1: Page 300.19(b) Footnote
27	Last Item		-	-	FF1: Page 300.19(b) Footnote
28	Total Rents Received		-	-	Sum Lines 25 thru 27
29	Short-Term and Non-Firm Point-to-Point Rev	II.N	$ -	$ -	N/A
30	- none -		-	-	
31	Total ST and Non-Firm Point-to-Point Revenues		-	-	Sum Lines 30 thru 30
32	Regional Network Service Revenues (456):	II.O			
33	RNS Transmission Revenue		-	-	
34	RNS PTF Post 2003 investment 1 % Adder		-	-	RNS Revenue Requirement
35	RNS PTF RTO Participation 0.5% Adder		-	-	RNS Revenue Requirement
36	Total Regional Network Services Revenues		-	-	Sum Lines 33 thru 35

37	Through or Out Revenues	II.P	$ -	$ -	N/A
38	- none -		-	-	
39	Total Through or Out Revenue		-	-	Sum Lines 38 thru 38
40	ISO-NE Scheduling & Dispatch Revenue	II.Q			
41	Nepool Scheduling & Dispatch Revenue		-	-	
42	RTO Participation 0.5% Adder		-	-	Reguional Schedule 1 Revenue Requirement
43	Total ISO-NE Scheduling & Dispatch Revenue		-	-	Sum Lines 42 thru 42

NSTAR Electric Company

Allocation Factors

Service Year Ended December 31, xxxx

Sheet 6

	(a)	(b)	(c)	(d)
		Tariff		
Line	**Description**	**Section**	**Amount**	**Reference**
1	**Transmission Wages & Salaries Allocation Factor**	I.A.1		
			$	
2	Transmission Related Direct Wages & Salaries		-	FF1: Page 354.21(b)
3	Total Direct Wages & Salaries		-	FF1: Page 354.28(b)
4	Administrative & General Wages & Salaries		-	FF1: Page 354.27(b)
5	Net Total Direct Wages & Salaries		-	Line 3 less Line 4
6	Transmission Wages & Salaries Allocation Factor		**0.0000%**	Line 2 / Line 5
7	**Plant Allocation Factor**	I.A.2		
			$	
8	Transmission Plant Investment		-	FF1: Page 207.58(g)
9	HQ Leases		-	
10	Transmission Related General Plant		-	Sheet 3, Line 2, Col (f)
11	Transmission Related Intangible Plant		-	Sheet 3, Line 3, Col (f)
12	Total Transmission Plant Investment		-	Sum Lines 8 thru 11
13	Total Plant in Service		-	FF1: Page 207.104(g)

14	Plant Allocation Factor		**0.0000%**	Line 12 / Line 13
15	**Construction Work in Progress Allocation Factor**	II.A.1.d	**50.0000%**	

NSTAR Electric Company

Cost of Long Term Debt

Service Year Ended December 31, xxxx

Sheet 7

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	FF1:256(a)	FF1:256(d)		FF1:256(e)	FF1:256(b)	FF1:256(h)		FF1:256(c)					
		Long Term Debt				Principal		Debt	Call				
			Term	Coupon	Original	Amount	Percent	Disc &	Premium on	Net	Cost to	Weighted	
Line	Series	Dated	(Years)	Rate	Issue	Outstanding	of Total	Exp	Debt	Proceeds	Maturity	Cost	Reference
							Col f / Col f Total			**Col f - Col h - Col i**	**Col d + ((Col h + Col i) / (Col e / Col d))**	Col h * Col g	
1	MIFA Bonds	2/8/94	20	5.75%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
2	4.875% Debentures	4/13/04	10	4.875%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
3	7.8% Debentures	5/10/95	15	7.80%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
4	4.875 Debentures	10/9/02	10	4.875%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
5	5.75% Debentures	3/13/06	30	5.750%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
6	5.625% Debentures	11/19/07	10	5.63%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
7	Total				$ -	$ -	0.00%	$ -	$ -	$ -		0.0000%	Sum Lines 1 Thru 6

Cost of Preferred Stock

	FF1:250(a)			FF1:250(a)		FF1:250(f)				
		Preferred Stock				Principal				
				Coupon	Original	Amount	Percent		Weighted	
	Series	Dated	Term	Rate	Issue	Outstanding	of Total		Cost	Reference
8	4.25%	6/13/1956	N/A	4.25%			0		0.0000%	FF1: Page 250 & 251
9	4.78%	7/10/1958	N/A	4.78%			0		0.0000%	FF1: Page 250 & 251
10	Total				$ -	$ -	0.00%		0.0000%	Sum Lines 8 Thru 9

Effective NSTAR ROI

Tariff Section II.A.2.a

	(a)	(b)	(c)	(d)	(e)	(f)
Line	**Description**	**Common**	**Preferred**	**LTD**	**Total**	**Reference**
11	Amount				$ -	Sheet 2, lines 2 thru 4
12	Cost	0.0000%	0.0000%	0.0000%		See Note
13	Actual Weighting	0.0000%	0.0000%	0.0000%	0.0000%	Line 11 / Total Line 11
14	Weighted Cost	0.0000%	0.0000%	0.0000%	0.0000%	Line 12 * Line 13
15	70% of Weighted Cost	0.0000%	0.0000%	0.0000%		Line 14 * 70%
16	Tariff Weighting	50.0000%	0.0000%	50.0000%	100.0000%	Tariff Section II.A.2.a
17	Weighted Cost	0.0000%	0.0000%	0.0000%	0.0000%	Line 12 * Line 16
18	30% of Weighted Cost	0.0000%	0.0000%	0.0000%		Line 17 * 30%

19	Blended Cost of Capital	0.0000%	0.0000%	0.0000%	0.0000%	Line 15 + Line 18
20	**Lower of Blended or Actual**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	Lower of line 14, col (e) or line 19, col (e) Tariff Section II.A.2.a

21 Note:

22 The Regurn on Equity component is specified in Tariff Section II.A.2.a.iii

23 The Cost of Preferred Stock is calculated on line 10

24 The Cost of Long Term Debt is calculated on line 7

NSTAR Electric Company

Annual Local Network Service Revenue Requirement

Service Year Ended December 31, xxxx

Sheet 8

Transmission Related ADIT - Tariff Section II.A.1.f

	(a)	(b)	(c)	(d)	(e)
Line	Description	Amount	Allocator	Rate Base	Notes
1	**Account 190**				
2	Item # 1		0.0000%	$ -	FF1: Page 234.2(c) Footnote
3	Item #2		0.0000%	-	FF1: Page 234.2(c) Footnote
4	Last Item	-	0.0000%	-	FF1: Page 234.2(c) Footnote
5	Total 190	$ -	0.0000%	$ -	Sum Lines 2 thru 4
6	**Account 283**				
7	Item # 1		0.0000%	-	FF1: Page 276.3(k) Footnote
8	Item #2		0.0000%		FF1: Page 276.3(k) Footnote

				-	
9	Last Item	-	0.0000%	-	FF1: Page 276.3(k) Footnote
		$		$	
10	Total 283	-	0.0000%	-	Sum Lines 7 thru 9
11	Wages & Salary Allocator	0.0000%			Sheet 6, Line 6, Col (d)
12	Plant Allocator	0.0000%			Sheet 6, Line 14, Col (d)

ATTACHMENT L
CREDITWORTHINESS POLICY

I. General Information:

This Attachment L details the specific requirements for the creditworthiness procedures of NSTAR. All customers taking (i) any service under Schedule 21-NSTAR or (ii) any FERC-regulated interconnection service from NSTAR must meet the terms of this Policy (where all the above, collectively, are referred to as "Services"). The creditworthiness of each customer must be established prior to receiving service from NSTAR. A customer will be evaluated at the time its application for service is provided to NSTAR. A credit review shall be conducted for each transmission customer not less than annually or upon reasonable request by the transmission customer. This Attachment L, when updated, will be done so in accordance with Section 10 of this Policy and as posted on NSTAR's OASIS.

All customers must comply with the terms of this Attachment L. Each customer should refer to NSTAR's web site at www.nstar.com, or NSTAR's OASIS site, for the NSTAR representative to whom to forward the information required by this Attachment L.

Upon receipt of a customer's information, NSTAR will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a customer, NSTAR will notify the customer of its Financial Assurance requirements. NSTAR will provide a written evaluation, upon request, to customers who are not required to provide Financial Assurance.

II. Financial Information:

Customers receiving transmission service or requesting interconnection service must submit, if available, the following:

- All current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch of the customer.
- Audited financial statements provided by a registered independent auditor for the two most recent years, or the period of its existence, if shorter, for the customer.

III. Creditworthiness Requirements:

A. The customer must meet at least one of the following quantitative criteria in order to receive unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges:

i) If rated, the customer must have either for itself or for its outstanding debt the following:

- Standard and Poor's or Fitch rating of at least a BBB, or
- Moody's rating of at least a Baa2.

ii) If un-rated or if rated below BBB/Baa2, as stated in a), the customer must meet all of the following:

- A Current Ratio of at least 1.0 times (current assets divided by all current liabilities);
- A Total Capitalization Ratio of less that 60% debt: total debt (including all short-term borrowing) divided by total shareholders' equity plus total debt;
- "Earnings before interest, taxes, depreciation and amortization" in most recent fiscal quarter divided by expense for interest" (EBITDA-to-Interest Expense Ratio) of at least 2.0 times; and
- Audited Financial Statement with an unqualified audit opinion.

iii) If the customer relies on the creditworthiness of a parent company, the customer's parent company must meet the criteria set out in (a) or (b) above, and must provide to NSTAR a written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from NSTAR.

iv) If the customer is a municipal that is a member of the Massachusetts Municipals Wholesale Electric Cooperative (MMWEC), MMWEC must meet the criteria set out in (a) or (b) above and provide to NSTAR a written guarantee that MMWEC will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from NSTAR.

B. If the customer does not qualify for unsecured credit under Section A, the customer will qualify for unsecured credit equivalent to two months of transmission service charges, or for interconnections, the credit equivalent of two months of the annual facilities charges and other ongoing charges, if one of the following qualitative factors is met:

- § The customer has, on a rolling basis, 12 consecutive months of payments to NSTAR with no missed, late or defaults in payment; or
- § The customer has an executed long-term contract for the sale of the full output (energy and capacity) of its generating unit and either has executed a corresponding service agreement under Schedule 21-NSTAR for the transmission of that output or the execution of such a service agreement is pending the customer's demonstration of creditworthiness pursuant to this Attachment L.

IV. <u>Financial Assurance</u>:

If the customer does not meet the applicable requirements for Creditworthiness set out in Section III above, then the customer must either:

- Pay in advance for service an amount equal to the lesser of the total charge for Transmission Service or the charge for three months of Transmission Service not less than 5 days in advance of the commencement of service; or

- Obtain Financial Assurance in the form of a: letter of credit, performance bond, or corporate guarantee equal to the equivalent of 3 months of Transmission Service charges prior to receiving service.

If the customer pays for service in advance, NSTAR will pay to the customer interest on the amounts not yet due to NSTAR , computed in accordance with the Commission's regulations at 18 CFR ? 35.191(a)(2)(iii).

V. <u>Contesting Creditworthiness Determination</u>:

The Transmission Customer may contest NSTAR's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. NSTAR will review and respond to the request within 20 calendar days.

VI. Process for Changing Credit Requirements:

In the event that NSTAR plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, NSTAR shall submit such changes in a filing to the Commission under Section 205 of the Federal Power Act. NSTAR shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

A. General Notification Process

i) NSTAR shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

ii) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s).

iii) NSTAR shall consult with interested stakeholders upon request.

iv) Following Commission acceptance of such filing and upon the effective date, NSTAR shall revise Attachment L and an updated version of Schedule 21-NSTAR shall be posted the ISO-NE website.

B. Transmission Customer Responsibility

When there is a change in requirements pursuant to this Attachment L, it is the responsibility of the customers to forward updated financial information to NSTAR at the address noted on NSTAR's OASIS site and indicate whether the change affects their ability to meet the requirements of this Attachment L. In such cases where the customer's status has changed, the customer must take the necessary steps to comply with the revised requirements of the Attachment L by the effective date of the change.

VII. Posting Collateral Requirements:

A. Changes in Customer's Financial Condition

Each customer must inform NSTAR, in writing, within five (5) business days of any material change in its financial condition, and, if the customer qualifies under Section III.A(c), that of its parent company. A material change in financial condition may include, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

B. Change in Creditworthiness Status

- A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in Section IV above if one or more of the following conditions apply:
- The customer no longer meets the applicable criteria for Creditworthiness in Section III above;
- The customer exceeds the amount of unsecured credit extended by NSTAR, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or
- The customer has missed two or more payments for any of the services offered by NSTAR in the last 12 months.

In the event that NSTAR determines that there is a change in the credit level or collateral requirements, the customer may request a written explanation of the basis for this change. Such notification should be sent to the NSTAR contact indicated on the NSTAR OASIS site. NSTAR shall respond to such request within

20 days of receipt of such notification.

Unless otherwise noted above, when there is a change in a customer's Creditworthiness Status requiring the customer to provide Financial Assurance, the customer must provide such Financial Assurance within 20 business days from the date the customer either notifies NSTAR, as required in Section VI.B above, or receives notice from NSTAR.

VIII. Ongoing Financial Review:

Each customer is required to submit to NSTAR annually or when issued, as applicable:

- Current rating agency report;
- Audited financial statements from a registered independent auditor; and
- 10-Ks and 8-Ks, promptly upon their issuance.

IX. Suspension of Service:

NSTAR may immediately suspend service (with notification to Commission) to a customer, and may initiate proceedings with Commission to terminate service, if the customer does not meet the terms described in Sections III through VIII above at any time during the term of service or if the customer's payment obligations to NSTAR exceed the amount of unsecured or secured credit to which it is entitled under this Attachment L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

Eversource

SCHEDULE 21-ES

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SCHEDULE 21-ES

LOCAL SERVICE SCHEDULE

This Local Service Schedule, designated Schedule 21-ES, governs the terms and conditions of service taken by Transmission Customers over the Transmission System of The Connecticut Light and Power Company, Public Service Company of New Hampshire and Western Massachusetts Electric Company (together, "Eversource"), but not over the Transmission System of their affiliate, NSTAR Electric Company, which provides service pursuant to Schedule 21-NSTAR.

I. COMMON SERVICE PROVISIONS

1 Definitions

Capitalized terms not defined herein shall have the meanings given them in the Tariff.

1.1 Annual Transmission Costs

The total annual cost of the Transmission System for purposes of Local Network Service shall be the amount specified in Attachments ES-H and ES-I, until amended by Eversource or modified by the Commission.

1.2 Annual True Up

The reconciliation to actual costs and actual loads of the estimated costs and loads costs used for billing purposes under Section 3.0 of this Local Service Schedule for any Service Year.

1.3 Category A Load Ratio Share

Ratio of a Transmission Customer's Category A Network Load to Eversource's total load computed in accordance with Sections 16.5 and 16.6 under Part III of this Local Service Schedule and calculated on a rolling twelve month basis. Also referred to as "Load Ratio Share".

1.4 Category B Load Ratio Share

Ratio of a Transmission Customer's Monthly Category B Load in the Designated State or Area for a Localized Facility to the Monthly Transmission System Category B Load for such Designated State or Area, calculated in accordance with Sections 16.5 and 16.6, and calculated on a rolling twelve month basis.

1.5 **Designated Agent**

See Tariff. Also, the Designated Agent of Eversource is Eversource Energy Service Company ("Eversource Service") which is a subsidiary of Eversource Energy.

1.6 Designated State or Area

The state or area to which the Commission allocates the costs of a Localized Facility identified in Section 16.3.

1.7 **Interest**

The amount computed in accordance with the Commission's regulations at 18 CFR §35.19a (a)(2)(iii). Interest on deposits and shall be calculated from the day the deposit check is credited to Eversource's account.

1.8 **Interruption**

A reduction in non-firm transmission service due to economic reasons pursuant to Schedule 21.

1.9 **Localized** Facility

Facility or costs that the New England System Operator determines should not be included in Attachment F of the ISO OATT.

1.10 **Network Load**

The load that a Network Customer designates for Local Network Service. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.11 **Network Operating Agreement**

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Part III of this Local Service Schedule.

1.12 **Network Upgrades**

Modifications or additions to transmission-related facilities that are integrated with and support Eversource's overall Transmission System for the general benefit of all users of such Transmission System.

1.13 **New England System Operator**

ISO New England Inc. ("ISO") or its successor entity.

1.14 **Party(ies)**

Eversource and the Transmission Customer receiving service under the Tariff.

1.15 **Short-Term Firm Point-To-Point Transmission Service**

Firm Point-To-Point Transmission Service with a term of less than one year.

1.16 Service Agreement

Service Agreement is a transmission service agreement for transmission service provided under this Local Service Schedule or Localized Costs Responsibility Agreement ("LCRA").

1.17 **Service Year**

The calendar year in which the Transmission Customer is receiving service under this Local Service Schedule.

1.18 **Eversource**

The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire, each an operating company of Eversource Energy, but excluding their affiliate NSTAR Electric Company, which provides Transmission Service pursuant to Schedule 21-NSTAR.

1.19 **Eversource's Monthly Transmission System Peak**

The maximum firm usage of the Eversource Transmission System in a calendar month (this does not include load of Eversource's customers exclusively connected to PTF).

1.20 **Eversource Transmission System**

The PTF and non-PTF facilities owned, controlled or operated by Eversource that are used to provide transmission service under this Local Service Schedule. This includes PTF facilities whose costs are not included in the regional rate.

1.21 **Transmission Service**

Point-To-Point Transmission Service provided under this Local Service Schedule on a firm and non-firm basis.

2. Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. Eversource is required to provide (or offer to arrange with the New England System Operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Service (i) Scheduling, System Control and Dispatch.

The Transmission Customer serving load within the Eversource Control Area shall also obtain the following ancillary services: (i) Reactive Supply and Voltage Control from Generation Sources, (ii) Regulation and Frequency Response, (iii) Energy Imbalance, (iv) Operating Reserve - Spinning, and (v) Operating Reserve - Supplemental.

The Transmission Customer serving load within the Eversource Control Area is required to acquire the appropriate Ancillary Services, whether from the New England System Operator, Eversource, another party, or by self-supply.

The Transmission Customer may not decline Eversource's or the New England System Operator's offer of appropriate Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from Eversource.

If Eversource is unable to provide Scheduling, System Control and Dispatch, Eversource can fulfill its obligation to provide this Ancillary Service by acting as the Transmission Customer's agent to secure this Ancillary Service from the New England System Operator. The Transmission Customer may elect to (i) have Eversource act as its agent to obtain Scheduling, System Control and Dispatch, (ii) secure Scheduling, System Control and Dispatch directly from the New England System Operator, or from a third party.

Eversource or New England System Operator shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedule that is attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by Eversource in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one’s wholesale merchant or an Affiliate’s use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Eversource system.

3. Billing and Payment

3.1 **Billing Procedure**

Within a reasonable time after the first day of each month, Eversource Service shall submit an invoice to the Transmission Customer for the charges for all services furnished or costs allocated under the Tariff during the preceding month.

The invoice shall be paid by the Transmission Customer within twenty five (25) days of the date of the invoice. All payments shall be made in immediately available funds payable to Eversource Service, or by wire transfer to a bank named by Eversource Service. Billing hereunder shall be based on cost estimates made by Eversource subject to Annual True-up when actual costs for the Service Year are known. Such Annual True-up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-up relates. The Annual True-up will include interest calculated in accordance with Section 35.19a of the Commission’s regulations. If the in service date of a forecasted capital addition changes, and the impact of such change on

Eversource's annual revenue requirement is ten percent or more, Eversource Service will adjust current billing to the Transmission Customer as appropriate.

3.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by Eversource Service.

3.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to Eversource Service on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after Eversource Service notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, Eversource may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between Eversource and the Transmission Customer, Eversource will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then Eversource may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy. Neither Party shall have the right to challenge any monthly bill or to bring any court or administrative action of any kind questioning the propriety of any bill after a period of twenty four (24) months from the date the bill was due; provided, however, that in the case of a bill based on estimates, such twenty-four month period shall run from the due date of the final adjusted bill.

3.4 Transmission Customer Right to Audit

Eversource shall keep complete and accurate accounts and records with respect to its performance under this Local Service Schedule and shall maintain such data for a period of at least two (2) years after final billing for audit by a Transmission Customer. The Transmission Customer shall provide thirty (30) days' written notice to Eversource to request an audit of all such accounts and records relevant to service provided to the Transmission Customer for a specific time period. The Transmission Customer shall have the right, during normal business hours and at its own expense, to examine, inspect and make copies of all such accounts and records relevant to service provided to the Transmission Customer at such offices where such accounts and records are maintained, insofar as may be necessary for the purpose of ascertaining the reasonableness and accuracy of all relevant data, estimates or statements of charges submitted hereunder to the Transmission Customer. The records made available to a Transmission Customer for auditing purposes hereunder shall not include information pertaining to the loads of or charges to an individual customer other than the Transmission Customer; unless the Transmission Customer requests that the Commission order that such information be made available to the Transmission Customer and the Commission so orders. Nothing in this section shall be interpreted as limiting the Transmission Customer's access to system-wide load or charge data.

3.5 Regulatory Oversight of Formula Rate

Eversource will submit to the Connecticut Public Utilities Regulatory Authority, the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission ("State Commissions") the following information:

(a) A copy of the New England Power Pool's ("NEPOOL's") or any successor's annual informational filing at FERC supporting the total transmission revenue requirement for New England, which contains information submitted by Eversource supporting its total transmission revenue requirement;

(b) Eversource's total transmission revenue requirement as calculated in Attachments H & I under Schedule 21-ES;

(c) A copy of Eversource's applications under Restated NEPOOL Agreement Section 15.5, concerning the installation of or material changes to transmission facilities (or any successor approval process), and Section 18.4, concerning plans for additions, retirements, or changes in the capacity of transmission facilities (including descriptions of facilities and cost estimates);

(d) A copy of ISO New England's or any successor's Regional Transmission System Plan, which contains all identified improvements to the New England power system approved by the ISO New England or any successor's board;

(e) A copy of Eversource's filing to each New England state's siting council for those projects to be recovered through the RNS or LNS rates, such copy to be filed with the State Commissions when the estimated costs of the projects in question are proposed to be included in the RNS and LNS rates;

(f) At the same time that new estimated rates are implemented, the estimated cost for each capital addition (on a project-by-project basis) the cost of which is to be included in the estimated rates; and, for each such capital addition with an estimated cost of $20 million or greater, Eversource will provide the following to the extent available: (i) a breakdown of the projected cost into the following categories: labor (broken down into planning, engineering, construction, and other), outside services (broken down into planning, engineering, construction and other), materials (broken down into station equipment, towers and poles, overhead conductor, underground conduit and conductor, and other), land (broken down into fee ownership, easement, and other), and other (if applicable) and (ii) a non-binding estimate of the total project costs by calendar quarter;

(g) Within 60 days after the true-up is rendered for a year, the actual cost for each capital addition that was placed in service during that year; and, for each such capital addition with an actual or estimated cost of $20 million or greater, Eversource will provide the following to the extent available: (i) a breakdown of the actual cost into the following categories: labor (broken down into planning, engineering, construction, and other), outside services (broken down into planning, engineering, construction, and other), materials (broken down into station equipment, towers and poles, overhead conductor, underground conduit and conductor, and other), land (broken down into fee ownership, easement, and other), and other (if applicable) and (ii) the actual total project costs by calendar quarter.

4. Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of Eversource to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

5. Creditworthiness: See Attachment ES-L to this Schedule 21-ES.

6. Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

II. POINT-TO-POINT TRANSMISSION SERVICE

Scheduling of Point-To-Point Transmission Service:

The System Operator will dispatch all resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate external transactions. Resources within the New England Control Area using Firm Point-to-Point Transmission Service shall be dispatched based on economic merit in accordance with Market Rule 1 and will have no physical scheduling or dispatch rights. Transmission Customers will be charged for congestion costs and any other costs associated with such dispatch in accordance with Market Rule 1.

7. Nature of Firm Point-To-Point Transmission Service

7.1 Classification of Firm Transmission Service

The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule ES-2, as appropriate, for Long and Short-Term Firm Point-To-Point Transmission Service. In the event that either a Transmission Customer has not made a capacity reservation, or a Transmission Customer exceeds its firm capacity reservation at the Point of Receipt and Point of Delivery the Transmission Customer shall be billed and pay for its actual use of such excess capacity in addition to any Reserved Capacity pursuant to Schedule ES-2, including ancillary services provided pursuant to Schedule ES-1 hereto.

8. Nature of Non-Firm Point-To-Point Transmission Service

8.1 Classification of Non-Firm Point-To-Point Transmission Service

The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule ES-3, as appropriate, for non-firm Point-To-Point Transmission Service. In the event that either a Transmission Customer has not made a capacity reservation, or a Transmission Customer exceeds its non-firm capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer shall be billed and pay for its actual use of such excess capacity in addition to any Reserved Capacity pursuant to Schedule ES-3, including ancillary services provided pursuant to Schedule ES-1 hereto. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and/or energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule ES-3.

9. Service Availability

9.1 Real Power Losses

Real Power Losses are associated with all transmission service. Eversource is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as determined under Market Rule 1. The applicable Real Power Loss factors are as follows:

The amount of transmission losses incurred in transmitting power from the POR(s) to the POD(s) ("Loss Amount") shall be determined from time to time by the New England System Operator in accordance with ISO procedures applicable at the time of delivery. The Loss Amounts, when determined by the New England System Operator, shall be posted on Eversource’s Open Access Same-Time Information System ("OASIS"). In the event that the New England System Operator, for any reason, does not determine the entire Loss Amount, the losses not determined by the New England System Operator shall be based on average system losses as set forth below:

Cumulative Losses in Percent

POR/POD	**Peak***	**Off-Peak**	**24 Hr. Avg.**
Bulk Transmission	1.98	2.42	2.21
Bulk Substation	2.46	2.92	2.70
Pri. Distribution	4.58	4.50	4.54

*Peak hours are defined as 0700-2300, Monday-Friday; Off-Peak hours are all other hours.

10. Procedures for Arranging Firm Point-To-Point Transmission Service

10.1 Deposit

A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either three month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month.

11. Additional Study Procedures For Firm Point-To-Point Transmission Service Requests:

11.1 Disbursement Methodology for Late Study Penalties

See Attachment ES-D to Schedule 21-ES.

12. Compensation for Transmission Service

The Transmission Customers taking Point-To-Point Transmission Service shall pay Eversource for any Direct Assignment Facilities, Ancillary Services and applicable study costs, along with the following:

12.1 Rates and Charges for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Services are provided in the Attachments appended to this Local Service Schedule: Firm Point-To-Point Transmission Services (Schedule ES-2); and Non-Firm Point-To-Point Transmission Services (Schedule ES-3).

12.2 Rates for Firm and Non-Firm Point-To-Point Transmission Services

Rates for Firm and Non-Firm Point to Point Transmission Services shall be determined as set forth in Attachments ES-2 and ES-3 of this Local Service Schedule on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 3 of this Local Service Schedule. Eversource shall use Part II of the Tariff to make its Third-Party Sales. Eversource shall account for such use at the applicable Tariff rates.

III. LOCAL NETWORK SERVICE

13. Nature of Local Network Service

13.1 Real Power Losses

Real Power Losses are associated with all transmission service. Eversource is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as determined under Market Rule 1. The applicable Real Power Loss factors are as follows:

The amount of transmission losses incurred in transmitting power across the Eversource Transmission System to the Network Customer's Network Load shall be determined from time to time by the New England System Operator in accordance with ISO procedures applicable at the time of delivery. The Loss Amounts, when determined by the New England System Operator, shall be posted on the Open Access Same-Time Information System ("OASIS"). In the event that the New England System Operator, for any reason, does not determine the entire Loss Amount, the losses not determined by the New England System Operator shall be based on average system losses as set forth below:

Cumulative Losses in Percent

POR/POD	Peak*	Off-Peak	24 Hr. Avg.
Bulk Transmission	1.98	2.42	2.21
Bulk Substation	2.46	2.92	2.70
Pri. Distribution	4.58	4.50	4.54

*Peak hours are defined as 0700-2300, Monday-Friday; Off-Peak hours are all other hours.

14. Network Resources

14.1 Use of Interface Capacity by the Network Customer

There is no limitation upon a Network Customer's use of the Eversource Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of Eversource's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

15. Additional Study Procedures For Local Network Service Requests

15.1 Disbursement Methodology for Late Study Penalties See Attachment ES-D to Schedule 21-ES

16. Rates and Charges

The Network Customer shall pay Eversource for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

16.1 Rates and Charges

Rates for Local Network Service shall be determined as set forth in Schedule ES-4 on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 3 of this Local Service Schedule.

16.2 Eligible Customers Taking Service Under the ISO Tariff

Any Eligible Customer taking Regional Network Service under the ISO Tariff in a Designated State or Area shall pay to Eversource Service the customer's Category B Load Ratio Share of the Formula Requirements as calculated in Schedule ES-4, Appendix B for such Designated State or Area**.** Eversource Service shall execute a LCRA under this Local Service Schedule, in the form set forth in Attachment ES-E, to recover such charges from such customer. Eversource Service shall not bill any such customer any such costs until (1) such LCRA has been executed with the

Eligible Customer, or (2) an unexecuted LCRA has been permitted to be made effective **by** the Commission.

16.3 Listing of Localized Facilities by Designated State or Area:

(a) Connecticut:
Bethel to Norwalk Project
Middletown to Norwalk Project
Glenbrook Cables Project
Greater Springfield Reliability Project (Connecticut portion)

(b) Massachusetts:
Greater Springfield Reliability Project (Massachusetts portion)

16.4 **Monthly Demand Charge**

The Network Customer shall pay monthly Demand Charges, which shall be determined by multiplying its Category A Load Ratio Share times one twelfth (1/12) of the Formula Requirements in Schedule ES-4, Appendix A, and by multiplying its Category B Load Ratio Share for the Designated State or Area times one twelfth (1/12) of the Formula Requirements in Schedule ES-4, Appendix B for the Localized Facilities that are in such Designated State or Area.

16.5 **Determination of Network Customer's Monthly Network Load**

The Network Customer's Monthly Category A Network Load is its hourly load (including its designated Network Load not physically interconnected with Eversource under Schedule 21) coincident with Eversource's Monthly Transmission System Peak.

The Network Customer's Monthly Category B Load for a Designated State **or** Area for a Localized Facility is its hourly load in such Designated State or Area coincident with the monthly transmission system peak load for such Designated State or Area.

For Localized Facilities for which the Designated State or Area is identified as "Connecticut" in Section 16.3(a) of this Schedule 21-ES, the customer's hourly load shall be all of the customer's

Regional Network Load in Connecticut, and the monthly transmission system peak load shall be all Regional Network Load in Connecticut.

For Localized Facilities for which the Designated State or Area is identified as "Massachusetts" in Section 16.3(b) of this Schedule 21-ES, the customer's hourly load shall be all of the customer's Regional Network Load in Massachusetts, and the monthly transmission system peak load shall be all Regional Network Load in Massachusetts; provided, that the customer's monthly load and the monthly transmission system peak load shall exclude the load of generators taking RNS for the delivery of offline station service.

16.6 **Determination of Eversource's Monthly Transmission System Load**

Eversource's Monthly Transmission System Category A Load is Eversource's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to this Local Service Schedule plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.[1]

Eversource's Monthly Transmission System Category B Load for the Designated State or Area for a **Localized** Facility is the monthly transmission system peak load for such Designated State or Area.[1]

For Localized Facilities for which the Designated State or Area is identified as "Connecticut" in Section 16.3(a) of this Schedule 21-ES, the monthly transmission system peak load shall be all Regional Network Load in Connecticut.

For Localized Facilities for which the Designated State or Area is identified as "Massachusetts" in Section 16.3(b) of this Schedule 21-ES, the monthly transmission system peak load shall be all Regional Network Load in Massachusetts; provided, that the monthly transmission system peak load shall exclude the load of generators taking RNS for the delivery of offline station service.

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1 Excludes MWs associated with lump sum payment transactions identified in footnote 2.

17. Operating Arrangements

17.1 Operation under the Network Operating Agreement

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

17.2 Network Operating Agreement

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Eversource Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between Eversource and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Eversource Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with Eversource, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and NPCC requirements. Eversource shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment ES-G.

SCHEDULE ES-1

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by Eversource (if Eversource is the Control Area operator) or indirectly by Eversource making arrangements with the New England System Operator that performs this service for the Eversource Transmission System. The Transmission Customer must purchase this service from Eversource or the New England System Operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the New England System Operator performs this service for Eversource, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Eversource by that New England System Operator.

Each Point-To-Point Transmission Customer under this Local Service Schedule will be charged for Transmission Scheduling, System Control and Dispatch Services for the total Reserved Capacity specified in each reservation for Point-To-Point Transmission Service made under this Local Service Schedule at the rates set forth in Appendix A of this Schedule ES-1. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer **shall** pay for its actual use of such excess capacity in addition to any Reserved Capacity. The charge for such excess use of capacity shall be determined by multiplying the sum of the actual use in excess of its capacity reservation times the hourly non-firm rate posted on Eversource's OASIS including ancillary services provided pursuant to Schedule ES-1 hereto.

Each Network Customer under this Local Service Schedule will be charged a monthly Transmission Scheduling, System Control and Dispatch Service Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Formula Requirements specified in Appendix B of this Schedule ES-1.

Each Transmission Customer with generation within the New England Control Area shall be required also to provide for Scheduling, System Control and Dispatch Service for that generation. It is anticipated that the Transmission Customer will obtain these services from the ISO. Eversource will make available Generation Scheduling, System Control and Dispatch Service at the rates set forth in Appendix C of this Schedule ES-1.

Each Transmission Customer with generation located outside of the New England Control Area shall be required to provide for Scheduling, System Control and Dispatching Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting for these services from the provider of these services within the Control Area where the generation is located.

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-1 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-1

Appendix A

POINT-TO-POINT TRANSMISSION RATE

Eversource's Formula Rate for Point-To-Point Transmission Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$\textit{Formula Rate}_i = (A_{i-1} - B_{i-1})\, C_{i-1} \quad \textit{WHERE:}$$

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of Eversource for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule ES-1.

- B_{i-1} is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling and dispatch revenues shall be those recorded on the books of each of the companies comprising Eversource hereunder in FERC Account No. 456.1 pertaining to Transmission of Electricity for Others and such other applicable FERC accounts for the calendar year prior to the Service Year.

- C_{i-1} is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

SCHEDULE ES-1

Appendix A

Exhibit 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses revenue requirements for each of the companies comprising Eversource hereunder is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES

Eversource's System Control and Load Dispatching Expense, for the calendar year prior to the Service Year, as recorded in FERC Account 561.1-561.4 and the revenue requirement calculation for the CL&P Dispatch Center Plant as described in Appendix A, Exhibit 2.

SCHEDULE ES-1

APPENDIX A

EXHIBIT 2

CL&P DISPATCH CENTER REVENUE REQUIREMENT

This exhibit calculates the CL&P Dispatch Center Revenue Requirement. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section I. of the ISO-NE Transmission, Markets and Services Tariff and as used in this exhibit have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch Center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period January 1, 2008 through December 31, 2008, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the CONVEX Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The Connecticut Light & Power

Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Exhibit 2.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

The Dispatch Center Investment Base will be the year-end balances of: (a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P's capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

A x B x C

where:

A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TE / (1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE ES-1

Appendix B

NETWORK TRANSMISSION FORMULA REQUIREMENTS

Eversource's formula requirements for Network Transmission Scheduling, System Control and Dispatch Service is determined from the following formula.

Formula $\text{Requirements}_i = (A_{i\text{-}1} - B_{i\text{-}1})$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- $A_{i\text{-}1}$ is the Annual Control Center Expenses (expressed in dollars) of Eversource for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix B of Schedule ES-1.

- $B_{i\text{-}1}$ is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling, system control and dispatch revenues shall be those recorded on the books of each of the companies comprising Eversource hereunder in FERC Account No. 456.1 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

SCHEDULE ES-1

APPENDIX B

EXHIBIT 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses for each of the companies comprising Eversource hereunder is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES

Eversource's System Control and Load Dispatching Expense), for the calendar year prior to the Service Year as recorded in FERC Account 561.1-561.4 and the revenue requirement calculation for the CL&P Dispatch Center Plant as described in Appendix B, Exhibit 2.

SCHEDULE ES-1

APPENDIX B

EXHIBIT 2

CL&P DISPATCH CENTER REVENUE REQUIREMENT

This exhibit calculates the CL&P Dispatch Center Revenue Requirement. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section I. of the ISO-NE Transmission, Markets and Services Tariff and as used in this exhibit have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch Center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period January 1, 2008 through December 31, 2008, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the CONVEX Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The Connecticut Light & Power

Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Exhibit 2.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

The Dispatch Center Investment Base will be the year-end balances of: (a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P's capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

A x B x C

where:

A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TE / (1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE ES-1
Appendix C
GENERATION RATES

Eversource's Formula Rate for Generation Scheduling, System Control and Dispatch Service ("Formula Rate") shall be calculated using the Point-to-Point Formula Rate for Transmission Scheduling, System Control, and Dispatch Service in Appendix A of Schedule ES-1.

SCHEDULE ES-2
FIRM POINT-TO-POINT SERVICE

I. Each month, Eversource Service shall bill the Transmission Customer for Long-Term Firm and Short-Term Firm Transmission Service and the Transmission Customer shall be obligated to pay Eversource the charges as set forth in this Schedule ES-2, as applicable.

A. <u>TRANSMISSION CHARGES</u>

1. <u>Determination of Transmission Charges</u>

The Transmission Charges will provide for recovery of the costs of the transmission facilities ofEversource. The Category A Transmission Charges for each month will equal the sum of the Category A Charges for each monthly (or longer term), weekly or daily transaction during such month. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer **shall** pay for its actual use of such excess capacity in addition to the charges for each monthly, weekly or daily transactions during such month. The charge for such excess use of capacity shall be determined by multiplying the actual hourly use in excess of its capacity reservation times the applicable Category A on-peak or off-peak hourly non-firm rate posted on Eversource's OASIS pursuant to Schedule ES-3 including ancillary services provided pursuant to Schedule ES-1 hereto.

The Category A Charge for each monthly (or longer term) transactions will be the product of: (a) Eversource's Category A Formula Rate (expressed in $ per kilowatt-year), divided by twelve (12) months, and (b) the Reserved Capacity set forth for such monthly (or longer term) transaction (expressed in kilowatts).

The Category A Charge for each weekly transaction will be the product of: (a) Eversource's Weekly Category A Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-week), and (b) the Reserved Capacity set forth for such weekly transaction (expressed in kilowatts). Eversource's Weekly Category A Rate is Eversource's Category A Formula Rate for Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Category A Charge for each daily transaction will be the product of: (a) Eversource's Daily Category A Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth for such daily transaction (expressed in kilowatts). Eversource's Daily Category A Rate is Eversource's Weekly Category A Rate for Short-Term Firm Point-To-Point Transmission Service divided by five (5) days. The total of the Transmission Customer's charges for daily transactions, under an individual reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

2. Eversource's Formula Rates

Eversource's Formula Rates for Long-Term Firm and Short-Term Firm Point-To-Point Service shall be determined in accordance with the rate formulas specified in Appendix A of this Schedule ES-2.

3. Tax Rates and Taxes

Eversource's Formula Rates set forth in this schedule in effect during a Service Year shall be based on the local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, Eversource's Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

4. Provision re: Exchanges

With respect to Entitlement Transactions or Energy Transactions or other transactions that involve an exchange, each party to such transaction shall be treated as an individual Transmission Customer under this Local Service Schedule. Accordingly, a separate Schedule ES-2 or other applicable charge(s) will be calculated for, and a separate bill will be rendered to, each such individual Transmission Customer.

5. Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Eversource must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6. Resales

The rates and rules governing charges and discounts in Sections I.A.1 and 5 of this Schedule ES-2 stated above shall not apply to resales of transmission service, compensation for which shall be governed by Schedule 21.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to Eversource Service each month the following additional charges for Long-Term, and Short-Term Firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Long-Term Firm or Short Term Firm Point-To-Point Transmission Service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES CHARGE**

Eversource shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreements.

C. **OTHER**

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-2 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-2

Appendix A

CATEGORY A RATE

FIRM POINT-TO-POINT TRANSMISSION SERVICE

Eversource's Category A Formula Rate for Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.
Formula $Rate_i = (A_i - B_i + C_i - D_i) / E_i$

WHERE:

- i equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H,

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services, to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load (E),[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments (expressed in dollars) to the New England System Operator as recorded in FERC Account 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with the Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- E is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-2

[Reserved]

SCHEDULE ES-3

NON-FIRM POINT-TO-POINT SERVICE

I. Eversource shall bill the Transmission Customer for Non-Firm Point-To-Point Transmission Service, and the Transmission Customer shall be obligated to pay Eversource the charges as set forth in this Schedule ES-3 as applicable.

A. **<u>TRANSMISSION CHARGES</u>**

1. <u>General</u>

The Transmission Customer shall pay to Eversource Service each month the Category A Transmission Charges calculated for all of the Transmission Customer's monthly transactions, weekly transactions, daily transactions and hourly transactions, each as set forth below. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer shall pay for its actual use of such excess capacity in addition to the charges for each monthly, weekly, daily or hourly transactions during such month. The charge for such excess use of capacity shall be determined by multiplying the actual hourly use in excess of its capacity reservation times the applicable Category A on-peak or off-peak hourly non-firm rate posted on Eversource's OASIS pursuant to this Schedule ES-3 including ancillary services provided pursuant to Schedule ES-1 hereto.

With respect to any wholesale transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a Transmission Charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

The Category A Transmission Charge for each month applicable to a monthly transaction shall be determined as the product of: (a) the Category A rate posted on Eversource's Open Access Same-Time Information System ("OASIS") at the time the service is reserved, not to exceed Eversource's Annual Category A Rate for Non Firm Point-To-Point Transmission Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such month (expressed in kilowatts).

The Category A Transmission Charge for each month applicable to weekly transactions shall be the sum of the transmission charges determined for each weekly transaction during such month. The transmission charge for each weekly transaction shall be determined as the product of: (a) the Category A rate posted on Eversource's OASIS at the time the service is reserved, not to exceed Eversource's Weekly Category A Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-week), and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such week (expressed in kilowatts). Eversource's Weekly Category A Rate is Eversource's Annual Category A Rate for Non-Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Transmission Charge for each month applicable to daily transactions will be the sum of the transmission charges determined for each daily transaction. The transmission charge for each daily transaction shall be determined as the product of: (a) the rate posted on Eversource's OASIS at the time the service is reserved, not to exceed Eversource's Daily Category A Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such day (expressed in kilowatts). Eversource's Daily Category A On-Peak Rate is Eversource's Weekly Category A Rate for Non-Firm Point-To-Point Transmission Service divided by five (5) days. Eversource's Daily Category A Off-Peak Rate is Eversource's Weekly Category A Rate for Non-Firm Point-To-Point Transmission Service divided by seven (7) days. The total of the Transmission Customer's charges for daily transactions, under an individual Reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

The Transmission Charge for each month applicable to hourly transactions will be the sum of the transmission charges determined for each hourly transaction during such month. The transmission charge for each hour of an hourly Transaction shall be determined as the product of: (a) the rate posted on Eversource's OASIS at the time the service is reserved, not to exceed Eversource's Daily Category A Firm Point-To-Point Transmission Service Rate divided by sixteen (16) hours (expressed in $ per kilowatt-hour), and (b) the Reserved Capacity as set forth in the Transmission Customer's applicable Reservation for such hour (expressed in kilowatts). Eversource's Hourly Category A On-Peak Rate is equal to Eversource's Daily Category A Rate for Non-Firm Transmission Service divided by sixteen (16) hours. Eversource's Hourly Category A Off-Peak Rate is equal to Eversource's Daily Category A Rate for Non-Firm Transmission Service divided by twenty-four (24) hours. The total of the Transmission Customer's charges for hourly transactions, under an individual Reservation, in a twenty-four (24) hour period shall not exceed the charges based on the Daily Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

2. Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Eversource must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

3. Resales

The rates and rules governing charges and discounts in Sections I.A.1 and 2 of this Schedule ES-3 stated above shall not apply to resales of transmission service, compensation for which shall be governed by Schedule 21.

4. Credit to the Transmission Charge

Whenever service provided hereunder is interrupted or curtailed by Eversource, the Local Control Center or the New England System Operator, the Transmission Charges to the Transmission Customer calculated pursuant to Section A, of this Schedule ES-3 shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service.

The credit to the Transmission Customer for each such hour of interruption or curtailment shall be calculated as the product of (i) the applicable equivalent hourly charge for hourly, daily, weekly, or monthly transactions, and (ii) the kilowatts of service interruption or curtailment during such hour.

5. Eversource's Annual Formula Rate for Non Firm Point-To-Point Transmission Service

Eversource's Annual Formula Rates for Non Firm Point-To-Point Transmission Service shall be expressed in $ per kilowatt-year and shall be determined in accordance with the rate formulas specified in Appendix A of this Schedule ES-3 ("Formula Rates").

6. Tax Rates and Taxes

The Formula Rates set forth in this Schedule ES-3 in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, the Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay Eversource Service each month the following additional charges for Non-firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Non-Firm Point-To-Point Transmission Service provided under this

Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES**

Eversource reserves its rights to make a Section 205 filing for recovery of its costs to administer this Local Service Schedule and the Service Agreements.

C. **OTHER**

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-3 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-3

Appendix A

CATEGORY A RATE

FOR NON-FIRM POINT-TO-POINT SERVICE

Eversource's Category A Formula Rate for Non-Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{Formula Rate}_i = (A_i - B_i + C_i - D_i) / E_i$$

WHERE:

- i equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H.

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load (E),[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments (expressed in dollars) to the New England System Operator as recorded in FERC Account 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with the Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- E is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-3[RESERVED]

SCHEDULE ES-4

CHARGE PROVISIONS FOR LOCAL NETWORK SERVICE

I. Network Customers will pay the following demand charges for Local Network Service.

A. **DEMAND CHARGE A**

1. Determination of Demand Charge:
   The Demand Charge will be determined in accordance with Section ~~16.3~~16.4 of this Local Service Schedule.

2. Eversource's Annual Transmission Revenue Requirements:
   The annual Transmission Revenue Requirements shall be determined in accordance with the formula specified in Appendix A of this Schedule ES-4 ("Formula Requirements").

B. **DEMAND CHARGE B**

1. Determination of Demand Charge
   The Demand Charge will be determined in accordance with Section ~~16.3~~16.4 of this Local Service Schedule.

2. Eversource Annual Transmission Revenue Requirements:
   The annual Transmission Revenue Requirements for each Localized Facility of a Designated State or Area shall be determined in accordance with the formula specified in Appendix B of this Schedule ES-4 ("Formula Requirements").

C. TAX RATES AND TAXES

The Formula Requirements set forth in this Schedule ES-4 in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, the Formula Requirements will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to Eversource Service each month the following additional charges for Local Network Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES CHARGE**

Eversource shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreements.

C. **OTHER**

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-4 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-4

Appendix A

NETWORK FORMULA REQUIREMENTS

FOR CATEGORY A COSTS

Eversource's formula requirements for Local Network Service is determined from the following formula.

$$\text{Formula Requirements}_i = A_i - B_i + C_i - D_i$$

WHERE:

- $_i$ equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H.

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load,[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments to (expressed in dollars) the New England System Operator as recorded in FERC Accounts 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

____

[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-4

Appendix B

NETWORK FORMULA REQUIREMENTS

FOR CATEGORY B COSTS

Eversource's formula requirements for Local Network Service and for Eligible Customers taking Regional Network Service under this Tariff in a Designated State or Area of a Localized Facility, is determined from the following formula, and separately determined for each Designated State or Area of a Localized Facility.

$$\text{Formula Requirements}_i = D_i$$

WHERE:

- $_i$ equals the Service Year.
- D is the annual Localized Transmission Revenue Requirements (expressed in dollars) of the Localized Facilities of Eversource for a Designated State or Area of a Localized Facility, as described in Attachment ES-I.

ATTACHMENT ES-C

AVAILABLE TRANSFER CAPABILITY METHODOLOGY

TABLE OF CONTENTS

1. Introduction

ISO is the regional transmission organization ("RTO"), serving the New England Control Area. ISO is responsible for the development, oversight, and fair administration of New England's wholesale market, management of the bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is interconnected to three neighboring Balancing Authority Areas ("BAA"): New Brunswick System Operator Area ("NBSO Area"), New York Independent System Operator Area ("NYISO Area"), and Hydro-Quebec TransEnergie Area ("HQTE Area").

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Service Provider for Regional Network Service ("Regional Transmission Service") associated with Pool Transmission Facilities, the Participating Transmission Owners ("PTOs") provide local transmission service over Non-Pool Transmission Facilities within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Transmission Service provided under Schedule 21 pursuant to the Transmission Operating Agreement ("TOA"). Pursuant to CFR § 37.6(b)[1] of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. The ISO is not responsible for the calculation of these values.

Pursuant to the terms of the Transmission Operating Agreement executed between the companies comprising Eversource hereunder as Participating Transmission Owners ("PTOs") and ISO, Eversource is a Transmission Service Provider and calculates TTC and ATC for certain Local Facilities over which Point-to-Point transmission service is provided under Schedule 21-ES of the ISO Open Access Transmission Tariff ("ISO OATT").

[1] §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted (§37.6(b)(1)(i)).

Non-PTF facilities are primarily radial paths that provide transmission service directly to interconnected generators. It is possible, in the future that a particular path may interconnect more nameplate capacity generation than the path's TTC. However, for Eversource's Non-PTF modeled by the ISO or the Local Control Center ("LCC"), the ISO or the LCC will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path consistent with ISO's economic, security constrained dispatch methodology.

Eversource does not currently have any Posted Paths based on the above definition. However, if Eversource does have any Posted Path(s) in the future, Eversource will calculate TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to those functions performed or utilized by Eversource as the Transmission Provider of Schedule 21-ES Local Point-to Point transmission service over Non-PTF pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)
- Use of Rollover Rights (ROR) in the calculation of ETC

As explained in Section 2, TTC and ATC are required to be calculated only for certain non-PTF internal Posted Paths over which Local Point-to-Point transmission service is provided under Schedule 21-ES. TTC and ATC is not calculated by Eversource for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and Eversource does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission's pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the ISO Area, the New England Control Area, out of the New England Control Area, or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

This process for submitting External Transactions into the New England Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, Eversource owns Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those Local Facilities, the market participant may obtain a transmission service reservation from Eversource under Schedule 21-ES prior to delivery of energy into the New England Wholesale Market. This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. Eversource **Total Transfer Capability (TTC)**

The Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21-ES is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on Eversource's OASIS site.

Eversource will calculate and post TTC on its OASIS site for all non-PTF Posted Paths that are eligible for Point-to-Point transmission service reservations. The TTC on Eversource's non-PTF Local Facilities that are eligible for Local Point-to-Point transmission service reservations are relatively static values. Eversource thus calculate the TTC for Non-PTF Posted Paths that may require Local Point-to-Point Local Point-to-Point transmission reservations on its OASIS provider page according to NAESB Standards.

4. Capacity Benefit Market (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of Eversource's ATC calculation and because CBM for the New England Control Area is set to zero (0), Eversource utilizes a zero (0) CBM value.

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservations (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}**)** are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. Eversource does not have any external interfaces, and therefore TRM for Eversource's non-PTF facilities is zero.

6. Calculation of ATC for Eversource's Local Facilities - General Description:

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a transmission provider's ATC methodology. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. With this simplified version of ATC, there is no detailed algorithm to be described or posted. Thus, for those non-PTF facilities that serve as a path for Eversource's Schedule 21-ES Point-to-Point Transmission Customers, Eversource has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Schedule 21-ES Firm ATC (ATC_F)

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F , $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-ES that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-ES transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

6.1.2 Calculation of ATC_F in the Schedule 21-ES Operating Horizon (OH)

For purposes of this Attachment C OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses, the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F , CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service under Schedule 21-ES is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-ES transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Because Firm Schedule 21-ES transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

6.2 Calculation of Schedule 21-ES Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-ES are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-ES transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-ES are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus $ETC_{F,}$ plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$)

6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

As stated above, Eversource's non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators. It is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

7. Posting of Schedule 21-ES ATC

7.1 Location of ATC Posting

ATC values are posted on Eversource's OASIS site.

7.2 Updates To ATC

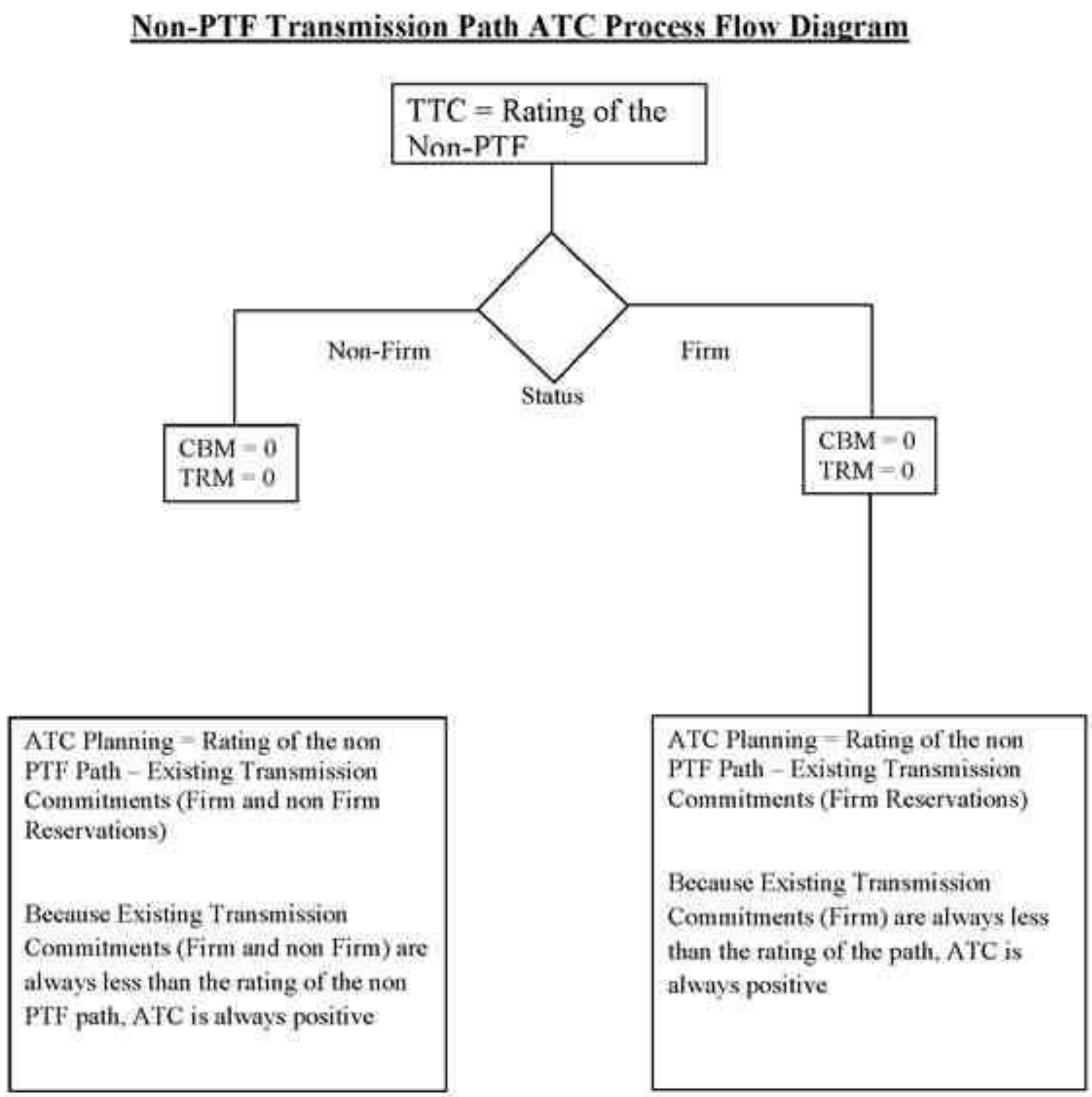
When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

7.3 Coordination of ATC Calculations

Schedule 21-ES non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms A link to the actual mathematical algorithm for the calculation of ATC for the Eversource non-PTF internal interfaces is located at https://www.eversource.com/Content/docs/default-source/Tranmission/attachment-6.pdf?sfvrsn=0.

8. Process Flow Diagram for ATC Calculation



ATTACHMENT ES-D
PENALTY DISBURSEMENT METHODOLOGY

Late Study Penalties: Penalties paid by the Transmission Provider pursuant to Schedule 21 are referred to as "Late Study Penalties," and therefore subject to distribution to all Transmission Customers that are not affiliated with the Transmission Provider. On the month following the end of each calendar quarter, each Transmission Customer that is not affiliated with the Transmission Provider shall receive, on the relevant monthly invoice, a credit for its share of the Late Study Penalties that were assessed during the applicable calendar quarter. The Transmission Customer's share of the Late Study Penalties (if any) will be determined as follows:

(a) For each quarter, the Transmission Provider will determine: (1) the sum of all Late Study Penalties assessed during the quarter measured in dollars (LSRq), and (2) the sum of all transmission revenue from Transmission Customers that are not affiliated with the Transmission Provider during that quarter, measured in dollars (LSTRq). Where:

LSRq = Late Study Penalty Revenue in the quarter
LSTRq = Transmission Revenue from Transmission Customers not affiliated with the Transmission Provider in the quarter

(b) For each quarter, each Transmission Customer that was not affiliated with the Transmission Provider will receive a credit equal to the product of (i) LSRq multiplied by (ii) a fraction derived from dividing the amount of transmission revenue from that Transmission Customer (TC1) during that quarter (measured in dollars), where TC1 is equal to one Transmission Customer, and a denominator equal to LSTRq.

(c) The Transmission Provider shall apply the credit for Late Study Penalties to service that the non-affiliated Transmission Customer takes from the Transmission Provider pursuant to this Schedule 21-ES. Any remaining credit will be refunded to the Transmission Customer.

ATTACHMENT ES-E

LOCALIZED COSTS RESPONSIBILITY **AGREEMENT**

This Localized Costs Responsibility Agreement ("LCRA" or "Agreement"), dated as of ______________________, is entered into by and between the Eversource Energy Service Company ("Eversource Service" or "COMPANY"), acting as agent for [The Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire], andthe "Transmission Customer".

The Transmission Customer is ____________________________________. The Transmission Customer has been determined to be an Eligible Customer taking Regional Network Service under the Tariff whose load **is located in the** Designated State or Area for a **Localized** Facility listed in **Section** 16.3 **of** Schedule 21-ES of the Tariff**.**

The Transmission Customer agrees to pay its portion of the cost of Localized Facilities in the Designated State or Area in which the Transmission Customer's load is located as provided in the Tariff and in accordance with Commission orders. Billing under this Agreement shall commence on the later of: (1) 0001 hours on ____________________, or (2) such other date as permitted by the Commission.

Charges under this Agreement shall terminate on the earlier of: (1) the date on which the costs of the Localized Facilities in the Designated State or Area in which the Transmission Customer's load is located are fully depreciated; or (2) the date upon which the Transmission Customer no longer takes Regional Network Service under the Tariff in the Designated State or Area in which the Transmission Customer's load is located; provided, that the Transmission Customer shall remain responsible for all final payment obligations. In the event that the Transmission Customer sells or assigns, or transfers its load to another entity ("New Transmission Customer"), the Transmission Customer must provide Eversource Service with at least ninety (90) calendar days advance written notice of the sale, assignment, or transfer.

The Transmission Customer shall remain liable for the performance of all obligations under this Agreement until a new LCRA has been executed between the New Transmission Customer and Eversource Service, or in the case of an unexecuted LCRA, such other date as it has been **permitted to** be made effective by the Commission. No sale or assignment shall **become effective** until the Parties have complied with all Applicable Laws and Regulations required for such sale, assignment, or transfer**.**

Other special provisions (if any)

____.

Any notice or request made to or by any Party regarding this greement shall be made in writing and shall be telecommunicated or delivered either in person, or by prepaid mail (return receipt requested) to the representative of the other Party as indicated below. Such representative and address for notices or requests may be changed from time to time by notice by one Party to the other.

COMPANY:

____

____

____

TRANSMISSION CUSTOMER:

____

____

____

Any exhibits to thisAgreement and the Tariff are incorporated herein and made a part hereof. ThisAgreement may be amended, from time to time, as provided for in Schedule 21-ES of the Tariff.

IN WITNESS WHEREOF, the Parties have caused thisAgreement to be executed by their respective authorized officials as of the date first above written.

EVERSOURCE ENERGY SERVICE COMPANY

By: ___________________________________

Its _______________________

TRANSMISSION CUSTOMER

By: ________________________________

Its ___________________________________

ATTACHMENT ES-G
NETWORK OPERATING AGREEMENT

This Network Operating Agreement is an appendix to Schedule 21-ES (this Local Service Schedule) of the OATT and operates as an implementing agreement for Local Network Service under this Local Service Schedule. This Network Operating Agreement is subject to and in accordance with Part III of this Local Service Schedule. All definitions and other terms and conditions of this Local Service Schedule are incorporated herein by reference.

1.0 Definitions:

1.1 Data Acquisition Equipment

Supervisory control and data acquisition ("SCADA"), remote terminal units ("RTUs") to obtain information from a Party's facilities, telephone equipment, leased telephone circuits, fiber optic circuits, and other communications equipment necessary to transmit data to remote locations, and any other equipment or service necessary to provide for the telemetry and control requirements of this Local Service Schedule.

1.2 Data Link

The direct communications link between the Transmission Customer's energy control center and Eversource's designated location(s) that will enable Eversource to receive real time telemetry and data from the Transmission Customer.

1.3 Metering Equipment

High accuracy, solid state kW, kVAR, kWh meters, metering cabinets, metering panels, conduits, cabling, high accuracy current transformers and high accuracy potential transformers, which directly or indirectly provide input to meters or transducers, metering recording devices, telephone circuits, signal or pulse dividers, transducers, pulse accumulators, metering sockets, test switch devices, enclosures, conduits, and any other metering, telemetering or communication equipment necessary to implement the provisions of this Local Service Schedule.

1.4 Protective Equipment

Protective relays, relaying panels, relaying cabinets, circuit breakers, conduits, cabling, current transformers, potential transformers, coupling capacitor voltage transformers, wave traps, transfer trip and fault recorders, which directly or indirectly provide input to relays, fiber optic communication equipment, power line carrier equipment and telephone circuits, and any other protective equipment necessary to implement the protection provision of this Local Service Schedule.

2.0 Term

The term shall be as provided in the Service Agreement consistent with this Local Service Schedule (including, but not limited to, application procedures, commencement of service, and effect of termination).

3.0 Point(s) Of Interconnection

Local Network Service will be provided by Eversource at the point(s) of interconnection specified in Appendix __, as amended from time to time. Each point of interconnection in this listing shall have a unique identifier, meter location, meter number, metered voltage, terms on meter compensation and designation of current or future year of in service.

4.0 Cogeneration And Small Power Production Facilities

If a Qualifying Facility is located or locates in the future on the System of the Transmission Customer, and the owner or operator of such Qualifying Facility sells the output of such Qualifying Facility to an entity other than the Transmission Customer, the delivery of such Qualifying Facility's power shall be subject to and contingent upon transmission arrangements being established with Eversource prior to commencement of delivery of any such power and energy.

5.0 Character Of Service

Network Transmission Service at the points of interconnection shall be in the form of single phase or balanced three-phase alternating current at a frequency of sixty (60) hertz. The Transmission Customer shall operate and maintain its electric system in a manner that avoids: (i) the generation of harmonic frequencies exceeding the limits established by the latest revision of IEEE-519; (ii) voltage flicker exceeding the limits established by the latest revision of IEEE-141; (iii) negative sequence currents; (iv) voltage or current fluctuations; (v) frequency variations; or (vi) voltage or power factor levels that could adversely affect Eversource’s electrical equipment or facilities or those of its customers, and in a manner that complies with all applicable NERC, NPCC, ISO and Eversource’s operating criteria, rules, regulations, procedures, guidelines and interconnection standards as amended from time to time.

6.0 Continuity Of Service

(a) Eversource and the Transmission Customer shall operate and maintain their respective network systems, in accordance with Good Utility Practice, and in a manner that will allow Eversource to safely and reliably operate the Eversource Transmission System in accordance with this Local Service Schedule, so that either Party shall not unduly burden the other Party; provided, however, that notwithstanding any other provision of this Local Service Schedule, Eversource shall retain the sole responsibility and authority for all operating decisions that could affect the integrity, reliability and security of the Eversource Transmission System.

(b) Eversource shall exercise reasonable care and Due Diligence to ensure Local Network Service hereunder in accordance with Good Utility Practice; provided, however, that Eversource shall not be responsible for any failure to ensure electric power service, nor for interruption, reversal or abnormal voltage of the service, if such failure, interruption, reversal or abnormal voltage is due to a Force Majeure.

7.0 Power Factor

(a) Where Local Network Service provided under this Local Service Schedule is for delivery of power to a load center of the Transmission Customer served from the Eversource Transmission System, the Transmission Customer shall maintain load power factor levels, during both on- and off- peak hours, appropriate to meet the operating requirements of Eversource, and shall follow the ISO standards and practices, as set forth in the Service Agreement.

(b) Where Local Network Service provided under this Local Service Schedule is for delivery of power from a generating facility connected to the Eversource Transmission System, the Transmission Customer shall deliver power at a lagging or leading power factor as set forth in the Service Agreement.

(c) Where Local Network Service provided under this Local Service Schedule is for delivery of power from outside the Eversource Transmission System, the obligation to maintain proper sending and receiving end voltages rests with the Transmission Customer, as set forth in the Service Agreement.

(d) In the event that the power factor levels and reactive supply requirements set forth in the Service Agreement are not maintained by the Transmission Customer, Eversource shall thereupon have the right to take the appropriate corrective action and to charge the Transmission Customer for the costs thereof.

Eversource shall have the right, at any time, unilaterally to make a Section 205 filing with the Commission for the recovery of any such costs.

8.0 Metering

(a) The Transmission Customer shall, at its expense, purchase all necessary metering equipment to accurately account for the electric power being transmitted under this Local Service Schedule. Eversource may require the installation of telemetering equipment for the purposes of billing, power factor measurements and to allow Eversource to maximize economic and reliable operation of its transmission system. Such metering equipment shall meet the specifications and accepted metering practices of Eversource and applicable criteria, rules, standards and operating procedures, or such successor rules and standards. At Eversource's option, communication metering equipment may be installed in order to transmit meter readings to Eversource's designated locations.

(b) Electric power being transmitted under this Local Service Schedule will be measured by meters at all points of interconnection and/or on generating facilities (Network and non-Network Resources) located on and outside the Transmission Customer's system as required by Eversource.

(c) The Transmission Customer shall purchase meters capable of time-differentiated (by hour) measurement of the instantaneous flow in kW and net active power flow in kWh and of reactive power flow. All meters shall compensate for applicable line and/or transformer losses in accordance with Good Utility Practice when measurement is made at any location other than the point of interconnection.

(d) Eversource reserves the right: (i) to determine metering equipment ownership; (ii) to determine the equipment installation at each point of interconnection; (iii) to require the Transmission Customer to install the equipment -- or -- install the equipment with the Transmission Customer supplying without cost to Eversource a suitable place for the installation of such equipment; (iv) to determine other equipment allowed in the metering circuit; (v) to determine metering accuracy requirements; (vi) to determine the responsibilities for operation, maintenance, testing and repair of metering equipment.

(e) Eversource shall have access to metering data, including telephone line access, which may reasonably be required to facilitate measurement and billing under this Local Service Schedule. Eversource may require the Transmission Customer provide, at its expense, a separate dedicated voice grade telephone circuit for Eversource and the Transmission Customer to remotely access each meter.

Metering equipment and data shall be accessible at all reasonable hours for purposes of inspection and reading.

(f) All metering equipment shall be tested in accordance with practices of Eversource, applicable criteria, rules, standards and operating procedures or upon the request by Eversource. If at any time metering equipment fails to register or is determined to be inaccurate, in accordance with Eversource’s practices and applicable criteria, rules, standards and operating procedures, the Transmission Customer shall make the equipment accurate as soon thereafter as practicable, and the meter readings and rate computation for the period of such inaccuracy, insofar as can reasonably be ascertained, shall be adjusted; provided, however, that no adjustment to charges shall be required for any period exceeding two (2) months prior to the date of the test. Representatives of Eversource will be afforded opportunity to witness such tests.

9.0 Network Load

The Transmission Customer shall provide Eversource with the actual hourly Network Load for each calendar month by the seventh day of the following calendar month.

10.0 Data Transfer:

(a) The Transmission Customer shall provide timely, accurate real time information to Eversource in order to facilitate performance of its obligations under this Local Service Schedule.

(b) The selection of real time telemetry and data to be received by Eversource and the Transmission Customer shall be necessary for safety, reliability, security, economics, and/or monitoring of real-time conditions that affect the Eversource Transmission System. This telemetry shall include, but is not limited to, loads, line flows (MW and MVAR), voltages, generator output, and status of substation equipment at any of the Transmission Customer's transmission and generation facilities. To the extent that Eversource or the Transmission Customer requires data that are not available from existing equipment, the Transmission Customer shall, at its expense and at locations designated by Eversource or the Transmission Customer, install any metering equipment, data acquisition equipment, or other equipment and software necessary for the telemetry to be received by Eversource or the Transmission Customer. Eversource shall have the right to inspect equipment and software associated with the data transfer in order to assure conformance with Good Utility Practices.

11.0 Maintenance of Equipment

The Transmission Customer shall, on a regular basis in accordance with practices of Eversource, applicable criteria, rules, standards and operating procedures or at the request of Eversource, and at its expense, test, calibrate, verify and validate the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule. Eversource shall have the right to inspect such tests, calibrations, verifications and validations of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule. Upon Eversource's request, the Transmission Customer will provide Eversource a copy of the installation, test and calibration records of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software. Eversource shall, at the Transmission Customer's expense, have the right to monitor the factory acceptance test, the field acceptance test, and the installation of any metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule.

12.0 Notification

(a) The Transmission Customer shall notify and coordinate with Eversource prior to the commencement of any work or maintenance by the Transmission Customer, Network Member, or contractors or agents performing on behalf of either or both, which may directly or indirectly have an adverse effect on the Transmission Customer or Eversource's data link, or the reliability of the Eversource Transmission System. All notifications for scheduled outages of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software must meet the requirements of the ISO and Eversource.

13.0 Emergency System Operations

(a) The Transmission Customer, at its expense, shall be subject to all applicable emergency operation standards promulgated by NERC, NPCC, ISO and Eversource which may include but not limited to underfrequency relaying equipment, load shedding equipment and voltage reduction equipment.

(b) Eversource reserves the right to take whatever actions they deem necessary to preserve the integrity of the Eversource Transmission System during emergency operating conditions. If the Local Network Service at the points of interconnection is causing harmful physical effects to the Eversource Transmission

System facilities or to its customers (e.g., harmonics, undervoltage, overvoltage, flicker, voltage variations, etc.), Eversource shall promptly notify the Transmission Customer and if the Transmission Customer does not take the appropriate corrective actions immediately, Eversource shall have the right to interrupt Local Network Service under this Local Service Schedule in order to alleviate the situation and to suspend all or any portion of Local Network Service under this Local Service Schedule until appropriate corrective action is taken.

(c) In the event of any adverse condition or disturbance on the Eversource Transmission System or on any other system directly or indirectly interconnected with the Eversource Transmission System, Eversource may, as it deems necessary, take actions or inactions that, in Eversource's sole judgment, result in the automatic or manual interruption of Local Network Service in order to: (i) limit the extent or damage of the adverse condition or disturbance; (ii) prevent damage to generating or transmission facilities; (iii) expedite restoration of service; or (iv) preserve public safety.

14.0 Cost Responsibility

(a) The Transmission Customer shall be responsible for the costs incurred by the Transmission Customer and Eversource to implement the provisions of this Local Service Schedule including, but not limited to, engineering, administrative and general expenses, material and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, and relocation of equipment, or software.

(b) Additionally, the Transmission Customer shall be responsible for all costs incurred by the Transmission Customer and Eversource for on-going operation and maintenance of the metering, telecommunications and safety protection facilities and equipment required to implement the provisions of this Local Service Schedule. Such work shall include, but not limited to, normal and extraordinary engineering, administrative and general expenses, material, and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, or relocation of equipment required to accommodate service under this Local Service Schedule.

15.0 Default

The Transmission Customer's failure to implement the terms and conditions of this Network Operating Agreement will be deemed to be a default under this Local Service Schedule and will result in Eversource seeking, consistent with FERC rules and regulations, immediate termination of service under this Local Service Schedule.

16.0 Regulatory Filings

Nothing contained in this Local Service Schedule or any associated Service Agreement, including this Network Operating Agreement, shall be construed as affecting in any way the right of Eversource to unilaterally make application to the Commission for a change in any portion of this Network Operating Agreement under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

IN WITNESS WHEREOF, the Parties have caused this Network Operating Agreement to be executed by their respective authorized officials as of the date written.

Date: _________________________

Eversource Energy Service Company
by: ______________________________
its Vice President

Transmission Customer
by: ______________________________
its ______________________________

ATTACHMENT ES-H

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

Attachment ES-H Methodology:

This formula sets forth the method that Eversource will use to determine its annual Total Transmission Revenue Requirements. The Transmission Revenue Requirements reflect Eversource's total cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to transmission customers under this Local Service Schedule. The Transmission Revenue Requirements will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31 of the following year. The calculation will be based on the previous calendar year's FERC Form 1 data, with an estimate of Eversource's current year average plant additions, Construction Work in Progress (CWIP), and the Allowance for Funds Used During Construction (AFUDC) regulatory liability account. Plant additions will be multiplied by a fixed charge carrying cost, and CWIP and the AFUDC regulatory liability account will be multiplied by the Cost of Capital. The revenue requirements will be updated thereafter each June 1 based on actual costs from the Service Year. The true-up information will be based on actual data, in lieu of allocated data if specifically identified in the FERC Form 1. For a capital addition whose cost exceeds $20 million, Eversource will make rate base adjustments to estimates and in the true-up process to represent the estimated and actual in-service dates for the capital addition. Specifically, Eversource will adjust for transmission plant, CWIP, AFUDC regulatory liability, accumulated depreciation and accumulated deferred taxes.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Eversource's Transmission-related direct wages and salaries, including those of affiliated companies, to Eversource's total direct wages and salaries, including those of affiliated companies, excluding administrative and general wages and salaries.

2. Plant Allocation Factor shall equal the ratio of the sum of total investment in Transmission Plant and Transmission Related General Plant to Total Plant in Service.

B. Terms

Administrative and General Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on Eversource's transmission projects as recorded in FERC Account 254 consistent with Commission orders.

Amortization of Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal Eversource's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal Eversource's transmission expense as recorded in FERC Account No. 403.

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's gross plant balance for the Dispatch Center as recorded in FERC Account Nos. 350-359 and 389-399.

Dispatch Center Depreciation Expense shall equal the Dispatch Center depreciation expense as recorded in FERC Account No. 403.

Dispatch Center Amortization of Investment Tax Credits shall equal the Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of Eversource's Dispatch Center deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource's Dispatch Center deferred tax balance as recorded in FERC Account No. 190.

Dispatch Center Municipal Tax Expense shall equal the Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

General Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 389-399, less the Dispatch Center general plant.

General Plant Depreciation Expense shall equal Eversource's general plant expenses as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal Eversource's general plant reserve balance as recorded in FERC Account No. 108 less the portion of such reserve for the Dispatch Center.

Merger-Related Costs shall equal Eversource's amortized merger-related costs as authorized by FERC or by state regulatory order.

Other Regulatory Assets/Liabilities – FAS 106 shall equal the net of Eversource's FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in Eversource's FERC Account No. 254.

Other Regulatory Assets/Liabilities – FAS 109 shall equal the net of Eversource's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Eversource's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in Eversource's FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal Eversource's balance in FERC Account No. 105.

Prepayments shall equal Eversource's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Eversource's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of Eversource's deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 408.1, 409.1.

Total Plant in Service shall equal Eversource's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal Eversource's Transmission reserve balance as recorded in FERC Account 108 less the portion of such reserve for the Dispatch Center.

Transmission Merger-Related Costs shall equal Eversource's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562-564 and 566-576.5 and shall exclude all HQ HVDC expenses booked to accounts 560 through 576.5 and expenses already included in Transmission Support Expense, as described in Section I below, that are included in FERC Account Nos. 560-576.5.

Transmission Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 350-359, less Dispatch Center transmission plant.

Transmission Plant Materials and Supplies shall equal Eversource's balance as assigned to transmission, as recorded in FERC Account 154.

Transmission Related Construction Work in Progress shall equal Eversource's investment in Transmission-related projects as recorded in FERC Account 107 consistent with commission orders.

II. Calculation of Transmission Revenue Requirements

The Transmission Revenue Requirement shall equal the sum of Eversource's (A) Return and Associated Income Taxes, (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expense (I) Transmission Support Expense, and(J) Transmission Related Taxes and Fees Charge.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be the average balances of (a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) Transmission Related Construction Work in Progress, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Other Regulatory Assets/Liabilities, less (i) AFUDC Regulatory Liability, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

(a) Transmission Plant will equal the balance of Eversource's investment in Transmission Plant.

(b) Transmission Related General Plant shall equal Eversource's balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the balance of Transmission Plant Held for Future Use.

(d) Transmission Related Construction Work in Progress shall equal the portion of Eversource's investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.

(e) Transmission Related Depreciation Reserve shall equal the balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related General Plant

Depreciation Reserve. Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor.

(f) Transmission Accumulated Deferred Taxes shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes multiplied by the Plant Allocation Factor, less the transmission and general plant components of Dispatch Center Accumulated Deferred Income Taxes.

(g) Transmission Related Loss on Reacquired Debt shall equal Eversource's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

(h) Other Regulatory Assets/Liabilities shall equal Eversource's electric balance of any deferred rate recovery of FAS 106 expense multiplied by the Transmission Wages and Salaries Allocation Factor, plus Eversource's electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(i) AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on Eversource's transmission projects as recorded in FERC Account 254 consistent with Commission orders.

(j) Transmission Prepayments shall equal Eversource's electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

(k) Transmission Materials and Supplies shall equal Eversource's electric balance of Transmission Plant Materials and Supplies.

(l) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense and Transmission Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Eversource's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of:

(i) the long term debt component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's long-term debt then outstanding and the ratio that long-term debt is to Eversource's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's preferred stock then outstanding and the ratio that preferred stock is to Eversource's total capital.

(iii) the return on equity component, shall equal the product of Eversource's return on equity ("ROE") of 11.14% and the ratio that common equity is to Eversource's total capital.

(b) Federal Income Tax shall equal

[(A+[(C+B)/D]x (FT)] divided by (1-FT)

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., and D is Transmission Investment Base, as Determined in II.A.1., above.

(c) State Income Tax shall equal

[A+[(C+B)/D] + Federal Income Tax)x(ST)] divided by (1-ST)

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., D is the Transmission

Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Transmission Plant, plus an allocation of General Plant Deprecation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor, less the amortization of AFUDC Regulatory Credit as recorded in Account 407.4, less the transmission plant and general plant components of Dispatch Center Depreciation Expense.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal Eversource's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal Eversource's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor less the transmission plant and general plant components of Dispatch Center Amortization of Investment Tax Credits.

E. Transmission Related Municipal Tax Expense shall equal Eversource's electric Total Municipal Tax Expense multiplied by the Plant Allocation Factor, less the transmission plant and general plant components of Dispatch Center Municipal Tax Expense.

F. Transmission Related Payroll Tax Expense shall equal Eversource's electric Payroll Tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal Transmission Operation and Maintenance Expenses.

H. Transmission Related Administrative and General Expenses shall equal the sum of (1) Eversource's Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by the Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments in Account 928 plus specific transmission related expenses included in Account 930.1, plus Transmission Merger-Related Costs and, (4) specific transmission related public education expenses included in Account 426.54.

I. Transmission Support Expense shall equal the expense paid by Eversource for transmission support.

J. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Local Service Schedule that is not specifically identified under any other section of this Local Service Schedule.

ATTACHMENT ES-I

ANNUAL LOCALIZED TRANSMISSION REVENUE REQUIREMENT

Attachment ES-I Methodology

This formula sets forth the method that Eversource will use to determine its annual total revenue requirements for each Localized Facility ("Localized Transmission Revenue Requirement"). Subsequent references in this formula to "Localized Facility" and "Localized Transmission Revenue Requirement" refer to the Localized Facility and Localized Facility Revenue Requirement for each individual Localized Transmission Project. Each Localized Facility is identified in Section 16.3.

The Localized Transmission Revenue Requirement will be calculated for an initial term for a Localized Facility commencing on the date of the New England System Operator's Schedule 12C cost allocation determination for the Localized Facility and ending on the May 31st following the date approved by the Commission for including the costs of the Localized Facilities in this Attachment ES-I ("Initial Term"), and continuing thereafter for successive 12 month periods commencing each June 1st ("Rate Year"). The Localized Transmission Revenue Requirement for the Initial Term for a Localized Facility will be calculated based on the estimated cost of the Localized Facilities for such period, and will be charged to customers in equal monthly installments beginning on the date permitted by the Commission, and continuing through the end of the Initial Term. The Localized Transmission Revenue Requirement for the Initial Term for a Localized Facility will be trued up for the appropriate calendar year by June 30th of the succeeding year(s) based on actual costs for the Initial Term.

The Localized Transmission Revenue Requirement for a Localized Transmission Project for a Rate Year commencing after the Initial Term (and for succeeding Rate Years) will be an annual calculation based on the previous calendar year's Localized Transmission Revenue Requirements, plus the forecasted revenue requirements of Localized Facilities to be placed in service in the upcoming Rate Year. Each June 30th, the Localized Transmission Revenue Requirement in effect during the portion of the Rate Year that occurred in the previous calendar year will be trued-up based on actual costs from such previous calendar year.

The true-up information will be based on actual data, in lieu of allocated data if specifically identified in the FERC Form 1, or based on allocated data if such specific information is not identified. For a capital addition whose cost exceeds $20 million, Eversource will make rate base adjustments to estimates and in the true-up process to represent the estimated and actual in-service dates for the capital addition. Specifically, Eversource will adjust for transmission plant, accumulated depreciation and accumulated deferred taxes.

The Localized Transmission Revenue Requirement for Eversource that is based on data for calendar year 2004 or later shall include a Localized Incremental Return and Associated Income Taxes on Eversource's Localized PTF transmission plant investments placed in-service on or after January 1, 2004 (such investments referred to herein as "Localized Post-2003 PTF Investment"). The Localized Incremental Return and Associated Income Taxes for Localized Post-2003 Investment shall incorporate an incentive ROE adder of 100 basis points for plant investments placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157 et al. for any projects included in the Regional System Plan ("RSP"), and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments. The data used in determining Eversource's Localized Incremental Return and Associated Taxes for Localized Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in Eversource accounting records.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. Localized Transmission Allocation Factor shall equal the ratio of Localized Transmission Plant in Service to total investment in Transmission Plant.

2. Total Localized Plant Allocation Factor shall equal the ratio of Localized Transmission Plant in Service to Total Plant in Service.

3. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Eversource's Transmission-related direct wages and salaries, including those of affiliated companies, to Eversource's total direct wages and salaries, including those of affiliated companies, and excluding administrative and general wages and salaries.

B. Terms

Administrative and General Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

Amortization of Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal Eversource's expenses as recorded in FERC Account No. 411.4.

Depreciation Expense for Localized Transmission Plant shall equal Eversource's Localized Facilities expenses as recorded in FERC Account No. 403.

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's gross plant balance for the Dispatch Center as recorded in FERC Account Nos. 350-359 and 389-399.

General Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 389-399 less Dispatch Center general plant.

General Plant Depreciation Expense shall equal Eversource's general plant expenses as recorded in FERC Account No. 403 less the portion of such expense for the Dispatch Center.

General Plant Depreciation Reserve shall equal Eversource's general plant reserve balance as recorded in FERC Account No. 108 less the portion of such reserve for the Dispatch Center.

Merger-Related Costs shall equal Eversource's amortized merger-related costs as authorized by FERC or by state regulatory order.

Payroll Taxes shall equal those payroll expenses as recorded in Eversource's FERC Account Nos. 408.1 and 409.1.

Prepayments shall equal Eversource's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Eversource's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of Eversource's deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 408.1, 409.1.

Transmission Merger-Related Costs shall equal Eversource's amortized merger-related transmission costs as authorized by FERC.

Localized Transmission Plant in Service shall equal Eversource's Localized Facilities gross plant balance as recorded in FERC Account Nos. 350-359.

Localized Transmission Plant Held for Future Use shall equal Eversource's Localized Facilities balance as recorded in FERC Account 105.

Localized Transmission Depreciation Reserve shall equal Eversource's Localized Facilities reserve balance as recorded in FERC Account 108.

Transmission Operation and Maintenance Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562-564 and 566-576.5 and shall exclude all HQ HVDC expenses booked to accounts 560 through 576.5 and expenses already included in Transmission Support Expense, as described in Section I below, which are included in FERC Account Nos. 560-576.5.

Transmission Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal Eversource's balance as assigned to transmission, as recorded in FERC Account 154.

Total Plant in Service shall equal Eversource's total gross plant balance as recorded in FERC Account Nos. 301-399.

II. Calculation of Localized Transmission Revenue Requirements

The Localized Transmission Revenue Requirements shall equal the sum of Eversource's (A) Localized Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment), (B) Localized Transmission Depreciation Expense, (C) Localized Transmission Related Amortization of Loss on Reacquired Debt, (D) Localized Transmission Related Amortization of Investment Tax Credits, (E) Localized Transmission Related Municipal Tax Expense, (F) Localized Transmission Related Payroll Tax Expense, (G) Localized Transmission Operation and Maintenance Expense, (H) Localized Transmission Related Administrative and General Expense , (I) Localized Transmission Support Expense, and (J) Localized Transmission Related Taxes and Fees Charge. The Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment for Eversource shall be calculated using the investment base components specifically identified in Section A.1 of the formula below.

A. <u>Localized Return and Associated Income Taxes</u> shall equal the product of the Localized Transmission Investment Base and the Cost of Capital Rate. To calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Plant will only include Sections II.A.1.(a), (c), and (d), in the manner indicated.

1. <u>Localized Transmission Investment Base</u>

The Localized Transmission Investment Base will be the average balances of (a) Localized Transmission Plant, plus (b) Localized Transmission Plant Held for Future Use less (c) Localized Transmission Related Depreciation Reserve, less (d) Localized Transmission Related Accumulated Deferred Taxes, plus (e) Localized Transmission Related Loss of Reacquired Debt, plus (f) Localized Transmission Prepayments, plus (g) Localized Transmission Materials and Supplies, plus (h) Localized Transmission Related Cash Working Capital.

(a) <u>Localized Transmission Plant</u> will equal the balance of (1) Eversource's investment in Localized Transmission Plant plus, (2) Eversource's balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the Localized Transmission Allocation Factor. In order to calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Post-2003 PTF Transmission Plant shall be separately identified.

(b) <u>Localized Transmission Plant Held for Future Use</u> shall equal Eversource's balance of Localized Transmission Plant Held for Future Use.

(c) <u>Localized Transmission Related Depreciation Reserve</u> shall equal the balance of Localized Transmission Depreciation Reserve plus the balance of Localized Transmission Related General Plant Depreciation Reserve. Localized Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor, further multiplied by the Localized Transmission Allocation Factor. In order to calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Related Depreciation Reserve associated with Localized Post-2003 PTF Investment shall equal Eversource's balance of Localized Transmission Depreciation Reserve.

(d) Localized Transmission Related Accumulated Deferred Taxes shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Total Localized Plant Allocation Factor. To calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Related Accumulated Deferred Taxes associated with Localized Post-2003 PTF Investment shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes multiplied by the Total Localized Plant Allocation Factor.

(e) Localized Related Loss on Reacquired Debt shall equal Eversource's electric balance of Total Loss on Reacquired Debt multiplied by the Total Localized Plant Allocation Factor.

(f) Localized Transmission Prepayments shall equal Eversource's electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor.

(g) Localized Transmission Materials and Supplies shall equal Eversource's electric balance of Transmission Plant Materials and Supplies multiplied by the Localized Transmission Allocation Factor.

(h) Localized Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of (i) Localized Transmission Operation and Maintenance Expense, plus (ii) Localized Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Eversource's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the average capital structure and will equal the sum of:

(i) the long term debt component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's long-term debt then outstanding and the ratio that long-term debt is to Eversource's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's preferred stock then outstanding and the ratio that preferred stock is to Eversource's total capital.

(iii) the return on equity component shall equal the product of Eversource's return on equity ("ROE") of 11.64% and the ratio that common equity is to Eversource's total capital. In order to calculate the Localized Incremental Return and Associated Taxes for Post-2003 PTF Investment, the Localized Incremental Return on Equity shall be the product of (1) Eversource's incremental return on equity of 1% for transmission plant investments associated with projects included in the RSP and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157 et al., and (2) any ROE incentive adder approved by the FERC under Order No. 679 for other transmission plant investments; and (3) the ratio of that common equity to total capital.[1]

(b) Federal Income Tax shall equal

[(A+[(C+B)/D]) x (FT)] divided by (1-FT)

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Localized Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Localized Transmission Depreciation Expense, as defined in Section II.B., and D is Localized Transmission Investment Base, as Determined in II.A.1., above.

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1 FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679.

(c) State Income Tax Shall equal:

[(A+[(C+B)/D] + Federal Income Tax) x (ST)] divided by (1-ST)

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the

Localized Transmission Related Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Localized Transmission Depreciation Expense, as defined in Section II.B., D is the Localized Transmission Investment Base, as determined in II.A.1. above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Localized Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Localized Transmission Plant, plus an allocation of General Plant Deprecation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor.

C. Localized Transmission Related Amortization of Loss on Reacquired Debt shall equal Eversource's electric Amortization of Loss on Reacquired Debt multiplied by the Total Localized Plant Allocation Factor.

D. Localized Transmission Related Amortization of Investment Tax Credits shall equal Eversource's electric Amortization of Investment Tax Credits multiplied by the Total Localized Plant Allocation Factor.

E. Localized Transmission Related Municipal Tax Expense shall equal Eversource's Total Municipal Tax Expense multiplied by the Total Localized Plant Allocation Factor.

F. Localized Transmission Related Payroll Tax Expense shall equal Eversource's electric Payroll Taxes expense, multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Localized Transmission Allocation Factor.

G. Localized Transmission Operation and Maintenance Expense shall equal Eversource's Transmission Operation and Maintenance Expense multiplied by the Localized Transmission Allocation Factor.

H. <u>Localized Transmission Related Administrative and General Expense</u> shall equal the sum of (1) Eversource's Administrative and General Expense multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor, (2) Property Insurance multiplied by the Total Localized Plant Allocation Factor, (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by the Total Localized Plant Allocation Factor, (4) Federal and State transmission related expenses or assessments in Account 928 multiplied by the Localized Transmission Allocation Factor, (5) specific transmission related expenses included in Account No. 930.1, multiplied by the Localized Transmission Allocation Factor, plus Transmission Merger-Related Costs multiplied by the Localized Transmission Allocation Factor and (6) specific Localized Facility related public education expenses included in Account 426.54.

I. <u>Transmission Support Expense</u> shall equal the expense paid by Eversource for transmission support for Localized Facilities.

J. <u>Transmission Related Taxes and Fees Charge</u> shall include any fee or assessment imposed by any governmental authority on transmission service provided under this Local Service Schedule that is not specifically identified under any other section of this Local Service Schedule, multiplied by the Localized Transmission Allocation Factor.

SCHEDULE 21-ES

ATTACHMENT ES-L

Creditworthiness Procedures

1. **General Information**

All customers taking any service under Schedule 21-ES, the Local Service Schedule ("LSS"), and the associated schedules of The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire ("Eversource") must meet the terms of this Attachment ES-L.

2. **Establishing Creditworthiness**

a) Each customer's creditworthiness must be established before receiving transmission services from Eversource. A customer will be evaluated at the time that its application for transmission service is provided to Eversource based on the creditworthiness information required under this Attachment ES-L. Eversource shall conduct a credit review of each Transmission Customer not less than annually or upon reasonable request by the Transmission Customer.

b) Eversource will review the customer's creditworthiness information for completeness and will notify the customer if additional information is required.

c) Upon completion of a creditworthiness evaluation of a customer, Eversource will forward a written evaluation to the customer if they determine that Financial Assurance must be provided.

3. Financial Information

Customers requesting transmission service must submit if available the following:

a) All current rating agency reports of the customer from Standard and Poor's ("S&P"), Moody's Investors Service ("Moody's"), and/or Fitch Ratings ("Fitch").

b) A Management Discussion and Analysis ("MD&A") along with audited financial statements provided by an independent registered public accounting firm or a registered independent auditor for the three (3) most recent fiscal years, or the period of the customer's existence, if shorter than three (3) years.

4. Creditworthiness – Qualification for Unsecured Credit

a) A customer may receive unsecured credit from Eversource equivalent to three (3) months of the transmission charges. The customer must meet at least one of the following criteria:

(i) If rated, the customer's lowest rating from the three rating agencies on its senior unsecured long-term debt; or if the customer does not have such a rating, then one rating level below the rating then assigned to the customer's corporate credit rating, as follows:

1. a Standard and Poor's or Fitch rating of at least BBB, or

2. a Moody's rating of least Baa2.

(ii) If un-rated or if rated below BBB/Baa2, as described in 4(a)(i) above, the customer must meet all of the following creditworthiness criteria for the three (3) most recent fiscal years:

1. A Capitalization Ratio (Debt divided by the sum of shareholders' equity and Debt) of no more than 60 percent Debt, where "Debt" is defined as the sum of all long-term and short-term debt, preferred securities and capital leases. Each of which is recorded in accordance with generally accepted accounting principles;

2. Earnings before interest, taxes, depreciation and amortization ("EBITDA") in the most recent fiscal quarter divided by interest expense (ratio of EBITDA-to-interest expense of at least three (3) times); and

3. Audited Financial Statements with an unqualified auditor opinion.

b) If the customer relies on the creditworthiness of a parent company, the parent company must satisfy the ratings criteria in Section 4(a) above, and must provide to Eversource a written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from Eversource.

c) If the customer or the customer's parent company do not qualify for unsecured credit under Sections 4(a) or (b) above, the customer can still qualify for unsecured credit equivalent to three (3) months of transmission service charges, if:

(i) the customer has, on a rolling basis, 12 consecutive months of payments to Eversource with no missed, late or defaults in payment; or

(ii) the customer has an executed long-term contract for the sale of the full output (energy and capacity) of its generating unit and either has executed a corresponding service transmission service agreement under Schedule 21-ES for the transmission of that output or the execution of such agreement is pending the customer's demonstration of creditworthiness.

5. Financial Assurance

If the customer does not meet the applicable requirements for unsecured credit set out in Section 4 then the customer must either:

a) pay in advance an amount equal to the lesser of the total charge for transmission service not less than five (5) days in advance of the commencement of service, in which case Eversource will pay to the customer interest on the amounts not yet due to Eversource, computed in accordance with 18 C.F.R. §35.19(a)(2)(iii) of the Commission's Regulations; or

b) obtain Financial Assurance in the form of a letter of credit or a parent guarantee equal to the equivalent of three (3) months of transmission service charges prior to receiving service.

(i) The letter of credit must be one or more irrevocable, transferable standby letters of credit issued by a United States commercial bank or a United States branch of a foreign bank provided that such customer is not an affiliate of such bank. The issuing bank must have a credit rating of at least A2 from Moody's or an A rating from S&P or Fitch, or an equivalent credit rating by another nationally recognized rating service reasonably acceptable to Eversource, provided that such bank shall have assets totaling not less than ten billion dollars ($10,000,000,000). All costs of the letter of credit shall be borne by the applicant for such letter of credit. In the event of an inconsistency in the ratings by Moody's, S&P, or Fitch, a "split rating", the lowest credit rating shall apply.

(ii) If the credit rating of a bank or other financial institution issuing a letter of credit to a customer falls below the levels specified in Section 5(b)(i) above, the customer shall have three (3) business days to obtain a suitable letter of credit from another bank or other financial institution that meets the specified levels unless Eversource agrees in writing to extend such period.

6. Notifications

Each customer must inform Eversource in writing within three (3) business days of any material change in its or its letter of credit issuer's financial condition, and if the customer qualifies under Section 4(b), that of its parent company. A material change in financial condition may include, without limitation, the following:

- **a)** change in ownership by way of a merger, acquisition, or substantial sale of assets;
- **b)** downgrade by a recognized major financial rating agency;
- **c)** placement on credit watch with negative implications by a major financial rating agency;
- **d)** a bankruptcy filing by the customer or parent;
- **e)** any action requiring the filing of a SEC Form 8-K;
- **f)** declaration of or acknowledgement of insolvency;
- **g)** report of a significant quarterly loss or decline in earnings;
- **h)** resignation of key officer(s); or
- **i)** issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

7. Ongoing Financial Review

Each customer is required to submit to Eversource annually or when issued, as applicable:

- **a)** current rating agency reports;
- **b)** audited financial statements from an independent registered public accounting firm or a registered independent auditor; and
- **c)** SEC Forms 10-K and 8-K, promptly upon their filing.

8. Change in Creditworthiness Status

A customer who has been extended unsecured credit pursuant to Section 4, must comply with the terms of Financial Assurance in Section 5, if one or more of the following conditions apply:

a) the customer no longer meets the applicable criteria for unsecured credit in Section 4;

b) the customer exceeds the amount of unsecured credit extended by Eversource, in which case Financial Assurance equal to the amount of exceeded unsecured credit must be provided within five (5) business days; or

c) the customer has missed two or more payments for any of the transmission services provided by Eversource in the last twelve (12) months.

9. Procedures for Changes in Credit Levels and Collateral Requirements

a) Eversource shall issue notice to a customer of any changes to the approved credit levels and/or collateral requirements within five (5) business days after (1) receiving notification of any material changes in financial condition under Section 6 above; (2) receiving the information required for the customer's ongoing financial review listed in Section 7 above; or (3) the occurrence of any of the events leading to a change in creditworthiness requirements listed in Section 8 above.

b) A customer may submit a written request that Eversource provide an explanation of the reasons for the changes in credit levels and/or collateral requirements within five (5) business days after receiving notification of the changes. Eversource will provide a written response within five (5) business days after receiving such a request.

10. Contesting Creditworthiness Determinations

A customer may contest Eversource's determination of its creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. The request should provide information supporting the basis for a re-evaluation of the customer's creditworthiness. Eversource will review the request and respond within 20 calendar days of receipt.

11. Process for Changing Credit Requirements

a) In the event Eversource plans to revise the Schedule 21-ES requirements for credit levels or collateral requirements described in this Attachment ES-L, they will make a filing under Section 205 of the Federal Power Act.

b) Eversource shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

c) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised changes(s) to this Attachment ES-L.

d) Eversource shall consult with interested stakeholders upon request.

e) Following Commission acceptance of such filing and upon the effective date, Eversource shall revise its Attachment ES-L an updated version of Schedule 21-ES shall be posed to the ISO-NE web site.

f) When Eversource changes its credit requirements for service under Schedule 21-ES, the customer is responsible for forwarding updated financial information to Eversource. The customer must indicate whether the change affects its ability to meet the requirements of Attachment ES-L. In cases where the customer's credit status has changed, the customer must take the necessary steps to comply with the revised credit requirements of Attachment ES-L by the effective date of the change.

12. Suspension of Service

Eversource may immediately suspend service (with notification to the Commission) to a customer, and may initiate proceedings with the Commission to terminate service, if the customer does not meet the terms described in Sections 4 through 8 at any time during the term of service or if the customer's payment obligations to Eversource exceed the amount of unsecured or secured credit to which it is entitled under this Attachment ES-L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

SCHEDULE 21 - UES

UNITIL ENERGY SYSTEMS, INC.
LOCAL SERVICE SCHEDULE

SCHEDULE 21-UES

Unitil Energy Systems, Inc. Local Service Schedule

I. COMMON SERVICE PROVISIONS

Unitil Energy Systems, Inc. ("UES") is a participant in the New England Control Area and has agreed to provide transmission and ancillary services over PTF pursuant to the Tariff. The services provided under this Schedule 21-UES apply only to Non-PTF, except in the case of service to Network Customers that have all or part of their Network Load directly connected to the PTF in the Local Network. These Network Customers shall pay for Local Network Service pursuant to Attachment H to this Schedule 21-UES. Provisions of this Schedule 21-UES shall have priority over any conflicting provisions in the Tariff.

1 Definitions

1.0 Annual Transmission Costs: The total annual cost of the Local Network for purposes of Local Network Service shall be the amount specified in Attachment H until amended by UES or modified by the Commission.

1.1 Curtailment: A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

1.2 Load Ratio Share: Ratio of a Transmission Customer's Network Load to UES's total load computed in accordance with Sections II.10 and II.10(a) of this Schedule under Sections Supplementing Schedule 21 of the OATT and calculated on a rolling twelve month basis.

1.3.1 Local Network: The transmission facilities owned, controlled, or operated by UES that are used to provide transmission service under Schedule 21 of the OATT.

1.4 Local Network Service (LNS): The transmission service provided under Schedule 21 of the OATT and this Schedule.

1.5 Network Load: The load that a Network Customer designates for Local Network Service under Schedule 21 of the OATT. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Schedule 21 of the OATT for any Local Point-To-Point Service that may be necessary for such non-designated load.

1.6 Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support the UES's overall Local Network for the general benefit of all users of such Local Network.

1.7 Parties: UES and the Transmission Customer receiving service under this Schedule and the OATT.

SECTIONS SUPPLEMENTING THE BODY OF THE TARIFF

Preamble

The following provisions supplement the provisions of the Tariff. Provisions of this Schedule 21-UES shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-UES correspond to or are consecutive to the section numbers in the body of the Tariff that are affected by the additional provisions herein.

Sections Supplementing Section I: General Terms and Conditions

1.7 Creditworthiness: For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, UES may require reasonable credit review procedures in accordance with Attachment L of Schedule 21-UES.

Sections Supplementing Section II of the Tariff: Open Access Transmission Tariff (OATT)

II.A. COMMON SERVICE PROVISIONS

II.4 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the

Control Areas affected by the transmission service. UES is required to provide (or offer to arrange with the ISO as discussed below), and the Transmission Customer is required to purchase, Local Scheduling, System Control and Dispatch Service. The following Ancillary Services are available pursuant to Section II.4 of the Tariff only to the Transmission Customer serving load within the New England Control Area (i) Reactive Supply and Voltage Control Service, (iii) Regulation and Frequency Response, (iii) Energy Imbalance, (iv) Ten-Minute Spinning Reserve Service, (v) Ten-Minute Non-Spinning Reserve Service and (vi) Thirty-Minute Operating Reserve Service.

II.8 Billing and Invoicing; Accounting

8.2 Invoicing: Within a reasonable time after the first day of each month, UES shall submit an invoice to the Transmission Customer for the charges for all services furnished under the OATT during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to UES, or by wire transfer to a bank named by the UES.

8.4 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to UES on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after UES notifies the Transmission

Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, UES may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between UES and the Transmission Customer, UES will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending

resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then UES may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

II.10.2 Stranded Cost Recovery

UES may seek to recover stranded costs from the Transmission Customer pursuant to this OATT in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, UES must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

SECTIONS SUPPLEMENTING SCHEDULE 21 OF THE OATT

I. Local Point-to-Point Service Over the Local Network Owned by UES

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-UES shall govern Local Point-To-Point transactions using the Local Network owned by UES. Provisions of this Schedule 21-UES shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-UES correspond to or are consecutive to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

To the extent not otherwise covered in the OATT, the then-current ISO New England Operating Documents, or the TOA, or the rules adopted thereunder, whenever UES implements least-cost redispatch procedures in response to a transmission constraint, UES and the Transmission Customer(s) taking Local Point-To-Point Service will each bear a proportionate share of the total redispatch cost.

3 Service Availability

b) Determination of Available Transfer Capability (ATC): A description of UES's specific methodology for assessing ATC is contained in Attachment C of this Schedule. In the event sufficient transfer capability may not exist to accommodate a service request, UES will respond by performing a System Impact Study.

g) Real Power Losses: Real power losses are associated with all transmission service. UES is not obligated to provide real power losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by UES. The applicable real power loss factors tabulated below will be applied to metered loads and Reserved Capacity amounts to account for losses on UES's system. The applicable real power loss factors are as follows:

Firm Local Point-to-Point Service = 0.53% at 34.5 kV subtransmission.
Non-firm Local Point-to-Point Service = 0.53% at 34.5 kV subtransmission

6) Procedures for Arranging Non-Firm Local Point-To-Point Service

f) Determination of Available Transfer Capability: Following receipt of a tendered schedule UES will make a determination on a non-discriminatory basis of ATC pursuant to Attachment C of this Schedule. Such determination shall be made as soon as reasonably practicable after receipt (during UES's normal business hours of 8:00 a.m. to 4:30 p.m., Monday to Friday), but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.

11 Sale or Assignment of Local Point-to-Point Service

c) Information on Assignment or Transfer of Service: UES currently has waiver from the obligations of FERC Order No. 889 to maintain an OASIS. In the future, upon implementation of any UES OASIS site, resellers may use UES's OASIS site to post transmission capacity available for resale.

II. <u>Local Network Service using Non-PTF Owned by UES</u>

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-UES shall govern Local Network Service using Non-PTF owned by UES. Provisions of this Schedule 21-UES shall have priority over any conflicting provision in the Tariff. The section numbers of this Schedule 21-UES correspond to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

Local Network Service allows the Network Customer to integrate, economically dispatch, and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which UES utilizes its Non-PTF to serve its Native Load Customers. Local Network Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Schedule 21 of the OATT.

2) Availability of Local Network Service

f) Real Power Losses: The Network Customer is responsible for replacing losses associated with all transmission service as calculated by UES. The applicable real power loss factors tabulated below will be applied to metered loads and Reserved Capacity amounts to account for losses on UES's system. The applicable real power loss factors are as follows:
Local Network Service = 0.53% at 34.5 kV subtransmission.

8) Load Shedding and Curtailments

a) Procedures: Prior to the Service Commencement Date, UES and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to Section II.20 of the Tariff, with the objective of responding to contingencies on the Local Network. The Parties will implement such programs during any period when the ISO, the Local Control Center or UES determines that a system contingency exists and such procedures are necessary to alleviate such contingency. UES will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

b) Transmission Constraints: During any period when UES determines that a transmission constraint exists on the Local Network, and such constraint may impair the reliability of UES's system, UES will take whatever actions, consistent with then-current ISO New England Operating Documents or the TOA, and the rules adopted thereunder, and with Good Utility Practice, that are reasonably necessary to maintain the reliability of UES's system. To the extent ISO determines that the reliability of the ISO New England transmission system can be maintained by redispatching resources, UES will initiate procedures pursuant to the OATT, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder to redispatch all Network Resources and UES's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between UES's use of the Local Network on behalf of its Native Load Customers and any Network Customer's use of the Local Network to serve its designated Network Load.

c) Cost Responsibility for Relieving Transmission Constraints: To the extent not otherwise covered in the OATT, the then-current ISO New England Operating Documents, or the TOA, or the rules adopted thereunder, whenever UES implements least-cost redispatch procedures in response to a transmission constraint, UES and the Network Customer(s) will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

d) Curtailments of Scheduled Deliveries: If a transmission constraint on UES's Local Network cannot be relieved through the implementation of least-cost redispatch procedures and UES determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with Section II.22 of the Tariff.

e) Allocation of Curtailments: The ISO, the Local Control Center or UES shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by UES and Network Customers in proportion to their respective Load Ratio Shares. Neither the ISO, the Local Control Center nor UES shall direct the Network Customer to Curtail schedules to an extent greater than either would Curtail UES's schedules under similar circumstances.

f) Load Shedding: To the extent that a system contingency exists on UES's Local Network and the ISO, the Local Control Center or UES determines that it is necessary for UES and the Network Customers to shed load, the Parties shall shed load in accordance with previously established procedures in accordance with Section II.22 of the Tariff, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder.

g) System Reliability: Notwithstanding any other provisions of this Schedule, UES reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on the part of UES for the purpose of making necessary adjustments to, changes in, or repairs on UES's lines, substations, and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the event of any adverse conditions or disturbances on UES's Local Network or on any other system(s) directly or indirectly interconnected with UES's Local Network, UES, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. UES will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to UES's use of its Local Network on behalf of its Native Load Customers. UES shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

9) Rates and Charges

In addition to the above sections that correspond to sections in Schedule 21 of the OATT, the following additional provision shall apply to Local Network Service over UES's Local Network.

a) Monthly Demand Charge: The Network Customer shall pay a Monthly Demand Charge which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of UES's Annual Transmission Revenue Requirement as specified in Attachment H to this Schedule 21-UES.

10) Determination of Network Customer's Local Monthly Network Load: The Network Customer's local monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with UES under Section II.5(c) of Schedule 21 of the OATT) coincident with UES's Monthly Local Network Peak. Monthly revenue requirements not otherwise paid for through charges to Eligible Customers for Local Point-to-Point Service will be allocated among UES's Network Customers receiving service under the tariff on the basis of their loads during the hour in the month in which the total connected load to the local network is at its maximum, without any adjustment for credits for generation.

In addition to the above sections that correspond to sections in Schedule 21 of the OATT, the following three provisions shall apply to Local Network Service over UES's local network.

10a) Determination of UES's Monthly Local Network Load: UES's monthly Local Network Load is UES's Monthly Local Network Peak minus the coincident peak usage of all firm Local Point-To-Point Service customers pursuant to Schedule 21 of the OATT plus the Reserved Capacity of all firm Local Point-To-Point Service customers.

10b) Recovery of PTF Transmission Revenue Requirements: The portion of UES's annual transmission revenue requirements with respect to PTF which is not recovered through the distribution of revenues from Regional Network Service or Local Point-to-Point Service shall be recovered from Eligible Customers taking Regional Network Service or Local Point-to-Point Service pursuant to Section II.13 of the Tariff.

SCHEDULE 1

Local Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into UES's Local Network Control Area. Local Scheduling, System Control and Dispatch Service is to be provided directly by UES and the ISO. The Transmission Customer must purchase this service from UES. The charges for UES's Local Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent that the ISO performs this service for UES, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to UES by the ISO.

Each firm Local Point-To-Point Service Customer under this Tariff will be charged for Local Scheduling, System Control and Dispatch Services for the total Reserved Capacity specified in each reservation for firm Local Point-To-Point Service made under the Tariff at the rates set forth in Appendix A of this Schedule 1.

Each Network Customer under this Tariff will be charged a monthly Local Scheduling, System Control and Dispatch Service Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Formula Requirements specified in Appendix B of this Schedule 1.
Each Transmission Customer with generation within the ISO's Control Area shall be required also to provide for Scheduling, System Control and Dispatch Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting with the ISO for these services on an unbundled basis. UES will make available Generation Scheduling, System Control and Dispatch Service at the rates set forth in Appendix C of this Schedule 1.

Each Transmission Customer with generation located outside of the ISO Control Area shall be required to provide for Scheduling, System Control and Dispatching Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting for these services from the provider of these services within the Control Area where the generation is located. UES shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule 1 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE 1

Appendix A

Determination Of UES's Local Network Point-To-Point Formula Rate

For Local Scheduling, System Control and Dispatch Service

UES's Formula Rate for Point-To-Point Local Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{FORMULA RATE}_i = \frac{A_{i-1} - B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of UES for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule 1.

- B_{i-1} is the actual local scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual local scheduling and dispatch revenues shall be those recorded on the books of UES in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

- C_{i-1} is the single annual coincident peak transmission and distribution load (expressed in kilowatts) of UES for the calendar year prior to the Service Year, as reported in FERC Form No. 1.

Schedule 1

Appendix A

Exhibit 1

Determination Of Annual Control Center Expenses

The rate formula for determination of the annual control center expenses revenue requirements for UES is determined as follows:

A. <u>ANNUAL CONTROL CENTER EXPENSES</u> = Sum of UES's (Account 556 System Control and Load Dispatching Expense) + (Account 557 Other Expense) X .50* for the calendar year prior to the Service Year.

*This factor reflects allocation to the transmission function of a portion (50 percent) of the costs recorded in Accounts 556 and 557 associated with dispatching transmission and generating facilities. This 50 percent allocation of control center costs is based on two functions performed by the control center (i) control of generation and (ii) control of transmission.

SCHEDULE 1

Appendix B

Determination Of UES's
Network Formula Requirements
For Local Scheduling, System Control
And Dispatch Service

UES's formula requirements for Network Local Scheduling, System Control and Dispatch Service is determined from the following formula.

Formula Requirements_i = $A_{i-1} - B_{i-1}$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of UES for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to Appendix A of Schedule 1.

- B_{i-1} is the actual local scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual local scheduling, system control and dispatch revenues shall be those recorded on the books of UES in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

SCHEDULE 1

Appendix C

Determination Of
UES's Formula Rate
For Generation Scheduling, System Control And Dispatch Service

UES's Formula Rate for Generation Scheduling, System Control and Dispatch Service ("Formula Rate") shall be calculated using the Formula Rate for Point-to-Point Local Scheduling, System Control and Dispatch Service in Appendix A of Schedule 21 - UES.

SCHEDULE 7

Long-Term Firm Local and Short-Term Firm Local Point-to-Point Service

The Transmission Customer shall compensate UES each month for firm Reserved Capacity at the sum of the applicable charges set forth below:

1) **Yearly delivery**: one-twelfth of the demand charge of
$ N/A /KW of firm Reserved Capacity per year.

2) **Monthly delivery**: $ N/A /KW of firm Reserved Capacity per month.

3) **Weekly delivery**: $ N/A /KW of firm Reserved Capacity per week.

4) **Daily delivery**: $ N/A /KW of firm Reserved Capacity per day.
The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of firm Reserved Capacity in any day during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by UES must be announced to all Eligible Customers solely by posting on Unitil.com, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on Unitil.com, and (3) once a discount is negotiated, details must be immediately posted on Unitil.com. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, UES must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on UES's Local Network.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section I.11 (a) of Schedule 21 of the OATT.

SCHEDULE 8

Non-Firm Local Point-To-Point Service*

The Transmission Customer shall compensate UES for non-firm Local Point-To-Point Service up to the sum of the applicable charges set forth below:

1) **Monthly delivery**: $ N/A /KW of Reserved Capacity per month.

2) **Weekly delivery**: $ N/A /KW of Reserved Capacity per week.

3) **Daily delivery**: $ N/A /KW of Reserved Capacity per day.
The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) **Hourly delivery**: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $ N/A /MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by UES must be announced to all Eligible Customers solely by posting on Unitil.com, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on Unitil.com, and (3) once a discount is negotiated, details must be immediately posted on Unitil.com. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, UES must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on UES's Local Network.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section I.11 (a) of

Schedule 21 of the OATT.

* Rates reflect a 25% discount off the firm Point-To-Point rates

SCHEDULE 9

DISTRIBUTION ADDER UNDER TARIFF

In the case where distribution facilities of UES are employed in providing service under Schedule 21 of the OATT, the Transmission Customer shall compensate UES for the use of such facilities. In addition to the charges contained in this Tariff, the compensation for such distribution facilities will be determined on a case-by-case basis.

All such charges shall be subject to appropriate regulatory approval.

ATTACHMENT C

Methodology To Assess Available Transfer Capability

1. Introduction

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, but does not include the transmission system in northern Maine (i.e., Aroostook and parts of Penobscot and Washington Counties) that is radially connected to New Brunswick and administered by the Northern Maine Independent System Administrator. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERS Standards: MOD-001 – Available Transmission System Capability ("MOD-001"). MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Service Provider for regional transmission service ("Regional Transmission Service") associated with Pool Transmission Facilities, the Participating Transmission Owners ("PTOs") provide local transmission service over Non-Pool Transmission Facilities within the RTOP footprint and are responsible for calculating TTC and ATC associated with Local Transmission Service provided under Schedule 21 pursuant to the Transmission Operating Agreement ("TOA"). Pursuant to CFR § 37.6(b)[13] of the FERC Regulations, Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. The ISO is not responsible for the calculation of these values.

Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a

13 Section §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted 13
2 Path as set out in this section.

customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.[14]

UES does not currently have any Posted Paths based on the above definition. However, to the extent that UES does in the future have a Posted Path, UES will calculate TTC using the NERC Standard MOD-029 – Rated System Path Methodology ("MOD-029") as outlined below.

1.1 Scope of Document

The scope of this document is limited to those functions performed by UES as the Transmission Service Provider of Schedule 21-UES Point-to Point transmission service over Local Facilities pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT:

- Methodology for calculating Total Transfer Capability (TTC)
- Methodology for calculating Available Transfer Capability (ATC)
- Existing Transmission Commitment (ETC)
- Use of Transmission Reliability Margin (TRM)
- Use of Capacity Benefit Margin (CBM)
- Use of Rollover Rights (ROR) in the calculation of ETC

TTC and ATC are required to be calculated only for certain non-PTF internal Posted Paths over which Point-to-Point transmission service is provided under Schedule 21-UES. TTC and ATC is not calculated by UES for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and UES does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission pro forma OATT.

Section § 37.6(b)(1)(i).

The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the New England Control Area, out of the New England Control Area or through the New England Control Area. The New England Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS or Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, UES owns Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those Local Facilities, the market participant may obtain a transmission service reservation from UES under Schedule 21-UES prior to delivery of energy into the Real-Time Energy Market.[15] This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. Schedule 21-UES Total Transfer Capability (TTC)

The TTC on UES' non-PTF Local Facilities that require Point-to-Point transmission service reservations are relatively static values and are calculated using the NERC Standard MOD-029 – Rated System Path Methodology. TTC is the amount of electric power that can be moved or transferred reliably from one area

15 See n - 2, 3 and 6, supra.

to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. UES calculates TTC according to this definition applying the process as described below.

3.1 Guidelines and Principles

When estimating TTC, UES will apply the following, as amended and/or adopted from time to time

- Good Utility Practice
- NERC criteria and guidelines
- ISO New England criteria, rules and reliability standards
- Northeast Power Coordinating Council (NPCC) criteria and guidelines
- Unitil Energy Systems, Inc. guides

3.2 Transmission System Model Representation

UES will estimate TTC using transmission system load flow models developed for UES' system. The models may include representations of other neighboring systems. UES will use system models that it deems appropriate for study of the request for firm transmission service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

3.3 Contingency Analysis

UES will perform, if necessary, power flow and transient stability analysis to ensure that the interface's physical limits will not be violated for credible system contingencies per NERC, NPCC and ISO reliability criteria. TTC, based on contingency analysis, is the incremental transfer capability of the transmission system following the loss of the most critical element while maintaining thermal, and stability performance of the system within acceptable regional practices and consistent with guidelines of Item 3.1 of this Attachment.

3.4 Posting TTCs

When necessary, UES will estimate TTC as outlined above and post on its website.

4. Capacity Benefit Margin (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the

Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of ATC calculation, CBM for the New England Control Area is set to zero (0).

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed firm transmission reservations (PTP_F) plus any rollover rights for firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed non-firm transmission reservations (PTP_{NF}). There are no allowances necessary for non-firm Network Integration Transmission Service ($NITS_{NF}$), non-firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. UES, under Schedule 21, does not have any external interfaces, and therefore, TRM for UES' non-PTF facilities is zero.

6. Calculation of ATC for UES' Local Facilities

General Description

This section defines the ATC calculations performed by UES for its non-PTF internal interfaces. Consistent with the NERC definition, the equation for Available Transfer Capability is: ATC = (TTC – CBM – TRM – Existing Transmission Commitments + Postbacks + counterflows). As discussed above, the CBM and TRM for the PTF interfaces for which UES calculates ATC are zero (0). As consistent with the ISO calculation, the equations for firm and non-firm Available Transfer Capability are:

Firm ATC = (TTC – CBM – TRM – firm ETC)
Non-firm ATC = (TTC – CBM – TRM – firm and non-firm ETC).[16]

As discussed above, the TRM and CBM for UES's non-PTF paths are zero. The purpose of the Existing Transmission Commitments ("ETC") component of the ATC equation is for FG&E to reduce the amount of ATC by the amount of existing firm transmission commitments that are not otherwise included in CBM or TRM. There is no requirement to purchase transmission service in advance of flowing energy in Real-Time, and there is no MW amount set aside by FG&E on any interface. One such example is point-to-point service commitments. Point-to-point service commitments sharing common transmission paths would be combined through system modeling to calculate the net existing transmission capacity (ETC) impact. This ETC value is then used in the ATC calculation shown above. Therefore there are no Existing Transmission Commitments to be applied in the ATC equation. For this reason, ETC equals zero (0) for the purposes of ATC calculation. Because Postbacks and counterflows are related to ETC and ETC is zero (0), both Postbacks and counterflows also are equal to zero (0).

As described in Section 2, under Schedule 21-UES, UES requires the purchase of transmission service in advance of delivery of energy to the New England Wholesale Market over certain non-PTF paths, and those existing transmission commitments would be applied to the ATC equation for the specific posted path. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Entities submit their bids and offers to move energy into, out of and through the Energy Market through External Transactions. As Real-Time approaches, the ISO determines which of the submitted External Transactions will be scheduled in the coming hour in accordance with the rules set forth in the ISO New England Operating Documents. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of External Transactions that the ISO will

16 Existing Transmission Commitments ("ETC")

schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF facilities that serve as a path for the UES' Schedule 21-UES Point-to-Point Transmission Customers, UES would post the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it would be posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Schedule 21-UES Firm ATC (ATC_F)

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C, PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-UES that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-UES transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

6.1.2 Calculation of ATC_F in the Schedule 21-UES Operating Horizon (OH)

For purposes of this Attachment C, OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily firm Transmission Service under Schedule 21-UES is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-UES transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the

OH is equal to the TTC minus ETC_F.

6.1.3 Because firm Schedule 21-UES transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

6.2 Calculation of Schedule 21-UES Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for non-firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), non-firm Postbacks ($Postbacks_{NF}$) and non-firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-UES are zero. Non-firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-UES transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-UES are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F, plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$).

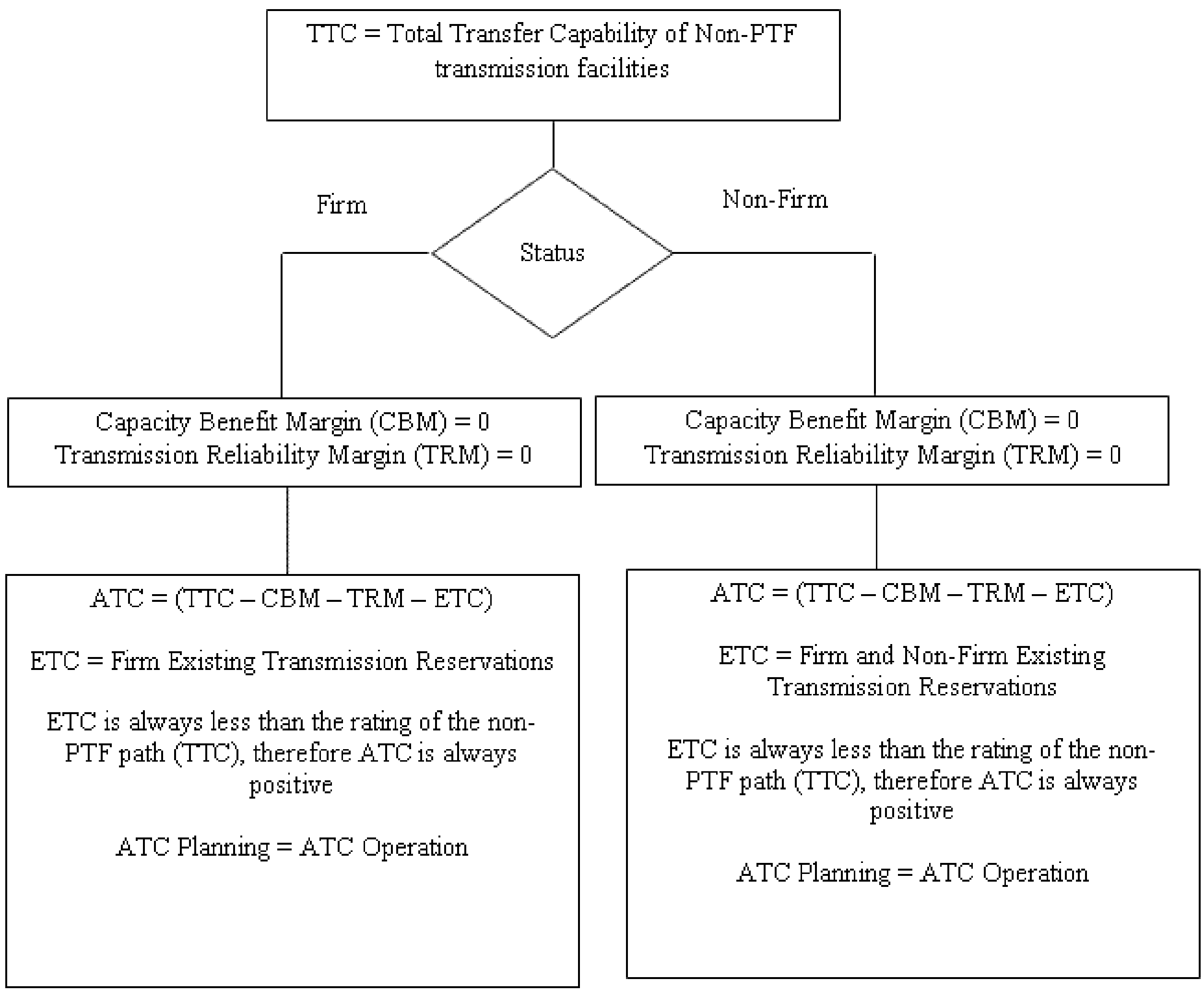
6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

As stated above, UES' non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators. It is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

ATC Process Flow Diagram for Non-PTF Interfaces

The process flow diagram illustrates the steps through which ATC is calculated both on an operating and planning horizon.



7. Posting of Schedule 21-UES ATC

7.1 Location of ATC Posting.

When necessary, UES will estimate ATC values for these internal paths as outlined above and post on its website, http://www.unitil.net/nepool/nh/pdf/atc_cbm_ttc_trm_ues.pdf.

7.2 Updates To ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

7.3 Coordination of ATC Calculations

Schedule 21-UES non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms

A link to the actual mathematical algorithm for the calculation of ATC for UES' non-PTF internal interfaces is located at http://www.unitil.com/sites/default/files/pdfs/ues_atc_algorithms_3_11.pdf .

ATTACHMENT D

Methodology for Completing a System Impact Study

UES will perform System Impact Studies for the purpose of determining the feasibility of integrating Network Load and Network Resources into UES's Local Network under Schedule 21 of the OATT, or for the purpose of determining the feasibility of providing Local Point-To-Point Service under this Tariff. All System Impact Studies will be completed using the same method employed by UES to integrate into UES's Local Network (i) generation resources owned or acquired to serve its Native Load Customers, and (ii) its Native Load Customers' load. Specifically, System Impact Studies will be performed by applying the applicable criteria, rules, standards and operating procedures. In addition to applying the aforementioned applicable criteria, rules, standards and operating procedures , to determine the feasibility of providing service to Network Load and/or Local Point-To-Point Service, System Impact Studies will also be performed by applying Unitil Service Corp.'s "Electric System Planning Guide."

ATTACHMENT E

Index Of Local Point-To-Point Service Customers

Customer	Date of Service Agreement

ATTACHMENT H

Annual Transmission Revenue Requirement

For Local Network Service

1. The Annual Transmission Revenue Requirement for purposes of the Local Network Service shall be $ N/A.

2. The amount in (1) shall be effective until amended by UES or modified by the Commission.

3. If UES receives a distribution pursuant to Section II.13 of the Tariff from ISO out of revenues paid for Through or Out Service or for In Service (as defined in the OATT), the amounts received shall reduce its local network service revenue requirements.

4. Any rate developed hereunder shall employ a cost of equity of 11.14%.

ATTACHMENT I

Index Of Local Network Service Customers

Customer	Date of Service Agreement
Unitil Energy Systems, Inc.	December 1, 2002

Attachment L

Creditworthiness Policy

1. Introduction

This guide establishes creditworthiness standards for transmission service and/or interconnection service customers ("Customers") entering into new or amended service agreements with Unitil Energy Systems, Inc. ("UES") under the ISO New England Open Access Transmission Tariff ("ISO-NE OATT").[17] In accordance with the Federal Energy Regulatory Commission's Policy Statement on Credit-Related Issues for Electric OATT Transmission Providers, Independent System Operators and Regional Transmission Organizations ("Policy Statement"), this Creditworthiness Policy is intended to make UES's credit-related practices more transparent and comprehensive. The following describes UES credit review procedures and the types of security that are acceptable to UES to protect against the risk of non-payment.

2. Creditworthiness

UES will evaluate the creditworthiness of Customers entering into new or amended transmission or interconnection service agreements with UES in order to assess a Customer's credit risk relative to the exposure of "Total Outstanding Obligation" as defined in Section 2.1 below, created by the transaction or transactions that UES has with the Customer. For purposes of determining the ability of a Customer to meet its obligations, UES may require the Customer to submit financial information for the credit review, including credit ratings, credit reports and audited financial statements for the last five years, including audited quarterly reports for the prior two years, if available. Further, the Customer will be expected to provide calculations of the following: Current Total Capitalization Ratio, Including Short-Term Debt; Tangible Net Worth for a period within sixty days of a Customer's request; Earnings Before Interest, Taxes, Depreciation and Amortization for twelve of the last fifteen consecutive months; and additional calculations and other information deemed necessary for the evaluation credit. In completing its evaluation, UES may consider other factors including but not limited to past billing history or the characteristics of service being requested.

2.1 Total Outstanding Obligation

The Customer's Total Outstanding Obligation to UES will be the sum total of the following components:

17 *See* ISO New England Inc., ISO New England Inc. Transmission, Markets and Services Tariff, Section II. This policy is applicable to transmission or interconnection service agreements established from time-to-time under Schedules 21 - UES of the ISO-NE OATT and to individually negotiated agreements for similar transmission or interconnection services.

2.1.1 If the Customer is making payments to UES for ongoing expenses (including, but not limited to, O&M expenses related to interconnections or other monthly charges such as monthly transmission charges under Schedule 21 – UES) the Customer will be required to provide security pursuant to Section 2.2 below, for four months' worth of the Customer's average payment obligation for such charges.

2.1.2 In accordance with the provisions of the ISO-NE OATT, a Customer will pay a Contribution in Aid of Construction ("CIAC") or transfer ownership of facilities to UES for transmission or interconnection facilities that are to be constructed on behalf of a Customer at the Customer's sole expense. If UES determines in good faith that the receipt of CIAC payments or property from the Customer are non-taxable, UES will require a form of security from the customer pursuant to Section 2.2 below for the amount of the potential tax liability to UES that would occur if such facilities were deemed taxable.

2.1.3 In accordance with the provisions of Schedule 21 – UES to the ISO-NE OATT, a Customer will pay a formula rate over time for return of and on the cost of capital incurred by UES on behalf of a Customer at the Customer's sole expense. The Customer will also be required to provide security pursuant to Section 2.2 below, for the unamortized balance of plant in service reserved for the sole use of the Customer.

2.2 Creditworthiness Requirements

A Customer will be considered creditworthy upon satisfying at least one of the following conditions or a combination of those conditions at the time that the customer enters into a transmission or interconnection service agreement and for so long as the Customer maintains satisfaction of at least one of these conditions for any outstanding obligations thereunder:

2.2.1 The Customer maintains a minimum credit rating from Standard & Poor's Long-term Issuer Credit Rating of BBB- or better or Moody's Investors Service Long-term Issuer Credit Rating of Baa3 or better so long as the Customer's Total Outstanding Obligation plus any other unsecured obligations with UES does not exceed the Credit Limits discussed in Section 4 below. When UES reviews a Customer's rating from two or more rating agencies and a split rating is present, the lower debt rating will apply. In the event that the Customer has no rating from either Standard & Poor's or Moody's Investors Service, a rating from Fitch may also be used with

acceptable ratings equivalent to those from either Standard and Poor's or Moody's Investors Service. If unrated, the Customer's financial statements will be reviewed to determine an equivalent rating based on the Customer's unsecured credit limits and/or financial statements.

If, at any time, the Customer's rating falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify UES within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to UES, as described in this Section 2.2.

2.2.2 The Customer provides and maintains in effect during the term of and until full and final payment and performance of the service agreement an unconditional and irrevocable standby letter of credit for the Total Outstanding Obligation in the form and substance and issued by a bank reasonably acceptable to UES. A draft, acceptable form letter of credit is attached. Any such bank must satisfy the creditworthiness criteria described in 2.2.1 above.

If, at any time, the bank's rating falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify UES within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to UES, as described in this Section 2.2.

2.2.3 If the Customer's parent or an affiliate company satisfies the creditworthiness criteria described in 2.2.1 above and, subject to the Credit Limits stated in Section 4 below, such company submits to UES and maintains in effect a letter of guaranty reasonably acceptable to UES as to amount, form and substance for the term of and until full and final payment and performance of the service agreement.

If, at any time, the credit rating of the Customer's parent or affiliate providing the guaranty falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify UES within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to UES, as described in this Section 2.

2.2.4 The Customer makes an advance payment to UES in immediately available funds for the Total Outstanding Obligation.

3. Customer Costs Requiring Prepayment

In accordance with the provisions of the ISO-NE OATT, a Customer will pay a Contribution in Aid of Construction ("CIAC") for transmission or interconnection facilities to be constructed by UES on behalf of a Customer at the Customer's sole expense. The Customer will have the option to (i) prepay the CIAC in immediately available funds to UES, or (ii) make periodic CIAC progress payments, as defined in the Customer's service agreement, to prepay in increments capital costs scheduled to be incurred by UES. If UES determines in good faith that such payments or property transfers made by the Customer should be reported as income subject to taxation, the Customer shall also prepay all costs associated with the cost consequences of the current tax liability imposed on UES by those facilities (the "Tax Gross- up").

4. Determination of Credit Limits

UES reserves the right to limit the total amount of unsecured credit extended to a Customer under 2.2.1 and 2.2.3 above such that the sum of all unsecured credit that such Customer has with UES, including the Total Outstanding Obligation, shall not exceed the Credit Limits defined below. Such limitations are based on an assessment of the Customer's or its Guarantor's credit rating and the net worth of the Customer's or its Guarantor's assets.

Standard and Poor's (or Equivalent) Rating	Unsecured Credit Limit as Percent of Customer's or Guarantor's Tangible Net Worth
A and above	1.00%
A-	0.50%
BBB+	0.30%
BBB	0.20%
BBB-	0.10%

Once UES has evaluated or reevaluated and determined the maximum Credit limits for each Customer, it will inform the prospective Customer of the amount of such credit limits. A customer may request in writing a reevaluation of the maximum Credit limits, within 14 days from the date that they were informed by UES of such limits. Justification for such a reevaluation should be contained in the request. All requests for reevaluation must be submitted directly to the UES Contract Administrator.

From time to time, principally due to unknown factors such as changing market, economic, banking or other financial conditions, but not solely limited to these factors, UES may find it necessary to modify or amend its creditworthiness policies and guidelines after a 15 day notice period and require that present and future Transmission Customers fulfill any additional conditions contained in the modified Creditworthiness Guide. Transmission Customers will have 30 days after the notice period to cure any deficiency.

FORM LETTER OF CREDIT

____________________________________ Bank

____

(address)

IRREVOCABLE STANDBY LETTER OF CREDIT

DATE: ______________________

AMOUNT U.S. $________________

____

FOR INTERNAL IDENTIFICATION PURPOSES ONLY

Our Number:

Beneficiary:	Applicant:
____________________________	___________________________
____________________________	___________________________
____________________________	___________________________
____________________________	___________________________

Attn: At the request of:

Ref:____

LADIES AND GENTLEMEN:

WE HEREBY ESTABLISH THIS IRREVOCABLE, AND UNCONDITIONAL, EXCEPT AS STATED HEREIN, LETTER OF CREDIT NUMBER _____________ (LETTER OF CREDIT), BY ORDER OF, FOR THE ACCOUNT OF, AND ON BEHALF OF [CUSTOMER NAME] (ACCOUNT PARTY) IN FAVOR OF UNITIL ENERGY SYSTEMS, INC. (BENEFICIARY) FOR DRAWINGS, IN ONE OF MORE DRAFTS, UP TO AN AGGREGATE AMOUNT NOT EXCEEDING U.S. $_______________ EFFECTIVE IMMEDIATELY. THE TERM 'BENEFICIARY' INCLUDES ANY SUCCESSOR OF THE NAMED BENEFICIARY.

THIS LETTER OF CREDIT CANNOT BE AMENDED, MODIFIED OR REVOKED WITHOUT THE PRIOR WRITTEN CONSENT OF BOTH THE BANK AND THE BENEFICIARY. THE BENEFICIARY SHALL NOT BE DEEMED TO HAVE WAIVED ANY RIGHTS UNDER THIS LETTER OF CREDIT, UNLESS AN OFFICER OF THE BENEFICIARY SHALL HAVE SIGNED A WRITTEN WAIVER EXPRESSLY REFERENCING THE RIGHT TO BE WAIVED. NO SUCH WAIVER SHALL BE EFFECTIVE AS TO ANY TRANSACTION THAT OCCURS SUBSEQUENT TO THE DATE OF THE WAIVER, NOT AS TO ANY CONTINUANCE OF A BREACH AFTER THE WAIVER.

WE HEREBY UNDERTAKE TO PROMPTLY HONOR YOUR DRAFT(S) DRAWN ON US, INDICATING OUR LETTER OF CREDIT NUMBER __________ IS ISSUED, PRESENTABLE AND PAYABLE AND WE GUARANTY TO THE DRAWERS, ENDORSERS, AND BONA FIDE HOLDERS OF THIS LETTER OF CREDIT, THAT DRAFTS UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT WILL BE HONORED. THIS LETTER OF CREDIT MAY NOT BE TRANSFERRED OR ASSIGNED BY US.

SUBJECT TO THE EXPRESS TERMS AND CONDITIONS HEREIN, FUNDS UNDER THIS LETTER OF CREDIT ARE AVAILABLE TO YOU BY PRESENTATION AT OUR OFFICES LOCATED AT [_______________] OF BENEFICIARY'S DRAWING CERTIFICATE ISSUED SUBSTANTIALLY IN THE FORM OF ANNEX 1 ATTACHED HERETO AND WHICH FORMS AN INTEGRAL PART HEREOF, DULY COMPLETED AND PURPORTEDLY BEARING THE ORIGINAL SIGNATURE OF AN OFFICER OF THE BENEFICIARY. PRRESENTATION OF ANY DRAWING CERTIFICATE UNDER THIS LETTER OF CREDIT MAY BE MADE IN PERSON TO US OR MAY BE SENT TO US BY TELEX TO [_________________] OR BY FACSIMILE TRANSMISSION TO FACSIMILE

TELEPHONE NUMBER [_______________].

ALL COMMISSIONS AND CHARGES WILL BE BORNE BY THE ACCOUNT PARTY. IF DOCUMENTS, IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT, ARE RECEIVED BEFORE 10:00 AM (EASTERN TIME) ON A BUSINESS DAY, PAYMENT WILL BE EFFECTED ON OR BEFORE 5:00 PM (EASTERN TIME) ON THE NEXT BUSINESS DAY. IF DOCUMENTS, IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT ARE RECEIVED AFTER 10:00 AM ON A BUSINESS DAY, PAYMENT WILL BE EFFECTED ON OR BEFORE 5:00 PM ON THE SECOND BUSINESS DAY FOLLOWING SUCH DATE OF RECEIPT.

EXCEPT AS EXPRESSLY STATED HEREIN, THIS UNDERTAKING IS NOT SUBJECT TO ANY AGREEMENT, CONDITION OR QUALIFICATION. THIS LETTER OF CREDIT DOES NOT INCORPORATE, AND SHALL NOT BE DEEMED MODIFIED OR AMENDED BY REFERENCE TO ANY DOCUMENT, INSTRUMENT OR AGREEMENT (A) THAT IS REFERRED TO HEREIN (EXCEPT FOR THE UNIFORM CUSTOMS, AS DEFINED BELOW), OR (B) IN WHICH THIS LETTER OF CREDIT IS REFERRED TO OR TO WHICH THIS LETTER OF CREDIT RELATES.

OUR OBLIGATION UNDER THIS LETTER OF CREDIT SHALL BE OUR INDIVIDUAL OBLIGATION AND IS IN NO WAY CONTINGENT UPON THE REIMBURSEMENT WITH RESPECT THERETO, OR UPON OUR ABILITY TO PERFECT ANY LIEN, SECURITY INTEREST OR ANY OTHER REIMBURSEMENT.

THIS LETTER OF CREDIT EXPIRES WITH OUR CLOSE OF BUSINESS ON [364 days from effective date]; HOWEVER, IT IS A CONDITION OF THIS LETTER OF CREDIT THAT IT SHALL BE DEEMED AUTOMATICALLY EXTENDED WITHOUT AMENDMENT FOR 364 DAYS FROM THE PRESENT OR ANY FUTURE EXPIRATION DATE HEREOF, UNLESS AT LEAST SIXTY (60) DAYS BEFORE ANY SUCH EXPIRATION DATE WE NOTIFY YOU BY REGISTERED MAIL ADDRESSED TO: [address of beneficiary, ATTN: ______________], THAT WE ELECT NOT TO RENEW THIS LETTER FOR SUCH ADDITIONAL PERIOD.

THIS LETTER OF CREDIT IS SUBJECT TO THE UNIFORM CUSTOMS AND PRACTICE FOR DOCUMENTARY CREDITS (1993 REVISION) INTERNATIONAL CHAMBER OF COMMERCE, PUBLICATION NO. 500. IF THIS LETTER OF CREDIT EXPIRES DURING THE INTERRUPTION OF BUSINESS AS DESCRIBED IN ARTICLE 17 THEREOF WE HEREBY SPECIFICALLY AGREE

TO EFFECT PAYMENT IF THE LETTER OF CREDIT IS DRAWN AGAINST WITHIN 30 DAYS AFTER THE RESUMPTION OF BUSINESS.

ANNEX 1 TO [BANKNAME]
IRREVOCABLE LETTER OF CREDIT NO. _____________

[INSERT DATE]
[BANK NAME]
[ATTENTION]
[BANK ADDRESS 1]
[BANK ADDRESS 2]

LADIES AND GENTLEMEN:

THE UNDERSIGNED ________________________________, A DULY ELECTED AND ACTING OFFICER OF UNITIL ENERGY SYSTEMS, INC. (THE "BENEFICIARY"), HEREBY CERTIFIES TO [INSERT BANK NAME] (THE "BANK"), WITH REFERENCE TO IRREVOCABLE LETTER OF CREDIT NO. _________ DATED _______________, ISSUED BY THE BANK IN FAVOR OF THE BENEFICIARY (THE "LETTER OF CREDIT"), AS FOLLOWS AS OF THE DATE THEREOF:

1. THE BENEFICIARY IS A PARTY TO THAT CERTAIN [INTERCONNECTION AGREEMENT], EFFECTIVE _______________, BETWEEN THE BENEFICIARY AND [CUSTOMER NAME] (THE "AGREEMENT").

2. BENEFICIARY IS MAKING A DRAWING UNDER THE LETTER OF CREDIT IN THE AMOUNT OF $___________ BECAUSE [CHECK APPLICABLE PROVISION]:

[____] (A) THERE CURRENTLY EXIST ONE OR MORE UNPAID AMOUNTS WHICH [CUSTOMER NAME] IS OBLIGATED TO PAY PURSUANT TO THE TERMS OF THE AGREEMENT.

[____] (B) THE BENEFICIARY HAS RECEIVED NOTICE FROM THE BANK OF ITS INTENTION NOT TO RENEW THE LETTER OF CREDIT BEYOND THE CURRENT EXPIRATION DATE AND [CUSTOMER NAME] HAS FAILED, PRIOR TO THE CLOSE OF BUSINESS ON _______________ [INSERT DATE WHICH IS NOT MORE THAN THIRTY (30) DAYS BEFORE THE PRESENT EXPIRATION DATE], TO DELIVER TO BENEFICIARY A REPLACEMENT LETTER OF CREDIT SATISFYING THE REQUIREMENTS OF THE AGREEMENT.

3. BASED UPON THE FOREGOING, THE BENEFICIARY HEREBY MAKES DEMAND UNDER THE LETTER OF CREDIT FOR PAYMENT OF U.S. DOLLARS __________________ AND _____/100THS (U.S. $_______________).

4. FUNDS PAID PURSUANT TO THE PROVISIONS OF THE LETTER OF CREDIT SHALL BE WIRE TRANSFERRED TO THE BENEFICIARY IN ACCORDANCE WITH THE FOLLOWING INSTRUCTIONS:

____

____

____

UNLESS OTHERWISE PROVIDED HEREIN, CAPITALIZED TERMS WHICH ARE USED AND NOT DEFINED HEREIN SHALL HAVE THE MEANING GIVEN EACH SUCH TERM IN THE LETTER OF CREDIT.

IN WITNESS WHEREOF, THIS CERTIFICATE HAS BEEN DULY EXECUTED AND DELIVERED ON BEHALF OF THE BENEFICIARY BY ITS DULY ELECTED AND ACTING OFFICER AS OF THIS _____ DAY OF ___________, _____.

BENEFICIARY: UNITIL ENERGY SYSTEMS, INC.

____

NAME:

____

TITLE:

SCHEDULE 21-VTransco

Local Service Schedule

Vermont Transco LLC

In accordance with paragraphs 126-130 of Commission Order No. 676-E, the NAESB Version 002 Standards listed below apply to the provision of transmission service pursuant to this Schedule 21-VTransco for service provided hereunder by Vermont Transco LLC:

Gas/Electric Coordination (WEQ-011, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009), Standards 011.12 and 011.13.

I. COMMON SERVICE PROVISIONS

This Local Service Schedule, designated Schedule 21-VTransco, governs the terms and conditions of service taken by Transmission Customers over VTransco's Transmission System who are not otherwise served under transmission service contracts with VTransco that are still in effect. In the event of a conflict between the provisions of this Schedule 21-VTransco and the other provisions of the Tariff, the provisions of this Schedule 21-VTransco shall control.

1 Definitions

Whenever used in this Schedule 21-VTransco, in either the singular or the plural, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Schedule 21-VTransco but not defined in this Section 1 shall have the meaning specified elsewhere in the Tariff, or if not defined therein, such terms shall have the meanings customarily attributed to such terms by the electric utility industry in New England.

1.1 Actual Transmission Costs: The total actual cost of VTransco's Transmission System for purposes of Local Network Service shall be the amount determined each month pursuant to the formula specified in Attachment D until amended by VTransco or modified by the Commission.

1.2 Firm Local Point-To-Point Transmission Service: Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery on VTransco's Transmission System pursuant to this Schedule 21.

1.3 Interruption: A reduction in non-firm transmission service due to economic reasons pursuant to the terms of this Schedule 21.

1.4 Load Ratio Share: Ratio of a Transmission Customer's Local Network Load to VTransco's total load computed in accordance with this Schedule 21-VTransco and calculated on a rolling twelve-month basis.

1.5 Local Network Customer: An entity receiving Local Network Service pursuant to the terms of this Schedule 21.

1.6 Local Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under this Schedule 21.

1.7 Local Point-To-Point Transmission Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under this Schedule 21.

1.8 Local Reserved Capacity: The maximum amount of capacity and energy that VTransco agrees to transmit for the Transmission Customer over VTransco's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under this Schedule 21. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.9 Non-Firm Local Point-To-Point Transmission Service: Point-To-Point Transmission Service on VTransco's Transmission System under this Schedule 21 that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption. Non-Firm Local Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.10 Parties: VTransco and the Transmission Customer receiving service under this Schedule 21-VTransco.

1.11 Receiving Party: The entity receiving the capacity and energy transmitted by VTransco to Point(s) of Delivery under this Schedule 21.

1.12 Service Commencement Date: The date that VTransco begins to provide service pursuant to the terms of an executed Service Agreement, or the date that VTransco begins to provide service in accordance with this Schedule 21.

1.13 Short-Term Firm Local Point-To-Point Transmission Service: Firm Local Point-To-Point Transmission Service under this Schedule 21-VTransco with a term of less than one year.

1.14 VTransco: Vermont Transmission Company, LLC.

1.15 VTransco's Monthly Transmission System Peak: The maximum firm usage of VTransco's Transmission System in a calendar month.

1.16 VTransco's Transmission System: The Non-PTF facilities owned, controlled or operated by VTransco that are used to provide transmission service under this Schedule 21.

2 [RESERVED]

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. VTransco offers to arrange with the ISO, and the Transmission Customer is required to purchase or otherwise obtain, the following Ancillary Services: (i) Scheduling, System Control and Dispatch. VTransco does not offer or provide any other ancillary services.

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1 of this Schedule 21-VTransco.

4 Billing and Payment

4.1 Billing Procedure: Within a reasonable time after the first day of each month, VTransco shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Schedule 21-VTransco during the preceding month.

The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to VTransco, or by wire transfer to a bank named by VTransco.

4.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by VTransco.

4.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to VTransco on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after VTransco notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, VTransco may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between VTransco and the Transmission Customer, VTransco will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then VTransco may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5 Accounting for VTransco's Use of the Tariff

VTransco shall record the following amounts, as outlined below.

5.1 Transmission Revenues: Include in a separate operating revenue account or sub-account the revenues it receives from Local Point-to-Point Transmission Service when making Third-Party Sales.

5.2 Study Costs and Revenues: Include in a separate transmission operating expense account or sub-account, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies that VTransco conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales, and include in a separate operating revenue account or sub-account the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under this Schedule 21.

6 Regulatory Filings

Nothing contained in the Tariff or any exhibit, appendix, schedule, attachment or Service Agreement related thereto shall be construed as affecting in any way the right of VTransco unilaterally to file with the Commission, or make application to the Commission for changes in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation with respect to this Schedule 21-VTransco under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder, or any other applicable statutes or regulations. Nothing contained in the Tariff or any exhibit, appendix, schedule, attachment or Service Agreement related hereto shall be construed as affecting in any way the ability of VTransco or any Transmission Customer receiving service under the Tariff to exercise any right under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

7 Force Majeure and Indemnification

7.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither VTransco nor the Transmission Customer will be considered in default as to any obligation under this Schedule 21 if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Schedule 21 is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Schedule 21.

7.2 Indemnification: The Transmission Customer shall at all times indemnify, defend, and save VTransco harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from VTransco's performance of its obligations under this Schedule 21 on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by VTransco.

8 Creditworthiness

VTransco's Creditworthiness Policy is provided in Attachment L of this Schedule 21-VTransco.

9 Dispute Resolution Procedures

9.1 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer and VTransco involving service under this Schedule 21 (excluding disputes arising from filings or rate changes or other changes to this Schedule 21-VTransco, or to any Service Agreement entered into under this Schedule 21-VTransco, which disputes shall be presented directly to the Commission forresolution) shall be referred to a designated senior representative of VTransco and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days (or such other period as the Parties may agree upon), such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below if the Parties in dispute agree to the use of such procedures.

9.2 External Arbitration Procedures: Any arbitration initiated under this Schedule 21-VTransco shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration Panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or ISO rules.

9.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Schedule 21 and any Service Agreement relevant to the dispute entered into under this Schedule 21 and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

9.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(A) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(B) one half the cost of the single arbitrator jointly chosen by the Parties.

9.5 Rights Under The Federal Power Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

10 Real Power Losses

Real Power Losses are associated with all transmission service. VTransco is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service provided over VTransco's Transmission System under this Schedule 21 as calculated by VTransco. The applicable Real Power Loss factor is 3.9 percent of the amount of energy to be transmitted.

11 Stranded Cost Recovery

VTransco may seek to recover stranded costs from the Transmission Customer pursuant to this Schedule 21 in accordance with the terms, conditions and procedures set forth in FERC Order Nos. 888 and 888-A. However, VTransco must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

II. LOCAL POINT-TO-POINT TRANSMISSION SERVICE

Preamble

VTransco will provide Firm and Non-Firm Local Point-To-Point Transmission Service over VTransco's Transmission System pursuant to the applicable terms and conditions of this Schedule 21. Local Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

12 Classification of Firm Transmission Service

The Transmission Customer will be billed for its Local Reserved Capacity under the terms of Schedule 7 of this Schedule 21-VTransco. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in this Schedule 21-VTransco. VTransco shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by VTransco) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery.

13. Classification of Non-Firm Point-To-Point Transmission Service

The Transmission Customer will be billed for Non-Firm Local Point-To-Point Transmission Service pursuant to Schedule 8 of this Schedule 21-VTransco. VTransco shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third Party Sales by VTransco) exceeds its non-firm local capacity reservation. Non-Firm Local Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application.

14 Response to a Completed Application

Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, VTransco shall make a determination of available transfer capability consistent with Attachment A of this Schedule 21-VTransco. VTransco shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application. Responses by VTransco must be made as soon as practicable to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

15 Limitations on Assignment or Transfer of Service

If an Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, VTransco will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of VTransco’s Transmission System or the generating or distribution facilities of other Vermont utilities.

16 Metering and Power Factor Correction at Receipt and Delivery Points(s)

16.1 Transmission Customer Obligations: Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under this Schedule 21 and to communicate the information to VTransco. Such equipment shall remain the property of the Transmission Customer.

16.2 Power Factor: Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as VTransco. The power factor requirements are specified in the Service Agreement where applicable.

17 Compensation for Transmission Service

Rates for Firm and Non-Firm Local Point-To-Point Transmission Service are provided in the Schedules appended to this Schedule 21-VTransco: Long-Term Firm and Shirt-Term Firm Local Point-To-Point Transmission Service (Schedule 7); and Non-Firm Local Point-To-Point Transmission Service (Schedule 8). VTransco shall use this Schedule 21 to make its Third-Party Sales. VTransco shall account for such use at the applicable rates described herein.

III. LOCAL NETWORK SERVICE

18 Secondary Service

The Local Network Customer may use VTransco's Transmission System to deliver energy to its Local Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Deliveries from resources other than Network Resources will have a higher priority than any Non Firm Local Point-To-Point Transmission Service under this Schedule 21-VTransco.

19 Network Resources

19.1 Transmission Arrangements for Network Resources Not Physically Interconnected With VTransco: The Local Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with VTransco's Transmission System. VTransco will undertake reasonable efforts to assist the Local Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

19.2 Limitation on Designation of Network Resources: The Local Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Local Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under this Schedule 21.

19.3 Use of Interface Capacity by the Network Customer: With the exception of any of interfaces with other transmission systems that are designated as constrained interfaces under VTransco's FERC Rate Schedule No. 1, as supplemented, there is no limitation upon a Local Network Customer's use of VTransco's Transmission System at any particular interface to integrate the Local Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, a Local Network Customer's use of VTransco's total interface capacity with other transmission systems may not exceed the Local Network Customer's Load.

19.4 Network Customer Owned Transmission Facilities: The Local Network Customer that owns existing transmission facilities that are integrated with VTransco's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Local Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of VTransco to serve its power and transmission customers. For facilities constructed by the Local Network Customer subsequent to the Service Commencement Date, the Local Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with VTransco. Calculation of the credit shall be addressed in either the Local Network Customer's Service Agreement or any other agreement between the Parties.

20 Local Network Load Not Physically Interconnected with VTransco

This section applies to both the initial designation and the subsequent addition of new Local Network Load not physically interconnected with VTransco. To the extent that the Local Network Customer desires to obtain transmission service for a load not connected to VTransco's Transmission System, the Local Network Customer shall have the option of (1) electing to include the entire load as Local Network Load for all purposes under this Schedule 21 and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Transmission Service under this Schedule 21. To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

21 Load Shedding and Curtailment

21.1 Procedures: Prior to the Service Commencement Date, VTransco and the Local Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Local Network Operating Agreement with the objective of responding to contingencies on VTransco's Transmission

System. The Parties will implement such programs during any period when the ISO or VTransco determines that a system contingency exists and such procedures are necessary to alleviate such contingency. If not otherwise notified by the ISO, VTransco will notify all affected Local Network Customers in a timely manner of any scheduled Curtailment.

21.2 Transmission Constraints: During any period when VTransco determines that a transmission constraint exists on VTransco's Transmission System, or that the ISO determines that a transmission constraint exists on the New England Transmission System, and such constraint may impair the reliability of VTransco's Transmission System, VTransco will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of VTransco's Transmission System. To the extent VTransco determines that the reliability of VTransco's Transmission System can be maintained by redispatching resources, VTransco will work with the ISO to initiate procedures pursuant to the Local Network Operating Agreement to redispatch all Network Resources and VTransco's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between VTransco's use of VTransco's Transmission System on behalf of its Native Load Customers and any Network Customer's use of VTransco's Transmission System to serve its designated Local Network Load.

21.3 Cost Responsibility for Relieving Transmission Constraints: Whenever VTransco implements least-cost redispatch procedures in response to a transmission constraint, VTransco and Local Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

21.4 Curtailments of Scheduled Deliveries: If a transmission constraint on VTransco's Transmission System or the New England Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and VTransco determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Local Network Operating Agreement.

21.5 Allocation of Curtailments: Working with the ISO, VTransco shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by VTransco and Local Network Customer in proportion to their respective Load Ratio Shares. VTransco shall not direct the Local Network Customer to Curtail schedules to an extent greater than VTransco would Curtail its own schedules under similar circumstances.

21.6 Load Shedding: To the extent that a system contingency exists on VTransco's Transmission System or the New England Transmission System and VTransco or the ISO determines that it is necessary for VTransco and the Local Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement.

21.7 System Reliability: Notwithstanding any other provisions of the Tariff, VTransco reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on VTransco's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on VTransco's Transmission System or on any other system(s) directly or indirectly interconnected with VTransco's Transmission System, VTransco, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. VTransco will give the Local Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to VTransco's use of VTransco's Transmission System on behalf of its Native Load Customers. VTransco shall specify the rate treatment and all related terms and conditions applicable in the event that the Local Network Customer fails to respond to established Load Shedding and Curtailment procedures.

22 Rates and Charges

The Local Network Customer shall pay VTransco for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, as otherwise described in this Schedule 21 and consistent with Commission policy, and also the following:

22.1 Monthly Demand Charge: The Local Network Customer shall pay a monthly Demand Charge, which shall be determined each month by multiplying its Load Ratio Share for that month times VTransco's Transmission Revenue Requirement for that month as specified in Attachment D of this Schedule 21-VTransco.

22.2 Determination of Network Customer's Monthly Local Network Load: VTransco's monthly Local Network Load is its hourly load (including its designated Local Network Load not physically interconnected) coincident with VTransco's Monthly Transmission System Peak.

22.3 Determination of VTransco's Monthly Transmission System Load: VTransco's monthly transmission system load is VTransco's Monthly Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Transmission Service customers pursuant to this Schedule 21-VTransco plus the Local Reserved Capacity of all Firm Local Point-To-Point Transmission Service customers.

22.4 Redispatch Charge: The Local Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Local Network Customer and VTransco. To the extent that VTransco incurs an obligation to the Local Network Customer for redispatch costs, such amounts shall be credited against the Local Network Customer's bill for the applicable month.

23 Operating Arrangements

23.1 Operation under The Network Operating Agreement: The Local Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement.

23.2 Network Operating Agreement: The terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of this Schedule 21 shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Local Network Customer within VTransco's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between VTransco and the Local Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside VTransco's Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of this Schedule 21, including scheduling protocols. The Local Network Operating Agreement will recognize that the Local Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the

Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with VTransco for Ancillary Service No. 1 , and with the ISO for Ancillary Service Nos. 2 through 7, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and NPCC requirements. VTransco shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Local Network Operating Agreement is included in Attachment C.

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided by VTransco making arrangements with the ISO to perform this service for VTransco's Transmission System. The Transmission Customer must purchase this service from VTransco. To the extent the ISO performs this service for VTransco; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to VTransco by the ISO. The Load Dispatching Revenue Requirement, as defined in this Schedule 1, will reflect VTransco's costs for its Load Dispatching. No subtransmission or distribution costs may be included in the Load Dispatching Revenue Requirement. The Load Dispatching Revenue Requirement will be a monthly calculation based on actual costs for the month subject to corrective adjustments after rendition. The calculation is set forth below:

The Load Dispatching Revenue Requirement shall equal the sum of Vermont Electric's (A) Load Dispatching Cost, plus or minus (B) Billing Adjustment.

A. <u>Load Dispatching Cost</u> shall equal VTransco's total load dispatching expense as recorded in FERC Account No. 561.

B. <u>Billing Adjustment</u> shall equal the difference in the actual cost of Load Dispatching for the two months.

SCHEDULE 2

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SCHEDULE 3

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SCHEDULE 7

Long-Term Firm and Short-Term Firm

Local Point-To-Point Transmission Service

The Transmission Customer shall compensate VTransco each month for Local Reserved Capacity at the sum of the applicable charges set forth below:

1) **Yearly delivery charge:** the same charge as for monthly delivery per MW of Local Reserved Capacity per month.

2) **Monthly delivery charge:** the revenue requirement for that month divided by the coincident peak demand for that month per MW of Local Reserved Capacity per month.

3) **Weekly delivery charge:** the charge for monthly delivery multiplied by twelve (12) and divided by fifty-two (52) per MW of Local Reserved Capacity per week.

4) **Daily delivery charge:** the charge for weekly delivery divided by five (5) per MW of Local Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in megawatts of Local Reserved Capacity in any day during such week.

5) **Discounts:** Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by VTransco must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate' use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, VTransco must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on VTransco's Transmission System.

6) **Resales:** The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

SCHEDULE 8

Non-Firm Local Point-To-Point Transmission Service

The Transmission Customer shall compensate VTransco for Non-Firm Local Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

1) **Monthly delivery charge:** the revenue requirement for that month divided by the coincident peak demand for that month per MW of Local Reserved Capacity per month.

2) **Weekly delivery charge:** the charge for monthly delivery multiplied by twelve (12) and divided by fifty-two (52) per MW of Local Reserved Capacity per week.

3) **Daily delivery charge:** the charge for weekly delivery divided by five (5) per MW of Local Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in megawatts of Reserved Capacity in any day during such week.

4) **Hourly delivery charge:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the charge for daily delivery divided by sixteen (16) per MWH. The total demand charge in any day, pursuant to a reservation for hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in megawatts of Local Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for hourly delivery, shall not exceed the rate specified in section (2) above times the highest amount in megawatts of Local Reserved Capacity in any hour during such week.

5) **Discounts:** Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by VTransco must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, VTransco must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on VTransco's Transmission System.

6) **Resales:** The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

ATTACHMENT A

Available Transfer Capability Methodology

<u>Introduction and Background</u>:

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

Pursuant to CFR § 37.6(b)[18] of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path.

Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.

VTransco does not currently have a Posted Paths based on the above definition. However to extent that VTransco does in the future have a Posted Path VTransco will calculate TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

Basic information on ATC and TTC may be found on VT Transco's website at:
http://www.vermonttransco.com/ATCTTC/Pages/default.aspx .

18 §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

Capacity Benefit Margin (CBM):

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of ATC calculation, As long as this market design is in place in New England, the CBM is set to zero (0). VTransco provides local transmission service over its non-PTF facilities that are connected to ISO-NE and the Vermont distribution utilities. VTransco does not reserve CBM for these paths, and the CBM is presently set to zero.

Existing Transmission Commitments, Firm (ETC_F):

The ETC_F are those confirmed Firm transmission reservation (PTP_F.) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF}):

The (ETC_{NF}**)** are those confirmed Non-Firm transmission reservations (PTP_{NF}) There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

Transmission Reliability Margin (TRM):

The Transmission Reliability Margin (TRM) is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. Since VTRANSCO provides transmission service over its non-PTF facilities that are connected only to the internal New England system, VTRANSCO does not reserve TRM for these paths, and the TRM is presently set to zero.

Calculation of ATC for VTransco's Local Facilities – General Description:

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology defines the required items to be identified when describing a transmission provider's ATC methodology.

As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of net energy transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF facilities that serve as a path for the VTransco Schedule 21-Vermont Transco Point-to-Point Transmission Customers, VTransco has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

Calculation of ATC_F in the Planning Horizon (PH):

For purposes of this Attachment A PH is any period before the Operating Horizon. Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service over Schedule 21-Vermont Transco that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-Vermont Transco transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

Calculation of ATC_F in the Schedule 21-Vermont Transco Operating Horizon (OH):

For purposes of this Attachment A OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. At that time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service over Schedule 21-Vermont Transco is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-Vermont Transco transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

Because Firm Schedule 21-Vermont Transco transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

<u>Calculation of ATC_{NF} in the PH:</u>

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-Vermont Transco are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-Vermont Transco transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

<u>Calculation of ATC_{NF} in the OH:</u>

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-Vermont Transco are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus $ETC_{F,}$ plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$)

<u>Negative ATC:</u>

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

For those non-PTF Vermont Transco facilities that are primarily radial paths that provide transmission service to directly interconnected generators it is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

Posting of ATC Related Information - ATC Values:

As described above, the ATC values for VTransco's non-PTF utilized for internal Point-to-Point transmission service are always positive, and are thus set at 9999. The ATC values for these internal posted paths are posted in accordance with NAESB standards on VTransco's provider page of the ISO-NE OASIS website Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

Updates To ATC:

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

Coordination of ATC Calculations:

Schedule 21-Vermont Transco non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

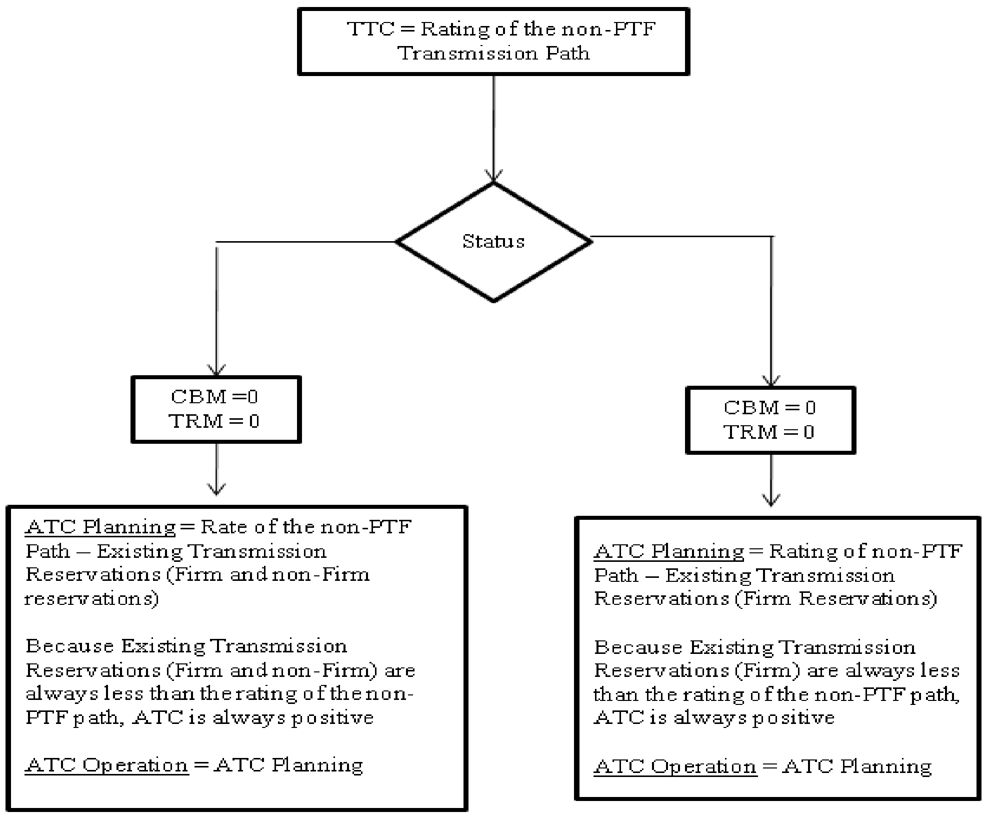
Mathematical Algorithms:

A link to the actual mathematical algorithm for the calculation of ATC for VTransco's non-PTF internal interfaces is located on VTransco's website at

http://www.vermonttransco.com/ATCTTC/Pages/default.aspx

Non-PTF Transmission Path ATC Process Flow Diagram

The process flow diagram illustrates the steps through which ATC is calculated both on an operating and planning horizon.



ATTACHMENT B

Methodology for Completing a System Impact Study

VTransco (or its designated agent) or the ISO may require System Impact Studies for the purpose of determining the feasibility of providing Long Term Firm Local Point-To-Point Transmission Service, integrating Network Resources or integrating Local Network Load for Transmission Customers (or Local Network Customers) under Schedule 21 of the Tariff. All System Impact Studies performed by VTransco will be completed using the same method employed by VTransco to provide firm transmission service to Purchasers under VTransco's FERC Rate Schedule No. 1, as supplemented. Specifically, System Impact Studies will be performed by applying NPCC Criteria and the "Reliability Standards of the New England Power Pool" while assuring that those loads fully dependent on VTransco's Transmission System that are receiving firm transmission service can be served reliably in accordance with VTransco's applicable reliability standards. The criteria, standards and guidelines referenced above are included as part of VTransco's annual FERC Form 715 filing.

ATTACHMENT C

Local Network Operating Agreement

This Local Network Operating Agreement is made this _____ day of ____________, 20__, by and between Vermont Transco LLC. ("VTransco"), and _____________________________ ("Local Network Customer").

WHEREAS, VTransco has determined that the Local Network Customer has made a valid request for Local Network Service in accordance with Schedule 21 of the Tariff; and

WHEREAS, the Local Network Customer has represented that it is an Eligible Customer qualified to take service under the Tariff,

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, the Parties hereto agree as follows:

1. General Terms and Conditions

This Local Network Operating Agreement is an implementing agreement for Local Network Service under VTransco's Tariff and is subject to the Tariff, as the Tariff is in effect at the time this Agreement is executed or as the Tariff thereafter may be amended. The Tariff as it currently exists or is hereafter amended is incorporated herein by reference. In the case of any conflict between this Local Network Operating Agreement and the Tariff, the Local Network Operating Agreement shall control.

VTransco agrees to provide transmission service to the Local Network Customer's equipment or facilities, subject to the Local Network Customer operating its facilities in accordance with applicable criteria, rules, standards, procedures, or guidelines of VTransco, its Affiliates, the ISO, and the Northeast Power Coordinating Council ("NPCC"), as they may be adopted and/or amended from time to time. In addition to those requirements, service to the Local Network Customer's equipment or facilities is provided subject to the following specified terms and conditions.

a. Electrical Supply: The electrical supply to the Point(s) of Delivery shall be in the form of three-phase sixty hertz alternating current at a voltage class determined by mutual agreement of the parties.

b. Coordination of Operations: VTransco shall consult with the Local Network Customer regarding timing of scheduled maintenance of VTransco's Transmission System. In the event of a curtailment of service or the implementation of load shedding procedures, VTransco shall use due diligence to resume delivery of electric power as quickly as possible.

2. Reporting Obligations

a. The Local Network Customer shall be responsible for providing all information required by the ISO and NPCC and by VTransco's dispatching functions. The Local Network Customer shall respond promptly and completely to VTransco's requests for information, including but not limited to data necessary for operations, maintenance, regulatory requirements and analysis. In particular, that information may include:

i. For Local Network Loads: 10-year annual peak load forecast; load power factor performance; load shedding capability; under frequency load shedding capability; disturbance/interruption reports; protection system setting conformance; system testing and maintenance conformance; planned changes to protection systems; metering testing and maintenance conformance; planned changes in transformation capability; conformance to harmonic and voltage fluctuation limits; dead station tripping conformance; and voltage reduction capability conformance.

ii. For Network Resources and interconnected generators: 10 year forecast of generation capacity retirements and additions; generator reactive capability verification; generator under frequency relaying conformance; protection system testing and maintenance conformance; planned changes to protection system; and planned changes to generation parameters.

b. The Local Network Customer shall supply accurate and reliable information to VTransco regarding metered values for MW, MVAR, volt, amp, frequency, breaker status indication, and all other information deemed necessary by VTransco for safe and reliable operation. Information shall be gathered for electronic communication using one or more of the following: supervisory control and data acquisition ("SCADA"), remote terminal unit ("RTU") equipment, and remote access pulse recorders ("RAPR"). All equipment used for metering, SCADA, RTU, RAPR, and communications must be approved by VTransco.

3. Operational Obligations

The Local Network Customer shall request permission from VTransco prior to opening and/or closing circuit breakers in accordance with applicable switching and operating procedures. The Local Network Customer shall carry out all switching orders from VTransco, VTransco’s Designated Agent, or the ISO in a timely manner.

a. The Local Network Customer shall balance the load at the Point(s) of Delivery such that the differences in the individual phase currents are acceptable to VTransco.

b. The Local Network Customer's equipment shall conform with harmonic distortion and voltage fluctuation standards of VTransco.

c. The Local Network Customer's equipment must comply with all environmental requirements to the extent they impact the operation of VTransco’s system.

d. The Local Network Customer shall operate all of its equipment and facilities connected to VTransco’s system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, and requirements of VTransco, the ISO, NPCC, the National Electric Safety Code and the National Electric Code.

e. The Local Network Customer is responsible for supplying voltage regulation equipment on its subtransmission and distribution facilities.

4. Notice of Transmission Service Interruptions

If at any time, in the reasonable exercise of VTransco’s judgment, operation of the Local Network Customer's equipment adversely affects the quality of service or interferes with the safe and reliable operation of the system, VTransco may discontinue transmission service until the condition has been corrected. Unless VTransco perceives that an emergency exists or the risk of an emergency is imminent, VTransco shall give the Local Network Customer reasonable notice of its intention to discontinue transmission service and, where practical, allow suitable time for the Local Network Customer to remove the interfering condition. VTransco’s judgment with regard to the discontinuance of service under this paragraph shall be made in accordance with Good Utility Practice. In the case of such discontinuance, VTransco shall immediately confer with the Local Network Customer regarding the conditions causing such discontinuance and its recommendation concerning timely correction thereof.

5. Access and Control

Properly accredited representatives of VTransco shall at all reasonable times have access to the Local Network Customer's facilities to make reasonable inspections and obtain information required in connection with Schedule 21 of the Tariff. Such representatives shall make themselves known to the Local Network Customer's personnel, state the object of their visit, and conduct themselves in a manner that shall not interfere with the construction or operation of the Local Network Customer's facilities. VTransco shall have control such that it may open or close the circuit breaker or disconnect and place safety grounds at the Point(s) of Delivery, or at the station, if the Point(s) of Delivery is remote from the station.

6. Point(s) of Delivery

Local Network Service shall be provided by VTransco to the Point(s) of Delivery as specified by the Local Network Customer in accordance with the Tariff.

7. Maintenance of Equipment

a. Unless otherwise agreed, VTransco shall own all metering equipment.

b. The Local Network Customer shall maintain all of its equipment and facilities connected to VTransco's system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations and requirements of VTransco, the ISO and NPCC.

c. VTransco may request that the Local Network Customer test, calibrate, verify or validate the data link, metering, data acquisition, transmission, protective, or other equipment or software owned by the Local Network Customer, consistent with the Local Network Customer's routine obligation to maintain its equipment and facilities or for the purposes of investigating potential problems on the Local Network Customer's facilities. The Local Network Customer shall be responsible for the cost to test, calibrate, verify or validate the equipment or software.

d. The Transmissions Provider shall have the right to inspect the tests, calibrations, verifications and validations of the Local Network Customer's data link, metering, data acquisition, transmission, protective, or other equipment or other software connected to VTransco's system.

e. The Local Network Customer, at VTransco's request, shall supply VTransco with a copy of the installation, test, and calibration records of the data link, metering, data acquisition, transmission, protective or other equipment or software owned by the Local Network Customer and connected to VTransco's system.

f. VTransco shall have the right, at the Local Network Customer's expense, to monitor the factory acceptance test, the field acceptance test, and the installation of any metering, data acquisition, transmission, protective or other equipment or software owned by the Local Network Customer and connected to VTransco's system.

8. <u>Emergency System Operations</u>

a. The Local Network Customer's equipment and facilities, etc. shall be subject to all applicable emergency operation standards required of and by VTransco to operate in an interconnected transmission network.

b. VTransco reserves the right to take whatever actions or inactions it deems necessary during emergency operating conditions to: (i) preserve the integrity of VTransco's Transmission System, (ii) limit or prevent damage, (iii) expedite restoration of service, or (iv) preserve public safety.

9. <u>Cost Responsibility</u>

The Local Network Customer shall be responsible for all costs incurred by VTransco relative to the Local Network Customer's facilities. Appropriate costs may be allocated to more than one Local Network Customer, in a manner within the reasonable discretion of VTransco.

10. <u>Additional Operational Obligations of Local Network Customer</u>

a. <u>Voltage or Reactive Control Requirements:</u>

i. Unless directed otherwise by VTransco, the Local Network Customer shall ensure that all generating facilities designated as Network Resources are operated with an automatic voltage regulator(s). The Local Network Customer shall ensure that the voltage regulator(s) control voltage at the Point(s) of Receipt consistent with the range of voltage scheduled by VTransco, VTransco's agent or the ISO.

ii. At the discretion of VTransco, VTransco's Designated Agent or the ISO, the Local Network

Customer may be directed to deactivate the automatic voltage regulator and to supply reactive power in accordance with a schedule which shall be provided by VTransco , VTransco’s Designated Agent or the ISO, and in such event the Local Network Customer shall act in accordance with such direction.

iii. If the Local Network Customer does not have sufficient installed capacity in generating facilities designated as Network Resources to enable the Local Network Customer to operate such facilities consistent with recommendations of VTransco, or if Network Resources fail to operate at such capacity, VTransco or VTransco’s Designated Agent may install, at the Local Network Customer's expense, reactive compensation equipment necessary to ensure the proper voltage or reactive supply at the Point(s) of Receipt.

b. Station Service: When generating facilities designated as Network Resources are producing electricity, the Local Network Customer shall supply its own station service power. If and when the Local Network Customer's generation facility is not producing electricity, the Local Network Customer shall obtain station service capacity and energy from the franchise utility providing service or other source.

c. Protection Requirements: Protection requirements are as defined elsewhere in this Tariff and applicable NPCC documents as may be adopted or amended from time to time.

d. Operational Obligations:

i. The ISO may require that generation facilities designated as Network Resources be equipped for Automatic Generation Control ("AGC"). The Local Network Customer shall be responsible for all costs associated with installing and maintaining an AGC system on applicable Network Resources.

ii. VTransco retains the right to require reduced generation at times when system conditions present transmission restrictions or otherwise adversely affect VTransco’s other customers. VTransco shall use due diligence to resolve the problems to allow the generator to return to the operating level prior to VTransco’s notice to reduce generation.

iii. All operations (including start-up, shutdown and determination of hourly generation) shall be coordinated with the ISO, VTransco or VTransco’s Designated Agent.

e. Coordination of Operations:

i. The Local Network Customer shall furnish VTransco with generator annual maintenance schedules for all Network Resources and shall advise VTransco if a Network Resource is capable of participation in system restoration and/or if it has black start capability.

ii. VTransco reserves the right to specify turbine and/or generator control (e.g., droop) settings as determined by the System Impact or Facilities Study or subsequent studies. The Local Network Customer agrees to comply with such specifications by VTransco at the Local Network Customer's expense.

iii. If the generator is not dispatchable by the ISO, the Local Network Customer shall notify VTransco at least 48 hours in advance of its intent to take its resource temporarily off-line and its intent to resume generation. In circumstances such as forced outages, the Local Network Customer shall notify VTransco as promptly as possible of the Network Resource's temporary interruption of generation and/or transmission.

f. <u>Power Factor Requirement:</u> The Local Network Customer agrees to maintain an overall Load Power Factor and reactive power supply within predefined sub-areas as measured at the Point(s) of Delivery within ranges specified by VTransco or ISO criteria, rules and standards which identify the power factor levels that must be maintained throughout the applicable sub-area for each anticipated level of total ISO load. The Local Network Customer agrees to maintain Load Power Factor and reactive power requirements within the range specified by VTransco or the ISO, as appropriate for the sub-area based on total ISO load during that hour. The ISO may revise the power factor limits required from time to time. If the Local Network Customer lacks the capability to maintain the Load Power Factor within the ranges specified, VTransco may install, at the Local Network Customer's expense, reactive compensation equipment necessary to ensure proper load power factor at the Point(s) of Delivery.

g. <u>Protection Requirement:</u> The Local Network Customer's relay and protection systems must comply with all applicable VTransco, ISO and NPCC criteria, rules, procedures, guidelines, standards or requirements as may be adopted or amended from time to time.

h. <u>Operational Obligation:</u> The Local Network Customer shall be responsible for operating and maintaining security of its electric system in a manner that avoids adverse impact to VTransco’s or other's interconnected systems and complies with all applicable VTransco , ISO and NPCC operating criteria, rules, procedures, guidelines and interconnection standards as may be amended or adopted from time to time. These actions include, but are not limited to: Voltage Reduction Load Shedding; Under Frequency Load Shedding, Block Load Shedding; Dead Station Tripping; Transferring Load Between Point(s) of Delivery; Implementing Voluntary Load

Reductions Including Interruptible Customers; Starting Stand-by Generation; Permitting VTransco Controlled Service Restoration Following Supply Delivery Contingencies on VTransco Facilities.

11. Failure to perform

If the Local Network Customer fails to carry out its obligations under this Agreement, the matter shall be subject to the dispute resolution procedures of the Tariff.

The Parties whose authorizing signatures appear below warrant that they shall abide by the foregoing terms and conditions.

VERMONT TRANSCO LLC

By:
Title:
Dated:______________________________

(Name of Local Network Customer)

By:
Title:
Dated:___________________________
____

ATTACHMENT D

Transmission Revenue Requirement

For Local Network Integration Transmission Service

VTransco owns and operates transmission facilities which are used to provide transmission service only. VTransco does not own or operate any generation or distribution facilities. VTransco only incurs transmission-related costs. Accordingly, there is no need to allocate a transmission-related portion of what otherwise would be considered a general expense. For the same reason, there is no need to refer to specific costs in the formula as "transmission-related."

The Transmission Revenue Requirement calculated below reflects all costs that VTransco incurs in connection with VTransco's Transmission System. Generation and distribution costs are not included in the Transmission Revenue Requirement. The Transmission Revenue Requirement for a particular month will be based on the most recent monthly data available at that time (which typically will be data from two months earlier). To the extent the charges for a particular month result in an over-recovery or under-recovery of VTransco's actual costs, an adjustment will be made to VTransco's Transmission Revenue Requirement as soon as possible (typically two months later when the specific data regarding the over- or under-recovery becomes available).

The calculation is set forth below:

The Transmission Revenue Requirement shall equal the sum of VTransco's: (A) Return and Income Taxes, (B) Depreciation Expense, (C) Amortization of Loss on Reacquired Debt, (D) Municipal Tax Expense, (E) Payroll Tax Expense, (F) Operation and Maintenance Expense, (G) Administrative and General Expense, minus (H) Support Revenue, plus (I) Support Expense, minus (J) Short-Term Transmission Service and (K) Rents received from Electric property and (L) Revenue received from the ISO, plus or minus (M) Billing Adjustment.

Definitions

A. Return and Income Taxes shall equal the sum of VTransco's Rate of Return, Cost of Capital, and Income Taxes.

1. Rate of Return shall equal on an annual basis: 11.14 percent of the par value of VTransco's outstanding Class A membership units, all as shown by VTransco's books as of the beginning of such month. The above rates shall not change from month to month, but may be modified in a proceeding initiated pursuant to the Federal Power Act.

2. Cost of Capital shall equal all fixed charges, including interest and amortization of debt discount and expense and premium on debt as recorded in FERC Account Nos. 419,427,428,431,432.

3. Income Taxes shall equal VTransco's income taxes including taxes on or measured by income as recorded in FERC Account Nos. 409-411.

B. Depreciation Expense shall equal VTransco's Depreciation Expense for Transmission Plant and General Plant as recorded in FERC Account Nos. 403 and 404.

C. Amortization of Loss on Reacquired Debt shall equal VTransco's Amortization of the balance on Loss on Reacquired Debt as recorded in FERC Account No. 428.1.

D. Municipal Tax Expense shall equal VTransco's total municipal tax expense as recorded in FERC Account No. 408.1.

E. Payroll Tax Expense shall equal VTransco's total electric payroll tax expense as recorded in FERC Account No. 408.1.

F. Operation and Maintenance Expense shall equal VTransco's expenses as recorded in FERC Account Nos. 560, 562-564 and 566-573 and shall exclude any Transmission Support Expense recorded in FERC Account No. 567.

G. Administrative and General Expense shall equal VTransco's expenses as recorded in FERC Account Nos. 920-935.

H. Transmission Support Revenues shall equal VTransco's revenue received for Transmission Support.

I. Transmission Support Expenses shall equal VTransco's expenses as recorded in FERC Account No. 567.

J. Short-Term Transmission Service shall equal any revenues received from transmission customers as payment for short-term point-to-point transmission service taken pursuant to Schedule 7 of this Schedule 21-VTransco.

K. Rents received from Electric property shall equal VTransco's rents received for the use by others of land, buildings, and other property devoted to electric operations as recorded in FERC Account No. 454.

L. Revenue Received from the ISO shall equal revenue received under the terms of the Tariff minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission.

M. Billing Adjustment shall equal the difference in the actual cost of transmission for the two month previous minus the Revenue Received for two months previous. In the event that the FERC accounts listed above are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts

Appendix A

PTF and non PTF Depreciation and General Plant Amortization Rates

Account	Description	Depreciation Rates (%) Effective July 1, 2017
<u>Transmission Plant</u>		
352.00	Structures and Improvements	2.35
353.00	Station Equipment	2.57
354.00	Towers and Fixtures	3.77
355.00	Poles and Fixtures	2.48
356.00	Overhead Conductors and Devices	1.71
357.00	Underground Conduit	2.51
357.00	Underground Conductors and Devices	2.67
359.00	Roads and Trails	1.27
<u>General Plant</u>		
390.00	Structures and Improvements	2.84
392.00	Transportation Equipment	5.79
397.00	Communication Equipment	4.69
<u>General Plant Amortization</u>		
391.00	Office Furniture and Equip (Pre 2013 Assets)	13.19
391.00	Office Furniture and Equip (Post 2012 Assets)	12.50
391.10	Computer Equipment (Pre 2013 Assets)	17.08
391.10	Computer Equipment (Post 2012 Assets)	20.00
391.20	Software (Pre 2013 Assets)	4.06
391.20	Software (2013-2015 Assets)	6.42
391.20	Software (Post 2015 Assets)	6.67
393.00	Stores Equipment (Pre 2013 Assets)	3.07
393.00	Stores Esquipment (Post 2012 Assets)	2.86
394.00	Tools, Shops and Garage Equipment (Pre 2013 Assets)	2.48

394.00	Tools, Shops and Garage Equipment (Post 2012 Assets)	2.78
395.00	Laboratory Equipment (Pre 2013 Assets)	4.00
395.00	Laborabory Equipment (Post 2012 Assets)	4.00
398.00	Miscellaneous Equipment (Pre 2013)	30.11
398.00	Miscellaneous Equipment (Post 2012)	9.09

ATTACHMENT L

Creditworthiness Procedures

I. Overview

This provision is applicable to any Transmission Customer taking transmission or interconnection service (referred to as "Service" or "Services") under ISO New England Inc., ISO New England Inc. Transmission, Markets and Services Tariff, Section II—Open Access Transmission Tariff Schedule 21-VTransco (the "Tariff"). The creditworthiness of each Transmission Customer must be established before receiving Service from VTransco. A credit review shall be conducted for each Transmission Customer not less than annually or upon reasonable request by the Transmission Customer. VTransco shall make this credit review in accordance with procedures based on specific quantitative and qualitative criteria to determine the level of secured and unsecured credit required from the Transmission Customer. A summary of VTransco's Creditworthiness Requirements are described in this Attachment L, and posted on its website at http://www.velco.com/Files/about%20velco/Creditworthiness.pdf.

Upon receipt of a customer's information, VTransco will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a customer under this Policy, VTransco will forward a written evaluation if the customer is required to provide Financial Assurance.

II. Financial Information:

A) Transmission Customers requesting Service may be required to submit, if available, the following information:

1) All current credit rating reports from commercially accepted credit rating agencies including Standard and Poor's, Moody's Investors Service, and Fitch Ratings, and

2) Audited financial statements by a registered independent auditor for the two most recent years, or the period of its existence, if shorter than two years.

III. Quantitative and Qualitative Standards for Creditworthiness Determination:

A) Transmission Customers, rated and un-rated, will be required to meet specific quantitative creditworthiness requirements, as detailed below:

1) To qualify for unsecured credit, the Transmission Customer must meet at least one of the following criteria:

(i) the Transmission Customer must not be in default of any payment obligation under the Tariff; and

(ii) if rated, the Transmission Customer must meet one of the following criteria:

(a) the Transmission Customer has been in business at least one year and has a senior secured credit rating of at least Baa1 (Moody's) or BBB+ (Standard & Poors); or

(b) The Transmission Customer's parent company meets the criteria set out in (a) above, and the parent company provides a written guarantee that the parent company will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of Service.

(iii) if unrated or if rated below the BBB+/Baa1, as stated in (ii), the Transmission Customer must meet all of the following for the last 4 quarters, or the last 2 years if quarterly information is not available:

(a) A Current Ratio of at least 2.0 times (current assets divided by all current liabilities);

(b) A Total Capitalization Ratio of less than 55% debt, defined as total debt (including all capitalized leases and all short-term borrowings) divided by the sum of total shareholders' equity plus total debt;

(c) EBITDA-to-Fixed Charge Ratio of at least 3.0 times, defined as earnings before interest, taxes, depreciation and amortization divided by fixed charges (interest on debt as defined in Total Capitalization Ratio above plus preferred dividends on any outstanding preferred equity); and

(d) Unqualified audit opinions in audited financial statements provided; or

(e) The Transmission Customer's parent company meets the criteria set out in (a) through (d) above, and the parent company provides a written guarantee that the parent company will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of Service.

B) Qualitative Standards for Creditworthiness Determination:

In conjunction with the quantitative standards above, VTransco will consider qualitative standards when determining creditworthiness, such as:

1) Years in business: a company in business fewer than five years will be considered a greater risk.

2) Management's experience in the industry: a management team with an average of less than five year's experience will be considered a greater risk.

3) Market risk: consideration of pricing exposure, credit exposures, and operational exposures.

4) Litigation Risk: a pending legal action with potential monetary damages approaching 3% of gross revenues will be considered as significantly increasing company risk.

5) Regulatory Environment (State and Local): a company subject to significant exposure to regulatory decisions, such as key planning decisions, shall be considered as having increased risk.

6) Prior payment history with other Transmission Providers or other vendors: a company with an excellent payment history of greater than or equal to five years shall be considered a lesser risk.

IV. Financial Assurance:

A) If the Transmission Customer does not meet the Creditworthiness Requirements, then VT Transco may require the Transmission Customer to provide additional Financial Assurance by complying with one of the following:

1) for Service for one month or less, the Transmission Customer shall pay to VTransco or place in an escrow account that is accessible to VTransco the total charge for Service by the later of five business days prior to the commencement of Service or the time when it makes the request for Service; or

2) for Service of greater than one month, the Transmission Customer shall pay to VTransco or place in an escrow account that is accessible to VTransco the charge for each month's Service not less than five business days prior to the beginning of the month. For Network Integration Transmission Service Customers, the advance payment for each month shall be based on a reasonable estimate by VTransco of the charge for that month.

3) not less than five days prior to the commencement of Service, the Transmission Customer shall provide an unconditional and irrevocable Letter of Credit (as defined below) from a financial institution reasonably acceptable to VTransco or an alternative form of security proposed by the Transmission Customer and acceptable to VTransco and consistent with commercial practices established by the Uniform Commercial Code that is equal to the lesser of the total charge for Service or the charge for 90 days of service.

(i) “Letter of Credit” means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank provided that such Transmission Customer is not an affiliate of such bank, and provided that such bank has an issuer and/or corporate credit rating of at least A2 from Moody’s or A from Standard and Poor’s or Fitch Ratings. In the event of different ratings from the rating agencies, the lowest rating shall apply.

(ii) Costs of a Letter of Credit shall be borne by the customer.

(iii) If the credit rating of the bank issuing the Letter of Credit falls below the specified rating, the customer shall notify VTransco in writing within five business days of such event and shall have two business days following written notice to provide other appropriate Financial Assurance.

V. Credit Levels:

A) Transmission Customers meeting the Creditworthiness Requirements in Section III will be extended unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges.

B) Transmission Customers not meeting the Creditworthiness Requirements above in Sections III and IV may not receive unsecured credit from VTransco.

VI. Ongoing Financial Review:

Each Transmission Customer is required to submit to VTransco annually or when issued, as applicable:

A) Current rating agency report;

B) Audited financial statements from a registered independent auditor; and

C) 10-Ks and 8-Ks, promptly on their issuance.

VII. Contesting Creditworthiness Determination:

The Transmission Customer may contest VTransco's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. VTransco will review and respond to the request within 20 calendar days.

VIII. Procedures for Changes in Credit Levels and Collateral Requirements:

VTransco shall issue reasonable advance notice of changes to the credit levels and/or collateral requirements. A Transmission Customer may request that VTransco provide an explanation of the reasons for the change by contacting VTransco at:

Chief Financial Officer
366 Pinnacle Ridge Rd.
Rutland, VT 05701

The specific procedures for changes in credit levels and collateral requirements are as follows:

A) General Notification process

1) VTransco shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.
2) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Policy.

3) VTransco shall consult with interested stakeholders upon request.

4) Following Commission acceptance of such filing and upon the effective date, VTransco shall revise its Attachment L Creditworthiness Policy and an updated version of Schedule 21-VTransco shall be posted the ISO-NE website.

B) Transmission Customer Responsibility

When there is a change in requirements, it is the responsibility of the Customer to forward updated financial information to VTransco and indicate whether the change affects the customer's ability to meet the requirements of the Creditworthiness Policy. In such cases where the customer's status has changed, the Customer must take the steps necessary to comply with the revised requirements of the Creditworthiness Policy by the effective date of the change.

C) Notification for Active Customers

1) "Active Customers" are defined as any current Transmission Customer that has reserved Service within the last 3 months.

2) All Active Customers will be notified via either e-mail or U.S. mail that the above posting has been made and must follow the steps outlined in the procedure.

IX. Posting Requirements

A) Changes in Customer's Financial Condition

Each customer must inform VTransco, in writing, within five (5) business days of any material change in its financial condition or the financial condition of a parent providing a guarantee. A material change in financial condition may include, but is not limited to, the following:

1) Change in ownership by way of a merger, acquisition, or substantial sale of assets;

2) A downgrade of long- or short-term debt rating by a major rating agency;

3) Being placed on a credit watch with negative implications by a major rating agency;

4) A bankruptcy filing;

5) A declaration of or acknowledgement of insolvency;

6) A report of a significant quarterly loss or decline in earnings;

7) The resignation of key officer(s);

8) The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results

B) Change in Creditworthiness Status:

A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in item IV if one or more of the following conditions apply:

1) The customer no longer meets the applicable criteria for Creditworthiness in item III;

2) The customer exceeds the amount of unsecured credit extended by VTransco, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or

3) The customer has missed two or more payments for any of the Services offered by VTransco in the last 12 months.

X. Suspension of Service:

VTransco may suspend service under this Schedule 21-VTransco to a Transmission Customer under the following circumstances;

A) If a Transmission Customer that qualifies for service as a result of providing a Letter of Credit or alternative form of security does not pay its bill within 20 days of receipt of the invoice as required by this Schedule 21-VTransco, and it has not complied with the billing dispute provisions of this Schedule 21-VTransco, VTransco may suspend service 30 days after notice to the Transmission Customer and the Commission that service will be suspended unless the Transmission Customer makes payment.

B) If a Transmission Customer that qualifies for service as a result of committing to prepay for service to or place the payment in an escrow account pursuant to Section IV A 1 or Section IV A 2 fails to prepay for service or place the amount in escrow as provided in such section, VTransco may suspend service immediately upon notice to the Transmission Customer and the Commission.

C) If a Transmission Customer to whom the provisions of Sections III through XI applies fails to meet any applicable requirements, VTransco may suspend service immediately upon notice to the Transmission Customer and the Commission. The suspension of service shall continue only for as long as the circumstances that entitle VTransco to suspend service continue. A Transmission Customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

ATTACHMENT F
ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF, including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of PTOs that are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF pursuant to Section II.49 of the Tariff, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO's costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12:

I. The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expense, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT and (O) Transmission Rents Received from Electric Property.

The details for implementation of Attachment F, as well as the definitions of the terms used in the Attachment F formula, shall be established in accordance with the Attachment F Implementation Rule contained in this OATT.

ATTACHMENT F
IMPLEMENTATION RULE

This rule sets forth details with respect to the determination each year of the Transmission Revenue Requirements for each PTO. Such Transmission Revenue Requirements shall reflect the PTO's costs for Pool Transmission Facilities ("PTF") and the Highgate Transmission Facilities ("HTF"), including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of PTOs which are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO's costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12. The HTF Transmission Revenue Requirements shall be subject to the limitations of inclusion of such costs as set forth in Appendix B to this Attachment. The owners of the HTF, or their designated agent, will submit the annual HTF Transmission Revenue Requirements calculation based on the previous calendar year's cost data from their FERC Form 1 or equivalent information from their official books and records, as appropriate.

The Post-96 Transmission Revenue Requirement for each PTO that is based on data for calendar year 2004 or later shall include an Incremental Return and Associated Income Taxes on the PTO's PTF transmission plant investments included in the Regional System Plan and placed in-service on or after January 1,2004 (such investments referred to herein as "Post-2003 PTF Investment"). The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment shall incorporate an incentive ROE adder of 100 basis points for plant investment placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157, et al. for any projects included in the RSP, and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments (however; the 125 basis point ROE incentive adder granted to NEEWS under Order No. 679 in Docket No. ER08-1548 and the 50 basis point ROE incentive adder for RTO participation shall not apply to the costs related to the Central

Connecticut Reliability Project, consistent with FERC's order) and for MPRP CWIP and NEEWS CWIP. The data used in determining each PTO's Incremental Return and Associated Taxes for Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in the PTO's accounting records.

The Post-1996 Pool PTF Rate, as calculated pursuant to Schedule 9, shall include for each PTO a Forecasted Transmission Revenue Requirement calculated in accordance with Appendix C to this Attachment F Implementation Rule. Additionally, the Pre-1997 and Post-1996 Pool PTF Rates shall include an Annual True-up calculated in accordance with Appendix C to this Attachment F Implementation Rule.

The PTOs shall make an annual informational filing on or before July 31 of each year showing the Pool PTF Rate in effect for the period beginning June 1 of that year through May 31 of the subsequent year.Further, the informational filing with respect to the determination of the Pool PTF Rate will include a breakdown by PTO of the amount of the change in PTF and HTF investment during the prior year and the PTF and HTF retirements or additions causing such change to beginning and end-of-year PTF balances and HTF balances (although beginning-of-year PTF balances and HTF balances are not used in the formula itself), and any additions to PTF and HTF, retirements of PTF and HTF, and reclassifications of PTF and HTF during the year for each PTO. If there are any corrections made to the information reflected in the informational filing after it has been submitted, the PTOs will file corrections to the informational filing. At least forty-five days before the informational filing is made with the Commission, the PTOs shall make available to Transmission Customers and any other interested parties a draft of the proposed filing for review and comment prior to the filing by posting such draft on the ISO website. The filing of the information filing does not re-open the formula rate set forth below for review, but rather is contestable only with respect to the accuracy of the information contained in the informational filing.

The ISO shall have the discretion to conduct audits of such charges, with advisory Stakeholder input on the scope of audit, including on any agreed-upon procedures to be used by the auditor. In this provision, the term "agreed-upon procedures" shall have the meaning afforded to it by the American Institute of Certified Public Accountants.

I. DEFINITIONS

Capitalized terms not otherwise defined in the Tariff and as used in this rule have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct wages and salaries including those of affiliated Companies to the PTO's total direct wages and salaries including those of the Affiliates' Companies and excluding administrative and general wages and salaries.

2. PTF/HTF Transmission Plant Allocation Factor shall equal the ratio of PTF/HTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF (Phase I/II HVDC-TF Leases).

3. Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, and Transmission Related Intangible and General Plant to Total Plant in service excluding Phase I/II HVDC-TF Leases.

B. TERMS

Administrative and General Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

Amortization of Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the PTO's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal the PTO's transmission expenses as recorded in FERC Account No. 403.

General Plant shall equal the PTO's gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation and Amortization Expense shall equal the PTO's general expenses as recorded in FERC Account No. 403 and NSTAR Electric's FERC Account No. 404 for items subject to amortization.

General Plant Amortization Reserve shall equal NSTAR Electric's general reserve balance as recorded in FERC Account No. 111.

HTF Transmission Plant shall equal the PTO's balance of investment in the Highgate Transmission Facilities as recorded in FERC Account Nos. 350-359.

Intangible Plant shall equal NSTAR Electric's gross plant balance as recorded in FERC Account No. 303. The only allowable Intangible Plant for inclusion are software, patent or rights costs.

Intangible Plant Amortization Expense shall equal NSTAR Electric's amortization expenses as recorded in FERC Account Nos. 404-405. The only allowable Intangible Plant Amortization Expense for inclusion is the amortization of software, patent or rights costs.

Intangible Plant Amortization Reserve shall equal NSTAR Electric's amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion is that related to the amortization of software, patent or rights costs.

Maine Power Reliability Program Construction Work In Progress ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107 for costs determined to be Pool- Supported PTF in accordance with Schedule 12 of this OATT.

Merger-Related Costs shall equal NSTAR Electric Company's ("NSTAR Electric"), CL&P's, Public Service Company of New Hampshire's ("PSNH") and WMECO's amortized merger-related costs as authorized by FERC or by state regulatory order.

New England East-West Solution Construction Work in Progress ("NEEWS CWIP") shall equal the NEEWS CWIP balances of The Connecticut Light and Power Company ("CL&P") and Western Massachusetts Electric Company ("WMECO") and New England Power Company

("NEP") as recorded in FERC Account No. 107 for costs determined to be Pool-Supported PTF in accordance with Schedule 12 of this OATT.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the PTO's FAS 106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the PTO's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the PTO's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in the PTO's FERC Account Nos. 408.1.

Phase I/II HVDC-TF Leases shall equal the PTO's balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

Plant Held for Future Use shall equal the PTO's balance in FERC Account No.105.

Prepayments shall equal the PTO's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the PTO's expenses as recorded in FERC Account No. 924.

PTF Transmission Plant shall equal the PTO's transmission plant as defined in the Section II.49 of the OATT and determined in accordance with Appendix A of this Rule, which is entitled "Rules for Determining Investment To be Included in PTF."

PTF/HTF Transmission Plant Investment shall equal the PTO's (a) PTF Transmission Plant plus (b) HTF Transmission Plant.

Total Accumulated Deferred Income Taxes shall equal the net of the PTO's deferred tax balance as recorded in FERC Account Nos. 281-283 and the PTO's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal the PTO's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal the PTO's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal the PTO's transmission reserve balance as recorded in FERC Account 108.

Transmission Merger-Related Costs shall equal NSTAR Electric's, CL&P's, PSNH's and WMECO's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564 and 566-573, and shall exclude all Phase I/II HVDC-TF expenses booked to accounts 560 through 573 and expenses already included in Transmission Support Expense, as described in Section K which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal the PTO's Gross Plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal the PTO's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP), (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related

Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT, (O) Transmission Rents Received from Electric Property and (P) Transmission Revenues from MEPCO Grandfathered Transmission Service Agreements. The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment for each PTO shall be calculated using the investment base components specifically identified in Section A. 1 of the formula below.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, Transmission Investment Base will only include Sections II.A. 1 .(a), (d), (e), (k), and (1) in the manner indicated.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of(a) PTF/HTF Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation and Amortization Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Transmission Related Loss on Re.acquired Debt, plus (g) Other Regulatory Assets/Liabilities, plus (h) Transmission Prepayments, plus (i) Transmission Materials and Supplies, plus (j) Transmission Related Cash Working Capital, plus (k) MPRP CWIP, plus (l) NEEWS CWIP.

(a) PTF Transmission Plant will equal the balance of the PTO's PTF Investment in (a) Transmission Plant plus (b) HTF Transmission Plant. This value excludes (i) the PTO's Phase I/II HVDC-TF Leases, (ii) the portion of any facilities, the cost of which is directly assigned under Schedule 11 to the OATT, to the Transmission Customer or a Generator Owner or Interconnection Requester, (iii) the Pre-1997 PTF gross plant investment associated with leased facilities occupied by the Phase II section of the Phase I/II HVDC-TF. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Post2003 PTF Transmission Plant shall be separately identified.

(b) Transmission Related Intangible and General Plant shall equal the sum of the PTO's balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor and the PTF/HTF Transmission Plant Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the PTO's balance of Transmission-related Plant Held for Future Use multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(d) Transmission Related Depreciation and Amortization Reserve shall equal the PTO's balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve. Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve shall equal the product of the sum of Intangible Plant Amortization Reserve, General Plant Depreciation Reserve and General Plant Amortization Reserve, and the Transmission Wages and Salaries Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Depreciation Reserve associated with Post-2003 PTF Investment shall equal the PTO's balance of Total Transmission Depreciation Reserve multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF Leases.

(e) Transmission Related Accumulated Deferred Taxes shall equal the PTO's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Related Accumulated Deferred Income Taxes associated with Post-2003 PTF Investment shall equal the PTO's balance of total property-related accumulated deferred income taxes as recorded in FERC accounts 281 and 282, multiplied by the ratio of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, to

Total Plant in Service excluding Phase I/II HVDC-TF Leases, further multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases.

(f) Transmission Related Loss on Reacquired Debt shall equal the PTO's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(g) Other Regulatory Assets/Liabilities shall equal the PTO's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the PTO's electric balance of FAS 109 multiplied by the Plant Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(h) Transmission Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(i) Transmission Materials and Supplies shall equal the PTO's electric balance of Transmission Plant Materials and Supplies, multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the PTO's Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph J of the formula.

(k) MPRP CWIP shall equal CMP's balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and in accordance with CMP's Accounting Procedures for MPRP CWIP. In order to calculate the Incremental Return and Associated Income Taxes for MPRP CWIP, MPRP CWIP shall be separately identified.

(l) NEEWS CWIP shall equal CL&P, WMECO and NEP's balances as recorded in FERC Account No. 107 for the NEEWS as authorized by Commission order and in accordance with the companies' respective Accounting Procedures for NEEWS CWIP. In order to calculate the Incremental Return and Associated Income Taxes for NEEWS CWIP, NEEWS CWIP shall be separately identified.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the PTO's Weighted Cost of Capital, plus (b) Federal Income Tax plus (e) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, shall only reflect item (iii) below and shall apply in the manner indicated below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.

(iii) the return on equity component, shall be the product of the allowed ROE of the PTO's common equity and the ratio that common equity is to the PTO's total capital. For pre-1997 and post-1996 assets, the ROE is 11.64%. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental return on equity shall be the product of: (1) the PTO's incremental return on equity of 1.0% for plant investments associated with projects included in the RSP and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157, et al.; (2) any ROE incentive approved by the FERC under Order No. 679 for other plant investments (however; the 125 basis point ROE incentive adder granted to NEEWS under Order No. 679 in Docket No. ER08-1548 and the 50 basis point

ROE incentive adder for RTO participation shall not apply to the costs related to the Central Connecticut Reliability Project, consistent with FERC's order) and MPRP CWIP and NEEWS CWIP, and (3) the ratio that common equity is to the PTO's total capital) [19]

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{I\text{-}FT}$$

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections ll.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section ll.B., and D is Transmission Investment Base, as determined in Section II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 - FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section ll.D.below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section

[19] FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679.

II.B.. D is the Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation and Amortization Expense shall equal the PTF/HTF Transmission Plant Allocation Factor, multiplied by the sum of (i) the PTO's Depreciation Expense for Transmission Plant, plus (ii) an allocation of Intangible Plant Amortization Expense and (iii) General Plant Depreciation and Amortization Expense calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation and Amortization Expense by the Transmission Wages and Salaries Allocation Factor.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal the PTO's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal the PTO's total electric municipal tax expense multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

F. Transmission Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal the PTO's Transmission Operation and Maintenance Expenses multiplied by the PTF/HTF Transmission Plant Allocation Factor.

H. Transmission Related Administrative and General Expenses shall equal the sum of the PTO's (1) Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, and (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments, plus specific transmission related expenses included in Account 930.1 plus Transmission Merger-Related Costs. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

I. Transmission Related Integrated Facilities Charges shall equal the PTO's transmission payments to Affiliates for use of the PTF and HTF integrated transmission facilities of those Affiliates.

J. Transmission Support Revenues shall equal the PTO's revenue received for PTF and HTF transmission support but excluding the support payments to PTOs or their designee pursuant to Schedule 11 and excluding the support payments to PTOs or their designee pursuant to Schedule 12 Part 1(a) and Part B.2, and excluding support payments, if any, made to PTOs or their respective designee pursuant to Part II.C of this OATT.

K. Transmission Support Expense shall equal the expense paid by (1) PTOs, (2) Transmission Customers or (3) Related Persons pursuant to Section II.49 of the Tariff for PTF and HTF transmission support other than expenses for payments made for congestion rights or for transmission facilities or facility upgrades placed in service on or after January 1, 1997, where the support obligation is required to be borne by particular PTOs or other entities in accordance with the OATT. Transmission Support Expenses by any entity other than a PTO, included in this provision, shall be capped at that entity's annual payment for Regional Network Service or its Point To Point Service for each individual Point To Point transaction from the resource with which the support payment is associated.

L. Transmission-Related Expense from Generators shall equal the expenses from generators that both (1) the PTO Administrative Committee determines should be included as transmission expense as a result of the impact of such generators on reducing transmission costs that would otherwise be required to be paid by Transmission Customers and (2) are reflected in a filing made by the PTOs with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the OATT.

M. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Section which is not specifically identified under any other section of this rule.

N. Revenues for Short-Term service under the OATT shall be revenues distributed to each PTO for short term service provided under the OATT, received after March 1, 1999. These revenues will be credited pro-rata between pre-1997 and post-1996 PTF revenue requirements in proportion to pre-1997 and post-1996 PTF Transmission Plant.

O. Transmission Rents Received from Electric Property shall equal any Account 454 Rents from electric property, associated with PTF and HTF Transmission Plant as defined in Section II.A.1.(a) above but not reflected as a credit in Transmission Support Revenues in paragraph K of this Attachment.

P. Transmission Revenues from MGTSAs shall equal any MGTSA revenues recorded in Account 456.

APPENDIX A TO ATTACHMENT F
IMPLEMENTATION RULE RULES FOR DETERMINING
INVESTMENT TO BE INCLUDED IN PTF

Section A – Transmission Lines*

Section B – Terminal Facilities*

Section C – Right of Way*

Effective June 1, 1998

*The following provision shall apply to Sections A, B and C below:

Of those transmission facilities that are upgrades, modifications or additions to the New England Transmission System on and after January 1, 2004, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section II.49 of this OATT shall be classified as PTF. Those transmission facilities that were PTF on December 31, 2003, and any upgrades to such facilities that meet the definition of PTF specified in this OATT, shall remain classified as PTF for all purposes under the Transmission, Markets and Services Tariff.

Section A: Rules for Determining Transmission Line Investment to be Included in PTF
Pool Transmission Facilities (PTF) are the transmission facilities owned by PTO rated 69 kV or above required to allow energy from significant power sources to move freely on the New England transmission network, and include:

1. All transmission lines and associated facilities owned by the PTOs rated 69 kV and above, except:
    a. those which are required to serve local load only, thereby contributing little or no parallel capability to the transmission network,

    b. generator leads, which are defined as the radial transmission from a generator bus to the nearest point on the transmission network,

    c. lines that are normally operated open.

d. those that are classified as MTF.

2. Terminal facilities (including substation facilities such as transformers, circuit breakers, and associated equipment) required to interconnect the lines which constitute PTF (see Section B).
3. If a PTO with significant generation in its system (initially 25 MW) is connected to the New England Transmission System and none of the transmission facilities owned by the PTO qualify to be included in PTF as defined in "1" and "2" above, then such PTO's connection to PTF will constitute PTF if both of the following requirements are met for this connection:

a. The connection is rated 69 kV or above.

b. The connection is the principal transmission link between the PTO and the remainder of the ISO PTF network.

The PTF facilities covered by this provision shall consist of a single line from the point of connection on the transmission network to the first bus within the PTO's system.

4. R/W and land required for the installation of PTF facilities listed in "1", "2", or "3" (see Section C).

The following examples indicate the intent of the above definitions:

a. Radial tap lines to local load are excluded.

b. Lines which loop, from two geographically separate points on the transmission network, the supply to the load bus from the transmission network are included.

c. Lines which loop, from two geographically separate points on the transmission network, the connections between a generator bus, and the transmission network are included.

d. Radial connection or connections from a generating station to a single substation or switching station on the transmission network are excluded unless the requirements of paragraph 3 above are met.

e. The cost of a PTF line will include only those costs associated with that line. When other facilities require rebuilding or undergrounding to permit the construction of a PTF facility, the investment costs in the relocated or undergrounded facility will not be included.

f. Where multiple circuit structures support a mixture of PTF and Non-PTF circuits, the total cost of the multiple circuit structures will be allocated between the circuits in accordance with the ratio of costs of comparable individual structures.

The PTOs shall review at least annually the status of transmission lines and related facilities and determine whether such facilities constitute PTF and shall prepare and keep current a schedule or catalog of PTF facilities.

All new facilities being installed should be properly classified at the time the facilities are approved under Section I.3.9 of the Transmission, Markets and Services Tariff.

Transmission facilities owned or supported by a Related Person of a PTO which are rated 69 kV or above and are required to allow Energy from significant power sources to move freely on the New England Transmission System shall also constitute PTF provided (i) such Related Person files with the ISO its consent to such treatment; and (ii) the ISO determines in consultation with the PTO Administrative Committee determines that treatment of the facility as PTF will facilitate accomplishment of the ISO's objectives. If such facilities constitute PTF pursuant to this paragraph, they shall be treated as "owned" or "supported," as applicable, by a PTO for purposes of the OATT and the other provisions of the TOA, including the ability to include the cost associated with such PTF and any Transmission Support Expenses for support of PTF made by its Related Person in that PTO's Annual Transmission Revenue Requirements pursuant to Attachment F of the OATT.

Section B: Rules for Determining Terminal Investment to be Included in PTF

Terminal Investment is investment associated with the terminal facilities of electrical lines, including substation facilities such as transformers, circuit breakers, disconnects and airbreaks, bus conductor, related protection equipment and other related facilities (see paragraph 7).

1. The investment in terminal facilities shall be included where these facilities are identifiable and serve directly for terminating and/or switching PTF lines.

2. In cases where a line terminal is used in conjunction with both PTF and Non-PTF lines and/or facilities, it will be considered a PTF facility providing the terminal facility is at 69 kV or above and carries any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation. PTF equipment is any element of the transmission system in those parallel paths. Any equipment not in these parallel paths is Non-PTF.

3. Where line terminals are installed solely for Non-PTF facilities, and do not carry any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation, such terminal cost shall not be included in PTF.

4. A two-winding transformer which connects PTF facilities at both terminals along with any switcher which can be identified as pertaining solely to the transformer, will be included in their entirety as PTF.

5. An autotransformer or three winding transformer which connects PTF facilities at two (2) or more terminals, along with any switchgear which can be identified as pertaining solely to the PTF-connected terminals of the transformer, will be included in their entirety as PTF. An autotransformer or three winding transformer which is connected to PTF at only one terminal will not be PTF.

6. When a transformer supplies only Non-PTF facilities, the entire transformer installation, including the high side disconnect switch or circuit breaker and associated structures or tap lines shall be excluded from PTF except for the portion of line terminal facilities covered by paragraph 2.

7. Other facilities – the investment in that portion of a multi-use substation or switching station which is identifiable as serving a PTF function shall be included in PTF, while the investment in such facilities which are identifiable as serving a Non-PTF function shall be excluded. The investment in land, structures, ground mats, fences, ducts, lighting, etc., can often be identified and thus allocated. The investment in other facilities in the substation or switching station, excluding transformers, which are not identifiable as serving either a PTF or a Non-PTF function and general overheads shall be allocated to PTF on the basis of the ratio of the investment in those facilities identified as PTF to the sum of the investments in the facilities which are identified as serving PTF and Non-PTF functions; the equipment cost of power transformers shall not be included in this

calculation for determining the division of investment, since this would produce a distorted balance.

8. Alternate method of allocating the cost of terminal facilities – In those cases where the major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and Non-PTF according to the number of terminals serving PTF and Non-PTF facilities.

9. In cases where microwave facilities are used in whole or part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by the microwave facilities except where these facilities are otherwise supported under the Microwave Sharing Agreement dated June 1, 1970 among some of the New England utilities.

10. Generator unit transformers and generator circuit breakers shall be excluded from PTF, unless otherwise included by paragraphs 1 or 5.

11. In cases where remote control (Supervisory Control) and telemetering facilities are used in whole or in part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by these facilities.

12. The PTO Administrative Committee may designate appropriate facilities as PTF.

Section C: Rules for Determining PTF R/W Costs

1. If a R/W has only PTF lines and no Non-PTF lines are expected to be added, the entire cost of the R/W is to be included as PTF.

2. If the R/W has only PTF lines but includes additional unused R/W which was purchased for future use by Non-PTF lines, the cost of the additional R/W is not to be included as PTF.

3. If the R/W contains both PTF and Non-PTF lines, the R/W cost to be assigned to PTF is to be determined as follows:

a. Where new or additional R/W is required to permit the construction of PTF line(s) and the added R/W is adequate to contain the new PTF, the cost of the new R/W is to be assigned to the PTF line(s), (even if the PTF line is located on the old R/W).

b. Where an existing R/W is used (without additional R/W), the amount allocated to PTF will be determined in accordance with paragraph 4.

c. Where a R/W is widened, but the new facilities, either PTF or Non-PTF, require partial use of the existing R/W, the incremental cost of the new R/W will be assigned to the new facilities. The width of the original R/W will be added to the width of the new R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W will be allocated to the new facilities in proportion to the width of the old R/W assigned to the new facilities. Thus, the R/W for the new facilities will be the additional R/W plus a share of the old R/W.

4. In allocating R/W between PTF and Non-PTF lines, each shall bear a share of the R/W in accordance with the following formulae.

a. Determine the R/W width required for each facility if constructed independently using appropriate type structures.

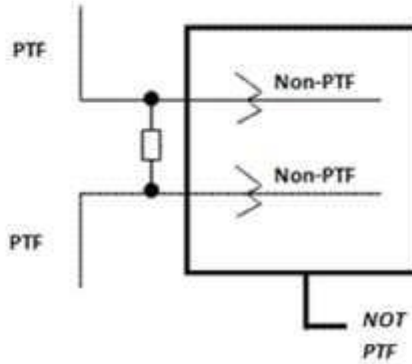
b. Allocate the actual R/W width to each facility in the proportion its independent R/W requirement would be to the sum of the independent R/W requirements.

5. R/W and land held for future PTF facilities may be included in PTF facilities only if specifically approved by the PTO Administrative Committee included under paragraph 1.

ATTACHMENT 1 TO APPENDIX A TO

ATTACHMENT F IMPLEMENTATION RULE

Examples of the Methods for Distinguishing PTF
from Non-PTF Terminal Facilities
in a Number of Typical Substation Configurations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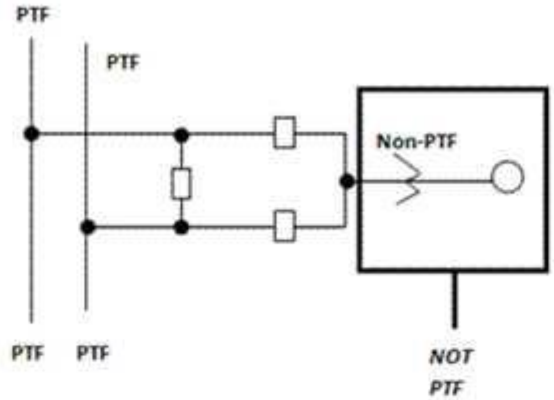
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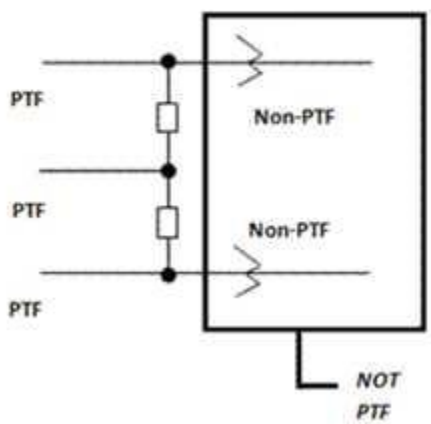
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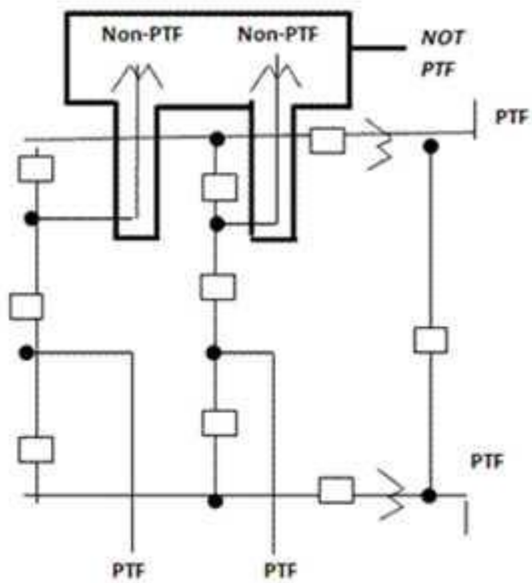
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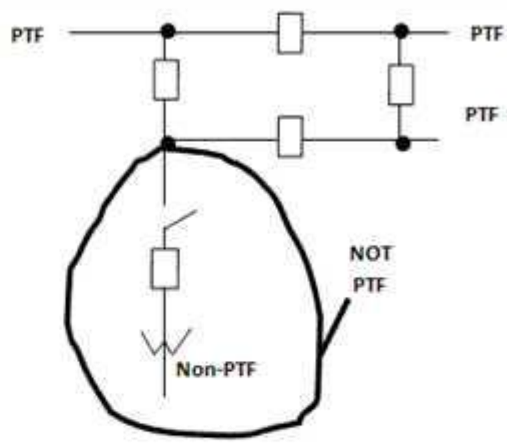
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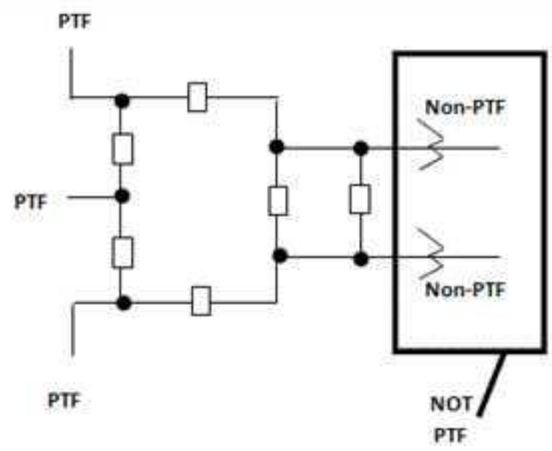
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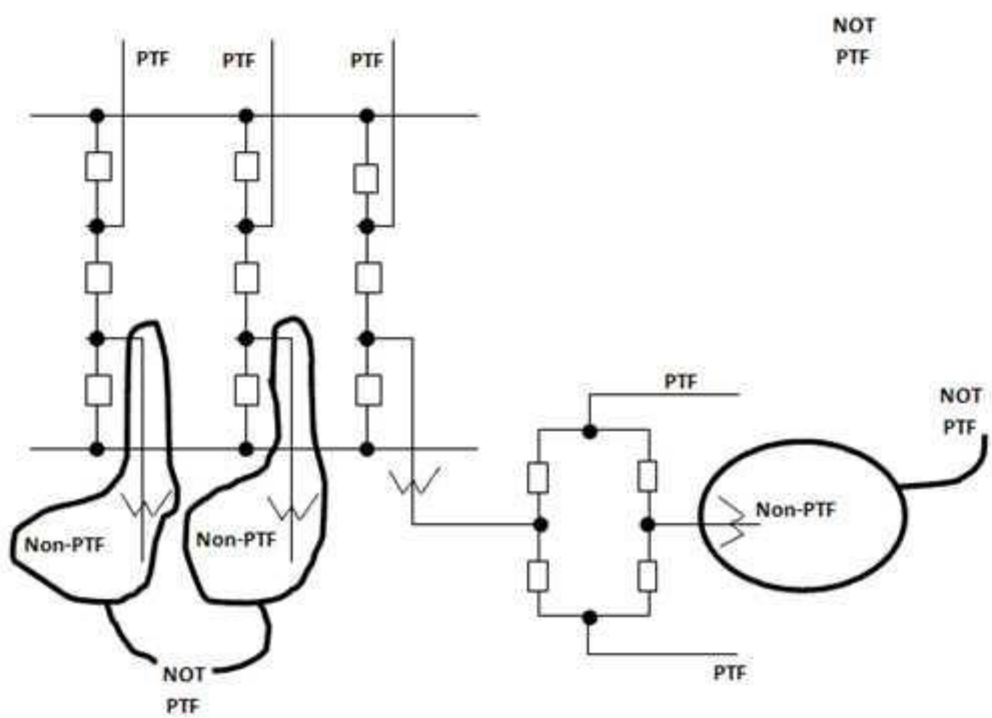
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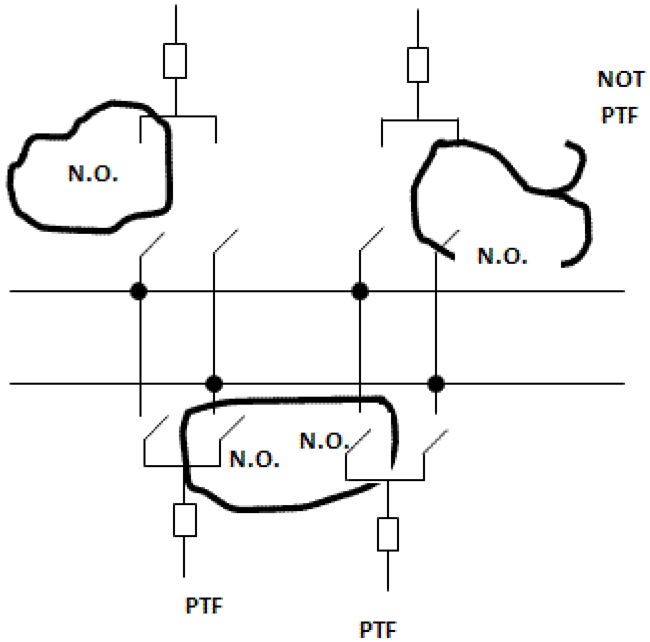
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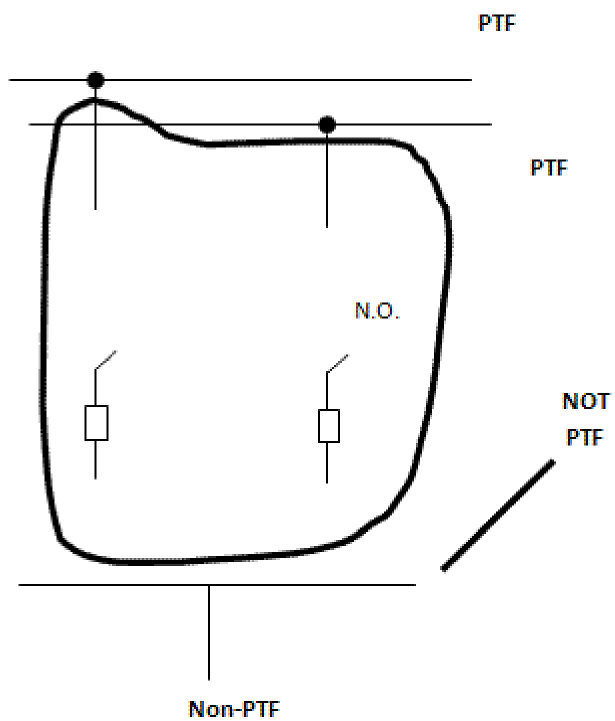
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APPENDIX B TO ATTACHMENT F IMPLEMENTATION RULE
HTF TRANSITION SCHEDULE

The inclusion of HTF Annual Transmission Revenue Requirements in Attachment F (and the calculation of the Pool PTF Rate) to this OATT will be limited by the provisions of this schedule.

VELCO, as a PTO and acting as agent for the HTF owners, may include the HTF Annual Transmission revenue Requirements (i.e., HTF Transmission Plant) within the Attachment F calculations. Additionally, the total HTF Annual Transmission Revenue Requirements included shall be limited to the following:

Year 1: A maximum of $1.2M in Year 1. For the sole purpose of this Schedule, "Year 1" shall be defined as the first full year after the Operations Date:

Year 2: A maximum of $2.0M in Year 2. For the sole purpose of this Schedule, "Year 2" shall be defined as the second full year after the Operations Date;

Year 3: A maximum of $2.8M in Year 3. For the sole purpose of this Schedule, "Year 3" shall be defined as the third full year after the Operations Date;

Year 4: A maximum of $3.5M in Year 4. For the sole purpose of this Schedule, "Year 4" shall be defined as the fourth full year after the Operations Date;

and

Year 5 and thereafter: All HTF Annual Transmission Revenue Requirements shall be included in Attachment F.

ATTACHMENT F IMPLEMENTATION RULE
APPENDIX C

I. DEFINITIONS

(i) Adjusted Carrying Charge Factor (ACCF): shall equal the sum of the Carrying Charge Factor and the quotient of (i) the Cost of Capital Rate multiplied by the PTOs' Transmission Related Accumulated Deferred Taxes associated with Post-1996 PTF Transmission Plant for the most recently concluded calendar year, and (ii) Post-1996 PTF Transmission Plant for the most recently concluded calendar year, as shown:

ACCF = CCF + [(COC * Transmission Related Accumulated Deferred Taxes associated with Post-1996 PTF Transmission Plant) ÷ Post-1996 PTF Transmission Plant]

(ii) Annual True-up – Pre-1997 (ATU): shall be the difference between the actual Pre-1997 Annual Transmission Revenue Requirements and the as-billed Pre-1997 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Pre-1997 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO's relevant Pre-1997 PTF cost data for the most recently concluded calendar year. The as-billed Pre-1997 Annual Transmission Revenue Requirements shall be those Pre-1997 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year.

(iii) Annual True-up – Post-1996 (ATU'): shall be the difference between the actual Post-1996 Annual Transmission Revenue Requirements and the as-billed Post-1996 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Post-1996 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO's relevant Post-1996 PTF cost data for the most recently concluded calendar year.The as-billed Post-1996 Annual Transmission Revenue Requirements shall be those Post-1996 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year and which included the sum of the Post-1996 Transmission Revenue Requirements for the year prior to the most recently concluded calendar year plus the Forecasted Transmission Revenue Requirements for the most recently concluded calendar year.

(iv) Carrying Charge Factor (CCF): shall reflect the most recent calendar year data used in determining Post-1996 Annual Transmission Revenue Requirements and shall equal the sum of Attachment F Sections II.A, excluding MPRP CWIP and NEEWS CWIP, through II.H divided by Attachment F Section II.A.1.a.

(v) Cost of Capital Rate (COC): shall be determined in accordance with Attachment F Section II.A.2.

(vi) Forecast Period: The calendar year immediately following the calendar year for which the most recent FERC Form 1 data is available.

(vii) Forecasted ADIT (FADIT): shall equal the PTOs' projected change in Accumulated Deferred Income Taxes from the most recently concluded calendar year related to accelerated depreciation and associated with PTF Transmission Plant for the Forecast Period calculated in accordance with Treasury regulation Section 1.167(l)-1(h)(6).

(viii) Forecasted CL&P NEEWS CWIP (FCCWIP): shall equal CL&P's estimated incremental change in NEEWS CWIP for the Forecast Period.

(ix) Forecasted MPRP CWIP (FCWIP): shall equal CMP's estimated incremental change in MPRP CWIP for the Forecast Period.

(x) Forecasted NEP NEEWS CWIP (FNCWIP): shall equal NEP's estimated incremental change in NEEWS CWIP for the Forecast Period.

(xi) Forecasted Transmission Plant Additions (FTPA): shall equal an estimate of the PTO's Post-1996 PTF plant additions for the Forecast Period.

(xii) Forecasted Transmission Revenue Requirement (FTRR): shall equal FTPA multiplied by the ACCF, minus FADIT multiplied by the COC, plus FCWIP multiplied by the MCOC, plus FCCWIP multiplied by CCOC, plus FWCWIP multiplied by WCOC, plus FNCWIP multiplied by NCOC, as shown:

FTRR = (FTPA * ACCF) - (FADIT * COC) + (FCWIP * MCOC) + (FCCWIP * CCOC) + (FWCWIP * WCOC) + (FNCWIP * NCOC)

(xiii) Forecasted WMECO NEEWS CWIP (FWCWIP): shall equal WMECO's estimated incremental change in NEEWS CWIP for the Forecast Period.

(xiv) MPRP Cost of Capital Rate (MCOC): shall be determined in accordance with Attachment F Section II.A.2.

(xv) NEEWS CL&P Cost of Capital Rate (CCOC): shall be determined in accordance with Attachment F Section II.A.2.

(xvi) NEEWS WMECO Cost of Capital Rate (WCOC): shall be determined in accordance with Attachment F Section II.A.2.

(xvii) NEEWS NEP Cost of Capital Rate (NCOC): shall be determined in accordance with Attachment F Section II.A.2.

II. INTEREST ON ANNUAL TRUE-UPS

Interest on the Annual True-up amounts (i.e., interest applicable to any over or under collection) shall be calculated in accordance with the methodology specified in the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii).

III. INFORMATIONAL FILINGS

The PTOs' annual informational filing shall include supporting documentation for their estimated capital additions to be placed in service during the current calendar year as well as supporting documentation pertaining to any annual true-up and interest calculations.

SCHEDULE 21 - EM

EMERA MAINE

BANGOR HYDRO DISTRICT

LOCAL SERVICE SCHEDULE

SCHEDULE 21-EM

I. COMMON SERVICE PROVISIONS

1 Definitions

1.1 Annual Transmission Costs: The total annual cost of the BHD Transmission System for purposes of Local Network Service shall be the amount specified in Attachment H until amended by Emera Maine or modified by the Commission.

1.2 BHD or Bangor Hydro District: Emera Maine's electric assets consisting of and/or directly interconnected with the BHD Transmission System.

1.2A BHD Transmission System: The facilities owned, controlled or operated by Emera Maine *and*, in accordance with the Transmission Operating Agreement, subject to the Operating Authority of the ISO, that are used to provide transmission service under Schedule 21 and Schedule 21-EM of the OATT.

1.3 Designated Agent: Any entity that performs actions or functions on behalf of Emera Maine, an Eligible Customer, or the Transmission Customer required under Schedule 21 and Schedule 21-EM of the OATT.

1.4 Direct Assignment Facilities: Facilities or portions of facilities that are constructed by Emera Maine for the sole use/benefit of a particular Transmission Customer requesting service under Schedule 21 and Schedule 21-EM of the OATT. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.5 Distribution Facilities: Facilities or portions of facilities directly interconnected with the BHD Transmission System but not reflected in transmission rates.

1.5A Emera Maine: Emera Maine, formerly named Bangor Hydro Electric Company. Except where the context clearly indicates otherwise, all references herein to Emera Maine shall be understood to refer to the BHD Transmission System as that term is defined herein, also known as the Emera Maine - Bangor Hydro District.

1.5B Monthly BHD Transmission System Peak: The maximum firm usage of the BHD Transmission System in a calendar month as calculated pursuant to the rate formula in Attachment P-EM.

1.6 Network Load: The load that a Network Customer designates for Local Network Service under this Schedule 21-EM. The Network Customer's Network Load shall include all load served by the output of any Local Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under this Schedule 21-EM for any Local Point-To-Point Service that may be necessary for such non-designated load.

1.7 Local Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Schedule 21 and Schedule 21-EM of the OATT.

1.8 Local Network Operating Committee: A group made up of representatives from the Network Customer(s) and Emera Maine established to coordinate operating criteria and other technical considerations required for implementation of Local Network Service

1.9 Local Network Resource: Any designated generating resource owned, purchased or leased by a Network Customer under the Local Network Service provisions of Schedule 21 and Schedule 21-EM of the OATT. Local Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

1.10 Local Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support the overall BHD Transmission System for the general benefit of all users of the BHD Transmission System.

1.11 Parties: Emera Maine and the Transmission Customer receiving service under Schedule 21-EM of the OATT.

1.12 Point(s) of Delivery: Point(s) on the BHD Transmission System where capacity and energy transmitted by Emera Maine will be made available to the Receiving Party under the local point-to-point service provisions of Schedule 21-EM of the OATT. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Local Point-To-Point Service.

1.13 Point(s) of Receipt: Point(s) of interconnection on the BHD Transmission System where capacity and energy will be made available to Emera Maine by the Delivering Party pursuant to the local point-to point service provisions of Schedule 21-EM of the OATT. The Point(s) of Receipt shall be specified in the Service Agreement for Local Long-Term Firm Point-To-Point Service.

1.14 Point-To-Point Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the local point-to-point service provisions of Schedule 21-EM of the OATT.

1.15 Reserved Capacity: The maximum amount of capacity and energy that Emera Maine agrees to transmit for the Transmission Customer over the BHD Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Schedule 21 and Schedule 21-EM of the OATT. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.16 Transmission Customer: Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that Emera Maine file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of this Schedule 21-EM. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Schedule 21-EM.

1.17 [Reserved].

1.18 Transmission Service: Local Point-To-Point Service provided over the BHD Transmission System under Schedule 21 and Schedule 21-EM of the OATT on a firm and non-firm basis.

2 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transfer Capability: For purposes of determining whether existing capability on the BHD Transmission System is adequate to accommodate a request for firm service under Schedule 21 and Schedule 21-EM of the OATT, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the OATT will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section I.1.b. of Schedule 21 of the OATT.

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. Emera Maine is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services: (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

Emera Maine is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within Emera Maine's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve - Spinning, and (iv) Operating Reserve - Supplemental. The Transmission Customer serving load within Emera Maine's Control Area is required to acquire these Ancillary Services, whether from Emera Maine, from a third party, or by self-supply. The Transmission Customer may not decline Emera Maine's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from Emera Maine. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by Emera Maine associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve.

Emera Maine shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer. In the event of an unauthorized use of any Ancillary Service by the Transmission Customer, Emera Maine may require the Transmission Customer to pay a penalty up to 200% of the specific Ancillary Service charge for the entire length of the reserved period but not exceeding one month.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of this Schedule 21-EM. Three principal requirements apply to discounts for Ancillary Services provided by Emera Maine in conjunction with its provision of transmission service as follows: (i) any offer of a discount made by Emera Maine must be announced to all Eligible Customers solely by posting on the ISO OASIS, (ii) any customer-initiated request for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (iii) once a discount is negotiated, details must be immediately posted on the ISO OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on Emera Maine's system. Sections 3.1 through 3.6 below list the six Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1-EM.

3.2 Reactive Supply and Voltage Control from Generation or Other Sources Service: The rates and/or methodology are described in Schedule 2-EM.

3.3 Regulation and Frequency Response Service: Where applicable the rates and/or methodology are described in Schedule 3-EM.

3.4 Energy Imbalance Service: Where applicable the rates and/or methodology are described in Schedule 4-EM.

3.5 Operating Reserve - Spinning Reserve Service: Where applicable the rates and/or methodology are described in Schedule 5-EM.

3.6 Operating Reserve - Supplemental Reserve Service: Where applicable the rates and/or methodology are described in Schedule 6-EM.

4 Billing and Payment

4.1 Billing Procedure: Within a reasonable time after the first day of each month, Emera Maine shall submit an invoice to the Transmission Customer for the charges for all services furnished under Schedule 21 and Schedule 21-EM of the OATT during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to Emera Maine, or by wire transfer to a bank named by Emera Maine.

4.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by Emera Maine.

4.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to Emera Maine on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after Emera Maine notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, Emera Maine may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between Emera Maine and the Transmission Customer, Emera Maine will continue to provide service under the Service Agreement as long as the Transmission Customer: (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then Emera Maine may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5 Accounting for Emera Maine's Use of the Tariff: Emera Maine shall record the following amounts, as outlined below.

5.1 Transmission Revenues: Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Schedule 21 and Schedule 21-EM of the OATT.

6 Regulatory Filings: Nothing contained in the Tariff (including this Schedule 21-EM of the OATT) or any Service Agreement shall be construed as affecting in any way the right of Emera Maine to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the OATT (including this Schedule 21-EM) or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under this Schedule 21-EM to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

7 Creditworthiness: The applicable Creditworthiness procedures are specified in Attachment Q-EM.

8 Dispute Resolution Procedures

8.1 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer and Emera Maine involving transmission service under Schedule 21 and Schedule 21-EM of the OATT (excluding applications for rate changes or other changes to Schedule 21-EM, or to any Service Agreement entered into under Schedule 21-EM, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of Emera Maine and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

8.2 External Arbitration Procedures: Any arbitration initiated under Schedule 21-EM shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

8.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of Schedule 21 and Schedule 21-EM of the OATT and any Service Agreement entered into under Schedule 21-EM and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

8.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(i) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(ii) one half the cost of the single arbitrator jointly chosen by the Parties

8.5 Rights Under The Federal Power Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act

II. LOCAL POINT-TO-POINT SERVICE

Preamble

Emera Maine will provide Firm and Non-Firm Local Point-To-Point Service pursuant to the applicable terms and conditions of Schedule 21 and Schedule 21-EM of the OATT. To the extent any terms of Schedule 21-EM conflict with any other provisions of the OATT, the terms of Schedule 21-EM shall control. Local Point-To-Point Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery. Service Agreements for Local Point-To-Point Service shall be based on the standard form service agreements in Attachment A of Schedule 21. Service Agreements for Local Retail Point-To-Point Service shall be based on the standard form service agreements in Attachment L-EM and Attachment M-EM of this Schedule 21-EM.

9 Nature of Firm Local Point-to-Point Service

9.1 Service Agreements: Emera Maine shall offer a standard form Firm Local Point-To-Point Service Agreement (Attachment A of Schedule 21) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Local Point-To-Point Service. Emera Maine shall offer a standard form Firm Local Point-To-Point Service Agreement (Attachment A of Schedule 21) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Local Point-To-Point Service pursuant to Schedule 21 and Schedule 21-EM of the OATT. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement.

If Emera Maine determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on the BHD Transmission System, Emera Maine will offer the Firm Transmission Service with the condition that Emera Maine may curtail the service prior to the curtailment of other Firm Transmission Service for a specified number of hours per year or during System Condition(s). If the Transmission Customer accepts the service, Emera Maine will use due diligence to provide the service until: (i) Network Upgrades are completed for the Transmission Customer, (ii) the Emera Maine determines through a biennial reassessment that it can no longer reliably provide such service, or (iii) the Transmission Customer terminates the service because the reassessment increased the number of hours per year of conditional curtailment or changed the System Conditions.

The Service Agreement shall, when applicable, specify any conditional curtailment options selected by the Transmission Customer. Where the Service Agreement contains conditional curtailment options and is subject to a biennial reassessment as described in above, Emera Maine shall provide the Transmission Customer notice of any changes to the curtailment conditions no less than 90 days prior to the date for imposition of new curtailment conditions. Concurrent with such notice, Emera Maine shall provide the Transmission Customer with the reassessment study and a narrative description of the study, including the reasons for changes to the number of hours per year or System Conditions under which conditional curtailment may occur.

9.2 Emera Maine Penalties Applicable to Curtailment of Firm Local Service. Pursuant to Schedule 21, Part I.1.f of the OATT, in the event the Transmission Customer fails to curtail service in response to a directive by Emera Maine, the Transmission Customer shall pay any applicable charges and the following penalty at the election of Emera Maine: up to 200% of the Firm Point-to-Point Transmission Service charge for the entire length of the reserved period but not exceeding one month. This penalty shall apply only to the portion of the service that the Transmission Customer fails to curtail in response to a Curtailment directive. If the Curtailment is for reliability purposes, Emera Maine may assess the penalty charge for failure to curtail if the Transmission Customer does not make the required reductions within 10 minutes of the Curtailment directive. If the Curtailment is for economic purposes, Emera Maine may assess the penalty charge for failure to curtail if the Transmission Customer does not make the required reductions within 20 minutes of the Curtailment directive.

9.3 Emera Maine Penalties for Exceeding Firm Reserved Capacity: Pursuant to Schedule 21, Part I.1.g of the OATT, in the event that a Transmission Customer (including Third-Party Sales by Emera Maine) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery, the Transmission Customer shall pay the following penalty at the election of Emera Maine: up to 200% of the Firm Point-to-Point Transmission Service charge for the period during which the Transmission Customer exceeded its firm reserved capacity.

The penalty for one or more hours of exceeding firm reserved capacity within a given day will be based on the rate for daily Firm Point-to-Point Transmission Service; the penalty for exceeding firm reserved capacity for a period of one or more days within a given week will be based on the rate for weekly Firm Point-to-Point Transmission Service; the penalty for exceeding firm reserved capacity for a period equal to one or more weeks within a given month will be based on the rate for monthly Firm Point-to-Point Transmission Service; and the penalty for exceeding firm reserved capacity for a period equal to one or more months within a given year will be based on the rate for annual Firm Point-to-Point Transmission Service.

More than one assessment for a given duration (e.g., daily) shall result in an increase of the penalty period to the next longest duration (e.g., weekly).

For the amounts exceeding firm reserved capacity, the Transmission Customer also must replace losses as required by this Schedule 21-EM.

All penalties collected under this provision shall be allocated equally to all Transmission Customers under this Schedule 21-EM that have not exceeded their firm reserved capacity.

10 Nature of Non-Firm Local Point-to-Point Service

10.1 Service Agreements: Emera Maine shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment A of Schedule 21-EM) to an Eligible Customer when it first submits a Completed Application for Non-Firm Local Point-To-Point Service pursuant to Schedule 21 and Schedule 21-EM of the OATT. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

10.2 Emera Maine Penalties for Exceeding Non-Firm Capacity Reservation: Pursuant to Schedule 21, Part I.2.e of the OATT, in the event that a Transmission Customer (including Third-Party Sales by Emera Maine) exceeds its non-firm capacity reservation, the Transmission Customer shall pay the following penalty at the election of Emera Maine: up to 200% of the Firm Point-to-Point Transmission Service charge for the period during which the Transmission Customer exceeded its firm reserved capacity.

The penalty for one or more hours of exceeding firm reserved capacity within a given day will be based on the rate for daily Firm Point-to-Point Transmission Service; the penalty for exceeding firm reserved capacity for a period of one or more days within a given week will be based on the rate for weekly Firm Point-to-Point Transmission Service; the penalty for exceeding firm reserved capacity for a period equal to one or more weeks within a given month will be based on the rate for monthly Firm Point-to-Point Transmission Service; and the penalty for exceeding firm reserved capacity for a period equal to one or more months within a given year will be based on the rate for annual Firm Point-to-Point Transmission Service.

More than one assessment for a given duration (e.g., daily) shall result in an increase of the penalty period to the next longest duration (e.g., weekly).

For the amounts exceeding the non-firm capacity reservation, the Transmission Customer must replace losses as required by this Schedule 21-EM.

All penalties collected under this provision shall be allocated equally to all Transmission Customers under this Schedule 21-EM that have not exceeded their firm reserved capacity.

10.3 Emera Maine Penalties Applicable to Curtailment of Non-Firm Local Point-to-Point Service: Pursuant to Schedule 21, Part I.2.g of the OATT, in the event the Transmission Customer fails to curtail service in response to a directive by Emera Maine, the Transmission Customer shall pay any applicable charges and the following penalty at the election of Emera

Maine: up to 200% of the Non-Firm Point-to-Point Transmission Service charge for the entire length of the reserved period but not to exceed one month. This penalty shall apply only to the portion of the service that the Transmission Customer fails to curtail in response to a Curtailment directive. If the Curtailment is for reliability purposes, Emera Maine may assess the penalty charge for failure to curtail if the Transmission Customer does not make the required reductions within 10 minutes of the Curtailment directive. If the Curtailment is for economic purposes, Emera Maine may assess the penalty charge for failure to curtail if the Transmission Customer does not make the required reductions within 20 minutes of the Curtailment directive.

11 Service Availability

11.1 Determination of Available Transfer Capability: A description of Emera Maine's specific methodology for assessing available transfer capability is contained in Attachment C of Schedule 21-EM. In the event sufficient transmission capability may not exist to accommodate a service request, Emera Maine will respond by performing a System Impact Study.

11.2 Real Power Losses: Pursuant to Schedule 21, Part I.3.g of the OATT, the applicable Real Power Loss factor for Emera Maine Local Transmission Service is 1.99%.

12 Procedures for Arranging Firm Local Point-To-Point Service

12.1 Deposit: A Completed Application for Firm Local Point-To-Point Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month; provided, however, Emera Maine shall have the right to waive the requirement of a deposit on a nondiscriminatory basis if Emera Maine determines that the Eligible Customer is creditworthy pursuant to Section 7 and is not in default of its obligations as defined in Section 4.3 at the time of the Application. Emera Maine will bill the Eligible Customer for any reasonable costs incurred by Emera Maine in connection with its review of the Application. If the Application is rejected by Emera Maine because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by Emera Maine in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by Emera Maine, if Emera Maine is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Local Point-To-Point Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by Emera Maine to the extent such costs have not already been recovered by Emera Maine from the Eligible Customer. Emera Maine will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Part I.7 of Schedule 21 of the OATT. If a Service Agreement for Firm Local Point-To-Point Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Local Point-To-Point Service. Applicable interest shall be computed in accordance with the Commission's regulations at 18 CFR § 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to Emera Maine's account.

13 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

13.1 Determination of Available Transfer Capability: Following receipt of a tendered schedule Emera Maine will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 11.2 of this Schedule 21-EM. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service: (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.

14 Additional Study Procedures For Firm Point-To-Point Transmission Service Requests

14.1 Expedited Procedures for New Facilities: In lieu of the procedures set forth in Part I.7 of Schedule 21 of the OATT, the Eligible Customer shall have the option to expedite the process by requesting Emera Maine to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate Emera Maine for all costs incurred pursuant to the terms of Schedule 21 and Schedule 21-EM. In order to exercise this option, the Eligible Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While Emera Maine agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate Emera Maine for all costs incurred pursuant to the provisions of Schedule 21 and Schedule 21-EM of the OATT. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

III. LOCAL NETWORK SERVICE

Preamble

Emera Maine will provide Local Network Service pursuant to the applicable terms and conditions contained in Schedule 21 and Schedule 21-EM of the OATT and Service Agreement. Local Network Service allows the Network Customer to integrate, economically dispatch, and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which Emera Maine utilizes the BHD Transmission System to serve its Native Load Customers. Local Network Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Schedule 21 and Schedule 21-EM of the OATT. Service Agreements for Local Network Service shall be based on the standard form service agreement in Attachment A of Schedule 21. Service Agreements for Local Retail Network Service shall be based on the standard form service agreement in Attachment N-EM and Umbrella Network Operation Agreement for Retail Local Network Service in Attachment O-EM of this Schedule 21-EM.

15. Nature of Local Network Service

15.1 Real Power Losses: As explained in Schedule 21, Part II.2.f. of the OATT, Real Power Losses are associated with all transmission service. Emera Maine is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by Emera Maine. The applicable Real Power Loss factor is 1.99%.

16 Initiating Service

16.1 Condition Precedent for Receiving Service: Subject to the terms and conditions of Schedule 21 and Schedule 21-EM of the OATT, Emera Maine will provide Local Network Service to any Eligible Customer, provided that: (i) the Eligible Customer completes an

Application for Local Network Service as provided under Schedule 21 and Schedule 21-EM of the OATT, (ii) the Eligible Customer and the Emera Maine complete the technical arrangements set forth in Sections 16.3 and 16.4 of Schedule 21-EM, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment A of Schedule 21 or requests in writing that a proposed unexecuted Service Agreement be filed with the Commission, and (iv) the Eligible Customer executes a Local Network Operating Agreement with Emera Maine pursuant to Attachment G-EM.

16.2 Application Procedures: An Eligible Customer requesting Local Network Service pursuant to Schedule 21 and Schedule 21-EM of the OATT must submit an Application, with a deposit approximating the charge for one month of service, to the ISO as far as possible in advance of the month in which service is to commence. Emera Maine shall have the right to waive the requirement of a deposit on a nondiscriminatory basis if Emera Maine determines that the Transmission Customer is creditworthy pursuant to Section 7 of Schedule 21-EM and is not in default of its obligations as defined in Section 4.3 of Schedule 21-EM at the time of the Application. Emera Maine will bill the Eligible Customer for any reasonable costs incurred by Emera Maine in connection with its review of the Application. Unless subject to the procedures in Section 2 of Schedule 21-EM, Completed Applications for Local Network Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. A Completed Application may be submitted by transmitting the required information by telefax. This method will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Schedule 21 and Schedule 21-EM of the OATT;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Emera Maine substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection). For each on-system Network Resource, such description shall include:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions
- Any periods of restricted operations throughout the year
- Maintenance schedules
- Minimum loading level of unit
- Normal operating level of unit
- Any must-run unit designations required for system reliability or contract reasons
- Arrangements governing sale and delivery of power to third parties from generating facilities located in Emera Maine's Control Area, where only a portion of unit output is designated as a Network Resource;

For each off-system Network Resource, such description shall include:

- Identification of the Network Resource as an off-system resource
- Amount of power to which the customer has rights
- Identification of the control area(s) from which the power will originate
- Delivery point(s) to the BHD Transmission System;
- Transmission arrangements on the external transmission system(s)
- Operating restrictions, if any
- Any periods of restricted operations throughout the year
- Maintenance schedules
- Minimum loading level of unit
- Normal operating level of unit
- Any must-run unit designations required for system reliability or contract reasons

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by Emera Maine
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- 10 year projection of system expansions or upgrades
- Transmission system maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested Local Network Service. The minimum term for Local Network Service is one year; and

(viii) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to Section 16.2(v) satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a noninterruptible basis.

Unless the Parties agree to a different time frame, the ISO or Emera Maine must acknowledge the request within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the ISO or Emera Maine shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, Emera Maine will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the ISO or Emera Maine shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The

Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. Emera Maine shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

16.3 Technical Arrangements to be Completed Prior to Commencement of Service: Local Network Service shall not commence until Emera Maine and the Network Customer, or a third party, have completed installation of all equipment specified under the Local Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the BHD Transmission System. Emera Maine shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

16.4 Network Customer Facilities: The provision of Local Network Service shall be conditioned upon the Network Customer's constructing, maintaining, and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the BHD Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

17 Network Resources

17.1 Operation of Network Resources: The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Emera Maine's Control Area such that the output of those facilities exceeds its designated Network Load, plus Non-Firm sales delivered pursuant to Schedule 21 and Schedule 21-EM of the OATT, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of Emera Maine to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the BHD Transmission System. For all Network Resources not physically connected with the BHD Transmission System, the Network Customer may not schedule delivery of energy in excess of the Network Resource's capacity, as specified in the Network Customer's Application pursuant to Schedule 21, Part II, section 3, unless the Network Customer supports such delivery within the BHD Transmission System by either obtaining Point-to-Point Transmission Service or utilizing secondary service pursuant to Schedule 21, Part II, section 2(g). Emera Maine shall specify the rate treatment and all related terms and conditions applicable in the event that a Network Customer's schedule at the delivery point for a Network Resource not physically interconnected with the BHD Transmission System exceeds the Network Resource's designated capacity, excluding energy delivered using secondary service or Point-to-Point Transmission Service.

17.2 Use of Interface Capacity by the Network Customer: There is no limitation upon a Network Customer's use of the BHD Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of Emera Maine's total interface capacity between the BHD Transmission System and other transmission systems may not exceed the Network Customer's Load.

18 Designation of Network Load

18.1 Network Load: The Network Customer must designate the individual Network Loads on whose behalf Emera Maine will provide Local Network Service. The Network Loads shall be specified in the Service Agreement.

18.2 New Network Loads Connected with Emera Maine: The Network Customer shall provide Emera Maine with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to the BHD Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. Emera Maine will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network

18.3 Network Load Not Physically Interconnected with Emera Maine: This section applies to both initial designation and the subsequent addition of new Network Load not physically interconnected with Emera Maine. To the extent that the Network Customer desires to obtain transmission service for a load outside the BHD Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Schedule 21 and Schedule 21-EM of the OATT and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Local Point-To-Point Service under Schedule 21 and Schedule 21-EM of the OATT. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

18.4 New Interconnection Points: To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the BHD Transmission System and a Network Load, the Network Customer shall provide Emera Maine with as much advance notice as reasonably practicable.

18.5 Changes in Service Requests: Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Local Network Service (e.g. the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by Emera Maine and charged to the Network Customer as reflected in the Service Agreement. However, Emera Maine must treat any requested change in Local Network Service in a non-discriminatory manner.

18.6 Annual Load and Resource Information Updates: The Network Customer shall provide Emera Maine with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Local Network Service under Schedule 21 and Schedule 21-EM of the OATT. The Network Customer also shall provide Emera Maine with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities, or operations affecting Emera Maine's ability to provide reliable service.

19 Load Shedding and Curtailments

19.1 Load Shedding: To the extent that a system contingency exists on the BHD Transmission System and Emera Maine determines that it is necessary for Emera Maine and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement.

20 Rates and Charges

The Network Customer shall pay Emera Maine for any Direct Assignment Facilities, Local Distribution Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

20.1 Monthly Demand Charge: The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its monthly Network Load times the monthly Local Network Service rate listed in the rate formula in Attachment P-EM.

20.2 Determination of Network Customer's Monthly Network Load: The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with Emera Maine under Section 18.3 of Schedule 21-EM) coincident with the Monthly BHD Transmission System Peak.

20.3 Stranded Cost Recovery: Emera Maine may seek to recover stranded costs from the Network Customer pursuant to Schedule 21 and Schedule 21-EM of the OATT in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However Emera Maine must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

21 Operating Arrangements

21.1 Operation Under The Local Network Operating Agreement: The Network Customer shall plan, construct, operate, and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement.

21.2 Local Network Operating Agreement: The terms and conditions under which the Network Customer shall operate its facilities, and the technical and operational matters associated with the implementation of Schedule 21 and Schedule 21-EM of the OATT, shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to: (i) operate and maintain equipment necessary for integrating the Network Customer within the BHD Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between Emera Maine and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the BHD Transmission System, interchange schedules, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Schedule 21 and Schedule 21-EM of the OATT, including scheduling protocols. The Local Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO) as defined in 18 C.F.R. § 39.1, (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with Emera Maine, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO. Emera Maine shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G-EM.

21.3 Local Network Operating Committee: A Local Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Local Network Operating Agreement. Each local Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 1-EM

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by Emera Maine (if Emera Maine is the Control Area operator) or indirectly by Emera Maine making arrangements with the Control Area operator that performs this service for the BHD Transmission System. The Transmission Customer must purchase this service from Emera Maine or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for Emera Maine, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Emera Maine by that Control Area operator.

The Transmission Customer shall pay up to the following transmission rates for service under Schedule 21-EM of the OATT:

1) **Yearly delivery:** (a) for all wholesale customers, customers who wheel-off the Emera Maine system, and retail point-to-point customers, the Annual Rate established pursuant to Attachment P-EM Section VI.A1 per KW of Reserved Capacity per year or (b) for retail network customers, the Annual Rate established pursuant to Attachment P-EM Section VI.A2 per KW of Reserved Capacity per year.

2) **Monthly delivery:** (a) for all wholesale customers, customers who wheel-off the Emera Maine system, and retail point-to-point customers, the Monthly Rate established pursuant to Attachment P-EM Section VI.A1 per KW of Reserved Capacity per month or (b) for retail network customers, the Monthly Rate established pursuant to Attachment P-EM Section VI.A2 per KW of Reserved Capacity per month.

3) **Weekly delivery:** (a) for all wholesale customers, customers who wheel-off the Emera Maine system, and retail point-to-point customers, Weekly Rate established pursuant to Attachment P-EM Section VI.A1 per KW of Reserved Capacity per week or (b) for retail network customers, the Weekly Rate established pursuant to Attachment P-EM Section VI.A2 per KW of Reserved Capacity per week.

4) **Daily delivery:** (a) for all wholesale customers, customers who wheel-off the Emera Maine system, and retail point-to-point customers, the Daily Rate established pursuant to Attachment P-EM Section VI.A1 per KW of Reserved Capacity per day or (b) for retail network customers, the Daily Rate

established pursuant to Attachment P-EM Section VI.A2 per KW of Reserved Capacity per day.

5) **Hourly delivery:** (a) for all wholesale customers, customers who wheel-off the Emera Maine system, and retail point-to-point customers, the Hourly Rate established pursuant to Attachment P-EM Section VI.A1 per KW of Reserved Capacity per hour or (b) for retail network customers, the Hourly Rate established pursuant to Attachment P-EM Section VI.A2 per KW of Reserved Capacity per hour.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

SCHEDULE 2-EM

REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION OR OTHER SOURCES SERVICE

In order to maintain transmission voltages on Emera Maine's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on Emera Maine's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by Emera Maine.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by Emera Maine (if Emera Maine is the Control Area operator) or indirectly by Emera Maine making arrangements with the Control Area operator that performs this service for the BHD Transmission System. The Transmission Customer must purchase this service from Emera Maine or the Control Area operator. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for Emera Maine, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Emera Maine by the Control Area operator.

The Transmission Customer shall pay up to the following transmission rates for service under Schedule 21 and Schedule 21-EM of the OATT:

Emera Maine is not the Control Area operator, and has divested itself of the generation in its service territory that provides Reactive Supply and Voltage Control from Generation Sources Service. To the extent Transmission Customers are also Transmission Customers under provisions of the OATT besides Schedule 21 and Schedule 21-EM, which provide Reactive Supply and Voltage Control from Generation Sources Service throughout the ISO Control Area, no additional charges for this service shall be charged hereunder. To the extent a Transmission Customer is a customer under Schedule 21 and Schedule 21-EM of the OATT, but not a customer under the other provisions of the OATT, Emera Maine will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer's account.

SCHEDULE 3-EM

REGULATION AND FREQUENCY RESPONSE SERVICE

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with Emera Maine (or the Control Area operator that performs this function for Emera Maine). Emera Maine must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from Emera Maine or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for Emera Maine, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Emera Maine by that Control Area operator.

The Transmission Customer shall pay up to the following transmission rates for service under Schedule 21-EM of the OATT:

Regulation and Frequency Response Service is provided within the ISO Control Area by a market in Automatic Generation Control administered for the benefit of the ISO Participants and non-Participants alike by the ISO. To the extent Transmission Customers under Schedule 21 and Schedule 21-EM of the OATT are also Transmission Customers under other provisions of the OATT, Regulation and Frequency Control Service will be provided under those other provisions of the OATT, and not hereunder. To the extent a Transmission Customer is a customer under the Schedule 21 and Schedule 21-EM of the OATT, but not a customer under the other provisions of the OATT, Emera Maine will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer's account.

SCHEDULE 4-EM

ENERGY IMBALANCE SERVICE

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. Emera Maine must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from Emera Maine or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for Emera Maine, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Emera Maine by that Control Area operator.

Within the ISO Control Area, Energy Imbalance Service is provided to load serving entities, which choose not to balance their hourly energy requirements with their own resources or bilateral arrangements, via the energy market administered by the ISO. Emera Maine has divested itself of the generation in its service territory, and is no longer capable of supplying this service itself. To the extent Transmission Customers under Schedule 21 and Schedule 21-EM of the OATT are also Transmission Customers under other provisions of the OATT, Energy Imbalance Service shall be provided under the other provisions of the OATT, and no additional charges for this service shall be charged hereunder. To the extent a Transmission Customer is a customer under the Schedule 21 and Schedule 21-EM of the OATT, but not a customer under the other provisions of the OATT, Emera Maine will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer's account.

SCHEDULE 5-EM

OPERATING RESERVE - SPINNING RESERVE SERVICE

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. Emera Maine must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from Emera Maine or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below.

Within the ISO Control Area, Spinning Reserve Service is provided to load serving entities, which choose not to supply their hourly spinning reserve requirements with their own resources or bilateral arrangements, via the 10-Minute Spinning Reserve Market administered by the ISO. Emera Maine has divested itself of the generation in its service territory, and is no longer capable of supplying this service itself. To the extent Transmission Customers under Schedule 21 and Schedule 21-EM of the OATT are also Transmission Customers under other provisions of the OATT, Spinning Reserve Service shall be provided under those other provisions, and no additional charges for this service shall be charged hereunder. To the extent a Transmission Customer is a customer under Schedule 21 and Schedule 21-EM of the OATT, but not a customer under other provisions of the OATT, Emera Maine will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer's account.

SCHEDULE 6-EM

OPERATING RESERVE - SUPPLEMENTAL RESERVE SERVICE

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. Emera Maine must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from Emera Maine or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below.

Within the ISO Control Area, Supplemental Reserve Service is provided to load serving entities, which choose not to supply their hourly supplemental reserve requirements with their own resources or bilateral arrangements, via the 10-Minute Non-Spinning and 30-Minute Reserve Markets administered by the ISO. Emera Maine has divested itself of the generation in its service territory, and is no longer capable of supplying this service itself. To the extent Transmission Customers under Schedule 21 and Schedule 21-EM of the OATT are also Transmission Customers under other provisions of the OATT, Supplemental Reserve Service shall be provided under the other provisions, and no additional charges for this service shall be charged hereunder. To the extent a Transmission Customer is a customer under Schedule 21 and Schedule 21-EM of the OATT, but not a customer under other provisions of the OATT, Emera Maine will pass through to the Transmission Customer any charges for this service assessed to it by the ISO for the Transmission Customer’s account.

SCHEDULE 7-EM

WHOLESALE OR WHEELING LONG-TERM FIRM AND SHORT-TERM FIRM LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall pay up to the following transmission rates for service under Schedule 21-EM of the OATT:

1) **Yearly delivery:** (a) in the case of wholesale load located on the Emera Maine system, the Annual Rate established pursuant to Attachment P-EM Section VI.B, plus the Annual Rate established pursuant to Attachment P-EM Section VI.C, plus, if applicable, the Annual Rate established pursuant to Attachment P-EM Section VI.D, all per KW of Reserved Capacity per year; or (b) in the case of wheeling off the Emera Maine system, the Annual Rate established pursuant to Attachment P-EM Section VI.E per KW of Reserved Capacity per year.

2) **Monthly delivery:** (a) in the case of wholesale load located on the Emera Maine system, the Monthly Rate established pursuant to Attachment P-EM Section VI.B, plus the Monthly Rate established pursuant to Attachment P-EM Section VI.C, plus, if applicable, the Monthly Rate established pursuant to Attachment P-EM Section VI.D, all per KW of Reserved Capacity per month; or (b) in the case of wheeling off the Emera Maine system, the Monthly Rate established pursuant to Attachment P-EM Section VI.E per KW of Reserved Capacity per month.

3) **Weekly Delivery:** (a) in the case of wholesale load located on the Emera Maine system, the Weekly Rate established pursuant to Attachment P-EM Section VI.B, plus the Weekly Rate established pursuant to Attachment P-EM Section VI.C, plus, if applicable, the Weekly Rate established pursuant to Attachment P-EM Section VI.D, all per KW of Reserved Capacity per week; or (b) in the case of wheeling off the Emera Maine system, the Weekly Rate established pursuant to Attachment P-EM Section VI.E per KW of Reserved Capacity per week.

4) **Daily delivery:** (a) in the case of wholesale load located on the Emera Maine system, the Daily Rate established pursuant to Attachment P-EM Section VI.B, plus the Daily Rate established pursuant to Attachment P-EM Section VI.C, plus, if applicable, the Daily Rate established pursuant to Attachment P-EM Section VI.D, all per KW of Reserved Capacity per day; or (b) in the case of wheeling off the Emera Maine system, the Daily Rate established pursuant to Attachment P-EM Section VI.E per KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Emera Maine must be announced to all Eligible Customers solely by posting on the ISO OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (3) once a discount is negotiated, details must be immediately posted on the ISO OASIS.

6) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Emera Maine must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the BHD Transmission System.

7) **Direct Assignment Costs:** Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule. Losses on Direct Assignment Facilities shall be the responsibility of the Transmission Customer.

8) **Network Upgrades:** Where a Facilities Study identifies the need for Network Upgrades to relieve a capacity constraint and Emera Maine undertakes such Network Upgrades, in addition to any charges for Direct Assignment Facilities and losses, as applicable, the Transmission Customer shall be required to pay the higher of the following two charges:

a) the base charge for Transmission Service set forth in this schedule, modified to include the cost of required Network Upgrades on a rolled-in basis; or

b) a charge based on the incremental cost of any Network Upgrades that would not have been needed for the Service requested by the Transmission Customer. Such incremental cost charge shall be based upon the Transmission Customer's appropriate share of the cost of such Network Upgrade up to one hundred percent of such cost.

If the requested Firm Point-to-Point Service requires use of Network Upgrades previously determined to have been necessary to provide Transmission Service for another Transmission Customer and if the costs of such Network Upgrades already are reflected in the rate for Transmission Service paid by such other Customer and are not reflected in the base rate for Firm Transmission Service, the subsequent Transmission Customer receiving Transmission Service shall pay a contribution to cover a portion of the cost of such Network Upgrades. The amount of the contribution shall be based on the subsequent Transmission Customer's pro-rata use of the Network Upgrades, as determined by FERC, and in the period of time over which the use occurs. The rate of the Transmission Customer(s) for whom the Network Upgrades originally were made shall be reduced by an amount equivalent to the contribution(s) made by other Transmission Customers pursuant to this section.

9) **Local Distribution Costs:** Any customer requiring transmission over facilities not included in the base transmission charge facilities below 34.5 KV shall pay a separate charge for service over those facilities. These charges shall be pursuant to Maine Public Utilities Commission rates, where applicable, and specified in a service agreement filed with the Commission.

10) **Taxes:** There shall be added to any amount calculated pursuant to any of the foregoing provisions of this Schedule 21-EM an amount in dollars sufficient to reimburse Emera Maine for any amounts paid or payable by them as sales, excise or similar taxes in respect of the total amount payable to Emera Maine pursuant to this Schedule 21-EM, in order to allow Emera Maine, after provision for such taxes, to realize the net amount payable to them under this Schedule 21-EM. The amount of these taxes shall be detailed in the Service Agreement. If the taxes or tax rates change, then Emera Maine shall have the right to revise the Service Agreement and file it with FERC.

SCHEDULE 8-EM

WHOLESALE OR WHEELING NON-FIRM LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall pay up to the following transmission rates for service under this Schedule 21-EM:

1) **Monthly delivery:** (a) in the case of wholesale load located on the Emera Maine system, the Monthly Rate established pursuant to Attachment P-EM Section VI.B, plus the Monthly Rate established pursuant to Attachment P-EM Section VI.C, plus, if applicable, the Monthly Rate established pursuant to Attachment P-EM Section VI.D, all per KW of Reserved Capacity per month; or (b) in the case of wheeling off the Emera Maine system, the Monthly Rate established pursuant to Attachment P-EM Section VI.E per KW of Reserved Capacity per month.

2) **Weekly delivery:** (a) in the case of wholesale load located on the Emera Maine system, the Weekly Rate established pursuant to Attachment P-EM Section VI.B, plus the Weekly Rate established pursuant to Attachment P-EM Section VI.C, plus, if applicable, the Weekly Rate established pursuant to Attachment P-EM Section VI.D, all per KW of Reserved Capacity per week; or (b) in the case of wheeling off the Emera Maine system, the Weekly Rate established pursuant to Attachment P-EM Section VI.E per KW of Reserved Capacity per week.

3) **Daily delivery:** (a) in the case of wholesale load located on the Emera Maine system, the Daily Rate established pursuant to Attachment P-EM Section VI.B, plus the Daily Rate established pursuant to Attachment P-EM Section VI.C, plus, if applicable, the Daily Rate established pursuant to Attachment P-EM Section VI.D, all per KW of Reserved Capacity per day; or (b) in the case of wheeling off the Emera Maine system, the Daily Rate established pursuant to Attachment P-EM Section VI.E per KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) **Hourly delivery:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed: (a) in the case of wholesale load located on the Emera Maine system, the Hourly Rate established pursuant to Attachment P-EM Section VI.B, plus the Hourly Rate established pursuant to Attachment P-EM Section VI.C, plus, if applicable, the Hourly Rate

established pursuant to Attachment P-EM Section VI.D, all per KW of Reserved Capacity per hour; or (b) in the case of wheeling off the Emera Maine system, the Hourly Rate established pursuant to Attachment P-EM Section VI.E per KW of Reserved Capacity per hour. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Emera Maine must be announced to all Eligible Customers solely by posting on the ISO OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (3) once a discount is negotiated, details must be immediately posted on the ISO OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Emera Maine must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the BHD Transmission System.

6) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

7) **Direct Assignment Costs:** Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule. Losses on Direct Assignment Facilities shall be the responsibility of the Transmission Customer.

8) **Network Upgrades:** Where a Facilities Study identifies the need for Network Upgrades to relieve a capacity constraint and Emera Maine undertakes such Network Upgrades, in addition to any charges for Direct Assignment Facilities and losses, as applicable, the Transmission Customer shall be required to pay the higher of the following two charges:

a) the base charge for Transmission Service set forth in this schedule, modified to include the cost of required Network Upgrades on a rolled-in basis; or

b) a charge based on the incremental cost of any Network Upgrades that would not have been needed for the Service requested by the Transmission Customer. Such incremental cost charge shall be based upon the Transmission Customer's appropriate share of the cost of such Network Upgrade up to one hundred percent of such cost.

If the requested Firm Point-to-Point Service requires use of Network Upgrades previously determined to have been necessary to provide Transmission Service for another Transmission Customer, and if the costs of such Network Upgrades already are reflected in the rate for Transmission Service paid by such other Customer and are not reflected in the base rate for Firm Transmission Service, the subsequent Transmission Customer receiving Transmission Service shall pay a contribution to cover a portion of the cost of such Network Upgrades. The amount of the contribution shall be based on the subsequent Transmission Customer's pro-rata use of the Network Upgrades, as determined by FERC and in the period of time over which the use occurs. The rate of the Transmission Customer(s) for whom the Network Upgrades originally were made shall be reduced by an amount equivalent to the contribution(s) made by other Transmission Customers pursuant to this section.

9) **Local Distribution Costs:** Any customer requiring transmission over facilities not included in the base transmission charge facilities below 34.5 KV shall pay a separate charge for service over those facilities. These charges shall be pursuant to Maine Public Utilities Commission rates, where applicable, and specified in a service agreement filed with the Commission.

10) **Taxes:** There shall be added to any amount calculated pursuant to any of the foregoing provisions of this Schedule 21-EM an amount in dollars sufficient to reimburse Emera Maine for any amounts paid or payable by them as sales, excise, or similar taxes in respect of the total amount payable to Emera Maine, pursuant to Schedule 21-EM in order to allow Emera Maine, after provision for such taxes, to realize the net amount payable to them under Schedule 21-EM. The amount of these taxes shall be detailed in the Service Agreement. If the taxes or tax rates change, then Emera Maine shall have the right to revise the Service Agreement and file it with FERC.

SCHEDULE 9-EM

RETAIL FIRM LOCAL POINT-TO-POINT SERVICE

The rates, terms and conditions of Retail Firm Local Point-To-Point Service shall be as stated in this Schedule 21-EM for Firm Local Point-To-Point Service, except as stated below. In the event that there are differences between this Schedule 9-EM and other provisions of Schedule 21-EM, this Schedule 9-EM shall control in all cases.

This Schedule 9-EM shall apply to retail customers, their Designated Agents, and to other entities taking transmission service under Schedule 21-EM to sell power to such retail customers. A retail customer is an entity that purchases electricity at retail Emera Maine or another entity, including the retail customer's Designated Agent.

A. The rates for Retail Firm Local Point-To-Point Service are as follows:

1) Yearly delivery: the Annual Rate established pursuant to Attachment P-EM Section VI.F.1, plus the Annual Rate established pursuant to Attachment P-EM Section VI.G.1, plus, if applicable, the Annual Rate established pursuant to Attachment P-EM Section VI.H.1, all per KW of Reserved Capacity per year.

2) Monthly delivery: the Monthly Rate established pursuant to Attachment P-EM Section VI.F.1, plus the Monthly Rate established pursuant to Attachment P-EM Section VI.G.1, plus, if applicable, the Monthly Rate established pursuant to Attachment P-EM Section VI.H.1, all per KW of Reserved Capacity per month.

3) Weekly delivery: the Weekly Rate established pursuant to Attachment P-EM Section VI.F.1, plus the Weekly Rate established pursuant to Attachment P-EM Section VI.G.1, plus, if applicable, the Weekly Rate established pursuant to Attachment P-EM Section VI.H.1, all per KW of Reserved Capacity per week.

4) Daily delivery: the Daily Rate established pursuant to Attachment P-EM Section VI.F.1, plus the Daily Rate established pursuant to Attachment P-EM Section VI.G.1, plus, if applicable, the Daily Rate established pursuant to Attachment P-EM Section VI.H.1, all per KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Emera Maine must be announced to all Eligible Customers solely by posting on the ISO OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (3) once a discount is negotiated, details must be immediately posted on the ISO OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Emera Maine must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the BHD Transmission System.

6) Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

7) Direct Assignment Costs: Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule. Losses on Direct Assignment Facilities shall be the responsibility of the Transmission Customer.

8) Network Upgrades: Where a Facilities Study identifies the need for Network Upgrades to relieve a capacity constraint and Emera Maine undertakes such Network Upgrades, in addition to any charges for Direct Assignment Facilities and losses, as applicable, the Transmission Customer shall be required to pay the higher of the following two charges:

a) the base charge for Transmission Service set forth in this schedule, modified to include the cost of required Network Upgrades on a rolled-in basis; or

b) a charge based on the incremental cost of any Network Upgrades that would not have been needed for the Service requested by the Transmission Customer. Such incremental cost charge shall be based upon the Transmission Customer's appropriate share of the cost of such Network Upgrade up to one hundred percent of such cost.

If the requested Retail Firm Point-to-Point Service requires use of Network Upgrades previously determined to have been necessary to provide Transmission Service for another Transmission Customer, and if the costs of such Network Upgrades already are reflected in the rate for

Transmission Service paid by such other Customer and are not reflected in the base rate for Retail Firm Transmission Service, the subsequent Transmission Customer receiving Transmission Service shall pay a contribution to cover a portion of the cost of such Network Upgrades. The amount of the contribution shall be based on the subsequent Transmission Customer's pro-rata use of the Network Upgrades, as determined by FERC, and in the period of time over which the use occurs. The rate of the Transmission Customer(s) for whom the Network Upgrades originally were made shall be reduced by an amount equivalent to the contribution(s) made by other Transmission Customers pursuant to this section.

9) Local Distribution Costs: Any customer requiring transmission over facilities not included in the base transmission charge facilities below 34.5 KV shall pay a separate charge for service over those facilities. These charges shall be pursuant to Maine Public Utilities Commission rates, where applicable, and specified in a service agreement filed with the Commission.

10) Taxes: There shall be added to any amount calculated pursuant to any of the foregoing provisions of Schedule 21-EM an amount in dollars sufficient to reimburse Emera Maine for any amounts paid or payable by them as sales, excise, or similar taxes in respect of the total amount payable to Emera Maine pursuant to Schedule 21-EM, in order to allow Emera Maine, after provision for such taxes, to realize the net amount payable to them under the Schedule 21-EM. The amount of these taxes shall be detailed in the Service Agreement. If the taxes or tax rates change, then Emera Maine shall have the right to revise the Service Agreement and file it with FERC.

B. The following sections of Schedule 21 and Schedule 21-EM are modified for a Transmission Customer taking Retail Firm Local Point-To-Point Service pursuant to Schedule 9-EM and under a Service Agreement for Retail Firm Local Point-To-Point Service.

a. Schedule 21: The reservation priority for existing firm service customers section is modified such that retail customers, irrespective of term, have the right to continue to take transmission service from Emera Maine when the contract expires, rolls over, or is renewed.

b. Section 4 of Schedule 21-EM: The billing, payment, and default section is applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from Emera Maine. If the Transmission Customer is a Designated Agent, Emera Maine shall bill directly and receive payment from the Designated Agent's retail customers for applicable transmission and ancillary charges (except for Energy Imbalance Service) unless other mutually agreeable provisions for payment are made. Emera

Maine shall bill directly the Designated Agent, if it is not Emera Maine, for Energy Imbalance Service, unless other mutually agreeable provisions for payment are made. For the direct billing of retail customers taking transmission service through a Designated Agent, the billing, payment, and default provisions shall be pursuant to Emera Maine's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-EM.

c. Section 8 of Schedule 21-EM: The dispute resolution procedures are applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from Emera Maine. For retail customers taking transmission service through a Designated Agent, the dispute resolution procedures shall be pursuant Emera Maine's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-EM.

d. Section 9.1 of Schedule 21-EM: The service agreements section is modified to add the following: "If the Eligible Customer submits a Completed Application for Retail Firm Point-To-Point Transmission for service to retail load, Emera Maine shall offer a standard form Retail Firm Local Point-To-Point Service Agreement (Attachment L-EM) or Retail Non-Firm Local Point-To-Point Service Agreement (Attachment M-EM), as applicable, to Eligible Customer."

e. Part I.5.a of Schedule 21: The first sentence of the application section is modified to state the following: "A request for Retail Firm Local Point-To-Point Service for periods of one year or longer must be made in a completed Application submitted to Emera Maine at least sixty (60) days in advance of the calendar month in which service is to commence." The second to last sentence of the application is modified to state the following: "A Completed Application may be submitted by transmitting the required information to Emera Maine by telefax."

f. Part I.5.d of Schedule 21: The first sentence of the notice of deficient application section is modified to state the following: "If an Application fails to meet the requirements of the Tariff, Emera Maine shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure." The third sentence is modified to state the following: "If such efforts are unsuccessful, Emera Maine shall return the Application."

SCHEDULE 10-EM

RETAIL NON-FIRM LOCAL POINT-TO-POINT SERVICE

The rates, terms, and conditions of Retail Non-Firm Local Point-To-Point Service shall be as stated in this Schedule 21-EM for Non-Firm Local Point-To-Point Service, except as stated below. In the event that there are differences between this Schedule 10-EM and Schedule 21-EM, this Schedule 10-EM shall control in all cases.

This Schedule 10-EM shall apply to retail customers, their Designated Agents, and to other entities taking transmission service under Schedule 21-EM to sell power to such retail customers. A retail customer is an entity that purchases electricity at retail from Emera Maine or another entity, including the retail customer's Designated Agent.

A. The rates for Retail Non-Firm Local Point-To-Point Service are as follows:

1) Monthly delivery: the Monthly Rate established pursuant to Attachment P-EM Section VI.F.1, plus the Monthly Rate established pursuant to Attachment P-EM Section VI.G.1, plus, if applicable, the Monthly Rate established pursuant to Attachment P-EM Section VI.H.1, all per KW of Reserved Capacity per month.

2) Weekly delivery: the Weekly Rate established pursuant to Attachment P-EM Section VI.F.1, plus the Weekly Rate established pursuant to Attachment P-EM Section VI.G.1, plus, if applicable, the Weekly Rate established pursuant to Attachment P-EM VI.H.1, all per KW of Reserved Capacity per week.

3) Daily delivery: the Daily Rate established pursuant to Attachment P-EM Section VI.F.1, plus the Daily Rate established pursuant to Attachment P-EM Section VI.G.1, plus, if applicable, the Daily Rate established pursuant to Attachment P-EM Section VI.H.1, all per KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the Hourly Rate established pursuant to Attachment P-EM

Section VI.F.1, plus the Hourly Rate established pursuant to Attachment P-EM Section VI.G.1, plus, if applicable, the Hourly Rate established pursuant to Attachment P-EM Section VI.H.1, all per KW of Reserved Capacity per hour. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Emera Maine must be announced to all Eligible Customers solely by posting on the ISO OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the ISO OASIS, and (3) once a discount is negotiated, details must be immediately posted on the ISO OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Emera Maine must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the BHD Transmission System.

6) Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Part I.11 of Schedule 21.

7) Direct Assignment Costs: Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule. Losses on Direct Assignment Facilities shall be the responsibility of the Transmission Customer.

8) Network Upgrades: Where a Facilities Study identifies the need for Network Upgrades to relieve a capacity constraint and Emera Maine undertakes such Network Upgrades, in addition to any charges for Direct Assignment Facilities and losses, as applicable, the Transmission Customer shall be required to pay the higher of the following two charges:

a) the base charge for Transmission Service set forth in this schedule, modified to include the cost of required Network Upgrades on a rolled-in basis; or

b) a charge based on the incremental cost of any Network Upgrades that would not have been needed for the Service requested by the Transmission Customer. Such incremental cost charge shall be based upon the Transmission Customer's appropriate share of the cost of such Network Upgrade up to one hundred percent of such cost.

If the requested Retail Non-Firm Local Point-to-Point Service requires use of Network Upgrades previously determined to have been necessary to provide Transmission Service for another Transmission Customer and if the costs of such Network Upgrades already are reflected in the rate for Transmission Service paid by such other Customer and are not reflected in the base rate for Retail Non-Firm Local Service, the subsequent Transmission Customer receiving Transmission Service shall pay a contribution to cover a portion of the cost of such Network Upgrades. The amount of the contribution shall be based on the subsequent Transmission Customer's pro-rata use of the Network Upgrades, as determined by FERC, and in the period of time over which the use occurs. The rate of the Transmission Customer(s) for whom the Network Upgrades originally were made shall be reduced by an amount equivalent to the contribution(s) made by other Transmission Customers pursuant to this section.

9) Local Distribution Costs: Any customer requiring transmission over facilities not included in the base transmission charge facilities below 34.5 KV shall pay a separate charge for service over those facilities. These charges shall be pursuant to Maine Public Utilities Commission rates, where applicable, and specified in a service agreement filed with the Commission.

10) Taxes: There shall be added to any amount calculated pursuant to any of the foregoing provisions of Schedule 21-EM an amount in dollars sufficient to reimburse Emera Maine for any amounts paid or payable by them as sales, excise or similar taxes in respect of the total amount payable to Emera Maine pursuant Schedule 21-EM, in order to allow Emera Maine, after provision for such taxes, to realize the net amount payable to them under Schedule 21-EM. The amount of these taxes shall be detailed in the Service Agreement. If the taxes or tax rates change, then Emera Maine shall have the right to revise the Service Agreement and file it with FERC.

B. The following sections of Schedule 21 and Schedule 21-EM are modified for a Transmission Customer taking Retail Non-Firm Local Point-To-Point Service pursuant to Schedule 10-EM and under a Service Agreement for Retail Non-Firm Local Point-To-Point Service.

a. Schedule 21: The reservation priority for existing firm service customers section is modified such that retail customers, irrespective of term, have the right to continue to take transmission service from Emera Maine when the contract expires, rolls over or is renewed.

b. Section 4 of Schedule 21-EM: The billing, payment, and default section is applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from Emera Maine. If the Transmission Customer is a Designated Agent, Emera Maine shall bill directly and receive payment from the Designated Agent's retail customers for applicable transmission and ancillary charges (except for Energy Imbalance Service), unless other mutually agreeable provisions for payment are made. Emera Maine shall bill directly the Designated Agent, if it is not Emera Maine, for Energy Imbalance Service unless other mutually agreeable provisions for payment are made. For the direct billing of retail customers taking transmission service through a Designated Agent, the billing, payment, and default provisions shall be pursuant to Emera Maine's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-EM.

c. Section 8 of Schedule 21-EM: The dispute resolution procedures are applicable to a Designated Agent taking transmission service on behalf of its retail customers and shall be pursuant Emera Maine's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-EM.

d. Section 10.4 of Schedule 21-EM: The service agreements section is modified to add the following: "If the Eligible Customer submits a Completed Application for Retail Non-Firm Local Point-To-Point Service for service to retail load, Emera Maine shall offer a standard form Retail Non-Firm Local Point-To-Point Service Agreement (Attachment M-EM) to Eligible Customer."

e. Part I.6.a of Schedule 21: The first two sentences of the application section are modified to state the following: "Eligible Customers seeking Retail Non-Firm Local Point-To-Point Service must submit a Completed Application to Emera Maine. A Completed Application may be submitted by transmitting the required information to Emera Maine by telefax."

SCHEDULE 11-EM

RETAIL LOCAL NETWORK SERVICE

The rates, terms and conditions of Retail Local Network Service shall be as stated in Schedule 21-EM, for Local Network Service, except as stated below. In the event that there are differences between this Schedule 11-EM and Schedule 21-EM, this Schedule 11 shall control in all cases.

This Schedule 11-EM shall apply to retail customers, their Designated Agents, and to other entities taking transmission service under Schedule 21-EM to sell power to such retail customers. A retail customer is an entity that purchases electricity at retail from Emera Maine or another entity, including the retail customer's Designated Agent.

A. The rate for Monthly Retail Local Network Service shall be the Monthly Rate established pursuant to Attachment P-EM SectionVI.F.2, plus the Monthly Rate established pursuant to Attachment P-EM Section VI.G.2, plus, if applicable, the Monthly Rate established pursuant to Attachment P-EM Section VI.H.2.

B. The following sections of Schedule 21 and Schedule 21-EM are modified for a Transmission Customer taking Retail Local Network Service pursuant to Schedule 11-EM and under a Service Agreement for Local Retail Network Service.

a. Schedule 21: The reservation priority for existing firm service customers section is modified such that retail customers, irrespective of term, have the right to continue to take transmission service from Emera Maine when the contract expires, rolls over or is renewed.

b. Section 4 of Schedule 21-EM: The billing, payment, and default section is applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from Emera Maine. If the Transmission Customer is a Designated Agent, Emera Maine shall bill directly and receive payment from the Designated Agent's retail customers for applicable transmission and ancillary charges (except for Energy Imbalance Service), unless other mutually agreeable provisions for payment are made. Emera Maine shall bill directly the Designated Agent, if it is not Emera Maine, for Energy Imbalance Service, unless other mutually agreeable provisions for payment are made. For the direct billing of retail customers taking transmission service through a Designated Agent, the billing, payment, and default provisions shall be pursuant to Emera Maine's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-EM.

c. Section 8 of Schedule 21-EM: The dispute resolution procedures are applicable to a Designated Agent taking transmission service on behalf of its retail customers and any retail customer taking service directly from Emera Maine. For retail customers taking transmission service through a Designated Agent, the dispute resolution procedures shall be pursuant Emera Maine's retail Terms and Conditions, the relevant portions of which are included in Schedule 12-EM.

d. Section 16.1 of Schedule 21-EM: The condition precedent for receiving service section is modified to add the following provision: "Unless retail Transmission Customers elect otherwise as provided in this Schedule 21 and Schedule 21-EM, retail Transmission Customers shall take service from Emera Maine as their Designated Agent pursuant to an Umbrella Service Agreement for Retail Local Network Service pursuant to Attachment N-EM; these retail Transmission Customers are not required to execute the service agreement which will be filed with FERC. Such retail Transmission Customers shall be obligated to comply with the applicable terms and conditions of Schedule 21 and Schedule 21-EM including paying for service notwithstanding the absence of a customer signature on a Service Agreement. If a retail Transmission Customer elects to take Retail Local Network Service directly from Emera Maine or through a Designated Agent other than Emera Maine, the Eligible Customer shall execute a Service Agreement for Retail Local Network Service pursuant to Attachment N-EM for service under Schedule 21-EM or request in writing that Emera Maine file a proposed unexecuted Service Agreement for Retail Local Network Service with the Commission and the Eligible Customer shall execute a Local Network Operating Agreement for Retail Local Network Service with Emera Maine pursuant to Attachment O-EM. The following additional requirement applies to a retail Transmission Customer that takes at least 500 KW of transmission service in any one hour in the calendar year from Emera Maine and takes Retail Local Network Service from Emera Maine as its Designated Agent: it shall execute a Service Agreement for Retail Local Network Service pursuant to Attachment N-EM for service under Schedule 21-EM or request in writing that Emera Maine file a proposed unexecuted Service Agreement for Retail Local Network Service with the Commission, if Emera Maine must construct either Direct Assignment Facilities or Network Upgrades in order to provide Transmission Service to the retail Transmission Customer."

e. Sections 16.2, 16.3, 16.4 of Schedule 21-EM: A retail Transmission Customer taking Retail Local Network Service from Emera Maine as its Designated Agent shall not be required to satisfy the application procedures and technical arrangements in sections 16.2, 16.3 and 16.4 of Schedule 21-EM, except that a retail Transmission Customer that takes at least 500 KW of transmission service in any one hour in the calendar year from Emera Maine and takes Retail Local Network Service from Emera Maine as its Designated Agent shall be required to comply with sections 16.3 and 16.4 of Schedule 21-EM to the extent Emera Maine deems it necessary to provide service.

f. Section 16.2(vii) of Schedule 21-EM: The minimum term application procedures section is modified, to change the last sentence to the following: "The minimum term for Local Network Service is one year, except that for service provided with respect to a state required retail access program, the minimum term is Emera Maine's typical monthly billing cycle for retail customers taking Retail Local Network Service directly from Emera Maine as its Designated Agent that are not required to execute a Service Agreement for Retail Local Network Service or provide notice that an unexecuted Service Agreement for Retail Local Network Service should be filed."

g. Section 18 of Schedule 21-EM: The designation of network load sections are modified to allow load distribution profiles of customer classes to be used for determining retail customer peak loads.

h. Sections 20.1 and 20.2 of Schedule 21-EM: The sections are superseded by the charges set out in this Schedule 11-EM.

i. Section 21 of Schedule 21-EM: The operating arrangements sections are not applicable for a retail Transmission Customer that takes Retail Local Network Service from Emera Maine as its Designated Agent. The operating arrangements for a Transmission Customer taking Retail Local Network Service directly from Emera Maine or through a Designated Agent other than Emera Maine shall be set forth in the Operating Agreement for Retail Local Network Service entered into between the Transmission Customer Emera Maine.

SCHEDULE 12-EM

RETAIL TERMS AND CONDITIONS

4-A PAYMENT OBLIGATION - GENERAL. The supply of service for any purpose at any location, is contingent upon payment of all charges provided for in this Rate Schedule as applicable to the Location and the character of service. Other terms including deposit requirements, late payment charges, and disconnection of service for non-payment are governed by several Maine Public Utilities Commission (MPUC) Rules and Regulations, namely:

MPUC Chapter 815 - Consumer Protection Standards For Electric And Gas Transmission And Distribution Utilities

MPUC Chapter 870 - Late Payment Charges, Interest Rates to be Paid on Customer Deposits, and Charges for Returned Checks

Copies of these Rules and Regulations hereinafter referred to as Chapters 815 and 870 of the MPUC Rules and Regulations are available for inspection at the MPUC's website.

Bills for utility service shall be due twenty-five (25) days after the postmarked date of the bill in accordance with Section 8(B) - Chapter 815 of the Commission's Rule and Regulations. No bill shall be subject to discount.

4-B GUARANTEE OF PAYMENTS:

Residential Accounts:

Emera Maine may require a deposit as security for the payment of bills and compliance with the Terms and Conditions as a prerequisite to the rendering or continuing of residential utility service by Emera Maine in accordance with Section 7(C) - Chapter 815 of the MPUC 's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

Non-Residential Accounts:

Emera Maine may require a deposit as security for the payment of bills and compliance with the Terms and Conditions as a prerequisite to the rendering or continuing of non-residential utility service by Emera

Maine in accordance with Section 7(B) - Chapter 815 of the MPUC's Rules and Regulations as in effect on the effective date hereof or amended from time to time hereafter.

4-C AMOUNT OF DEPOSIT.

Residential Accounts:

The amount of the deposit for residential utility service shall be determined in accordance with the provisions of Section 7(E) - Chapter 815 of the MPUC's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

Non-Residential Accounts:

The amount of the deposit for non-residential utility service shall be determined in accordance with the provisions of Section 7(D) - Chapter 815of the MPUC's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

4-D REFUND OF DEPOSIT.

Residential Accounts:

Refund of deposits for residential utility service shall be determined in accordance with Section 7(I) - Chapter 815 of the MPUC's Rules and Regulations as in effect on the effective date hereof and amended from time to time hereafter.

Non-Residential Accounts:

Refund of deposits for non-residential utility service shall be determined in accordance with Section 7(I) - Chapter 815 of the MPUC's Rules and Regulations as in effect on the effective date hereof and amended from time to time thereafter.

4-E INTEREST ON DEPOSITS. Emera Maine will pay interest on all customer deposits in accordance with Section 2 - Chapter 870 of the MPUC's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

4-F LATE PAYMENT CHARGE. All customers having bills not paid within twenty-five (25) days from the postmark date of the bill shall be subject to a late payment charge. The late payment charge shall be the maximum rate allowed in accordance with Section 1 - Chapter 870 of the MPUC's Rules and

Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

4-G DISCONNECTION OF SERVICE FOR CAUSE.

Residential Accounts:

The disconnect of residential customers for cause shall be governed by Chapter 815 of the MPUC's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

Non-Residential Accounts:

The disconnect of non-residential customers for cause shall be governed by Chapter 815 of the MPUC's Rules and Regulations as in effect on the effective date hereof or as amended from time to time hereafter.

4-H COLLECTION CHARGE. When an employee is sent to the Customer's premises for the purpose of disconnecting service and the Customer tenders payment in full of the bill to prevent disconnection, the employee shall either accept payment, give a receipt and leave the service intact, or else, without disconnecting, direct the Customer to go to the utility's nearest office within a reasonable time and tender payment there. The employee must know the full amount to be paid but shall not be required to make change or negotiate payment arrangements. When payment is made under these circumstances, Emera Maine will charge the Customer an amount not to exceed $10.00.

4-I CHARGE FOR RETURNED CHECKS. Customers whose checks have been returned to Emera Maine by financial institutions for non-payment shall be subject to a charge of $5.00 per check.

4-J SINGLE-METER, MULTI-UNIT DWELLINGS. In cases of disconnection of single-meter, multi-unit dwellings in which the Customer is the landlord, in addition to any other applicable fees, the landlord shall be required to pay a collection fee of $50.00. In addition, Emera Maine may require each dwelling unit to be individually metered at the landlord's expense before service will be restored.

ATTACHMENT A-EM

[Reserved]

ATTACHMENT B-EM

[Reserved]

ATTACHMENT C-EM

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

Following receipt of a Completed Application for Service, Emera Maine will assess its available transfer capability (ATC) to determine if sufficient capability exists to accommodate firm transmission service in accordance with Schedule 21 and Schedule 21-EM of the OATT.

ATC will be assessed considering Emera Maine's existing and projected native load requirements, existing firm transactions and all other requests for firm transmission service on a priority basis as per Schedule 21 and Schedule 21-EM of the OATT.

The Emera Maine assessment of ATC involves calculating, using Transmission Reliability Margins (TRM), the Incremental Transfer Capability and Total Transfer Capability (TTC) of the interface between Emera Maine and the ISO and specific path availabilities when they are requested by potential transmission customers.

The assessment of available transfer capability uses the basic North American Electric Reliability Council (NERC) transfer capability measures of First Contingency Incremental Transfer Capability (FCITC) and First Contingency Total Transfer Capability (FCTTC). Additionally, the assessment will comply with acceptable adjacent operating system standards and utilize the Northeast Power Coordinating Council (NPCC) criteria and guidelines. The assessment of available transmission will be performed using system models and load flow analysis. The following is a more detailed description of the process for determining ATC.

1. Roles of ISO New England and Emera Maine

As explained in Attachment C of the OATT, while the ISO is the Transmission Service Provider for Regional Network Service associated with Pool Transmission Facilities (PTF), there are additional Transmission Service Providers within the RTO footprint that calculate ATC associated with transmission services offered over the non-PTF external tielines and that calculate TTC and ATC associated with Local Transmission Service. The ISO is not responsible for the calculation of these values.

Pursuant to the terms of the Transmission Operating Agreement executed between Emera Maine as a Participating Transmission Owner (PTO) and ISO, Emera Maine is a Transmission Service Provider and calculates TTC and ATC for certain facilities over which Local Point-to-Point Service is provided under Schedule 21-EM. These are primarily radial paths that provide transmission service to directly interconnected generators.

1.1 Scope of Attachment C-EM

As the Transmission Service Provider of Schedule 21-EM Local Point-to Point Service pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT, Emera Maine performs the following functions within the scope of Attachment C-EM:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)

As explained further below in Section 2, TTC,ATC, and ETC are calculated only for certain non-PTF internal paths over which Local Point-to-Point Service is required under Schedule 21-EM pursuant to NERC Standards (MOD-001-1) regarding Available BHD Transmission System Capability and (MOD-029-1) regarding Rated System Path Methodology. TTC, ATC, and ETC are not calculated by Emera Maine for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and Emera Maine does not require advance reservation for such network service.

As defined by ISO and as applicable to all Transmission Service Providers under the RTO footprint, the following functions will be performed:

- Use of Capacity Benefit Margin (CBM) methodology
- Use of Transmission Reliability Margin (TRM) methodology
- Use of Rollover Rights (ROR) in the calculation of ETC

In addition, as explained further below in Sections 4 and 5, the NERC Standards (MOD 004-1) regarding Capacity Benefit Margin and (MOD 008-1) regarding Transmission Reliability Margin calculation methodology.

2. Transmission Service in the New England Markets

As explained in Attachment C of the OATT, the process by which generation located inside New England supplies energy to bulk electric system differs from the pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides supply offers to the New England energy market which are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, market participants may submit energy transactions to move energy into the ISO Area, out of the ISO Area or through the ISO Area. The New England Real-Time Energy Market clears these energy transactions based on forecast Locational Marginal Pricing (LMPs) and the availability of the external interfaces. With those external energy transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

This process for submitting energy transactions into the New England Real-Time energy market does not require an advance physical reservation for use of the PTF. In the event that the net of economic energy transactions is greater than the capability of an external interface, the energy transactions selected to flow are selected based on the New England Wholesale Market rules. For any energy transactions that are scheduled to flow in Real-Time based on the economics of the system, a transmission reservation is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, Emera Maine owns Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service is required. On those Local Facilities, the market participant must obtain a transmission service reservation from Emera Maine under Schedule 21-EM prior to delivery of energy into the New England Wholesale Market. Attachment C-EM addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. Schedule 21-EM Total Transfer Capability

The TTC on Emera Maine's non-PTF Local Facilities that require Local Point-to-Point Service reservations are relatively static values. Consistent with the NERC definition, TTC is the amount of electric power that can be moved or transferred reliably between the BHD Transmission System and other interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. Emera Maine thus calculates the TTC for posted paths as the rating of the particular radial transmission path.

3.1 Posting TTCs

Emera Maine will calculate and post TTC on its OASIS site for all non-PTF posted paths that require Local Point-to-Point Service reservations. The posting of the TTCs is performed for those non-PTF facilities that serve as a path for Emera Maine's Transmission Customers. TTC is calculated as the rating of the limiting element that constitutes that path.

4. Capacity Benefit Margin

The use of CBM within the ISO Area is governed by the overall ISO approach to capacity planning requirements. Load Serving Entities (LSEs) operating within the ISO Area are required to arrange their Installed Capability requirements prior to the beginning of any given month in accordance with New England Wholesale Market rules. As such, Load Serving Entities do not utilize CBM to ensure their capacity needs are met, and CBM is, therefore, not relevant within the New England market design. As long as this market design is in place in New England, the CBM is set to zero.

Wherever applicable, the administration of Schedule 21-EM is consistent with the services provided under the ISO OATT by ISO. Emera Maine provides local transmission service over its non-PTF facilities that are connected only to the New England system and they do not interconnect with other systems. Therefore, Emera Maine does not reserve CBM for these paths, and the CBM is presently set to zero.

5. Transmission Reliability Margin

The TRM is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation. It is used only for external interfaces under the New England market design. As Emera Maine under Schedule 21 provides transmission service over its non-PTF facilities that are connected only to the internal New England system, Emera Maine does not reserve TRM for these paths, and the TRM is presently set to zero.

6. Calculation of ATC for Emera Maine's Local Facilities

6.1 ATC Calculation General Description

This section defines the ATC calculations performed by Emera Maine for its non-PTF internal interfaces. Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$. Additionally, consistent with

NERC definition, ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$). As discussed above, the TRM and CBM for Emera Maine's non-PTF posted paths is zero. The purpose of the ETC (Existing Transmission Commitment) component of the ATC equation is for the Transmission Provider to ensure all existing transmission service commitments that reduce the ATC available to Firm and Non-Firm Local Point-to-Point Service Customers are accounted for. As described in Section 2, under Schedule 21-EM, Emera Maine requires the purchase of transmission service in advance of delivery of energy to the New England Wholesale Market over certain non-PTF paths, and those existing transmission commitments would be applied to the ATC equation for the specific posted path. As a practical matter, the ratings of the radial transmission paths are generally higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be generally available.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. In Real-Time, ETC effectively becomes equal to 0 (zero), as the ISO does not recognize nor utilize OASIS scheduled transmission reservations in its determination of generation dispatch pursuant to the Market Rules. Therefore, in Real-Time, the ATC is equal to TTC minus the amount of net energy transactions subject to ISO security constrained dispatch for each non-PTF interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC minus total Real-Time generation dispatch for each non-PTF interface. Because ISO Real-Time generation dispatch determines transmission usage in this time period for those non-PTF facilities that serve as a path for Schedule 21-EM Point-to-Point Transmission Customers, and existing transmission reservations are not determinate of transmission capacity usage in Real-Time, Emera Maine posts the ATC as 9999, consistent with industry practice. Actual ATC on these paths varies depending on the time of day. Thus, ATC is posted with an ATC of "9999" to reflect the fact that there are generally no restrictions on these paths for commercial transactions.

6.2 Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservation (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

6.3 Existing Transmission Commitments, Non-Firm (ETC_{NF})

The (ETC_{NF}**)** are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

7. Posting of ATC Related Information

7.1 Calculation of ATC Values

As described above, the Real-Time ATC values for Emera Maine's non-PTF internal assets that are utilized for Point-to-Point transmission service are almost always positive, and are thus set at 9999. The Real-Time ATC values for these internal posted paths are posted in accordance with NAESB standards on Emera Maine's OASIS website.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described in Section 6.1 where ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

To the extent a posted path is constrained, Emera Maine shall post the ATC in accordance with the general formula set forth in Section 6.1 of this Attachment C-EM.

Further, the mathematical algorithm and mathematical definition of Available Transmission Capability (ATC) for non-PTF for Emera Maine under Schedule 21-EM are posted on Emera Maine's website at www.emeramaine.com.

8. Non-PTF Transmission Path ATC Process Flow Diagram

TTC = Rating of the non-PTF Transmission Path

CBM = 0 TRM = 0

<u>ATC Planning</u> = Rating of the non PTF Path - Existing Transmission Reservations (Firm and non Firm Reservations) Because Existing Transmission Reservations (Firm and non Firm) are should be less than the rating of the non PTF path, ATC should always be positive <u>ATC Operation</u> = Rating of the non PTF Path - generation scheduled by ISO-NE and operating on the path

CBM = 0 TRM = 0

<u>ATC Planning</u> = Rating of the non PTF Path - Existing Transmission Reservation (Firm Reservations) Because Existing Transmission Reservations (Firm) should be less than the rating of the path, ATC should always be positive <u>ATC Operation</u> = ATC Planning

Note: Firm includes Conditional Firm

ATTACHMENT D-EM

METHODOLOGY FOR COMPLETING A SYSTEM IMPACT STUDY

Emera Maine will respond to an executed System Impact Study Agreement as per time outlined in Schedule 21 and Schedule 21-EM of the OATT. The System Impact Study shall identify any system constraints and redispatch options, additional required Direct Assignment facilities, or network upgrades to provide the requested service.

The transmission capability will be calculated in accordance with both the NERC definitions for "First Contingency Incremental Transfer Capability" and "First Contingency Total Transfer Capability."

First Contingency Incremental Transfer Capability (FCITC) - is the amount of electric power, incremental above normal base power transfers, that can be transferred over the interconnected BHD Transmission System in a reliable manner based on all of the following conditions:

1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits.

2. The electric systems are capable of absorbing the dynamic power swings and remaining stable following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit, and

3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

With reference to condition 1 above, in the case where pre-contingency facility loadings reach normal thermal ratings at a transfer level below that at which any first contingency transfer limits are reached, the transfer capability is defined as that transfer level at which such normal ratings are reached. Such a transfer capability is referred to as a normal incremental transfer capability (NTC).

First Contingency Total Transfer Capability (FCTTC) - is the total amount of electric power (net of normal base power transfers plus first contingency incremental transfers) that can be transferred between two areas of the interconnected transmission systems in a reliable manner based on conditions 1, 2, and 3 in the FCITC definition above.

The capability evaluation will utilize load flow analysis based on the Emera Maine's system load flow database. When Emera Maine feels no stability problems exist, it will generally use the Transmission 2000 Power Flow Program for software to conduct the study. This software may change in the future, without notice, but the replacement software will have the same minimum capabilities as its predecessor. If stability concerns exists, the studies may require a contractor to perform the studies. In conducting the studies, Emera Maine will adhere to good utility practice including the NPCC documents, relating to design and operation of interconnected power systems, and information submitted in the FERC Form No. 715.

The Emera Maine database will be modified to include the resources and the load information to be provided by the Customer as well as additional detail on the BHD Transmission System.

Emera Maine will perform the same types of studies related to transmission service requests as it performs transmission studies for its own use of the system. However, as a practical matter, it must be noted that planning studies must gauge the performance of the system based on a limited number of simulations. In actual daily operations of the system, the limits as determined in the transfer capability study may vary due to system conditions.

The transfer capability studies will analyze the impact of the proposed transmission request on the thermal capability, voltage profile, and stability of the BHD Transmission System. The transfer capability available will be the remaining capacity after accounting for Company import requirements to service its Native Load Customers reliably and prior contractual commitments, including any network transmission service or firm transmission service contract(s) previously filed and submitted as applications for Local Network or Firm Local Point-To-Point Service. In addition, Emera Maine will take into account Non-Firm Transmission Service when evaluating the transfer capability available for Non-Firm Transmission Service.

Emera Maine will notify the Eligible Customer immediately upon completion of the System Impact Study, if the BHD Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. A copy of the completed System Impact Study and related work papers will be made available to the Eligible Customer.

ATTACHMENT E-EM

INDEX OF EMERA MAINE POINT-TO-POINT TRANSMISSION SERVICE CUSTOMERS

[See Electric Quarterly Reports]

ATTACHMENT G-EM

EMERA MAINE LOCAL NETWORK OPERATING AGREEMENT

Example

THIS AGREEMENT, entered into this ________________ day of _____________,

______ is between the Transmission Customer and Emera Maine, either or both of which area hereinafter referred as "Party" or "Parties".

WHEREAS, the Transmission Customer is directly interconnected with Emera Maine's electric system and the Parties desire to formalize that interconnection; and

WHEREAS, Emera Maine has certain duties and obligations to meet its own capacity and energy requirements and to support its own system safely and economically; and

WHEREAS, the Transmission Customer has certain duties and obligations to meet its own capacity and energy requirements and to support its own system safely and economically; and

WHEREAS, to the extent provided herein the Transmission Customer and Emera Maine are willing to operate their facilities in a manner that assists each Party in meeting its own system reliability, economics, and obligations;

NOW THEREFORE, in consideration of the mutual covenants and agreements hereinafter set forth, the Parties agree as follows:

I. ADDITIONAL DEFINITIONS NOT CONTAINED IN THE OATT OR SCHEDULE 21-EM OF THE OATT

The following terms shall have the following meanings under this Agreement, including the Attachments hereto:

A. "Transmission Customer's Interconnection Equipment" is all equipment and facilities (1) necessary for the interconnection of the Transmission Customer's system and Emera Maine's system, and (2) located on the Transmission Customer's side of the Point(s) of Delivery. This equipment may include, but is not limited to, connection, switching, and safety equipment.

B. "Emera Maine's Interconnection Equipment" is all equipment and facilities (1) necessary for the interconnection of Emera Maine's system and the Transmission Customer's system, and (2) located on Emera Maine's side of the Point(s) of Delivery. This equipment may include, but is not limited to, connection, switching, and safety equipment.

C. "System Emergency" is a condition on Emera Maine's system or on a system with which Emera Maine's system is interconnected which, in Emera Maine's sole judgment at the time of the occurrence, is likely to result in imminent disruption of service to a network service customer or is imminently likely to endanger life or property.

II. TERM

This Agreement shall become effective on the date specified or such other date as FERC may approve (the "Effective Date"). This Agreement terminates on the later of the date of termination of the Transmission Customer being a Transmission Customer of Emera Maine or of the date of termination of the Transmission Service Agreement between Emera Maine and the Customer.

III. CHARACTER OF SERVICE

A. All electric energy delivered to the Transmission Customer shall be in the form of three-phase alternating current at a frequency of approximately sixty (60) Hz.

B. Emera Maine agrees that it will only curtail or interrupt service to the interconnection as provided under this Agreement or in accordance with Schedule 21, Parts I.1.f, I.2.g., II.7, and Schedule 21-EM, sections 13.6 and 14.7, of the OATT.

C. Except as expressly provided in this Agreement, the interconnection may not be de-energized without the approval of FERC.

IV. INTERCONNECTION EQUIPMENT DESIGN AND CONSTRUCTION

A. Each Party, at its own expense, shall design, purchase, construct, install, and be responsible for maintaining all of its Interconnection Equipment that connects its Interconnection Equipment to the other Party's Interconnection Equipment.

B. Each Party's Interconnection Equipment and any changes to its Interconnection Equipment shall meet all standards of Good Utility Practices.

C. The construction, design, installation, and maintenance of each Party's Interconnection Equipment shall meet all standards of Good Utility Practice. Each Party shall allow the other Party reasonable access to the construction site during any construction for the purpose of inspecting the Interconnection Equipment.

D. Neither Party will bear any costs of the other Party's Interconnection Equipment required by this Agreement. The cost of Direct Assignment Facilities currently used by Emera Maine is set forth in Appendix A of this Agreement and will be paid for by the Transmission Customer.

Emera Maine may recover from the Transmission Customer costs in connection with Direct Assignment Facilities in accordance with the OATT. Prior to Emera Maine incurring any such expense, the Transmission Customer shall be responsible for forwarding to Emera Maine funds sufficient to cover the expense or may pay directly for changes to the interconnection. Emera Maine will provide the Transmission Customer with actual expenses associated with the funding of new Direct Assignment Facilities within sixty (60) days of completion of construction, and appropriate payment will be made within (30) days thereafter.

E. Each Party may inspect the other Party's Interconnection Equipment to determine if all standards of Good Prudent Utility Practice are met. Neither Party shall be required to deliver to or receive electricity from the other Party's Interconnection Equipment until those standards are met, subject to the provisions of Section III.C, Article VII and Section VIII.C of this Agreement.

F. The Transmission Customer shall not connect any generators after the execution of this Agreement without first informing Emera Maine in writing six months in advance of such connection. Any third party generating facilities connected after the date of the execution of this Agreement shall comply with the then-existing interconnection requirements for non-utility generation as it is used by Emera Maine and as it applies to generation connected directly to the Emera Maine system. The Transmission Customer shall be responsible to ensure compliance with these requirements as set forth in writing by Emera Maine.

G. The Transmission Customer agrees to provide to Emera Maine complete documentation, to the extent available, of the Transmission Customer's Interconnection Equipment, including, but not limited to, power one-line diagrams, relaying diagrams, plan, sectional and elevation views, grading plans, conduit plans, foundation plans, fence and grounding plans, and detailed steel erection diagrams. In addition, the Transmission Customer agrees to provide to Emera Maine complete documentation of any changes to the Transmission Customer's Interconnection Equipment. Emera Maine agrees to provide the Transmission

Customer complete documentation for all Direct Assignment Facilities constructed by Emera Maine for the Transmission Customer or provided by Emera Maine to the Transmission Customer.

H. Based on the representations of the Parties to one another, the Parties agree that as of the Effective Date of this Agreement, all of Emera Maine's Interconnection Equipment and the Transmission Customer's Interconnection Equipment satisfy the requirements of this Agreement.

V. METERING

A. Emera Maine shall own, install, and maintain all metering devices and equipment required to measure the energy and capacity delivered to the Transmission Customer at the point of interconnection with the BHD Transmission System.

B. Emera Maine will measure the energy and capacity delivered on an hourly basis using 15-minute interval integrating meters with recorded readings. The readings will be remotely recorded by Emera Maine and will be made available to the Transmission Customer or a third party designated by the Transmission Customer. These readings will include the integrated kWh load for the Transmission Customer for 2, 15, and 60 minute intervals, the integrated load for the Transmission Customer for the previous 24-hour period, and the kVAR/hour.

C. Emera Maine shall provide pulses from its metering (kWh, kVAR) for use in the Transmission Customer-owned and maintained electronic recorder(s). Emera Maine shall permit the Transmission Customer to install a telecommunications link with the Transmission Customer-owned recorder(s).

D. Emera Maine shall provide pulses (kWh) to the Transmission Customer-owned and maintained load management systems (totalizer and transponder), and agrees (1) that the Transmission Customer may own and maintain a V2h meter and (2) to pulse readings from that meter to the Transmission Customer-owned recorder(s).

E. All metering equipment used to measure energy and capacity shall be sealed, and the seals shall be broken only by Emera Maine and only upon occasions when the meters are to be inspected, tested or adjusted.

F. Emera Maine shall provide access, including telecommunications access, to the Emera Maine meters for a representative of the Transmission Customer at reasonable times for the purposes of reading and inspecting, provided that the Transmission Customer's access shall not interfere with Emera Maine's normal business operations.

G. Unless otherwise mutually agreed, the meters shall not be tested or recalibrated, and none of the connections, including those of the transformers, shall be disturbed or changed, except in the presence of duly authorized representatives of each of the Parties or unless either Party, after reasonable notice, fails or refuses to have its representative present.

H. Emera Maine shall make annual tests of the metering devices and equipment for measuring all energy and capacity. The cost of this annual test shall be shared equally between Emera Maine and the Transmission Customer. The transmission Customer will reimburse Emera Maine for all expenses and cost incurred under this Section within thirty (30) days after Emera Maine provides the Transmission Customer with an invoice for such cost and expenses. Upon request in writing within 90 days and at the expense of the Transmission Customer, Emera Maine will make additional tests; provided, however, if the Transmission Customer requests an additional test and errors greater than 2% are discovered, Emera Maine shall pay the expense of the additional test. If a meter fails to register or if the measurement made by a meter is found to be inaccurate, then a retroactive billing adjustment shall be made by Emera Maine in accordance with Article X of this Agreement correcting all previous bills from Emera Maine to the Transmission Customer that were based upon measurements made by the meter during the actual period in which the meter failed to register or was inaccurate. A payment for the adjusted billing shall be made by the Transmission Customer in accordance with Articles X and XI of this Agreement.

I. Emera Maine shall notify the Transmission Customer prior to all metering tests and the Transmission Customer shall have the right to observe the tests. If a meter is found to be inaccurate or defective, it shall be adjusted, repaired, or replaced at the Transmission Customer's expense in order to provide accurate metering. Emera Maine shall provide to the Transmission Customer a written report of results of all meter tests.

VI. MONITORING

A. Emera Maine shall own, install, and maintain all automatic control and monitoring devices and equipment on its system up to the POD with the Transmission Customer required under this Agreement. This equipment shall: (i) be compatible with the Emera Maine System Operators SCADA control system; (ii) permit direct control of the interconnecting circuit breaker and motor-operated switch by Emera Maine system operators; (iii) provide for the transmission of all data that Emera Maine deems necessary to permit the Emera Maine system operator to monitor the overall operation of the interconnection equipment; (iv) provide for necessary data to permit Emera Maine to monitor Unscheduled Energy; and (v) provide such other capabilities as Emera Maine deems necessary, including, but not limited to, the ability to open the interconnection between the Transmission Customer and Emera Maine under the conditions specified in Articles VII and VIII of this Agreement.

B. The Transmission Customer shall provide to Emera Maine on a daily basis, at the Transmission Customer's expense, the following: (1) the instantaneous kW and kVARh load for the Transmission Customers; (2) the integrated kWh load for the Transmission Customer for 2, 15, and 60 minute intervals; (3) the integrated load for the Transmission Customer for the previous 24-hour period; and (4) any other information, as may be reasonably requested by Emera Maine. Emera Maine agrees that the Transmission Customer has provided sufficient devices and equipment for these purposes.

VII. PROTECTION AND CONTROL OF INTERCONNECTION EQUIPMENT

The Transmission Customer, at its expense, shall design, purchase, construct, install, and be responsible for the expense of maintaining all of the Interconnection Equipment that isolates the Transmission Customer's equipment from Emera Maine's system. All such Interconnection Equipment shall be of sufficient size to accommodate the delivery of energy and capacity under the Service Agreement between Emera Maine and the Transmission Customer and shall be of utility grade, acceptable to Emera Maine.

The required protective relay system shall be capable of detecting faults to allow for disconnection of the Transmission Customer's load at the POD to facilitate restoration of service, maintain system stability, mitigate any fault damage, and protect the general public, the Transmission Customer and Emera Maine personnel. This protective relay system must be approved by Emera Maine, which approval shall not be unreasonably withheld. Emera Maine shall provide relay settings and have the right to review and make recommendations with respect to the design, equipment selection, operation, and routine maintenance and testing of the protective relay system. The Transmission Customer shall purchase and install the protective relay system at its own expense. The Transmission Customer shall maintain the protective relay system in accordance with Section IX.B.

The protective relay system shall include, without limitation, the following:

A. Linkable main disconnect switch with arc restrictions that permits isolation of the load from the BHD Transmission System;

B. An automatic circuit breaker that is (1) capable of tripping the Transmission Customer both automatically and by remote control from Emera Maine and (2) capable of synchronizing the Transmission Customer load to the BHD Transmission System;

C. Underfrequency protective relays used in conjunction with the automatic circuit breaker in Section VII.B above;

D. Potential and current transformers;

E. Phase fault protection and ground fault protection.

Should Emera Maine consistent with Good Utility Practices, determine that the Transmission Customer is not providing proper operation of the protective relay system, Emera Maine shall so notify the Transmission Customer in writing, providing specific engineering detail of the acceptable testing operation and maintenance procedures and shall provide the Transmission Customer with a period of time that is reasonable under the circumstances to accomplish the specified corrective actions, but in no event less than five (5) days. If the Transmission Customer fails to accomplish the required corrective actions within the time specified in the notice, Emera Maine may, after giving such actual further notice (including no further notice) to the Transmission Customer as Emera Maine shall, in its sole discretion, determine to be reasonable under the terms of the OATT (including Schedule 21-EM) open the Interconnection between the Transmission Customer and Emera Maine until the required corrective action is accomplished. Emera Maine shall take the action contemplated in the previous sentence only if the Transmission Customer's failure to take the corrective action could, in Emera Maine's reasonable judgment, result in a System Emergency or is otherwise required by Good Utility Practices. Emera Maine shall not be responsible for any loss, damage, expense, or liability whatsoever experienced by the Transmission Customer resulting from the opening of the interconnection as permitted under this paragraph. The Transmission Customer moreover agrees to indemnify and hold harmless Emera Maine, its officers, agents, employees, and directors from and against all loss, damage, expense, and liability of any type whatsoever for any claim or other liability resulting from such opening of the interconnection.

VIII. INTERCONNECTION OPERATION

A. Emera Maine will operate and maintain its nominal transmission voltage within a range of +/- 5% at the point of interconnection between Emera Maine and the Transmission Customer. The Transmission Customer, at its expense, shall maintain appropriate voltage on its system in accordance with Good Utility Practice

B. The Transmission Customer shall have a reactive operating range (power factor) that is continuous throughout the 95% lead to 95% lag range; provided, however, that under normal operating conditions the Transmission Customer shall not deliver excess reactive power to the Emera Maine system unless otherwise agreed to by Emera Maine.

C. During a System Emergency, the Transmission Customer at Emera Maine's request, shall operate its system in a manner to mitigate the System Emergency. That operation may call for full or partial interruption of power, but in an amount and duration only as reasonably required by the System Emergency.

D. The Transmission Customer shall, in the event of an unscheduled outage or limitation of transmission facilities, report that outage or limitation immediately to Emera Maine's dispatcher. Further, the Transmission Customer shall notify Emera Maine when the outage or limitation has been remedied.

E. In the event the Transmission Customer load requires Emera Maine to serve the load, curtailment of delivery to the Transmission Customer will be in accordance with the Backup Service Agreement between Emera Maine and the Transmission Customer in effect at the time. The Backup Service Agreement is attached as Appendix B to the Agreement.

IX. MAINTENANCE AND MODIFICATION TO THE INTERCONNECTION

A. Each Party shall maintain and replace at its expense during the term hereof all its Interconnection Equipment, in accordance with established practices and standards for the operation and maintenance of power system equipment.

B. The Transmission Customer shall arrange with Emera Maine for an annual, visual inspection of all Interconnection Equipment and associated maintenance records. Every two years, the Transmission Customer shall arrange a relay calibration test and operation test of the Transmission Customer's Interconnection Equipment. These tests must be performed by a qualified contractor, approved by Emera Maine and acceptable to the Transmission Customer, or by Emera Maine itself. After the relay calibration tests are completed, Emera Maine may perform a relay system functional test. The Transmission Customer shall bear the cost of any relay testing and other assistance that may be requested of Emera Maine before and after the system is made operational. The Transmission Customer shall reimburse Emera Maine for all its costs and expenses, including administrative expenses, incurred under this Section within thirty (30) days after Emera Maine provides the Transmission Customer with an invoice for such costs and expenses.

C. At the Transmission Customer's request during the Term of this Agreement, Emera Maine shall move any of its lines or other equipment used exclusively for the purpose of furnishing and delivering to the Transmission Customer electric energy, if: (i) the Transmission Customer furnishes without charge or expense to Emera Maine a new, suitable, and sufficient right(s)-of-way to enable Emera Maine to deliver electric energy, and (ii) the Transmission Customer reimburses Emera Maine in advance on a progress payment basis for all costs incurred by Emera Maine in connection with the moving of said lines or equipment. The Transmission Customer is responsible for securing for Emera Maine such new location and new right(s)-of-way.

D. Emera Maine retains the right, after prior consultation with the Transmission Customer, to increase the transmission voltage level to accommodate system requirements. In the event of an interconnection voltage upgrade, the Transmission Customer shall be responsible, at its own expense, for making all equipment alterations to receive energy at the new transmission voltage. Emera Maine shall provide the Transmission Customer with two (2) years written notice of the planned upgrade and shall coordinate its construction schedule with the Transmission Customer.

E. In the event of a failure of the Transmission Customer facilities, Emera Maine shall, at the Transmission Customer's expense, make best efforts, consistent with its own practices, to transfer service to the backup facilities owned by the Transmission Customer. Such transfer may include, but would not be limited to, removal and installation of substation buswork and field relocation of protective relay sensing circuits.

X. BILLING AND PAYMENTS

Billing and Payments shall be in accordance with Section 4 of the Schedule 21-EM of the OATT.

XI. AUDITS OF ACCOUNTS AND RECORDS

Within three (3) years following any calendar year, during which service was rendered hereunder, Emera Maine and the Transmission Customer shall have the right to audit each other's applicable accounts and records during normal business hours at the offices where such accounts and records are maintained; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service under the OATT for said calendar year. The costs of the audit shall be borne by the party requesting the audit.

XII. SCHEDULING

A. Local Point-to-Point Service

Schedules for Local Point-to-Point Service must be submitted pursuant to Part I.1.h and Part I.2.f of

Schedule 21 of the OATT.

B. Local Network Service

Schedules for the Transmission Customer Local Network Service must be submitted to Emera Maine no later than 10:00 a.m. of the day prior to commencement of such service. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour. The Transmission Customer will arrange for monthly schedules of hourly transfer from the network resources to Emera Maine and any Transmission Provider involved in scheduling of control area interchanges. The Transmission Customer schedule change will be permitted on an instantaneous basis if Emera Maine and the Transmission Customer and all intervening control areas agree and agreements are in place to provide for scheduling modifications. Emera Maine will furnish to dispatchers of the Delivering Party hour-to-hour schedules equal to those furnished by the Receiving Party and shall deliver capacity and energy at the POD's in an amount provided by the schedules. Should the Transmission Customer, Delivering Party, or Receiving Party revise or terminate any schedule, such party shall notify Emera Maine.

XIII. ACCESS

A. Emera Maine will grant, with a reasonable notification and without cost to the Transmission Customer for the Term of this Agreement, any access that may be necessary for reasonable ingress and egress over property owned by Emera Maine in order to operate, inspect, maintain, replace, and remove control facilities, meters, recorders, load management system (totalizer and transponder), telecommunications link, and any other Transmission Customer-owned Interconnection Equipment, provided that such access shall not disrupt or otherwise interfere with the normal operations of Emera Maine.

B. The Transmission Customer will grant, with a reasonable notification and without cost to Emera Maine for the Term of this Agreement, any access that may be necessary for reasonable ingress and egress over property owned by the Transmission Customer in order to operate, inspect, maintain, replace, and remove Emera Maine-owned Interconnection Equipment, provided that such access shall not disrupt or otherwise interfere with the normal operations of the Transmission Customer.

IN WITNESS WHEREOF the Parties hereto have caused this instrument to be executed in their corporate names by their duly authorized representatives.

WITNESSES: EMERA MAINE

____

By: ____________________

Its: ____________________

Dated: ____________________

TRANSMISSION CUSTOMER

____

By: ____________________

Its: ____________________

Dated: ____________________

APPENDIX A-EM

CUSTOMER DIRECT ASSIGNMENT FACILITIES

ATTACHMENT H-EM

[Reserved]

ATTACHMENT I-EM

INDEX OF NETWORK CUSTOMERS

[See Electric Quarterly Reports]

ATTACHMENT J-EM

[Reserved]

ATTACHMENT K-EM

[Reserved]

ATTACHMENT L-EM

UMBRELLA SERVICE AGREEMENT FOR RETAIL FIRM LOCAL POINT-TO-POINT SERVICE

1.0 This Service Agreement, dated as of _______, including the specifications for Retail Firm Local Point-To-Point Service attached hereto and incorporated herein, is entered into, by and between Emera Maine and ______________, ("Transmission Customer") (hereinafter referred to individually as "Party" or collectively as "Parties").

2.0 The Transmission Customer has been determined by Emera Maine to have a completed application for Firm Point-To-Point Service under Schedule 21 and Schedule 21-EM of the OATT and to have satisfied the conditions for service imposed by Schedule 21 and Schedule 21-EM of the OATT to the extent necessary to obtain service with respect to its participation in the State of Maine's retail access program.

3.0 Service under this agreement shall commence on the later of: (1) __________, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as permitted by the Commission. Service under this Service Agreement shall terminate on _________, unless earlier terminated for default. Upon termination the Transmission Customer will remain responsible for any outstanding charges incurred under Schedule 21 and Schedule 21-EM of the OATT and this Service Agreement, including any costs incurred and apportioned or assigned to the Transmission Customer by FERC, including any costs associated with Direct Assignment Facilities and/or Network Upgrades.

4.0 The Transmission Customer agrees to supply information Emera Maine deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Customer has provided Emera Maine with assurance of creditworthiness in accordance with the provisions of Section 11 of Schedule 21-EM of the OATT. The Transmission Customer has provided an application deposit in the amount of $_________ in accordance with the provisions of Schedule 21-EM of the OATT.

6.0 If the Transmission Customer is a Designated Agent delivering power to retail customers, the Transmission Customer represents and warrants that it is duly authorized to sign this agreement on behalf of its retail customers and shall provide reasonable documentation upon request demonstrating such authorization.

7.0 Emera Maine agrees to provide and the Transmission Customer agrees to take and pay for Retail Firm Local Point-To-Point Service in accordance with the provisions of Schedule 21 and Schedule 21-EM of the OATT, and this Service Agreement. Retail Transmission Customers taking service directly or through a Designated Agent pursuant to this Service Agreement and under Schedule 21 and Schedule 21-EM of the OATT shall continue to pay Maine Public Utilities Commission ordered stranded costs and other distribution-related cost, as applicable. If the Transmission Customer is a Designated Agent delivering power to retail customers and taking transmission service on their behalf, the Transmission Customer agrees that Emera Maine shall collect receipts for applicable transmission and ancillary charges (except for Energy Imbalance Service) directly from retail customers served by Emera Maine unless other mutually agreeable provisions for payment are made. Emera Maine shall bill directly the Designated Agent, if it is not Emera Maine, for Energy Imbalance Service.

8.0 Monthly bills will be sent to the Transmission Customer at the following address:

____

____

____

9.0 Payment to Emera Maine by the Transmission Customer must be made by electronic wire transfer or such other means as will cause payment to be available for Emera Maine's use on the date payment is due. Unless other arrangements are made with Emera Maine, the Transmission Customer shall transfer all payments by wire to the following:

Bank: _______________________

ABA No.: ____________________

Account Name: _______________

Account No.: _________________

10.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Emera Maine:

____

____

____

Transmission Customer:

____

____

____

11.0 The OATT (including Schedule 21 and Schedule 21-EM) are incorporated herein and made a part hereof.

12.0 Nothing contained in this Service Agreement shall be construed as affecting in any way Emera Maine's right unilaterally to file with FERC, or to make application to FERC, or other regulatory bodies having jurisdiction for changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act, and pursuant to FERC's rules and regulations promulgated thereunder, or under applicable statutes or regulations or the Transmission Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

13.0 This Service Agreement may be executed in any number of counterparts with the same effect as if all parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

14.0 The OASIS Standards and Protocols document states that if a Transmission Provider approves a request for service, the Transmission Customer must confirm. Once the Transmission Customer confirms an approved purchase, a reservation is considered to exist. In order for a request to remain valid, the Transmission Customer must confirm within the following time periods or the request is deemed withdrawn:

Transmission Provider approves request within _______________	Transmission Customer must confirm within ___________ or request

before start of service	is deemed withdrawn
24 hours or less	1 hour
25-48 hours	24 hours before transaction begins
2-6 days	24 hours
7-30 days	72 hours
31-90 days	1 week
90 days or more	15 days

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Emera Maine:

By:_____________________ _______________ _______________

Name Title Date

Transmission Customer:

By:_____________________ _______________ _______________

Name Title Date

Specifications For Retail Firm Local Point-To-Point Service

1.0 Term of Service: ____

Start Date: ____

Termination Date: ____

2.0 Description of capacity and energy to be transmitted by Emera Maine including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt: ____

Delivery Party: ____

4.0 Point(s) of Delivery: ____

Receiving Party: ____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): ____

6.0 Designation of Party subject to reciprocal service obligation: ______________________

7.0 Name(s) of any intervening systems providing transmission service:

____

____

8.0 Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of Schedule 21 and Schedule 21-EM of the OATT)

8.1 Transmission Charge:

____

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:

____

____

8.4 Ancillary Services Charges:

Schedule 1 (Scheduling): ____

Schedule 2 (Reactive Supply): ____

Schedule 3 (Regulation): ____

Schedule 4 (Energy Imbalance): ____

Schedule 5 (Spinning Reserve): ____

Schedule 6 (Supplemental Reserve): _____________________________________

8.5 Losses: ____

8.6 Taxes: ____

8.7 Local Distribution Costs: ____

9.0 Description of Method of Supplying of Losses: __________________________________

____

10.0 Source of supply of each Ancillary Service not provided by Emera Maine:

ATTACHMENT M-EM

UMBRELLA SERVICE AGREEMENT FOR RETAIL NON-FIRM LOCAL POINT-TO-POINT SERVICE

1.0 This Service Agreement, dated as of _______, including the specifications for Retail Non-Firm Local Point-To-Point Service attached hereto and incorporated herein, is entered into, by and between Emera Maine and ______________, ("Transmission Customer") (hereinafter referred to individually as "Party" or collectively as "Parties").

2.0 The Transmission Customer has been determined by Emera Maine to have a completed application for Non-Firm Local Point-To-Point Service under Schedule 21 and Schedule 21-EM of the OATT and to have satisfied the conditions for service imposed by Schedule 21 and Schedule 21-EM of the OATT to the extent necessary to obtain service with respect to its participation in the State of Maine's retail access program.

3.0 Service under this agreement shall commence on the later of: (1) __________, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as permitted by the Commission. Service under this Service Agreement shall terminate on _________, unless earlier terminated for default. Upon termination the Transmission Customer will remain responsible for any outstanding charges incurred under Schedule 21 and Schedule 21-EM of the OATT and this Service Agreement, including any costs incurred and apportioned or assigned to the Transmission Customer by FERC, including any costs associated with Direct Assignment Facilities and/or Network Upgrades.

4.0 The Transmission Customer agrees to supply information Emera Maine deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Customer has provided Emera Maine with assurance of creditworthiness in accordance with the provisions of Section 11 of Schedule 21-EM of the OATT.

6.0 If the Transmission Customer is a Designated Agent delivering power to retail customers, the Transmission Customer represents and warrants that it is duly authorized to sign this agreement on behalf of its retail customers and shall provide reasonable documentation upon request demonstrating such authorization.

7.0 Emera Maine agrees to provide and the Transmission Customer agrees to take and pay for Retail Non-Firm Local Point-To-Point Service in accordance with the provisions of Schedule 21 and Schedule 21-EM of the OATT and this Service Agreement. Retail Transmission Customers taking service directly or through a Designated Agent pursuant to this Service Agreement and under Schedule 21 and Schedule 21-EM of the OATT shall continue to pay Maine Public Utilities Commission ordered stranded costs and other distribution-related costs, as applicable. If the Transmission Customer is a Designated Agent delivering power to retail customers and taking transmission service on their behalf, the Transmission Customer agrees that Emera Maine shall collect receipts for applicable transmission and ancillary charges (except for Energy Imbalance Service) directly from retail customers served by Emera Maine, unless other mutually agreeable provisions for payment are made. Emera Maine shall bill directly the Designated Agent, if it is not Emera Maine, for Energy Imbalance Service.

8.0 Monthly bills will be sent to the Transmission Customer at the following address:

____

____

____

9.0 Payment to Emera Maine by the Transmission Customer must be made by electronic wire transfer or such other means as will cause payment to be available for Emera Maine's use on the date payment is due. Unless other arrangements are made with Emera Maine, the Transmission Customer shall transfer all payments by wire to the following:

Bank: ______________________

ABA No.: ___________________

Account Name: ______________

Account No.: ________________

10.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Emera Maine:

____

____

____

Transmission Customer:

____

____

____

11.0 The OATT (including Schedule 21 and Schedule 21-EM) are incorporated herein and made a part hereof.

12.0 Nothing contained in this Service Agreement shall be construed as affecting in any way the Emera Maine's right unilaterally to file with FERC, or to make application to FERC, or other regulatory bodies having jurisdiction for changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act, and pursuant to FERC's rules and regulations promulgated thereunder, or under applicable statutes or regulations, or the Transmission Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

13.0 This Service Agreement may be executed in any number of counterparts with the same effect as if all parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

EMERA MAINE:

By:______________________ ________________ ________________

Name Title Date

Transmission Customer:

By:______________________ ________________ ________________

Name Title Date

Specifications For Retail Non-Firm Local Point-To-Point Service

1.0 Term of Service: ____

Start Date: ____

Termination Date: ____

2.0 Description of capacity and energy to be transmitted by Emera Maine including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt: ____

Delivery Party: ____

4.0 Point(s) of Delivery: ____

Receiving Party: ____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

____

6.0 Designation of Party subject to reciprocal service obligation: ______________________

7.0 Name(s) of any intervening systems providing transmission service:

____

____

8.0 Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of Schedule 21 and Schedule 21-EM of the OATT.)

8.1 Transmission Charge:

____

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:

____

____

8.4 Ancillary Services Charges:

Schedule 1 (Scheduling): ____

Schedule 2 (Reactive Supply): ____

Schedule 3 (Regulation): ____

Schedule 4 (Energy Imbalance): ____

Schedule 5 (Spinning Reserve): ____

Schedule 6 (Supplemental Reserve): _______________________________________

8.5 Losses: ____

8.6 Taxes: ____

8.7 Local Distribution Costs: ____

9.0 Description of Method of Supplying of Losses: ___________________________________

____

10.0 Source of supply of each Ancillary Service not provided by Emera Maine:

____

ATTACHMENT N-EM

UMBRELLA SERVICE AGREEMENT FOR RETAIL LOCAL NETWORK SERVICE

1.0 This Service Agreement, dated as of ___________, including the specifications for Retail Local Network Service attached hereto and incorporated herein, is entered into, by and between Emera Maine, and ______________, ("Network Customer") (hereinafter referred to individually as "Party" or collectively as "Parties").

2.0 A retail customer of Emera Maine that does not elect to (i) take transmission service directly from Emera Maine, or (ii) take transmission service from Emera Maine through a Designated Agent other than Emera Maine, shall be deemed to take Retail Local Network Service from Emera Maine as its Designated Agent. Such retail customer is not required to sign a Service Agreement, but shall take Retail Local Network Service from the Emera Maine as its Designated Agent under this Service Agreement. A retail customer that takes at least 500 KW of transmission service in any one hour in the calendar year from Emera Maine and takes Retail Local Network Service from Emera Maine as its Designated Agent is not required to sign a Service Agreement for Retail Local Network Service, unless Emera Maine must construct either Direct Assignment Facilities or Network Upgrades in order to provide Transmission Service to the retail customer.

3.0 If an application is required under Schedule 21 and Schedule 21-EM of the OATT, the Network Customer has been determined by Emera Maine to have a completed application for Local Network Service under Schedule 21 and Schedule 21-EM of the OATT and to have satisfied the conditions for service imposed by Schedule 21 and Schedule 21-EM of the OATT to the extent necessary to obtain service with respect to its participation in the State of Maine's retail access program.

4.0 Service under this agreement shall commence on the later of: (1) __________, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as permitted by the Commission. The Service Agreement shall be effective for an initial term of one year for a retail customer taking Retail Local Network Service directly from Emera Maine or through a Designated Agent other than Emera Maine or for any Network Customer required to execute a Service Agreement or provide notice that an unexecuted Service Agreement should be filed. Thereafter, it will continue from year to year unless terminated by the Network Customer or Emera Maine by giving the other one-year advance written notice or by mutual agreement of the Parties, unless earlier terminated for default. The Service Agreement shall be effective for an initial term of one of Emera Maine's typical monthly billing cycles for retail customers taking Retail Local Network Service from Emera Maine as their Designated Agent that are not required to execute a Service Agreement or provide notice that an unexecuted Service Agreement should be filed. Thereafter, it will continue from typical monthly billing cycle to typical monthly billing cycle unless terminated by the Network Customer or Emera Maine by giving the other one month advance written notice or by a mutual agreement of the Parties, unless earlier terminated. Upon termination the Network Customer shall remain responsible for any outstanding charges incurred under Schedule 21 and Schedule 21-EM of the OATT and this Service Agreement, including any costs incurred and apportioned or assigned to the Network Customer by FERC, including any costs associated with Direct Assignment Facilities and/or Network Upgrades.

5.0 The Network Customer agrees to supply information Emera Maine deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

6.0 The Network Customer has provided Emera Maine with assurance of creditworthiness in accordance with the provisions of Section 7 of Schedule 21-EM of the OATT.

7.0 If the Network Customer is a Designated Agent delivering power to retail customers, the Network Customer represents and warrants that it is duly authorized to sign this agreement on behalf of its retail customers and shall provide reasonable documentation upon request demonstrating such authorization.

8.0 Emera Maine agrees to provide and the Network Customer agrees to take and pay for Retail Local Network Service in accordance with the provisions of Schedule 21 and Schedule 21-EM of the OATT and this Service Agreement. Retail customers taking service directly or through a Designated Agent pursuant to this Service Agreement and under Schedule 21 and Schedule 21-EM of the OATT shall continue to pay Maine Public Utilities Commission ordered stranded costs and other distribution-related costs, as applicable. If the Network Customer is a Designated Agent delivering power to retail customers and taking transmission service on their behalf, the Network Customer agrees that Emera Maine shall collect receipts for applicable transmission and ancillary charges (except for Energy Imbalance Service) directly from retail customers served by Emera Maine unless other mutually agreeable provisions for payment are made. Emera Maine shall bill directly the Designated Agent, if it is not Emera Maine, for Energy Imbalance Service.

9.0 Monthly bills will be sent to the Network Customer at the following address:

____

____

____

10.0	Payment to Emera Maine by the Network Customer must be made by electronic wire transfer or such other means as will cause payment to be available for Emera Maine's use on the date payment is due. Unless other arrangements are made with Emera Maine, the Network Customer shall transfer all payments by wire to the following:

Bank: _______________________

ABA No.: ____________________

Account Name: _______________

Account No.: _________________

11.0	Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Emera Maine:

____
____
____

Network Customer:

____
____
____

12.0	The OATT (including Schedule 21 and Schedule 21-EM) are incorporated herein and made a part hereof.

13.0	Nothing contained in this Service Agreement or any associated Operating Agreement shall be construed as affecting in any way Emera Maine's right unilaterally to file with FERC, to make application to FERC, or other regulatory bodies having jurisdiction for changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act, and pursuant to FERC's rules and regulations promulgated thereunder, or under applicable statutes or regulations; or the Network Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

14.0 This Service Agreement may be executed in any number of counterparts with the same effect as if all parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

EMERA MAINE:

By:______________________ ________________ ________________

Name Title Date

Network Customer:

By:______________________ ________________ ________________

Name Title Date

Specifications For Retail Local Network Service

1.0 Term of Service: ____

Start Date: ____

Termination Date: ____

2.0 Description of capacity and energy to be transmitted by Emera Maine including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt: ____

Delivery Party: ____

4.0 Point(s) of Delivery: ____

Receiving Party: ____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved

Capacity): ____

6.0 Designation of Party subject to reciprocal service obligation: _____________________

7.0 Name(s) of any intervening systems providing transmission service:

____

____

8.0 Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of Schedule 21 and Schedule 21-EM of the OATT.)

8.1 Transmission Charge:

____

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:

____

____

8.4 Ancillary Services Charges:

Schedule 1 (Scheduling): ____

Schedule 2 (Reactive Supply): ____

Schedule 3 (Regulation): ____

Schedule 4 (Energy Imbalance): ____

Schedule 5 (Spinning Reserve): ____

Schedule 6 (Supplemental Reserve): _____________________________________

8.5 Losses: ____

8.6 Taxes: ____

8.7 Local Distribution Costs: ____

9.0 Description of Method of Supplying of Losses: __________________________________

____

10.0 Source of supply of each Ancillary Service not provided by Emera Maine:

____

ATTACHMENT O-EM

UMBRELLA NETWORK OPERATING AGREEMENT FOR RETAIL LOCAL NETWORK SERVICE

1.0 This Network Operating Agreement, dated as of ________, is entered into, by and between Emera Maine and _________________ ("Network Customer") (hereinafter referred to individually as "Party" or collectively as "Parties").

2.0 The Network Customer has been determined by Emera Maine to have a completed application for Local Network Service under Schedule 21 and Schedule 21-EM of the OATT and to have satisfied the conditions for service imposed by Schedule 21 and Schedule 21-EM of the OATT to the extent necessary to obtain service with respect to its participation in the State of Maine's retail access program.

3.0 The Parties have entered into a Service Agreement for Retail Local Network Service under Schedule 21-EM of the OATT.

4.0 All terms used in this Operating Agreement shall have the meaning defined in Schedule 21 and Schedule 21-EM of the OATT unless a different definition is specifically provided for herein.

5.0 Emera Maine and the Network Customer agree that the provisions of this Operating Agreement, the Service Agreement for Retail Local Network Service, and Schedule 11-EM of Schedule 21-EM of the OATT govern Emera Maine's provision of Retail Local Network Service to the Network Customer in accordance with Schedule 21 and Schedule 21-EM of the OATT, as it may be amended from time to time.

6.0 Power and energy transmitted by Emera Maine for the Network Customer shall be delivered as three-phase alternating current at a frequency of approximately 60 Hertz, and at the nominal voltages at the delivery and receipt points. When multiple delivery points are provided to a specific Network Load, they shall not be operated in parallel by the Network Customer without the approval of Emera Maine. Emera Maine and the Network Customer shall also establish and monitor standards and operating rules and procedures to assure that BHD Transmission System integrity and the safety of customer, the public, and employees are maintained or enhanced when such parallel operation is permitted either on a continuing basis or for intermittent switching or other service needs. Each Party shall exercise due diligence and reasonable care in maintaining and operating its facilities so as to maintain continuity of service.

7.0 Emera Maine reserves the right to inspect the facilities and operating records of a Network Customer upon mutually agreeable terms and conditions.

8.0 The Network Customer shall be required at all times to maintain, consistent with North American Electric Reliability Council ("NERC") and Northeast Power Coordinating Council ("NPCC") guidelines, a balance between its owned or purchased generation resources and load. The provision of Transmission Service under Schedule 21 and Schedule 21-EM of the OATT is not an offer to provide generation sufficient to meet the Network Customer's load requirements. The Network Customer must meet its load reliability either through the construction and ownership of generation facilities and/or the purchase of power from a third party and the purchase of such Ancillary Services from Emera Maine or a third party.

9.0 The Network Customer shall purchase in appropriate amounts all of the required Ancillary Services described in Schedule 21 and Schedule 21-EM of the OATT from Emera Maine or, where applicable, self-supply or obtain these services from other providers. Where the Network Customer elects to self-supply or have others provide Ancillary Services, the Network Customer must demonstrate that it has either acquired the Ancillary Services from another source or is capable of self-supplying the services. The Network Customer must designate the supplier of Ancillary Services.

10.0 Emera Maine reserves the right to take whatever actions it deems necessary to preserve the reliability and integrity of its electric system, limit or prevent damage, expedite restriction of service, ensure safe and reliable operation, avoid adverse effects on the quality of service, or preserve public safety. If the Transmission Service is causing harmful physical effects to the BHD Transmission System facilities or to its customers (e.g., harmonics, undervoltage, overvoltage, flicker, voltage variations, etc.), Emera Maine shall promptly notify the Network Customer and if the Network Customer does not take the appropriate corrective actions immediately, Emera Maine shall have the right to interrupt Transmission Service in order to alleviate the situation and to suspend all or any portion of the Transmission Service until appropriate corrective action is taken.

11.0 If the function of any Party's facilities is impaired, the capacity of any delivery point is reduced, or synchronous operation at any delivery point(s) becomes interrupted, either manually or automatically, as a result of force majeure or maintenance coordinated by the Parties, the Parties will cooperate to remove the cause of such impairment, interruption, or reduction, so as to restore normal operating conditions expeditiously.

12.0 It is recognized by the Parties that the BHD Transmission System is, and will be, directly or indirectly interconnected with BHD Transmission Systems owned or operated by others, that the flow of power and energy between such systems will be controlled by the physical and electrical characteristics of the facilities involved and the manner in which they are operated, and that part of the power and energy being delivered under this Operating Agreement may flow through such other systems rather than through the facilities of Emera Maine. Each Party will at all times cooperate with other interconnected systems in establishment of arrangements that may be necessary to relieve any hardship in such other systems and in the systems of the other entities caused by energy flows of scheduled deliveries hereunder.

13.0 No later than December 15 of each year, the Network Customer shall provide Emera Maine the following information:

a) a three (3) year projection of monthly peak demands with the corresponding power factors and annual energy requirements on an aggregate basis for each delivery point. If there is more than one delivery point, provide the monthly peak demands and energy requirements at each delivery point for the normal operating configuration;

b) a three (3) year projection by month of planned generating capabilities and committed transactions with third parties which resources are expected to be used by the Network Customer to supply the peak demand and energy requirements provided in (a);

c) a three (3) year projection by month of the estimated maximum demand in kilowatts that the Network Customer plans to acquire from the generation resources owned by the Network Customer, and generation resources purchased from others;

d) a projection for each of the next three (3) years of transmission facility additions to be owned and/or constructed by the Network Customer which facilities are expected to affect the planning and operation of the BHD Transmission System.

Information exchanged by the Parties under Section 13 will be used for system planning and protection only, and will not be disclosed to third parties absent mutual consent or order of a court or regulatory agency.

Emera Maine will incorporate this information in its system load flow analyses performed during the first half of each year. Following the completion of these analyses, Emera Maine will provide the following to the Network Customer only in the event of a constraint or a partial limitation:

a) A statement regarding the ability of the BHD Transmission System to meet the forecast deliveries at each of the delivery points;

b) A detailed description of any constraints on Emera Maine's system within the three (3) year horizon that will restrict forecast deliveries.

c) In the event that studies reveal a potential limitation of Emera Maine's ability to deliver power and energy to any of the delivery points, Emera Maine and Network Customer shall identify appropriate remedies for such constraints including but not limited to: construction of new transmission facilities, upgrade or other improvements to existing transmission facilities, or temporary modification to operation procedures designed to relieve identified constraints. Emera Maine will, consistent with Good Utility Practice, endeavor to construct and place into service sufficient transmission capacity to maintain reliable service to the Network Customer. An appropriate sharing of the costs to relieve such constraints will be determined by the Parties, consistent with FERC rules, regulations, policies, and precedents then in effect. If the Parties are unable to agree upon an appropriate remedy or sharing of the costs, Emera Maine shall submit its proposal for the remedy or sharing of such costs to the FERC for approval consistent with Schedule 21 and Schedule 21-EM of the OATT.

14.0 Prior to service commencing under this Operating Agreement and the Service Agreement for Retail Local Network Service, and prior to the beginning of each month thereafter, the Network Customer shall provide to Emera Maine, the Network Customer's daily peak load expressed in terms of tenths of a megawatt and shall include all losses within the BHD Transmission System.

15.0 Prior to the beginning of each month, the Network Customer shall provide to Emera Maine forward hourly loads and energy schedules for all energy flowing into the BHD Transmission System.

16.0 The Network Customer shall provide Emera Maine, at least twelve (12) hours in advance of every calendar day, Network Customer's hourly energy schedules for the next calendar day for all energy flowing into the BHD Transmission System. The Network Customer may modify its hourly energy schedules up to twenty (20) minutes before the start of the next clock hour. The hourly schedule must be stated in increments of tenths of a megawatt and shall include all losses within the BHD Transmission System. These hourly schedules will be used by Emera Maine to determine whether any Energy Imbalance Service charges apply, pursuant to Schedule 4 of the OATT and Schedule 4-EM of Schedule 21-EM of the OATT.

17.0 The procedures by which a Network Customer will determine the peak and hourly loads reported to Emera Maine pursuant to this Operating Agreement may be set forth in a separate schedule to this Operating Agreement. Load distribution profiles of customer classes may be used to determine peak and hourly loads.

18.0 Prior to service commencing under this Operating Agreement and the Service Agreement for Retail Local Network Service, the Network Customer shall designate its Network Resources consistent with Schedule 21 and Schedule 21-EM of the OATT. Consistent with Schedule 21 and Schedule 21-EM of the OATT, changes in the designation of Network Resources will be treated as an application for modification of service.

19.0 In accordance with Part II.4.d of Schedule 21 and Section 33 of Schedule 21-EM of the OATT, the ISO and/or Emera Maine may require redispatching of generation resources or curtailment of loads to relieve existing or potential BHD Transmission System constraints.

20.0 The Network Customer and Emera Maine shall implement load-shedding procedures to maintain the reliability and integrity of the BHD Transmission System as provided in Section 45 of the OATT and in accordance with applicable NERC and NPCC requirements and Good Utility Practice. Load shedding may include (1) automatic load shedding, (2) mutual load shedding, and (3) rotating interruption of customer load. When manual load shedding or rotating interruptions are necessary, Emera Maine shall notify the Network Customer of the required action and the Network Customer shall comply immediately.

21.0 This Operating Agreement shall become effective, and remain in effect, for the same term as the term of the Retail Local Network Service Agreement entered into by Emera Maine and Network Customer pursuant to which Emera Maine will provide Retail Local Network Service under Schedule 21 and Schedule 21-EM of the OATT.

22.0 Any dispute among the Parties regarding this Operating Agreement shall be resolved pursuant to Section 12 of Schedule 21-EM of the OATT, or otherwise, as mutually agreed by the Parties.

23.0 This Operating Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns, but shall not be assigned by any Party, except to successors to all or substantially all of the electric properties and assets of such Party, without the written consent of the others. Such written consent shall not be unreasonably withheld.

24.0 The interpretation, enforcement, and performance of this Operating Agreement shall be governed by the laws of the State of Maine, except laws and precedent of such jurisdiction concerning choice of law shall not be applied.

25.0 The OATT (including Schedule 21 and Schedule 21-EM) and Retail Local Network Service Agreement, as they are amended from time to time, are incorporated herein and made a part hereof. To the extent that a conflict exists between the terms of this Operating Agreement and the terms of Schedule

21 and Schedule 21-EM of the OATT, Schedule 21 and Schedule 21-EM of the OATT shall control.

26.0 Nothing contained in this Operating Agreement or any associated Service Agreement shall be construed as affecting in any way Emera Maine's right unilaterally to file with FERC, or make application to FERC, or other regulatory body for changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act and pursuant to FERC's rules and regulations promulgated thereunder, or under other applicable statutes or regulations, or to the Network Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

27.0 Except as otherwise provided, any notice that may be given to or made upon any Party by the other Party under any of the provisions of the Operating Agreement shall be in writing, unless otherwise specifically provided herein and shall be considered delivered when the notice is either personally delivered or deposited in the United States mail, certified, or registered postage prepaid, to the following:

Emera Maine

[name]

[title][address]

[phone]

[fax]

Network Customer

[name]

[title]

[address]

[phone]

[fax]

Any notice, request, or demand pertaining to operating matters may be delivered in person or by first class mail, messenger, telephone, telegraph, or facsimile transmission as may be appropriate and shall be confirmed in writing as soon as practical thereafter, if any Party so requests in any particular instance.

28.0 This Operating Agreement may be executed in any number of counterparts with the same effect as if all parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

IN WITNESS WHEREOF, the Parties have caused this Operating Agreement to be executed by their respective authorized officials:

EMERA MAINE: Date:

By: ______________________________ _______________

TRANSMISSION CUSTOMER: Date:

By: ______________________________ _______________

ATTACHMENT P-EM

FORMULAIC RATES DESCRIPTION

I. INTRODUCTION

This Attachment P-EM sets forth details with respect to the determination each year of Emera Maine's Transmission Revenue Requirement and its Scheduling Revenue Requirement. Except where otherwise noted or where the context otherwise indicates, all values referenced herein shall be understood to be end of year or full calendar year values as reflected on Emera Maine's FERC Form 1 ("FF1").

The Transmission Revenue Requirement will reflect the costs for the BHD Transmission System, as detailed in Section III below. The Transmission Revenue Requirement will be calculated annually, effective each June 1, based in part on the previous calendar year's data and the FF1 data for that previous year (the "Reported Year"), and based in part on forecasted amounts. The calendar year immediately following the Reported Year is referred to herein as the "Forecast Period." Reported Year load, revenue and sales data may be adjusted, as appropriate, to reflect known and measurable anticipated changes for the subject rate year. To the extent any such adjusted data used in the annual calculation of charges differs from actual data for the Forecast Period, Emera Maine will apply a true-up (equal to the difference between adjusted and actual data multiplied by the applicable tariff rate), with interest, through the Annual True-Up with Interest provided for in Section III.N, herein.

The Scheduling Revenue Requirement will reflect the costs of provision of the Ancillary Service "Scheduling, System Control and Dispatching Service" ("Scheduling") for the BHD Transmission System, as detailed in Section IV below. The Scheduling Revenue Requirement will be calculated annually, effective each June 1, based on the previous calendar year's data and the FF1 data for the Reported Year.

If and to the extent such FF1 data are not applicable to the BHD in whole or in part, such data (i) where practicable, will be expressly excluded from the calculations in this Attachment P-EM (*i.e.*, directly assigned to an Emera Maine business unit other than the BHD) or (ii) allocated between the BHD and one or more other business units of Emera Maine, as detailed herein.

Retail transmission price changes will take effect contemporaneously with annual changes to distribution rates. The transmission revenue effect of any difference (positive or negative) between when transmission price changes would normally occur (June 1) and when they actually occur will be accrued with interest, calculated pursuant to Section 35.19a of FERC's regulations and included in the next determination of transmission prices for retail transmission customers.

Subject to the foregoing, separate Transmission Revenue Requirements will be calculated pursuant to this Attachment P-EM, applicable to the following:

A. Wholesale Load on the BHD Transmission System
   1. for Non-Pool Transmission Facilities ("PTF") Service
   2. for PTF Service
   3. for Emera Maine's unit costs of acting as customer's agent for service

B. Wheeling Off the BHD Transmission System (Non-PTF Service)

C. Retail Load on the BHD Transmission System
   1. for Non-PTF Service
   2. for PTF Service
   3. for Emera Maine's unit costs of acting as customer's agent for service

Each revenue requirement will be calculated in accordance with the general formula set forth in Section III (modified, as appropriate, for each specified revenue requirement in accordance with the detailed provisions of this Attachment P-EM).

Capitalized terms not otherwise defined in Section 1 of the OATT and as used in this Attachment P-EM have the definitions provided herein.

II. ALLOCATORS/ADJUSTMENT FACTORS

This Section II establishes three types of allocation factors (allocators) to be used in this Attachment P-EM: (i) factors that allocate values between the BHD and other Emera Maine business units ("Company Allocators"), (ii) factors that allocate values within the BHD, such as between transmission and distribution, or between PTF and non-PTF ("BHD Allocators"), and (iii) a factor that allocators values based on salaries and wages. Additionally, this Section establishes an adjustment factor based on the Settlement reached in Docket No. ER00-980-000 on November 1, 2000.

A. Definitions

For purposes of this Section II, the following terms shall be defined as follows.

(1) BHD Total Transmission Plant (Recorded) shall equal the balance of Account Nos. 350-359.1 [FF1 at 207:58g] as directly assigned to the BHD, excluding any values for transmission investments for which Emera Maine received up-front customer contributions that it does not have to repay.

(2) BHD Total Transmission Plant (Adjusted) shall equal:

(a) BHD Total Transmission Plant (Recorded), less

(b) the amounts therein applicable to generator step-ups and generator radial lines, plus

(c) the gross book value of distribution plant reclassified to transmission in accordance with the FERC approved jurisdictional delineation of facilities for retail transmission,

provided that the foregoing values in

(a), (b), and (c) reflect values for BHD only and exclude any values for transmission investments for which Emera Maine received up-front customer contributions that it does not have to repay.

B. Allocators

(1) Company Allocators

(a) Company Customer Count Allocator (BHD) shall equal:

(i) the number of BHD customers contributing to the total average number of customers per rate schedule as reported on FF1 at 304:43d, divided by

(ii) the total of average number of customers per rate schedule as reported on FF1 at 304:43d.

(b) Company Customer/Load/Sales Allocator (BHD) shall equal:

(i) Company Customer Count Allocator (BHD) divided by three, plus

(ii) Company Monthly Peak Loads Allocator (BHD) divided by three, plus

(iii) Company Energy Sales Allocator (BHD) divided by three.

(c) Company Customer/Revenue Allocator (BHD) shall equal:

(i) the Company Revenue Allocator (BHD) (described below) divided by two, plus

(ii) the Company Customer Count Allocator (BHD) (described below) divided by two.

(d) Company Customer/Sales Allocator (BHD) shall equal:

(i) Company Customer Count Allocator (BHD) divided by two, plus

(ii) Company Energy Sales Allocator (BHD) divided by two.

(e) Company Energy Sales Allocator (BHD) shall equal:

(i) the contribution by BHD loads to the total quantity of electricity sold for the year as reported on FF1 at 304:43b, divided by

(ii) the total quantity of electricity sold for the year as reported on FF1 at 304:43b.

(f) Company Monthly Peak Loads Allocator (BHD) shall equal:

(i) the contribution by BHD loads to the total of monthly peak loads for the year as reported on FF1 at 400:17b, divided by

(ii) the total of monthly peak loads for the year as reported on FF1 at 400:17b.

(g) Company Revenue Allocator (BHD) shall equal:

(i) the contribution by BHD loads to the revenues from electricity sales as reported on FF1 at 304:43c, divided by

(ii) total Emera Maine revenues from electricity sales as reported on FF1 at 304:43c.

(h) Company Total Plant Allocator (BHD) shall equal:

(i) the value reported as Total Electric Plant in Service on FF1 at 207:104g as directly assigned to the BHD, divided by

(ii) the value reported as Total Electric Plant in Service on FF1 at 207:104g.

(2) BHD Allocators

(a) BHD Plant Allocator (Transmission) shall equal:

(i) BHD Total Transmission Plant (Adjusted) plus Transmission-Related General and Intangible Plant (defined in Section III.A.1.b below), divided by

(ii) the value reported as Total Electric Plant in Service on FF1 at 207:104g as directly assigned to the BHD.

(b) BHD Revenue Allocator (Transmission) shall equal:

(i) the contribution by BHD loads to that amount of revenues reported on FF1 at 304:43c attributable to transmission service (either bundled or unbundled), divided by

(ii) the contribution by BHD loads to total revenues as reported on FF1 at 304:43c.

(c) BHD Transmission Plant Allocator (PTF) shall equal:

(i) the balance of Account Nos. 350-359.1 [FF1 at 207:58g] attributable to PTF based on company records, excluding any values for transmission investments for which Emera Maine received up-front customer contributions that it does not have to repay, divided by

(ii) BHD Total Transmission Plant (Adjusted).

(3) Salaries and Wages Allocator, Adjustment Factor

(a) Company Salaries and Wages Allocator (Transmission) shall equal:

(i) transmission salaries and wages as reported on FF1 at 354:21b, divided by

(ii) the difference between (i) total operations and maintenance salaries and wages as reported on FF1 at 354:28b, less (ii) administrative and general salaries and wages as reported on FF1 at 354:27b.

(b) BHD Transmission Plant Adjustment Factor shall equal:

(i) BHD Total Transmission Plant (Adjusted), divided by

(ii) BHD Total Transmission Plant (Recorded).

III. CALCULATION OF TRANSMISSION REVENUE REQUIREMENT

In general, the Transmission Revenue Requirement shall equal:

(A) Return and Associated Income Taxes,

plus (B) Transmission-Related Depreciation Expense,

minus (C) Transmission-Related Amortization of Investment Tax Credits,

plus (D) Transmission-Related Property Tax Expense, plus (E) Transmission-Related Payroll Tax Expense,

plus (F) Transmission Operation and Maintenance Expense,

plus (G) Transmission-Related Administrative and General Expense,

minus (H) Revenues from Point-to-Point Transactions Under the Tariff,

minus (I) Other Transmission-Related Revenues,

plus (J) RNS and ISO Costs,

minus (K) RNS and ISO Revenues,

plus (L) Support Payments,

plus (M) Incremental Forecasted Transmission Revenue Requirement,

plus (N) Annual True-Up with Interest.

For service provided to retail loads in the BHD, the Transmission Revenue Requirement shall also include as part of the Annual True-Up with Interest: (a) the product of (i) Total Customer Accounts Expenses as reported on FF1 at 322:164b multiplied first by (ii) the Company Customer/Revenue Allocator (BHD) and then multiplied by (iii) the BHD Revenue Allocator (Transmission).

Through the application of the BHD Allocators described in Section II.B.2. above, the Transmission Revenue Requirement shall be functionalized between PTF and Non-PTF, resulting in the PTF Revenue Requirement and Non-PTF Revenue Requirement, respectively.

There shall be separately calculated, in addition to the PTF and Non-PTF revenue requirements, Emera Maine's costs of acting as customer's agent for service as directly assigned to the BHD.

A. Return and Associated Income Taxes shall equal Transmission Investment Base multiplied by Cost of Capital Rate.

(1) Transmission Investment Base shall equal:

(a) BHD Total Transmission Plant (Adjusted),

plus (b) Chester SVC Plant,

plus (c) Transmission-Related General and Intangible Plant,

plus (d) Transmission Plant Held for Future Use,

less (e) Transmission-Related Depreciation Reserve,

less (f) Transmission-Related Accumulated Deferred Taxes, plus (g) Other Transmission-Related Regulatory Assets/Liabilities,

plus (h) Transmission-Related Prepayments,

plus (i) Transmission Materials and Supplies,

plus (j) Transmission-Related Cash Working Capital.

(a) BHD Total Transmission Plant (Adjusted) is as defined above and shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

(b) Chester SVC Plant shall equal one-half of the gross value recorded on the books of Chester SVC Partnership of the control system upgrades placed in service in 2014, and shall be directly assigned to PTF function.

(c) Transmission-Related General and Intangible Plant shall equal the following value calculated in the following arithmetic order:

(i) the balance of Account Nos. 301-303 and 389-399.1 [FF1 at 205:5g and 207:99g] as directly assigned to the BHD, less

(ii) any amounts attributable to FERC hydroelectric relicensing recorded in Account No. 302 [FF1 at 205:2g], less

(iii) any Customer Information System ("CIS") costs recorded in Account No. 303 [FF1 at 205:4g] as directly assigned to the BHD, multiplied by

(iv) Company Salaries and Wages Allocator (Transmission), plus

(v) the CIS costs recorded in Account No. 303 [FF1 at 205:4g] multiplied by the BHD Revenue Allocator (Transmission).

The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

(d) Transmission Plant Held for Future Use shall equal the balance recorded in Account No. 105 attributable to transmission plant as directly assigned to the BHD [FF1 at 214:d] multiplied by the BHD Transmission Plant Adjustment Factor and further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

(e) Transmission-Related Depreciation Reserve shall equal:

(i) the balance of Account No. 108 attributable to transmission plant [FF1 at 219:25b] as directly assigned to the BHD Transmission System multiplied by the BHD Transmission Plant Adjustment Factor, plus

(ii) the balance recorded in Account No. 108 attributable to intangible plant and general plant [FF1 219:28b] as directly assigned to the BHD Transmission System, exclusive of any amounts attributable to FERC hydroelectric relicensing or the CIS, multiplied by the Company Salaries and Wages Allocator (Transmission), plus

(iii) the balance recorded in Account No. 108 attributable to the CIS as directly assigned to the BHD multiplied by the BHD Revenue Allocator (Transmission), plus

(iv) one-half of the accumulated depreciation recorded on the books of Chester SVC Partnership of the control system upgrades placed in service in 2014.

The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF), provided however that all Chester SVC amounts shall be directly assigned to PTF function.

(f) Transmission-Related Accumulated Deferred Taxes shall equal:

(i) the balance of Account No. 282 [FF1 at 113:63c] attributable to transmission plant and directly assigned to the BHD, but exclusive of ASC-740 amounts (formerly FASB 109), plus

(ii) the balance of Account No. 282 [FF1 at 113:63c] attributable to general and intangible plant and directly assigned to the BHD, but exclusive of amounts attributable to ASC-740 and the CIS, multiplied by the Company Salaries and Wages Allocator (Transmission), plus

(iii) the balance of Account No. 282 [FF1 at 113:63c] attributable to the CIS as directly assigned to the BHD multiplied by the BHD Revenue

Allocator (Transmission), plus

(iv) the balance of Account No. 283 [FF1 at 113:64c] as directly assigned to the BHD, but exclusive of amounts attributable to property taxes, stranded costs, retail rate-making, affiliated companies, or any ASC-740 amounts, multiplied by the Company Salaries and Wages Allocator (Transmission), plus

(v) the balance of Account No. 283 [FF1 at 113:64c] attributable to property taxes multiplied first by the Company Total Plant Allocator (BHD) and then multiplied by the BHD Plant Allocator (Transmission), plus

(vi) the balance of Account No. 190 [FF1 at 111:82c] as directly assigned to the BHD, exclusive of amounts associated with accrued vacation, stranded costs, retail rate-making, affiliated companies, or any ASC-740 amounts, multiplied by the Company Salaries and Wages Allocator (Transmission), plus

(vii) the balance of Account No. 190 [FF1 at 111:82c] attributable to accrued vacation multiplied first by the Company Customer/Load/Sales Allocator (BHD) and then multiplied by the Company Salaries and Wages Allocator (Transmission).

The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

(g) Other Transmission-Related Regulatory Assets/Liabilities shall equal:

The Company Salaries and Wages Allocator (Transmission) multiplied by the sum of:

(i) pension and post-retirement benefits other than pension amounts recorded in Account Nos. 182.3, 228.3 and 254 [FF1 at 111:72c, 112:29c and 113:60c], as directly assigned to the BHD, plus

(ii) deferred employee transition costs recorded in Account No. 228.3 [FF1 at 112:29c] as directly assigned to the BHD, plus

(iii) pension and post-retirement benefits other than pension amounts reported as Accumulated Other Comprehensive Income [FF1 at 122a:10c] as directly assigned to the BHD.

The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

(h) <u>Transmission-Related Prepayments</u> shall equal the balance of Account No. 165 [FF1 at 111:57c] multiplied first by the Company Total Plant Allocator (BHD) and then multiplied by the Company Salaries and Wages Allocator (Transmission). The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

(i) <u>Transmission Materials and Supplies</u> shall equal the balance of Account No. 154 of transmission plant materials and supplies [FF1 at 227:8c] multiplied by the Company Total Plant Allocator (BHD). The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

(j) <u>Transmission-Related Cash Working Capital</u> shall equal 12.5% (45 days/360 days) multiplied by the sum of Transmission Operation and Maintenance Expense (as defined herein in Section III.F.) and Transmission-Related Administrative and General Expense (as defined herein in Section III.G.), with the resultant value allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF). In addition, the value for Transmission-Related Cash Working Capital for PTF function shall also include 12.5% of the value of Support Payments (as defined herein in Section III.L.).

For calculation of the revenue requirement for transmission service to retail loads, this figure shall also include 12.5% (45 days/360 days) of the product of (i) Total Customer Accounts Expenses as reported on FF1 at 322:164b multiplied first by (ii) the Company Customer/Revenue Allocator (BHD) and then multiplied by (iii) the BHD Revenue Allocator (Transmission).

(2) <u>Cost of Capital Rate</u>

shall equal (a) Weighted Cost of Capital, plus (b) Federal Income Tax, plus (c) State Income Tax.

(a) Weighted Cost of Capital will be calculated based upon the average beginning and end of year capital structure at the end of each year and will equal the sum of:

(i) the long-term debt component, which shall equal the product of Emera Maine's long-term debt cost rate calculated on a net proceeds basis, and the ratio that Total Long-Term Debt as reported on FF1 at 112:24 is to Emera Maine Total Capital (defined below), plus

(ii) the preferred stock component, which shall equal the product of Emera Maine's preferred stock cost rate, and the ratio that Preferred Stock Issued as reported on FF1 at 112:3 is to Emera Maine Total Capital, plus

(iii) the return on equity component, which shall equal the product of 11.14~~10.57~~ percent and the ratio that Emera Maine Common Equity Adjusted (defined below) is to Emera Maine Total Capital,

Where:

(x) Emera Maine Common Equity Adjusted equals (aa) Total Proprietary Capital as reported on FF1 at 112:16 less (bb) goodwill associated with the transactions approved by the Commission in Docket Nos. EC01-13 and EC10-67 less (cc) the balance of Account No. 216.1 [FF1 at 112:12] less (dd) the balance of Account No. 204 [FF1 at 112:3] plus (ee) the absolute value of the balance of Account No. 219 [FF1 at 112:15]; and

(y) Emera Maine Total Capital equals (aa) Total Long-Term Debt as reported on FF1 at 112:24 plus (bb) Preferred Stock Issued as reported on FF1 at 112:3 plus (cc) Emera Maine Common Equity Adjusted.

(b) Federal Income Tax shall equal:

$$\frac{(A+[(B+C)/D]) \times FT}{1-FT}$$

where

FT = Emera Maine's federal income tax rate;

A = the sum of the preferred stock component and the return on equity component determined in Sections III.A.2.(a)(ii) and (iii) above;

B = Transmission-Related Amortization of Investment Tax Credits, as determined in Section III.C., below;

C = the equity AFUDC component of transmission depreciation expense as directly assigned to the BHD;

D = Transmission Investment Base.

(c) State Income Tax shall equal:

$$\frac{((A+[(B+C)/D]) + E) \times ST}{1-ST}$$

where:

ST = Emera Maine's state income tax rate;

A = the sum of the preferred stock component and return on equity component determined in Sections III.A.2.(a)(ii) and (iii) above;

B = Transmission-Related Amortization of Investment Tax Credits as determined in Section III.C. below;

C = the equity AFUDC component of transmission depreciation expense as directly assigned to the BHD;

D = Transmission Investment Base; and

E = Federal Income Tax calculated in Section III.A.2(b) above.

B. Transmission-Related Depreciation Expense shall equal:

(1) the balance of Account No. 403 attributable to transmission plant as directly assigned to the BHD [FF1 at 336:7b] multiplied by the BHD Transmission Plant Adjustment Factor, plus

(2) the balance of Account No. 403 attributable to intangible plant or general plant [FF1 at 336:1b and 336:10b] as directly assigned to the BHD, exclusive of any amounts attributable to FERC hydroelectric relicensing and the CIS, multiplied by the Company Salaries and Wages Allocator (Transmission),

(3) the balance of Account No. 403 attributable to the CIS as directly assigned to the BHD, multiplied by the BHD Revenue Allocator (Transmission), plus

(4) one-half of the depreciation expense recorded on the books of Chester SVC Partnership of the control system upgrades placed in service in 2014of Chester SVC Partnership.

The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF), provided however that all Chester SVC amounts shall be directly assigned to PTF function.

For purposes of calculating charges under this Schedule 21-EM, the following depreciation rates shall apply:

FERC Account	Description	Proposed Rate
350.2	Rights of Way	1.39%
353	Station Equipment	2.13%
353.1	Station Equipment - SCADA	3.61%
354	Towers and Fixtures	2.19%
354.1	Towers and Fixtures - 115 kV	6.47%
354.2	Towers and Fixtures - 345 kV	2.69%
355	Poles and Fixtures	3.36%
355.1	Poles and Fixtures - 115 kV	3.06%
355.2	Poles and Fixtures - 345 kV	2.69%
355.3	Poles and Fixtures - Steel Poles	2.02%
356	Overhead Conductors and Devices	3.34%
356.1	Overhead Conductors and Devices - 115 kV	2.31%
356.2	Overhead Conductors and Devices - 345 kV	2.51%
357	Underground Conduit	1.41%
358	Underground Conductors and Devices	1.76%
359	Roads and Trails	1.68%
390	Structures and Improvements (Average Rate)	4.83%*
390 - Item	Park Street	2.81%
390 - Item	Main St. - Bus Garage and Store / Boiler Bldg.	15.47%
390 - Item	Main St. - Stockroom	0.55%
390 - Item	Main St. - Quonset Hut	2.35%
390 - Item	Main St. - Meter / Planner Bldg.	0.84%
390 - Item	Eddington	6.10%
390 - Item	Ellsworth Office Bldg. - New	4.05%
390 - Item	Graham Sta. - Internal Combustion Bldg.	0.81%
390 - Item	Graham Sta. - Steam Plant Bldg.	1.19%
390 - Item	Graham Sta. - Transformer Bldg.	2.13%
390 - Item	Graham Sta. - Car Barn	2.69%
390 - Item	Lamoine Service Center	2.74%
390 - Item	Lamoine Transformer Bldg.	0.00%
390 - Item	Lincoln Service Center - New	2.67%
390 - Item	Lincoln Transformer Bldg. (Northern)	2.39%
390 - Item	Machias Transformer Bldg.	1.65%
390 - Item	Machias Division Office	0.75%
390 - Item	Machias Garage and Washbay	2.40%
390 - Item	West Enfield	0.00%
390 - Item	Charleston	2.10%
390 - Item	Hampden Fleet Maintenance Bldg.	1.83%

390 - Item	Hampden Rte. 202 Site	1.81%
390 - Item	Cranberry Isle	1.12%
390 - Item	Illinois Avenue	2.81%
390 - Item	Telecom	2.73%
391.12	Office Furniture and Equipment - PC	25.90%
391.13	Office Furniture and Equipment - Office Machines	14.19%
391.14	Office Furniture and Equipment - Furniture	5.82%
391.15	Office Furniture and Equipment - Unallocated	20.51%
392	Transportation Equipment - Cars	3.18%
393	Stores Equipment	9.47%
394	Tools, Shop and Garage Equipment	5.82%
395	Laboratory Equipment	7.67%
396	Power Operated Equipment - Trucks	6.97%
397.1	Communication Equipment - General Equip.	6.52%
397.2	Communication Equipment - AMR Substation Equip.	4.42%
397.21	Communication Equipment - Fiber	4.28%
397.3	Communication Equipment - General Equip. - SCADA	3.45%
398	Miscellaneous Equipment	6.30%
* This value represents the average rate of the structure-specific depreciation rates that will be applied to Account No. 390.		

C. Transmission-Related Amortization of Investment Tax Credits shall equal the balance of Account No. 411.4 [FF1 at 266:8f] as directly assigned to the BHD multiplied by the BHD Plant Allocator (Transmission). The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

D. Transmission-Related Property Tax Expense shall equal the balance of Account No. 408.1 [FF1 at 114:14c] attributable to property tax multiplied first by the Company Total Plant Allocator (BHD) and then multiplied by the BHD Plant Allocator (Transmission). The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

E. Transmission-Related Payroll Tax Expense shall equal the balance of Account No. 408.1 [FF1 at 263:i] attributable to payroll tax multiplied first by the Company Customer/Load/Sales Allocator (BHD) and then multiplied by the Company Salaries and Wages Allocator (Transmission). The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

F. Transmission Operation and Maintenance Expense shall equal:

(1) the balance of Account Nos. 560, 562-564 and 566-573 [FF1 at 321:83b, 321:93b-95b,

321:97b, 321:98b, 321:111b] attributable to transmission plant and as directly assigned to the BHD, less

(2) expenses for the support of other utilities' facilities recorded in Account Nos. 560, 562-564 and 566-573 [FF1 at 321:83b, 321:93b-95b, 321:97b, 321:98b, 321:111b] attributable to transmission plant and as directly assigned to the BHD, with the resulting difference multiplied by

(3) the BHD Transmission Plant Adjustment Factor.

The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

G. Transmission-Related Administrative and General Expense shall equal:

(1) (a) the balance of Account Nos. 920-935 [FF1 at 323:197b], less (b) the balance of Account Nos. 924 and 928 [FF1 at 323:185b and 323:189b], less (c) the balance of Account No. 923 [FF1 at 323:184b] attributable to regulatory proceedings or regulatory compliance activities, less (d) the balance of account No. 926 attributable to post-retirement benefits other than pensions ("PBOP"), all multiplied first by the Company Customer/Sales Allocator (BHD) and then multiplied by the Company Salaries and Wages Allocator (Transmission), plus

(2) the balance of Account No. 924 [FF1 at 323:185b] multiplied first by the Company Total Plant Allocator (BHD) and then multiplied by the BHD Plant Allocator (Transmission), plus

(3) the balance of Account No. 928 [FF1 at 323:189b] applicable to Commission Annual Charges as required by 18 C.F.R. § 382.201 as directly assigned to BHD and then multiplied by the BHD Transmission Plant Adjustment Factor, plus

(4) the balance of Account No. 928 [FF1 at 323:189b] constituting transmission-related expenses or assessments, other than Commission Annual Charges, and either (a) directly assigned to the BHD or (b) if not so directly assigned, multiplied by the Company Salaries and Wages Allocator (Transmission), plus

(5) the balance of Account No. 923 [FF1 at 323:184b] attributable to regulatory proceedings

or regulatory compliance activities involving the BHD Transmission System or services provided over the BHD Transmission System, multiplied by the BHD Transmission Plant Adjustment Factor, plus

(6) $1,344,505 (a fixed figure for PBOP as directly assigned to the BHD) multiplied by the Company Salaries and Wages Allocator (Transmission), plus

(7) the balance of Account No. 407.3 [FF1 at 114:12c] applicable to pension and post-retirement benefits other than pension regulatory amortization expense, as directly assigned to the BHD and multiplied by the Company Salaries and Wages Allocator (Transmission), plus

(8) the balance of Account No. 407.3 [FF1 at 114:12c] attributable to deferred employee transition costs multiplied by the Company Salaries and Wages Allocator (Transmission).

The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

H. <u>Revenues from Point-to-Point Transactions Under the Tariff</u> shall equal:

(1) the balance of Account No. 456 [FF1 at 300:21b] as directly assigned to the BHD, plus

(2) the transmission component of revenues for sales that use the BHD Non-PTF transmission system, as recorded in Account No. 456.1 [FF1 at 300:22b] (if the transactions are not reflected in adjusted monthly peak loads).

Ninety percent of the resulting value shall be credited only to the Non-PTF Revenue Requirement.

I. <u>Other Transmission-Related Revenues</u> shall equal the sum of the following values as directly assigned to the BHD:

(1) the balance of Account No. 454 [FF1 at 300:19b] attributable to electric property associated with transmission plant multiplied by the BHD Transmission Plant Adjustment Factor, plus

(2) all transmission-related revenues recorded in the balance of Account No. 456 [FF1 at 300:21b] attributable to transmission except: (a) non-penalty revenues associated with the

rolled-in base transmission rates for point-to-point or network transmission service or ancillary services, (b) revenues associated with service provided under the Tariff, (c) revenues associated with operations and maintenance performed on other utilities' facilities; (d) revenues associated with the assignment of Hydro Quebec DC support obligations, and (e) revenues associated with generator radial lines and step-up transformers for which Emera Maine did not receive up-front customer capital contributions, or for which Emera Maine received up-front customer capital contributions that Emera Maine is obligated to repay, plus

(3) the balance of Account No. 454 [FF1 at 300:19b] attributable to rents from the use of general plant multiplied by the Company Salaries and Wages Allocator (Transmission).

The resulting figure shall be further allocated to PTF and Non-PTF functions based on the BHD Transmission Plant Allocator (PTF).

J. RNS and ISO Costs shall equal the transmission payments Emera Maine makes to the ISO for Regional Network Service ("RNS") and all associated regional transmission-related services, such amounts fully assigned to PTF function.

K. RNS and ISO Revenues shall equal the transmission revenues Emera Maine receives from the ISO, less any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment, such amounts fully assigned to PTF function.

L. Support Payments shall equal, as the case may be: (1) PTF support payments (exclusive of such amounts attributable to the Hydro Quebec HVDC tie), such amounts fully assigned to PTF function or (2) Non-PTF integrated support payments (inclusive of such amounts associated with Non-PTF facilities integrated with the BHD Transmission System), such amounts fully assigned to Non-PTF function.

M. Incremental Forecasted Transmission Revenue Requirement shall equal (1) Forecasted Transmission Plant Additions multiplied by the Carrying Charge Factor, plus (2) Incremental Forecasted RNS Charges, less (3) Incremental Forecasted RNS Credits,

where:

Forecasted Transmission Plant Additions represents the costs attributable to transmission assets that are projected to go into service during the Forecast Period, Carrying Charge Factor represents the costs to service the BHD Transmission System and is inclusive of the investment return associated with Emera Maine's pre-tax weighted average cost of capital, plus interest and other certain expenses,

Incremental Forecasted RNS Charges represents the difference in the forecast RNS charges for the Forecast Period as compared to the actual Reported Year RNS charges, and

Incremental Forecasted RNS Credits represents the difference in the forecast RNS credits for the Forecast Period as compared to the actual Reported Year RNS credits, with each reduced by any incremental revenues associated with Commission-approved adders for RTO participation and new transmission investment.

N. Annual True-Up with Interest shall equal (1) Prior Year Annual True-Up plus (2) Interest on Annual True-Up.

(1) Prior Year Annual True-Up shall equal (a) Prior Year Actual Transmission Revenue Requirement less (b) Prior Year Implemented Transmission Revenue Requirement.

(a) Prior Year Actual Transmission Revenue Requirement represents the actual costs and revenues incurred during the Reported Year as calculated in accordance with the methodology set forth in this Section III. For service provided to retail loads in the BHD, the Prior Year Actual Transmission Revenue Requirement shall also include: (a) the product of (i) Total Customer Accounts Expenses as reported on FF1 at 322:164b multiplied first by (ii) the Company Customer/Revenue Allocator (BHD) and then multiplied by (iii) the BHD Revenue Allocator (Transmission).

(b) Prior Year Implemented Transmission Revenue Requirement represents the previous year's Transmission Revenue Requirement upon which transmission rates were based upon during the previous rate period.

(2) Interest on Annual True-Up equals the monthly interest accrued on the Prior Year Annual True-Up from June 1 through May 31 of the previous rate period calculated in accordance with 18 C.F.R. Section 35.19a.

IV. SCHEDULING REVENUE REQUIREMENT

A. Definitions

For purposes of this Section IV, the following terms shall be defined as follows.

(1) Scheduling, System Control and Dispatching Expense shall equal the balance of Account Nos. 561.1-561.8 [FF1 at 321:85b-92b].

(2) ISO Scheduling Credits and Schedule 1 Revenues shall equal such amounts associated with short-term and non-firm transactions and penalties for unauthorized use of Schedule 1 service as set forth in ISO monthly billing statements to Emera Maine.

B. Scheduling Revenue Requirement

The Scheduling Revenue Requirement shall equal the following:

(1) Scheduling, System Control and Dispatching Expense,

minus (2) ISO Scheduling Credits and Schedule 1 Revenues.

V. ANNUAL UPDATE AND INFORMATIONAL FILING

By June 15 of each year, Emera Maine shall make an informational filing with the FERC and serve copies of such filing on FERC Trial Staff, the Maine Public Utilities Commission ("MPUC"), and all OATT customer that request to receive a copy (collectively, "Interested Parties"). Through this informational filing, Emera Maine will show its implementation of the Rate Formula for the rates that became effective the previous June 1. Emera Maine shall include in the informational filing the following:

- Excel spreadsheets detailing the calculation of the formula rate as described in this Attachment P-EM, including all applicable worksheets.

- FERC Form 1 cites for those applicable inputs, including supporting material for all calculations and all formula inputs that reflect a level of detail not reported in the FERC Form 1.

- Information regarding the discounts given to transmission customers over the prior rate period. This information shall include the name of the transmission customer, the transmission path, the price, the quantity, and the period of the discount. Emera Maine shall provide a brief explanation of the transmission customer's justification of the discount. Emera Maine shall not provide to any Interested

Party any customer's confidential information absent the Interested Party's execution of the Commission's model protective order. Emera Maine shall not be required to provide explanations for discounts provided pursuant to a settlement agreement, except that (1) Emera Maine shall provide an explanation in the first informational filing after the discount begins, and (2) if terms of the discount not previously applied are implemented after the first year of the discount, Emera Maine shall provide an explanation of the new terms.

Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the Rate Formula, including the discounts for which Emera Maine is required to provide explanations, under the same discovery rules that were in effect in FERC Docket No. ER00-980-000, including the requirement that responses be provided within ten (10) Business Days on a best efforts basis. Discovery requests may be served through the 30th day, or the first Business Day following the 30th day if the 30th day is not a Business Day, following the informational filing.

If an Interested Party disputes the implementation of the Rate Formula, such Interested Party shall communicate and detail its dispute in writing to Emera Maine and the other Interested Parties by the close of business on the 60th day, or the first Business Day following the 60th day if the 60th day is not a Business Day, following the informational filing. Thereafter, Emera Maine and the Interested Parties shall make a good faith effort to meet by appropriate means to resolve such dispute. If such dispute is not resolved in a timely manner, Interested Parties shall have until the close of business on the 90th day, or the first Business Day following the 90th day if the 90th day is not a Business Day, following the informational filing, to file a complaint with the Commission concerning the implementation of the Rate Formula for the current rate year.

If no such complaint is filed, and no investigation is instituted by the Commission of its own accord, such rates shall become final; provided, however, that Emera Maine's compliance with the filed rate under the Federal Power Act Section 306, 16 U.S.C. § 825e, is not limited by the informational filing procedures of this Attachment P-EM (1) where the costs included in the filed rate were imprudently incurred, (2) where the costs claimed were fraudulently included in the filed rates, or (3) where the costs were otherwise improperly included in the filed rate and where, despite the exercise of due diligence, that fact would not ordinarily come to the attention of the Interested Parties, provided, however, a party may not assert this right if it could have through the exercise of due diligence determined that the costs were improperly included in the filed rate. Further, the procedures established in this Attachment P-EM do not limit the ability of the Commission to investigate and render decisions on Emera Maine's FERC-jurisdictional rates.

These procedures similarly do not limit the ability of the MPUC to investigate and render decisions on Emera Maine's MPUC-jurisdictional rates or to use its processes to obtain information from Emera Maine. These procedures established in Attachment P-EM do not limit the rights of any party to contest under section 206 of the Federal Power Act, 16 U.S.C. § 824e, the prudence of any costs included in the informational filing.

VI. RATE DESIGN FOR FORECASTED TRANSMISSION REVENUE REQUIREMENT WITH ANNUAL TRUE UP AND INTEREST

A.1. Wholesale (Point-to-Point and Network), Wheeling Off (Point-to-Point) and Local Retail Point-to-Point Scheduling, System Control and Dispatch Service

The components of the Scheduling, System Control and Dispatch Service rates are (1) the Scheduling Revenue Requirement and (2) the average monthly Network Load for the Reported Year that includes loads associated with wheeling off the Emera Maine system.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

A.2. Local Retail Network Scheduling, System Control and Dispatch Service

The components of the rates for retail customers interconnected on the Emera Maine system and taking Local Retail Network Service are (1) the Scheduling Revenue Requirement, (2) the average monthly Network Load for the Reported Year that includes loads associated with wheeling off the Emera Maine system, and (3) the applicable retail conversion factors for the applicable retail customer class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW) is calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2) x (3)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

B. <u>Rates for Wholesale Customers Interconnected on the Emera Maine System - Non-PTF Service</u>

The components of the transmission rates for wholesale customers interconnected on the Emera Maine system and taking Non-PTF Service are (1) the Non-PTF Revenue Requirement and (2) the average monthly Network Load for the Reported Year that includes loads associated with wheeling off the Emera Maine system.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

C. <u>Rates for Wholesale Customers Interconnected on the Emera Maine System - PTF Service</u>

The components of the rates for wholesale customers interconnected on the Emera Maine system and taking PTF Service are (1) the PTF Revenue Requirement and (2) the average monthly Network Load for the Reported Year that excludes loads associated with wheeling off the Emera Maine system.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12

Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

D. Rates for Wholesale Customers Interconnected on the Emera Maine System - Emera Maine's Unit Costs of Acting as Customer's Agent for Service

The components of Emera Maine's unit costs of acting as customer's agent for service are (1) the Reported Year plus Incremental Forecasted RNS Charges and (2) the average monthly Network Load for which Emera Maine provides ISO services.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

E. Rates for Wheeling Off the Emera Maine System

The components of the rates for wheeling off the Emera Maine system are (1) the Non-PTF Revenue Requirement and (2) the average monthly Network Load for the Reported Year that includes loads associated with wheeling off the Emera Maine system.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

F.1. Rates for Local Retail Point-to-Point Customers Interconnected on the Emera Maine System - Non-PTF Service

The components of the rates for Local Retail Point-to-Point Customers interconnected on the Emera Maine system and taking Non-PTF Service are (1) the Non-PTF Revenue Requirement and (2) the average monthly Network Load for the Reported Year that includes loads associated with wheeling off the Emera Maine system.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

F.2. Rates for Local Retail Network Customers Interconnected on the Emera Maine System - Non-PTF Service

The components of the rates for Local Retail Network Customers interconnected on the Emera Maine system and taking Non-PTF Service are (1) the Non-PTF Revenue Requirement, (2) the average monthly Network Load for the Reported Year that includes loads associated with wheeling off the Emera Maine system, and (3) the applicable retail conversion factors for the applicable retail customer class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The rates (after conversion of rate units to kW) are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2) x (3)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365

Hourly Rate	Annual Rate divided by 8760

G.1. Rates for Local Retail Point-to-Point Customers Interconnected on the Emera Maine System - PTF Service

The components of the rates for Local Retail Point-to-Point Customers interconnected on the Emera Maine system and taking PTF Service are (1) the PTF Revenue Requirement, and (2) the average monthly Network Load for the Reported Year that excludes loads associated with wheeling off the Emera Maine system.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

G.2. Rates for Local Retail Network Customers Interconnected on the Emera Maine System - PTF Service

The components of the rates for Local Retail Network Customers interconnected on the Emera Maine system and taking PTF Service are (1) PTF Revenue Requirement and (2) the average monthly Network Load for the Reported Year that excludes loads associated with wheeling off the Emera Maine system, and (3) the applicable retail conversion factors for the applicable retail customer class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW) is calculated as follows using the numbers described immediately above:

Annual Rate	(1) ÷ (2) x (3)
Monthly Rate	Annual Rate divided by 12
Weekly Rate	Annual Rate divided by 52

Daily Rate Annual Rate divided by 365

Hourly Rate Annual Rate divided by 8760

H.1. Rates for Local Retail Point-to-Point Customers Interconnected on the Emera Maine System - Emera Maine's Unit Costs of Acting as Customer's Agent for Service

The components of the rates for Local Retail Point-to-Point Customers interconnected on the Emera Maine system and taking PTF Service are (1) Reported Year plus Incremental Forecasted RNS Charges and (2) the average monthly Network Load for which Emera Maine provides ISO services.

The rates are calculated as follows using the numbers described immediately above:

Annual Rate (1) ÷ (2)

Monthly Rate Annual Rate divided by 12

Weekly Rate Annual Rate divided by 52

Daily Rate Annual Rate divided by 365

Hourly Rate Annual Rate divided by 8760

H.2. Rates for Local Retail Network Customers Interconnected on the Emera Maine System - Emera Maine's Unit Costs of Acting as Customer's Agent for Service

The components of the rates for Local Retail Network Customers interconnected on the Emera Maine system and taking PTF Service are (1) the Reported Year plus Incremental Forecasted RNS Charges and (2) the average monthly Network Load for which Emera Maine provides ISO services and (3) the applicable retail conversion factors for the applicable retail customer class (12 cp kW to kWh conversion factors for those classes not having billing demands or 12 cp kW to kW conversion factors for those classes that are demand metered and have billing demands).

The annual rate (after conversion of rate units to kW) is calculated as follows using the numbers described immediately above:

Annual Rate (1) ÷ (2) x (3)

Monthly Rate Annual Rate divided by 12

Weekly Rate	Annual Rate divided by 52
Daily Rate	Annual Rate divided by 365
Hourly Rate	Annual Rate divided by 8760

ATTACHMENT Q-EM

CREDITWORTHINESS GUIDE

1. General Information:

This Creditworthiness Guide details the specific requirements for the creditworthiness for Emera Maine. All customers taking (i) any service under Schedule 21-EM, the Local Service Schedule ("LSS") for Emera Maine under the OATT, (ii) any service provided under the Schedule 20A service schedule of Emera Maine under the OATT, for service over the Phase I/II HVDC-TF or (iii) any FERC-regulated interconnection service from Emera Maine must meet the terms of this Guide (where all the above, collectively, are referred to as "Services"). The creditworthiness of each customer must be established prior to receiving transmission service from Emera Maine. A customer will be evaluated at the time its application for transmission service is provided to Emera Maine. A credit review shall be conducted for each transmission customer periodically or upon reasonable request by the transmission customer. This Creditworthiness Guide ("Guide") when updated, will be done so in accordance with Section 4 of this Guide:

The information requested under this Guide should be forwarded to the individual identified on Emera Maine's website, www.emeramaine.com <http://www.emeramaine.com>.

Upon receipt of a customer's information, Emera Maine will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a Customer under this Guide, Emera Maine will forward a written evaluation if the customer is required to provide Financial Assurance. Emera Maine also will provide a written evaluation, upon request, to customers who are not required to provide Financial Assurance.

2. Financial Information

Customers receiving transmission service or requesting Interconnection Service may submit, if available, the following:

- All current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch of the customer.

- Audited financial statements provided by a registered independent auditor for the two most recent years, or the period of its existence, if shorter, for the customer.

3. Creditworthiness Requirements

A. The customer must meet at least one of the following criteria based on the information provided in Section 2 of this Guide:

a) If rated, the customer must have either for itself or for its outstanding debt the following:

- Standard and Poor's or Fitch rating of at least a **BBB**, or

- Moody's rating of at least a **Baa2**.

b) If un-rated or if rated below BBB/Baa2, as stated in a), the customer must meet all of the following:

- A Current Ratio of at least 1.0 times (current assets divided by all current liabilities);

- A Total Capitalization Ratio of less that 60% debt: total debt (including all short-term borrowing) divided by total shareholders' equity plus total debt;

- "Earnings before interest, taxes, depreciation, and amortization" in most recent fiscal quarter divided by expense for interest" (EBITDA-to-Interest Expense Ratio) of at least 2.0 times; and

- Audited Financial Statement with an unqualified audit opinion.

c) If the customer relies on the creditworthiness of a parent company, the customer's parent company must meet the criteria set out in (a) or (b) above, and must provide to Emera Maine a written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from Emera Maine.

d) If the customer is a municipal that is a member of the Massachusetts Municipals Wholesale Electric Cooperative (MMWEC), MMWEC must meet the criteria set out in (a) or (b) above and provide to Emera Maine a written guarantee that MMWEC will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from Emera Maine.

B. If the customer does not qualify for unsecured credit under Section A, the customer will qualify for unsecured credit equivalent to two months of transmission service charges, or for interconnections, the credit equivalent of two months of the annual facilities charges and other ongoing charges, if the customer has, on a rolling basis, 12 consecutive months of payments to Emera Maine with no missed, late or defaults in payment.

4. Financial Assurance

If the customer does not meet the applicable requirements for Creditworthiness set out in Section 3 or if required by the terms of an agreement or state law or regulation, then the customer must:

- Pay in advance for service an amount equal to the lesser of the total charge for Transmission Service or the charge for three months of Transmission Service, not less than 5 days in advance of the commencement of service;

- Obtain Financial Assurance in the form of a letter of credit, performance bond, or corporate guarantee equal to the equivalent of 3 months of Transmission Service charges prior to receiving service; or

- Obtain Financial Assurance in the form of a letter of credit based on the value of any new facilities or upgrades associated with such Transmission Service.

If the customer pays for service in advance, Emera Maine will pay to the customer interest on the amounts not yet due to Emera Maine, computed in accordance with the Commission's regulations at 18 CFR § 35.19a(a)(2)(iii).

5. Credit Levels

If the Customer meets the applicable criteria outlined in Section 3, that Customer may receive unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges.

6. Contesting Creditworthiness Determination

The Transmission Customer may contest Emera Maine's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. Emera Maine will review and respond to the request within 20 calendar days.

7. Process for Changing Credit Requirements

In the event that Emera Maine plans to revise its requirements for credit levels or collateral requirements, as detailed in this Creditworthiness Guide, the following process shall be followed:

A. General Notification Process

1) Emera Maine shall submit such changes in a filing to the Federal Energy Regulatory Commission ("Commission") under Section 205 of the Federal Power Act. Emera Maine shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

2) Emera Maine shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

a) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Guide.

b) Emera Maine shall consult with interested stakeholders upon request.

3) Emera Maine shall consult with ISO-NE and the IRH Management Committee regarding any filing described above, at least 30 days in advance of such filing.

4) Following Commission acceptance of such filing and upon the effective date, Emera Maine shall revise its Creditworthiness Guide and an updated version of Schedule 21-EM shall be posted the ISO-NE website.

B. Transmission Customer Responsibility

1) When there is a change in requirements, it is the responsibility of the Transmission Customers to forward updated financial information to Emera Maine, to the address noted below, and indicate whether the change affects their ability to meet the requirements of this Creditworthiness Guide. In such cases where the customer's status has changed, the Customer must take the necessary steps to comply with the revised requirements of the Creditworthiness Guide by the effective date of the change.

2) Correspondence associated with Creditworthiness should be forwarded to the contact indicated in Emera Maine's Creditworthiness Guide.

C. Notification for Active Customers

1) Active Customers are defined as any current Transmission Customer that has reserved transmission service within the last 6 months.

2) All Active Customers will be notified via either e-mail or U.S. mail that the above posting has

been made and must follow the steps outlined in this procedure.

8. Posting Collateral Requirements

A. Changes in Customer's Financials

Each customer must inform Emera Maine, in writing, within five (5) business days of any material change in its financial condition, and, if the customer qualifies under Section 3A (c), that of its parent company. A material change in financial condition may include, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition, or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

B. Change in Creditworthiness Status

A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in item 4 if one or more of the following conditions apply:

- The customer no longer meets the applicable criteria for Creditworthiness in item 3;
- The customer exceeds the amount of unsecured credit extended by Emera Maine, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or
- The customer has missed two or more payments for any of the Services offered by Emera Maine

in the last 12 months.

9. Ongoing Financial Review

Each customer qualifying under Section 3.A of this Guide is required to submit to Emera Maine annually or when issued, as applicable:

- Current rating agency report;
- Audited financial statements from a registered independent auditor; and
- 10-Ks and 8-Ks, promptly upon their issuance.

10. Suspension of Service

Emera Maine may immediately suspend service (with notification to Commission) to a customer, and may initiate proceedings with Commission to terminate service, if the customer does not meet the terms described in items 3 through 7 at any time during the term of service or if the customer's payment obligations to Emera Maine exceed the amount of unsecured or secured credit to which it is entitled under this Guide. A customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

SCHEDULE 21-CMP

Local Service Schedule

Central Maine Power Company

I. COMMON SERVICE PROVISIONS

This Local Service Schedule, designated Schedule 21-CMP, governs the terms and conditions of service taken by Transmission Customers over Central Maine's Transmission System. In the event of a conflict between the provisions of this Schedule 21-CMP and other provisions of the Tariff, with respect to Local Service, the provisions of this Schedule 21-CMP shall control.

1 Definitions

Whenever used in this Schedule 21-CMP, in either the singular or plural, the following capitalized terms shall have the meanings specified in the Definition Section of this Part I. Terms used in this Schedule 21-CMP but not defined in this Definition Section shall have the meanings specified in Section 1 of the Tariff. Terms used in this Schedule 21-CMP that are not defined in the Tariff, shall have the meanings customarily attributed to such terms by the electric utility industry in New England. Sections, Schedules or Attachments referred to in this Schedule 21-CMP shall mean a section or schedule in or an attachment to this Schedule 21-CMP unless otherwise stated.

1.4 Annual Transmission Revenue Requirement:

The annual revenue requirements of Central Maine's Transmission System for purposes of this Schedule 21-CMP shall be the amount calculated pursuant to the formulas in Attachment G-W and Attachment G-R, as applicable, and as updated each June 1, or until amended by Central Maine or modified by the Commission.

1.6 Backyard Generation (or Behind-The-Meter Generation):

Generation which interconnects directly with a customer's facilities that will offset all or a portion of a customer's electric load requirements. Any generation used to supply any portion of Local Network Load will not qualify for demand credits associated with Backyard Generation. Such credits shall only be applicable to load not designated as Local Network Load. In such instances, the customer shall be responsible for taking and paying for an appropriate level of Local Point-To-Point Transmission Service.

Notwithstanding any other provisions of this Schedule 21-CMP or Tariff, the Local Network Load of transmission-level retail customers with Behind-The-Meter Generation shall be determined in accordance with Schedule No. 12 of this Schedule 21-CMP.

1.7 Central Maine:

The Central Maine Power Company.

1.8 CMP-Owned Interconnection Facilities:

Facilities and equipment, or portions thereof, owned by Central Maine that are necessary to interconnect a customer with Central Maine's Transmission System.

1.13 Control Area Operator:

ISO, or any successor organization or entity, responsible for the continued operation of the New England Control Area and the administration of the Tariff, subject to regulation by the Commission.

1.16 Designated Agent:

Any entity that performs actions or functions required under this Schedule 21-CMP or Tariff on behalf of Central Maine, an Eligible Customer, an Eligible Generator Customer or a Transmission Customer.

1.17 Direct Assignment Facilities:

Facilities or portions of facilities that are constructed by or for Central Maine for (1) the sole use/benefit of a particular Transmission Customer requesting service under this Schedule 21-CMP or (2) the use by a Generator Owner or developer of a generating station requesting to be interconnected to Central Maine's Transmission System. Direct Assignment Facilities shall be specified in the Service Agreement or Interconnection Agreement that in addition to the applicable terms and conditions of this Schedule 21-CMP and OATT governs service to the Transmission Customer; and shall be subject to Commission acceptance.

1.19 Eligible Generator Customer:

Any electric utility or other person generating energy for sale for resale that owns or develops a new generating unit or changes the electrical characteristics of an existing generating unit that is or will be directly interconnected with Central Maine's Transmission System. For purposes of this Schedule 21-CMP, an Eligible Generator Customer is also considered an Eligible Customer as defined in Section I.2.2 of the OATT.

1.26 Interconnection Agreement:

An agreement between Central Maine and an Eligible Customer or an Eligible Generator Customer for Interconnection Service.

1.27 Interconnection Service:

Those services required to electrically connect Transmission Customer's facilities to Central Maine's Transmission System. Interconnection Service includes, but is not limited to, the identification, design, and construction of facilities required to establish and maintain such electrical connection as identified by a completed System Impact Study and Facilities Study. The customer's and Central Maine's contractual obligations associated with Interconnection Service shall be specified in an Interconnection Agreement which shall be executed and filed with the Commission prior to the commencement of such service.

1.30 Load Ratio Share:

Ratio of a Transmission Customer's Local Network Load to Central Maine's total Local Network Load computed in accordance with Sections 21.II.8.b and 21.II.8.c of the Local Network Service under Part III of this Schedule 21-CMP.

1.35 Local Network Load:

The load that a Local Network Customer designates for Local Network Transmission Service under Part III of this Schedule 21-CMP. The Local Network Customer's Local Network Load shall include all load served by the output of any Network Resources designated by the Local Network Customer (including losses) and shall not be credited or reduced for any Backyard Generation. All Local Network Customers shall be required to have installed appropriate metering to determine such Backyard Generation, in accordance with the Network Operating Agreement. A Local Network Customer may elect to designate less than its total load as Local Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete Points of Delivery as Local Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of this Schedule 21-CMP for any Local Point-To-Point Transmission Service that may be necessary for such non-designated load.

Notwithstanding any other provisions of this Schedule 21-CMP and Tariff, the Local Network Load of transmission-level retail customers with Behind-The-Meter Generation shall be determined in accordance with Schedule No. 12 of this Schedule 21-CMP.

1.38 Local Point-To-Point Transmission Service:

Local Point-To-Point Service, including, without limitation, service over CMP-Owned Interconnection Facilities, is a service provided to (1) Eligible Customers, pursuant to Part II of this Schedule 21-CMP by Central Maine over its Local Network, and (2) Eligible Generator Customers that own and develop generating units that are directly interconnected to Central Maine's Transmission System, pursuant to an Interconnection Agreement.

1.40 Native Load Customers:

The wholesale and retail power customers of Central Maine on whose behalf Central Maine, by statute, franchise, regulatory requirement, or contract, has an obligation to construct and operate Central Maine's Transmission System to meet the reliable electric needs of such customers, including but not limited to customers taking service under Schedule No. 12 of this Schedule 21-CMP.

1.45 Network Operating Agreement:

An executed agreement that contains the terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Part II of Schedule 21 and Part III of this Schedule 21-CMP.

1.50 Part I:

The sections of this Schedule 21-CMP containing the definitions and common service provisions.

1.51 Part II:

The sections of this Schedule 21-CMP pertaining to Local Point-To-Point Transmission Service in conjunction with Schedule 21 and the applicable common service provisions of Part I and appropriate Schedules and Attachments.

1.52 Part III:

The sections of this Schedule 21-CMP pertaining to Local Network Transmission Service in conjunction with Schedule 21 and the applicable common service provisions of Part I and appropriate Schedules and Attachments.

1.61 Regional Application:

A request by an Eligible Generator Customer for Interconnection Service submitted to the Control Area Operator pursuant to the provisions of the OATT.

1.71 Transmission Customer:

Any Eligible Customer or Eligible Generator Customer (or its Designated Agent) that (i) executes a Service Agreement or an Interconnection Agreement, or (ii) requests in writing the filing of a proposed unexecuted Service Agreement to receive Transmission Service under Part II of this Schedule 21-CMP. This term is used in the Part I common service provisions to include customers receiving Transmission Service under Part II and Part III of this Schedule 21-CMP.

1.73 Transmission Service:

Transmission service provided over Central Maine's Local Network, designated as Local Network Service or Local Point-To-Point Service that is provided pursuant to Schedule 21 and this Schedule 21-CMP.

1.74 Transmission System:

The facilities owned, controlled or operated by Central Maine that are used to provide Transmission Service under the OATT, Schedule 21 and Part II and Part III of this Schedule 21-CMP. Central Maine's Transmission System consists of two parts: (1) those transmission facilities which qualify as PTF in accordance with section 49 of the OATT and (2) those remaining transmission facilities which constitute Central Maine's Local Network.

2 Purpose of This Schedule 21-CMP

This Schedule 21-CMP is intended to provide Transmission Service as a compliment to the regional service to be provided under the OATT which is a two-tier transmission arrangement integrating regional service which is provided under the OATT, and Local Network Service and Point-To-Point Service, including, without limitation, service over CMP-Owned Interconnection Facilities as provided under Schedule 21 and this Schedule 21-CMP.

In addition, this Schedule 21-CMP is designed to implement services related to retail access in the State of Maine. Accordingly, the rate schedules and associated service agreements allow Central Maine to act as the agent for its distribution-level customers for the purpose of arranging and obtaining Regional Network Service pursuant to the OATT. Similarly, Central Maine can act as the agent for a transmission-level customer, if such a customer so requests, and certain designated conditions are fulfilled. To the extent any of the provisions in Schedule 12 of this Schedule 21-CMP contradict any of the terms located elsewhere in this Tariff, the provisions in Schedule 12 shall govern for service to retail customers.

3 Reserved:

4 Ancillary Services

Ancillary Services are needed with Transmission Service to maintain reliability within the New England Control Area.

4.1 Ancillary Services supporting Transmission Service over PTF:

Ancillary Services to support Transmission Service over PTF are provided pursuant to the OATT.

4.2 Ancillary Services supporting Transmission Service over Central Maine's Local Network:

Pursuant to this Schedule 21-CMP, Central Maine will provide and the Transmission Customer is required to purchase from Central Maine, for all Transmission Services provided over its Local Network: Scheduling, System Control and Dispatch Service.

4.3 Unauthorized Use, Pricing and Discounts:

In the event of an unauthorized use of any Ancillary Service by the Transmission Customer, the Transmission Customer will be required to pay the charge, excluding any discount offered, which would otherwise be applicable. Such charge shall apply for the period of unreserved use.

The specific Ancillary Services, prices and/or compensation methods are described in the OATT and in this Schedule 21-CMP on the Schedules that are attached to and made part of this Schedule 21-CMP and OATT. Three principle requirements apply to discounts for Ancillary Services provided by Central Maine in conjunction with its provision of Transmission Service as follows: (1) any offer of a discount made by the Central Maine must be announced to all Eligible Customers and Eligible Generator Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by Central Maine's wholesale merchant or an Affiliate's use, if any) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers and Eligible Generator Customers on Central Maine's Local Network.

4.4 Descriptions and Rate Schedules for Ancillary Services:

Sections 4.4.1 below lists the Ancillary Services that Central Maine provides.

4.4.1 Scheduling, System Control and Dispatch Service:

The rates and/or methodology are described in Schedule 1 of this Schedule 21-CMP when provided by Central Maine.

8 Billing and Payment

8.1 Billing Procedure:

Within a reasonable time after the first day of each month, Central Maine shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Schedule 21-CMP during the preceding month. The invoice shall be paid by the Transmission Customer within ten (10) days of receipt. All payments shall be made, in accordance with the procedure specified by Central Maine in immediately available funds payable to Central Maine, or by wire transfer to a bank named by Central Maine.

8.3 Customer Default:

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to Central Maine on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after Central Maine notifies the Transmission Customer to cure such failure, or if the Transmission Customer violates any provision of its Service Agreement, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, Central Maine may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between Central Maine and the Transmission Customer, Central Maine will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then Central Maine may provide notice to the

Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with applicable Commission rules and regulations, and may proceed with such suspension.

10 Regulatory Filings

10.2 Informational Filings

By June 30 of each year, Central Maine shall submit to FERC an informational filing which identifies: (a) the data used to update any formula rates that year, with specific references to Central Maine's FERC Form 1 when applicable; (b) the calculations performed using that data; (c) the results of such calculations; and (d) the basis for any adjustment to the CCS Charge described in Schedule No. 1. When the data used in the formula rates is not identical to data found in FERC Form 1, Central Maine shall include supporting materials. Copies of the informational filing shall be served on FERC Staff, the Maine Public Utilities Commission, and any other party that sends a written request for a copy of the informational filing, such request to be sent no earlier than May 1 of the year in which the informational filing is being requested, and to include the name and address where the copy of the informational filing is to be sent. Copies of the informational filing shall be sent by first class mail.

Within 45 days of the date on which Central Maine submits the informational filing to FERC, the FERC Staff, the Maine Public Utilities Commission, and any party that has requested the informational filing for that year, may submit discovery requests to Central Maine. Central Maine shall make a good faith effort to respond within 10 days of the date on which each particular request is sent. However, such discovery requests are to be limited in scope to the accuracy of the data inputs used in the formula rates, the accuracy of the calculations done using those data inputs, whether Central Maine has properly applied the formula rate, and the accuracy of the data and calculation underlying the adjustment to the CCS Charge. Central Maine shall not be required to respond to discovery requests addressing any other matters. Within 60 days of the date on which Central Maine submits its informational filing to FERC, the FERC Staff, the Maine Public Utilities Commission, and any other party that has requested Central Maine's informational filing, may contest: (1) the accuracy of the data inputs used in the formula rates; (2) the accuracy of the calculations performed using those data inputs; (3) whether Central Maine has properly applied the formula rate; and (4) the accuracy of the data and calculations underlying the adjustment to the CCS Charge. Central Maine and the contesting party shall attempt to resolve any such issues informally. Central Maine shall not be required to respond to any matters raised that are beyond the scope described in (1), (2) (3) or (4). Nor shall Central Maine be required to respond to any matters that are raised more the 60 days after the date on which Central Maine submitted its informational filing to FERC, whether within the scope of (1), (2) (3) and (4), or not. Nothing in this Section 10.2 shall limit the rights of FERC and the Maine Public Utilities Commission to investigate and rule on Central Maine's rates under applicable law. Nor shall this Section 10.2 limit the rights of any party to contest the prudence of any additional costs included in the informational filing under Section 206 of the Federal Power Act.

11 Force Majeure and Indemnification

11.1 Force Majeure:

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, any order, regulation or restriction imposed by a court or governmental military or lawfully established civilian authorities, or any other cause beyond a party's control. Neither Central Maine nor the Transmission Customer will be considered in default as to any obligation under or related to this Schedule 21-CMP if prevented from fulfilling the obligation due to an event of Force Majeure; provided that no event of Force Majeure shall excuse any payment obligation hereunder or under a Service Agreement. However, a party whose performance under or related to this Schedule 21-CMP is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under or related to this Schedule 21-CMP, and shall promptly notify Central Maine or the Transmission Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure

11.2 Indemnification:

The Transmission Customer shall at all times indemnify, defend, and save Central Maine harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from Central Maine's performance of its obligations under or related to this Schedule 21-CMP on behalf of the Transmission Customer or resulting from the Transmission Customer's acts or omissions under or related to this Schedule 21-CMP, except to the extent that Central Maine is found liable for gross negligence or intentional wrongdoing. For the purposes of this Section

11.2, the term “third parties” includes without limitation, customers under the Tariff, ISO and any other Transmission Owners.

11.3 Limitations of Liability

Central Maine shall not be liable (whether based on contract, indemnification, warranty, tort, strict liability or otherwise) for money damages or other compensation to the Transmission Customer for actions or omissions by Central Maine in performing its obligations under or related to Schedule 21-CMP, or any Service Agreement hereunder, except to the extent that Central Maine is found liable for gross negligence or intentional misconduct and in which case Central Maine shall be liable for only actual direct damages. To the extent the Transmission Customer has claims against Central Maine, the Transmission Customer may only look to the assets of Central Maine for the enforcement of such claims and may not seek to enforce any claims against the Affiliates of Central Maine or the respective directors, members, officers, employees or agents of Central Maine or any of its Affiliates who the Transmission Customer acknowledges and agrees have no personal or other liability for obligations of Central Maine by reason of their status as Affiliates or directors, members, officers, employees or agents of Central Maine or any of its Affiliates. In no event shall Central Maine be liable for any incidental, consequential, multiple, punitive, special, exemplary, or indirect damages, or loss of revenues or profits, attorneys fees or costs arising out of, or connected in any way with the performance or non-performance of this Schedule 21-CMP or any Service Agreement hereunder, even if such damages are foreseeable or the damaged party has advised Central Maine of the possibility of such damages and regardless of whether any such damages are deemed to result from the failure or inadequacy of any exclusive or other remedy.

11.4 Survival:

The provisions of this Section 11 survive termination or expiration of this Schedule 21 or a Service Agreement hereunder.

12 Creditworthiness

For the purpose of determining the ability of the Transmission Customer, or the Eligible Generator Customer taking Interconnection Service, to meet its obligations related to service hereunder, Central Maine may require reasonable credit review procedures in accordance with Attachment L of Schedule 21-CMP.

13 Dispute Resolution Procedures

13.1 Internal Dispute Resolution Procedures:

Any dispute between a Transmission Customer and Central Maine involving Transmission Service under this Schedule 21-CMP (excluding applications for rate changes or other changes to this Schedule 21-CMP, or to any Service Agreement entered into under this Schedule 21-CMP, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of Central Maine and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days or such other period as the parties may agree upon by mutual agreement, such dispute may be submitted to mediation and/or arbitration and resolved in accordance with the arbitration procedures set forth in Section I.6 of the Tariff.

13.2 Rights Under The Federal Power Act:

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission, or seek any other available remedy, under relevant provisions of the Federal Power Act.

II. LOCAL POINT-TO POINT TRANSMISSION SERVICE

Preamble

Firm and Non-Firm Local Point-To-Point Transmission Service over Central Maine's Local Network will be provided pursuant to the applicable terms and conditions of Schedule 21 and this Schedule 21-CMP. Local Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

Central Maine will provide Interconnection Service to owners and developers of generating units directly interconnected to Central Maine's Transmission System in accordance with an Interconnection Agreement between Central Maine and the Eligible Customer or Eligible Generator Customer.

21.I.1 Nature of Firm Local Point-To-Point Transmission Service

21.I.1.d Service Agreements:

A standard form Firm Local Point-To-Point Transmission Service Agreement shall be offered to: (1) an Eligible Generator Customer upon completion of a System Impact Study when no new transmission facilities are required; or (2) an Eligible Generator Customer upon the completion of a Facilities Study or prior to the commencement of construction when new transmission facilities are required. Service Agreements for daily and weekly reservations may be treated as blanket service agreements (i.e., covering more than a single transaction) so long as the Transmission Customer deposits an amount, as described in Section 21.I.5.c, equal to the monthly cost of Transmission Service associated with the Transmission Customer's anticipated maximum transmission reservation request (MWs). If the Transmission Customer exceeds that anticipated maximum, the Transmission Customer shall increase its deposit.

21.I.1.g Classification of Firm Local Transmission Service:

(i) The Transmission Customer taking Firm Local Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 10.a of Schedule 21 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 10.b of Schedule 21 provided that if Central Maine or another entity has constructed new facilities or upgraded facilities to accommodate the original firm service, Central Maine shall continue to be compensated for its facility costs by the Transmission Customer.

(iii) The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7 of this Schedule 21-CMP. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 10 of Schedule 21.

(iv) In the event that a Transmission Customer exceeds its firm Reserved Capacity in any single hour at any Point of Receipt or Point of Delivery, Central Maine shall require that Transmission Customer to apply for additional Firm Local Point-to-Point Transmission Service under this Schedule 21-CMP. The additional Transmission Service shall be for an amount equal to the greatest amount of such excess over its firm Reserved Capacity for the remainder of the term of the Service Agreement. Charges for such additional service will relate back to the first day of the month following the month in which Central Maine notifies such Transmission

Customer that it is subject to the provisions of this paragraph. This charge shall apply until either:

(a) the Transmission Customer applies for and receives Local Network Transmission Service under Part III to replace the service provided by Local Point-to-Point Transmission Service; or

(b) the Transmission Customer modifies its facilities in such a way, at customer's expense, to ensure that the Transmission Customer will not exceed its firm Reserved Capacity during the remaining term of the Service Agreement.

21.I.2 Nature of Non-Firm Local Point-To-Point Transmission Service

21.I.2.d Service Agreements:
Service Agreements for daily and weekly reservation may be treated as blanket service agreements (i.e., covering more than a single transaction).

21.I.2.e Classification of Non-Firm Local Point-To-Point Transmission Service:

(i) Reserved

(ii) In the event that a Transmission Customer exceeds its non-firm Reserved Capacity in any single hour at any Point of Receipt or Point of Delivery, Central Maine shall require that Transmission Customer to apply for additional non-firm Local Point-to-Point Transmission Service under Schedule 21 and this Schedule 21-CMP. The additional Transmission Service shall be for an amount equal to the greatest amount of such excess over its Non-Firm Reserved Capacity for the remainder of the term of the Service Agreement. Charges for such additional service will relate back to the first day of the month following the month in which Central Maine notifies such Transmission Customer that it is subject to the provisions of this paragraph. This charge shall apply until either:

(a) the Transmission Customer applies for and receives Local Network Transmission Service under Part III to replace the service provided by Local Point-to-Point Transmission Service; or

(b) the Transmission Customer modifies its facilities in such a way, at customer's expense, to ensure that the Transmission Customer will not exceed its non-firm Reserved Capacity during the remaining term of the Service Agreement.

21.I.3 Service Availability

21.I.3.b Determination of Available Transfer Capability:
A description of the specific methodology for assessing available transfer capability (ATC) over PTF that is posted on the OASIS is contained in the OATT. Central Maine's specific methodology for assessing ATC over its Local Network which is posted on the OASIS is contained in Attachment C of this Schedule 21-CMP. In the event sufficient Local Network transfer capability may not exist to accommodate a service request, Central Maine will, at the request of an Eligible Customer or an Eligible Generator Customer, respond by performing a System Impact Study.

21.I.3.c Initiating Service in the Absence of an Executed Service Agreement:
If the Transmission Customer refuses, or otherwise does not provide written notice to Central Maine and/or the ISO, as applicable, directing Central Maine and/or the ISO, as applicable, to file an unexecuted Local Service Agreement, the ISO and/or Central Maine, as applicable, may make such a filing prior to the commencement of service. Transmission Service shall commence and the Transmission Customer shall be obligated to (i) compensate Central Maine at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of this Tariff including posting appropriate security deposits in accordance with the terms of Section 21.I.5.c.

21.I.3.g Real Power Losses:
Real Power Losses are associated with all Transmission Service. Neither the ISO nor Central Maine are obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all Transmission Service as calculated by Central Maine or the Control Area Operator. In cases where Central Maine or the Control Area Operator does not determine and allocate the actual losses, such losses shall be set at 1.5 percent for demand and 0.9 percent for energy.

21.I.3.h Load Shedding:

To the extent that system contingency exists on Central Maine's Transmission System, and Central Maine determines shedding of load is necessary, the parties shall shed load in accordance with procedures under the Tariff and the rules adopted thereunder, or in accordance with other mutually agreed to provisions.

21.I.4 Transmission Customer Responsibilities

21.I.4.a Conditions Required of Transmission Customers:

Local Point-To-Point Transmission Service and Interconnection Service shall be provided only if the following conditions are satisfied by the Transmission Customer:

(i) The Transmission Customer has pending a Completed Application for Local Service or a Completed Application for regional service, as applicable;

(ii) The Transmission Customer or Eligible Generator Customer meets the creditworthiness criteria set forth in Section 12;

(iii) The Transmission Customer or Eligible Generator Customer will have arrangements in place for any other Transmission Service necessary to effect the delivery from the generating source to Central Maine prior to the time service under Schedule 21 and Part II of this Schedule 21-CMP commences;

(iv) The Transmission Customer or Eligible Generator Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer or Eligible Generator Customer under Schedule 21 and Part II of this Schedule 21-CMP, whether or not the Transmission Customer or Eligible Generator Customer takes service for the full term of its reservation; and

(v) The Transmission Customer or Eligible Generator Customer has executed a Local Point-To-Point Transmission Service Agreement or has agreed to receive service pursuant to Section 21.I.3.c.

21.I.5 Procedures for Arranging Firm Local Point-To-Point Transmission Service

21.I.5.a Application:

All Eligible Generator Customers requesting Interconnection Service shall be required to submit a Regional Application for service to the Control Area Operator in accordance with the relevant provisions of the OATT. Upon notification by the Control Area Operator of its receipt of a Regional Application, Central Maine shall determine whether any Transmission or Ancillary Services provided under Schedule 21 and this Schedule 21-CMP will be applicable to the Eligible Generator Customer. To the extent such services provided under Schedule 21 and this Schedule 21-CMP are applicable, the customer will be notified by tendering a Transmission Service Agreement which shall be executed and filed with the Commission, or filed with the Commission unexecuted as provided for in Schedule 21 and Section 21.I.3.c of this Schedule 21-CMP.

21.I.5.c Deposit:

A Completed Application for Firm Local Point-To-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or, if the Application is for a specific Short-Term Firm Local Point-To-Point Transmission Service, the full charge for Reserved Capacity for service requests of less than one month, including charges for Transmission Service and all applicable Ancillary Services. In the alternative, a Transmission Customer may pay in advance the total expected charge for all services requested.

If the Transmission Customer subsequently enters into a System Impact Study Agreement, which may result in a modification to or an upgrade of Central Maine's Transmission System, or construction of Direct Assignment Facilities to provide the requested service, the deposit shall be based on the average monthly rate for Firm Local Point-To-Point Transmission Service as stated in Schedule 7. Once the Transmission Customer's monthly financial obligation is determined at the conclusion of the Facilities Study, the Transmission Customer's deposit shall be adjusted accordingly.

If the local Application is for "umbrella" Short-Term Firm Local Point-To-Point Transmission Service, the Transmission Customer must specify in the local Application the maximum capacity and maximum duration expected to be requested which shall be the basis for the deposit required, subject to this Section 21.I.5.c. The deposit shall be based on that maximum capacity and duration, and shall equal the lesser of (a) three (3) months full charges or (b) charges associated with the maximum duration. In the alternative, a Transmission Customer may pay, at least 24 hours before the requested service is to commence, the total expected charge for each request for such Short-Term Firm Local Point-To-Point Transmission Service. In lieu of a cash deposit, Central Maine will accept an irrevocable letter of credit of equal value from a financial institution acceptable to Central Maine. A letter of credit in a form that Central Maine would find generally acceptable is appended as Attachment J to this Schedule 21-CMP.

21.I.5.d Notice of Deficient Application:

If the Control Area Operator, independently or in conjunction with Central Maine, determines that a Regional Application for Interconnection Service fails to satisfy the relevant requirements, the process described in the applicable provisions of the OATT shall apply.

21.I.5.e Response to a Completed Application:

Following submission to the Control Area Operator of a Regional Application by an Eligible Generator Customer, Central Maine will not take any action until it receives a System Impact Study Agreement from the Control Area Operator.

21.I.5.f Execution of Service Agreement:

For service requested by an Eligible Generator Customer, whenever Central Maine determines that a System Impact Study is not required and that the service can be provided, it shall notify the Control Area Operator and the Eligible Generator Customer as soon as practicable but no later than thirty (30) days after receiving notice from the Control Area Operator of the Completed Regional Application. Failure of an Eligible Generator Customer to execute and return the Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section 21.I.3.c, within fifteen (15) days after it is tendered will be deemed a withdrawal and termination of the Regional Application and any deposit submitted shall be refunded with Interest. Nothing herein limits the right of an Eligible Generator Customer to file another Regional Application after such withdrawal and termination. Where a System Impact Study is required, the provisions of Section 21.I.7 of Schedule 21 will govern the execution of a Service Agreement.

21.I.6. Procedures for Arranging Non-Firm Local Point-To-Point Transmission Service

21.I.6.f Determination of Available Transfer Capability:

Following receipt of a tendered schedule Central Maine will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 21.I.3.b of this Schedule 21-CMP. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.

21.I.7 Additional Study Procedures For Firm Local Point-To-Point Transmission Service Requests

21.I.7.a Notice of Need for System Impact Study:

If the request for service has been made pursuant to a Regional Application and Central Maine determines that a System Impact Study is necessary to accommodate the requested service, Central Maine shall so inform the Control Area Operator and the Eligible Generator Customer as soon as practicable. In such cases, Central Maine shall enter into a System Impact Study Agreement with the Control Area Operator or the Eligible Generator Customer, or both, as applicable, provided that the agreement requires the Eligible Generator Customer to reimburse Central Maine for performing the required System Impact Study. Central Maine shall not engage in any activity related to the System Impact Study until the Eligible Customer executes and delivers the System Impact Study Agreement to Central Maine. If the Eligible Generator Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn.

21.I.12 Metering and Power Factor Correction at Receipt and Delivery Points(s)

21.I.12.a Transmission Customer Obligations:

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of this Tariff and to communicate the information to Central Maine. Unless otherwise agreed, such equipment shall remain the property of Central Maine.

21.I.12.c Power Factor:

Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as Central Maine pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable. Where a Transmission Customer fails to maintain a power factor within the same range as Central Maine pursuant to

Good Utility Practices, Central Maine may make whatever improvements or repairs are required to restore or maintain the power factor, and charge the Transmission Customer accordingly.

21.I.13 Compensation for Local Point-To-Point Transmission Service

Rates for Firm and Non-Firm Local Point-To-Point Transmission Service are provided in the Schedules appended to this Schedule 21-CMP: Firm Local Point-To-Point Transmission Service (Schedule 7); and Non-Firm Local Point-To-Point Transmission Service (Schedule 8); Retail Access Transmission and Distribution Services (Schedule 12); Monthly Carrying Charge For Meter Services (Schedule 13); and Monthly Carrying Charge For Direct Assignment Facilities (Schedule 14).

When a generator interconnected with Central Maine's non-PTF system: (1) wheels power to a wholesale load located on New York State Electric & Gas Corporation's system or (2) wheels power through New York State Electric & Gas Corporation's system to a point in the PJM control area, and in either case is subject to the New York State Electric & Gas Corporation Transmission Service Charge pursuant to the New York Independent System Operator Open Access Transmission Tariff or (3) wheels power to a wholesale load located on Rochester Gas and Electric Corporation's system and is subject to the Rochester Gas and Electric Corporation Transmission Service Charge under the New York Independent System Operator Open Access Transmission Tariff, Central Maine will waive its Transmission Service charge for Local Point-To-Point Transmission Service, which is described in Schedule Nos. 7 and 8 of this Schedule 21-CMP, each month said Transmission Service Charge under the New York Independent System Operator Open Access Transmission Tariff exceeds the applicable Central Maine Local Point-To-Point Transmission Service charge. The Eligible Generator Customer shall provide CMP with written notice when a wheeling transaction is subject to both a charge for Local Point-To-Point Transmission Service on CMP's system and a New York State Electric & Gas Corporation or Rochester Gas and Electric Corporation Transmission Service Charge under the New York Independent System Operator Open Access Transmission Tariff. Upon receipt of such notice, Central Maine will coordinate with New York State Electric & Gas Corporation or Rochester Gas and Electric Corporation to identify charges so that Central Maine can determine when to waive its Transmission Service charge pursuant to this paragraph.

When a generator interconnected with Central Maine's Non-PTF system wheels power to a retail load located on New York State Electric & Gas Corporation's system or Rochester Gas and Electric Corporation's system pursuant to the applicable retail access program approved by the New York Public Service Commission, Central Maine will waive its Transmission Service charge for Local Point-To-Point

Transmission Service. As used in this paragraph, the terms "Transmission Service charge" under the Schedule 21-CMP and the New York State Electric & Gas Corporation or Rochester Gas and Electric Corporation "Transmission Service Charge" under the New York Independent System Operator Open Access Transmission Tariff include only the embedded cost charge defined in the applicable tariff and no other charges. For example, the calculation and waiver of charges discussed in this paragraph do not include calculations or waivers of Ancillary Service charges, Congestion charges, losses, contributions in aid of construction, or Direct Assignment Facilities charges, the application of which will remain unchanged by this paragraph.

21.I.15 Interconnection Service

Any entity proposing to interconnect with Central Maine's transmission facilities, that is not party to an agreement executed on or before July 9, 1996, in which Interconnection Service is addressed, that (1) proposes to site a new generating unit and directly interconnect to Central Maine's Transmission System, or (2) proposes to materially change electrical characteristics or increase the capacity of an existing generating unit and remain connected to Central Maine's Transmission System, shall submit an Application for Interconnection Service to the Control Area Operator and shall comply with applicable provisions of this Schedule 21-CMP, the OATT, and the Interconnection Agreement. The Transmission Customer shall enter into an Interconnection Agreement or an interim construction agreement with Central Maine, at Central Maine's discretion, prior to the construction of any facilities required to provide the requested service as identified in the System Impact Study and Facilities Study.

III. LOCAL NETWORK SERVICE

21.II.2.f Real Power Losses:

Real Power Losses are associated with all Transmission Service. The ISO or Central Maine is not obligated to provide Real Power Losses. The Local Network Customer is responsible for replacing losses associated with all Transmission Service as calculated by Central Maine or the Control Area Operator. The applicable Real Power Losses will be calculated according to procedures set by Central Maine or the Control Area Operator. In cases where Central Maine or the Control Area Operator does not determine and allocate the actual losses, such losses shall be set at 1.5 percent for demand and 0.9 percent for energy.

21.II.3 Initiating Service

21.II.3.a Condition Precedent for Receiving Service:

Local Network Transmission Service will be provided only if the Eligible Customer satisfies the conditions in Section 3.a of Schedule 21 and executes a Local Network Operating Agreement with Central Maine pursuant to Attachment F to this Schedule 21-CMP. Central Maine shall serve as the Designated Agent for all of its distribution-level retail customers participating in Maine's retail access program. As their agent, Central Maine shall assume all responsibilities under Schedule 21.II, Sections 3 and 4, including all associated subsections of this Schedule 21-CMP on their behalf. All of Central Maine's retail transmission-level customers may either take unbundled service directly under the terms of this OATT or may designate Central Maine to serve as their agent to arrange and maintain network service under the terms of the OATT.

21.II.3.b Application Procedures:

The applicable deposit related to the provisions described in Section 3.b of Schedule 21.II for Part III of this Schedule 21-CMP is a deposit approximating the charge for one month of service.

21.II.4 Network Resources

21.II.4.d Operation of Network Resources:

The Local Network Customer shall not operate its designated Network Resources, which are not subject to central dispatch by the Control Area Operator, such that the output of those facilities exceeds it's designated Local Network Load, plus non-firm sales delivered pursuant to Part II of this Schedule 21-CMP, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of Central Maine to respond to an emergency or other unforeseen condition that may impair or degrade the reliability of the Transmission System.

21.II.4.f Transmission Arrangements for Network Resources Not Physically Interconnected With Central Maine's Local Network:

The customer shall be obligated to reimburse Central Maine for all costs Central Maine incurs in assisting the customer in obtaining such arrangements. Upon the customer's request, Central Maine shall provide the Transmission Customer an estimate of such costs before they are incurred. Upon the customer's request, Central Maine shall provide reasonable itemization of such costs along with any invoice related to those costs.

21.II.4.i Use of Interface Capacity by the Local Network Customer:

There is no limitation upon a Local Network Customer's use of Central Maine's Local Network Transmission System at any particular interface to integrate the Local Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, a Local Network Customer's use of the Central Maine's total interface capacity with other Transmission Systems may not exceed the Customer's Local Network Load.

21.II.5 Designation of Load

21.II.5.c Network Load Not Physically Interconnected with Central Maine's Local Network:

Central Maine shall include such load as part of a Transmission Customer's Local Network Load only if a scheduling and Interconnection Agreement acceptable to Central Maine is in effect with the Control Area in which the load is located.

21.II.6 Additional Study Procedures For Local Network Transmission Service Requests

21.II.6.d Facilities Study Procedures:

If a System Impact Study indicates that additions or upgrades to the Local Network Transmission System are needed to supply the Eligible Generator Customer's request for Interconnection Service, Central Maine shall execute a Facilities Study Agreement, as directed by the Control Area Operator, with the Eligible Generator Customer. For a service request to remain a Completed Regional Application, the Eligible Generator Customer shall execute the Facilities Study Agreement in a timely manner. If the Eligible Generator Customer elects not to execute the Facilities Study Agreement, its Regional Application shall be deemed withdrawn and its deposit (less reasonable Administrative Costs incurred by Central Maine) shall be returned with Interest.

21.II.7 Load Shedding and Curtailments

21.II.7.a Procedures:

Prior to the Service Commencement Date, Central Maine and the Local Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Local Network Operating Agreement with the objective of responding to contingencies on the Local Network Transmission

System. The parties will implement such programs during any period when Central Maine determines that a system contingency exists and such procedures are necessary to alleviate such contingency. Central Maine will notify all affected Local Network Customers in a timely manner of any scheduled Curtailment.

21.II.7.b Transmission Constraints:

During any period when Central Maine determines that a transmission constraint exists on the Local Network Transmission System, and such constraint may impair the reliability of Central Maine's system, Central Maine will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of Central Maine's system. To the extent either Central Maine or the Control Area Operator determine that the reliability of the Transmission System can be maintained by redispatching resources, Central Maine can initiate procedures pursuant to the Local Network Operating Agreement, the Tariff, and other Control Area Operator rules and procedures including, without limitation, Market Rule 1. Any redispatch under this Section may not unduly discriminate between Central Maine's use of the Local Network Transmission System on behalf of its Native Load Customers and any Local Network Customer's use of the Local Network Transmission System to serve its designated Local Network Load.

21.II.7.d Curtailments of Scheduled Deliveries:

If a transmission constraint on Central Maine's Local Network Transmission System cannot be relieved through the implementation of redispatch procedures and the Control Area Operator or Central Maine, under the Control Area Operator's direction, determines that it is necessary to curtail scheduled deliveries, the parties shall curtail such schedules in accordance with any applicable provisions of the Local Network Operating Agreement, the Tariff and any Control Area Operator rules and procedures including, without limitation, Market Rule 1.

21.II.7.f Load Shedding:

To the extent that a system contingency exists on Central Maine's or the New England Transmission System and Central Maine or the ISO determines that it is necessary for Central Maine and the Local Network Customer to shed load, the parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement, or in accordance with other mutually agreed to provisions.

21.II.7.g System Reliability:

Notwithstanding any other provisions of this Tariff, Central Maine and the Control Area Operator reserve the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to curtail Local Network Transmission Service without liability on Central Maine's or the Control Area Operator's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Local Network Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on Central Maine's Transmission System or on any other system(s) directly or indirectly interconnected with Central Maine's Transmission System, including without limitation all PTF, Central Maine or the Control Area Operator, consistent with Good Utility Practice, also may curtail Local Network Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. Central Maine or the Control Area Operator shall give the Local Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Transmission Service will be not unduly discriminatory relative to Central Maine's use of the Local Network Transmission System on behalf of its Native Load Customers. Central Maine shall specify the rate treatment and all related terms and conditions applicable in the event that the Local Network Customer fails to respond to established Load Shedding and Curtailment procedures.

21.II.8 Rates and Charges

Retail customers taking unbundled Transmission Service do so pursuant to the rates described in Schedule 12 of this Schedule 21-CMP. Otherwise, The Local Network Customer shall pay Central Maine for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

21.II.8.a Monthly Demand Charge:

The Local Network Customer shall pay a monthly demand dharge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of Central Maine's Annual Transmission Revenue Requirement. The Annual Transmission Revenue Requirement is calculated pursuant to Attachment G-R or Attachment G-W as applicable.

21.II.8.b Determination of Local Network Customer's Monthly Local Network Load:

The Local Network Customer's monthly Local Network Load is its hourly load (including its designated Local Network Load not physically interconnected with Central Maine's Local Network under Section 21.II.5.c) coincident with Central Maine's Monthly Local Network Transmission System peak.

21.II.8.c Determination of Central Maine's Monthly Local Network Transmission System Load:

Central Maine's monthly Local Network Transmission System load is Central Maine's Monthly Local Network Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Transmission Service customers pursuant to Schedule 21 and Part II of this Schedule 21-CMP plus the Reserved Capacity of all Firm Local Point-To-Point Transmission Service Customers.

21.II.8.d Redispatch Charge:

All costs associated with redispatch of resources shall be charged and allocated in accordance with the Tariff and any Control Area Operator rules and procedures including, without limitation, Market Rule 1.

21.II.8.e Stranded Cost Recovery:

Central Maine may seek to recover stranded costs from the Local Network Customer pursuant to this Schedule 21 in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, Central Maine must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

21.II.10 Operating Arrangements

21.II.10.a Operation under The Local Network Operating Agreement:

The Local Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement. If Central Maine and the Local Network Customer agree in the Interconnection Agreement, the Interconnection Agreement can serve as a Local Network Operating Agreement.

21.II.10.b Local Network Operating Agreement:

The terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Schedule 21 and Part III of this Schedule 21-CMP shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the parties to (i) operate and maintain equipment necessary for integrating the Local Network Customer within Central Maine's Local Network Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between Central Maine and the Local Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside Central Maine's Local Network Transmission System, interchange schedules, unit outputs for redispatch required under Section21.II.7, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Schedule 21 and Part III of this Schedule 21-CMP, including scheduling protocols. The Local Network Operating Agreement will recognize that the Local Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with Central Maine for Ancillary Service No. 1 and contracting with the Control Area Operator for Ancillary Service Nos. 2 through 6 or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services which may be provided by another entity, by contracting with another entity, consistent with Good Utility Practice, which satisfies any applicable requirements imposed by NERC, the NPCC, Central Maine or the Control Area Operator. For those Ancillary Services that may be provided by another entity, Central Maine shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Local Network Operating Agreement is included in Attachment F.

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into Central Maine's Local Network Control Area. Central Maine or its designee responsible for operating the Local Network can only provide this service, and the Transmission Customer must purchase this service from Central Maine or its designee. As set forth in Section 4, the Transmission Customer is required to purchase this Ancillary Service from Central Maine. The charges for Scheduling, System Control and Dispatch Service are to be based on the formula rate set forth below.

This formula sets forth the details for determining the annual revenue requirement for Scheduling, System Control and Dispatch Service. The revenue requirement reflects the cost of owning, operating and maintaining Central Maine's Local Control Center used for providing Scheduling, System Control and Dispatch Service to customers under this Schedule 21. The term "Local Control Center" used throughout this formula refers to Central Maine's entire system dispatch control center operation. Central Maine's system dispatch control center is comprised of the system dispatch center, which provides services at the regional or PTF level, and the local area dispatch center for services over Central Maine's Local Network.

The Revenue Requirement will be an annual formula rate calculation, effective for an initial term commencing on March 1, 2000 and ending on May 31, 2000, based on 1998 test year data, and updated thereafter each June 1, based on the previous calendar year's FERC Form 1 data, as shown below, using end-of-year balances for each rate base item, as further set forth below.

I. DEFINITIONS

Capitalized terms not otherwise defined in the OATT and in Section 1 of Schedule 21-CMP have the following definitions:

A. ALLOCATION FACTORS

1. Wages and Salaries Allocation Factor shall equal the ratio of the Local Control Center Direct Wages and Salaries to total direct wages and salaries excluding administrative and general wages and salaries.

2. Local Control Center Wages and Salaries Allocation Factor shall equal the ratio of the Transmission Local Control Center Direct Wages and Salaries to total Local Control Center Direct Wages and Salaries.

3. Local Control Center Plant Allocation Factor shall equal the ratio of the total Investment in Local Control Center Related Plant to Total Plant in service.

B. TERMS

Administrative and General Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928, and 930.1.

Amortization of Investment Tax Credits shall equal Central Maine's credits as recorded in FERC Account No. 411.4

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of Central Maine's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in Central Maine's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of Central Maine's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Central Maine's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in Central Maine's FERC Account Nos. 408.1.

Prepayments shall equal Central Maine's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Central Maine's expenses as recorded in FERC Account No. 924.

Local Control Center Direct Wages and Salaries shall equal Central Maine's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account Nos. 556, 561-561.4, and 581.

Local Control Center Operation and Maintenance Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 556, 561-561.4, and 581.

Local Control Center Plant Depreciation Reserve shall equal Central Maine's depreciation reserve balance for Local Control Center Related Plant as recorded in FERC Account Nos. 108 and 111.

Local Control Center Plant Materials and Supplies shall equal Central Maine's balance as recorded in FERC Account No. 154.

Local Control Center Related Depreciation Expense shall equal Central Maine's depreciation and amortization expense for Local Control Center Related Plant as recorded in FERC Account Nos. 403 and 404.

Local Control Center Related Plant shall equal Central Maine's gross plant balances used for system control and dispatch purposes and the Local Control Center related portion of intangible and general plant as recorded in FERC Account Nos. 301-399. To the extent that such plant includes any amounts recorded as transmission investment in FERC Account Nos. 350-359, such amounts will be excluded for purposes of determining Annual Transmission Revenue Requirements pursuant the formula in Attachment G to this Schedule 21-CMP. Local Control Center Related intangible and general plant shall equal the sum of Central Maine's balances in FERC Account Nos. 301-303 and 389-399, not otherwise directly assigned under this Schedule 21-CMP, multiplied by the Wages and Salaries Allocation Factor.

Local Control Center Support Revenues shall equal the revenues received from Local Control Center supporters as recorded in FERC Account Nos. 454 and 456, excluding any revenues received under Schedule 1 of this Schedule 21-CMP or Schedule 1 of the OATT.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and 190.

Total Municipal Tax Expense shall equal Central Maine's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal Central Maine's total gross plant balance as recorded in FERC Account Nos. 301-399.

Transmission Local Control Center Direct Wages and Salaries shall equal Central Maine's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account Nos. 561-561.4.

II. CALCULATION OF TOTAL LOCAL CONTROL CENTER REVENUE REQUIREMENTS

The Local Control Center Revenue Requirement shall equal the sum of the Local Control Center related (A) Return and Associated Income Taxes, (B) Depreciation Expense, (C) Amortization of Investment Tax Credits, (D) Municipal Tax Expense, (E) Payroll Tax Expense, (F) Operations and Maintenance Expense, (G) Administrative and General, minus (H) Support Revenues.

A. Return and Associated Income Taxes shall equal the product of the Local Control Center Investment Base and the Cost of Capital Rate.

1. Local Control Center Investment Base

The Local Control Center Investment Base will be the year end balances of Local Control Center related: (a) Plant, less (b) Depreciation Reserve, less (c) Accumulated Deferred Taxes, plus (d) Other Regulatory Assets/Liabilities, plus (e) prepayments, plus (f) Materials and Supplies, plus (g) Cash Working Capital.

(a) Local Control Center Related Plant shall equal the balance of Central Maine's Investment in Local Control Center plant and the balance of unassigned intangible and general plant multiplied by the Wages and Salaries Allocation Factor.

(b) Local Control Center Related Depreciation Reserve shall equal the Depreciation Reserve and Accumulated Amortization for Central Maine's investment in Local Control Center Related Plant.

(c) Local Control Center Related Accumulated Deferred Taxes shall equal Central Maine's electric balance of Accumulated Deferred Income Taxes multiplied by the Local Control Center Plant Allocation Factor.

(d) Local Control Center Related Other Regulatory Assets/Liabilities shall equal Central Maine's electric balance of any deferred recovery of FAS 106 expenses multiplied by the Wages and Salaries Allocation Factor, plus Central Maine's electric balance of FAS 109 multiplied by the Local Control Center Plant Allocation Factor.

(e) Local Control Center Related Prepayments shall equal Central Maine's electric balance of prepayments multiplied by the Local Control Center Plant Allocation Factor.

(f) Local Control Center Related Materials and Supplies shall equal Central Maine's electric balance of Plant Materials and Supplies, multiplied by the Local Control Center Plant Allocation Factor.

(g) Local Control Center Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Local Control Center Operation and Maintenance Expense and Local Control Center Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Central Maine's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of Central Maine's long-term debt then outstanding, including any unamortized discounts and premiums, and any unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to Central Maine's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Central Maine's preferred stock then outstanding and the ratio that preferred stock is to Central Maine's total capital.

(iii) the return on equity component, which equals the product of Central Maine's Return on Equity of ~~10.57~~11.14% and the ratio that common equity is to Central Maine's total capital.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.C. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., and D is Local Control Center Investment Base, as determined in II.A.1., above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.C. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., D is the Local Control Center Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.1.(b) above.

B. <u>Local Control Center Depreciation Expense</u> shall equal the Local Control Center Related Depreciation and Amortization Expense.

C. <u>Local Control Center Related Amortization of Investment Tax Credits</u> shall equal Central Maine's electric Amortization of Investment Tax Credits multiplied by the Local Control Center Plant Allocation Factor.

D. <u>Local Control Center Related Municipal Tax Expense</u> shall equal Central Maine's total electric municipal tax expense multiplied by the Local Control Center Plant Allocation Factor.

E. <u>Local Control Center Related Payroll Tax Expense</u> shall equal Central Maine's total electric payroll tax expense, multiplied by the Wages and Salaries Allocation Factor.

F. Local Control Center Operation and Maintenance Expense shall equal Central Maine's Operation and Maintenance Expenses recorded in FERC Account Nos. 556, 561-561.4, and 581.

G. Local Control Center Related Administrative and General Expenses shall equal the sum of (1) Central Maine's Administrative and General Expenses multiplied by the Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Local Control Center Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments, not otherwise directly assigned to transmission, multiplied by the Local Control Center Plant Allocation Factor, plus any other Federal and State Local Control Center related expenses or assessments, plus specific Local Control Center related expenses included in Account 930.1.

H. Local Control Center Support Revenues shall equal Central Maine's revenue received from providing system control and dispatch service other than under Schedule 1 of the OATT or Schedule 21-CMP.

III. CALCULATION OF LOCAL SCHEDULE 1 REVENUE REQUIREMENTS

The total Local Control Center Revenue Requirements derived in Section II, above, are further multiplied by the Local Control Center Wages and Salaries Allocation Factor defined in Section I. A. 2., above, to determine the transmission related Revenue Requirement. The transmission related Revenue Requirement is then reduced by the revenues recorded in FERC Account No. 456 that Central Maine receives: (1) under Schedule 1 of the OATT, except that such revenues shall exclude any incremental revenues associated with FERC-approved ROE adders for RTO participation and new transmission investment,(2) for short-term service, non-firm service, or any penalties associated with the provision of Scheduling, System Control and Dispatch service under this Schedule 21-CMP, (3) for Control Center Service ("CCS") Charges received from generators who have elected such arrangements, (4) for Schedule 1 related revenues received pursuant to wheeling out transactions whether such services are provided under this Schedule 21-CMP or pursuant to an Interconnection Agreement, and for (5) Schedule 1 related revenues received by Central Maine pursuant to Transmission Service Agreements that pre-dated Order No. 888, to the extent that such transactions are treated as a revenue credit rather than in the determination of Load Ratio Share. The Schedule 1 related revenues associated with such pre-dated contacts will be prorated between Attachment G and Schedule 1 of this Schedule 21-CMP based on gross investment in plant for the services at issue. The credits for wheeling out revenues and for the CCS Charge shall change from month to month based on the actual amounts received by Central Maine for the prior month or for the most recent month that the data is available. The Revenue Requirement in this Schedule shall be revised each month to reflect the annualized amount of such credits.

IV. SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE CHARGES:

The charge for Scheduling, System Control and Dispatch service will be re-determined annually on June 1 of each year, and shall be in effect for the succeeding twelve months. The rate per kilowatt for each month is one-twelfth of the annual rate determined by dividing the annual Revenue Requirement calculated in III. above, by Central Maine's average monthly Local Network Transmission System load (as defined in Section 21.II.8.c) for the prior calendar year. Each Local Network Customer shall pay the Schedule 1 rate on the basis of the number of kilowatts of Monthly Local Network Load. (as defined in Section21.II.8.b).

Each Transmission Customer taking Local Point to Point Transmission Service shall pay the Schedule 1 rate on the basis of the highest amount of Reserved Capacity for each Local Point-To-Point Transmission Service transaction as follows:

For Monthly Service - Annual rate divided by 12 months
For Weekly Service - Annual rate divided by 52 weeks
For Daily Service - Weekly rate divided by 7 days
For Hourly Service – Daily rate divided by 24 hours

Exceeding Capacity Reservations: As set forth in Section 4.3, in the event the Transmission Customer exceeds the Capacity Reservation specified in the customer's Transmission Service Agreement as determined by Central Maine, the Transmission Customer shall be retroactively charged the rates specified above without any discount, if one is in place at the time, for any capacity exceeding the amount reserved. Such charge shall apply for the period of unreserved use.

Control Center Services Charge

In lieu of taking Scheduling, System Control and Dispatch Service directly under the terms of this Schedule, a generator interconnected to Central Maine's PTF via Direct Assignment Facilities may elect to compensate Central Maine for the cost incurred in providing Control Center Services to such generators via: (a) a Scheduling, System Control and Dispatch Service Charge, incorporated into the generator's Interconnection Agreement, which reflects exactly the same charges and terms described in this Schedule; or (b) a Control Center Service ("CCS") Charge, the terms of which are incorporated into the generator's Interconnection Agreement. If the generator elects (a) or (b), it must incorporate a provision into its Interconnection Agreement in which it agrees to pay charges identical to those described in Schedule Nos. 13 and 14 of this Schedule 21-CMP, however, the generator shall not be required to pay any capital carrying charge in Schedule Nos. 13 and 14 if its has paid a contribution in aid of construction ("CIAC") or made any other payment that reflects all of the capital costs associated with such facilities for which the generator is ultimately responsible.

The CCS Charge shall be based on the following two-part rate:

For Generators less than or equal to 500 MW:
Fixed Charge: $11,304.00 per year, plus
Variable Charge: $0.25 per kw-year.

For Generators greater than 500 MW:
Fixed Charge: $11,304.00 per year, plus
Variable Charge: $0.19 per kw-year.

The maximum level of capacity (kw) for which the generator's interconnection was designed shall be used to establish the billing demand determinants in the calculation of the CCS Charge.
These charges shall be increased or decreased in direct proportion to the amount that the cost of owning, operating and maintaining the control center increases or decreases, as determined each June 1.

A generator may elect to switch its payment method for Scheduling, System Control and Dispatch Service, once per year, to be effective June 1, provided that the generator sends written notice of its desire to switch, between May 1 and May 15 of that year, to the Manager of Transmission Services at Central Maine. Once Central Maine receives such notice, the generator shall not be permitted to switch again until the next year.

If a generator is paying for Scheduling, System Control and Dispatch Service directly under the terms of this Schedule, or pursuant to provisions in its Interconnection Agreement that mirror the exact terms of this Schedule, Central Maine shall reduce the generator's bill each month to reflect the amounts paid for service under this Schedule for the same month by load that the generator is serving, provided that the load is located in Central Maine's service territory, and the generator has been designated a Network Resource by the load. There is no reduction to a generator's bill, regardless of where the load is located and whether the generator is designated a Network Resource, when the generator is paying the CCS Charge.

SCHEDULE 7

Long and Short Term Firm Local Point-To-Point Transmission Service

Each Transmission Customer who takes Firm Local Point-to-Point Transmission Service shall pay Central Maine each month on the basis of the highest amount of Reserved Capacity for each transaction reserved as Firm Local Point to Point Transmission Service. Except as provided otherwise below, the charges will be re-determined annually on June 1 of each year, and shall be in effect for the succeeding twelve months. The rate per kilowatt for each month is one-twelfth of the annual rate determined by dividing the Annual Transmission Revenue Requirement calculated pursuant to the Attachment G formula, by Central Maine's average monthly Local Network Transmission System load (as defined in Section21.II.8.c) for the prior calendar year.

Each Transmission Customer taking Firm Local Point to Point Transmission Service shall pay the firm local point-to-point rate on the basis of the highest amount of Reserved Capacity for each transaction reserved as Firm Local Point-To-Point Transmission Service as follows:

1) **Yearly reservation**: one-twelfth of the annual rate per kilowatt of Reserved Capacity per year.

2) **Monthly reservation**: one-twelfth of the annual rate per kilowatt of Reserved Capacity per month.

3) **Weekly reservation**: 1/52nd of the annual rate per kilowatt of Reserved Capacity per week.

4) **Daily reservation**: 1/5th of the weekly rate per kilowatt of Reserved Capacity per day.

Provided that the total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

Notwithstanding the rates described above, through February 28, 2003, each generator that is interconnected with Central Maine's integrated non-PTF system and taking Firm Local Point to Point Transmission Service shall for each transaction pay at a rate of $3.00 per kW-year multiplied by the highest amount of Reserved Capacity for that transaction. The charges for reservations of less than one year shall be determined as described above. If in a given month, a generator is serving load in Central

Maine's service territory, Central Maine shall reduce the amount billed to the generator for that month's service to account for any amounts paid by such load, except that for short-term transactions where it has not been demonstrated to Central Maine's satisfaction that the generator is serving load in Central Maine's service territory, Central Maine shall bill the generator the total amount owed without any reduction, and issue a refund once it has not been demonstrated to Central Maine's satisfaction that load in its service territory is being served via such transaction. Satisfactory methods of demonstrating that load is being served in Central Maine's service territory include: (a) an affidavit executed by the generator and an affidavit executed by the load, each stating that the generator is serving the load and identifying how much service is being provided; (b) a copy of the executed contract between the generator and the load; or (c) any other method that Central Maine agrees is satisfactory. If, for any reason, the load being served in Central Maine's territory is overstated, the generator shall immediately reimburse Central Maine for all monies that would have been collected based on the correct amount of load, with interest calculated at a rate equal to Central Maine's overall rate of return. If, for any reason, the amount of load served by the generator is understated, Central Maine shall reimburse the generator for all monies that were paid in excess of the amount that should have been paid based on the correct load with interest calculated pursuant to Section 35.19a of FERC's regulations. A generator shall not receive any reduction to the amount it is billed, nor any refund, as described herein, to the extent it is wheeling power out of Central Maine's service territory. Generators are not permitted to purchase transmission on behalf of load at the $3.00 rate. Load must pay for transmission at the full rates described in this OATT. On March 1, 2003, and subsequently, the $3.00 rate and the reduction for service to load in Central Maine's service territory shall expire and be considered void.

The charges described in this schedule are subject to waiver under the circumstances and pursuant to the conditions described in Section 21.I.13 of this Schedule 21-CMP.

5) **Discounts**: Three principal requirements apply to discounts for Transmission Service as follows: (1) any offer of a discount made by Central Maine must be announced to all Eligible Customers solely by posting on the OASIS; (2) any customer-initiated requests for discounts (including requests for use by Central Maine's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, Central Maine must offer the same discounted Transmission Service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same Point(s) of Delivery on the Transmission System.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to the resales of Transmission Service, compensation for which shall be governed by Schedule 21 § 11 (a).

SCHEDULE 8

Non-Firm Local Point-To-Point Transmission Service

Each Transmission Customer who takes Non-Firm Local Point-to-Point Transmission Service shall pay Central Maine each month on the basis of the highest amount of Reserved Capacity for each transaction reserved as Non-Firm Local Point to Point Transmission Service. The charges will be re-determined annually on June 1 of each year, and shall be in effect for the succeeding twelve months. The rate per kilowatt for each month is one-twelfth of the annual rate determined by dividing the Annual Transmission Revenue Requirement calculated pursuant to the Attachment G formula, by Central Maine's average monthly Local Network Transmission System load (as defined in Section21.II.8.c) for the prior calendar year.

Each Transmission Customer taking Non-Firm Local Point to Point Transmission Service shall pay the non-firm local point-to-point rate on the basis of the highest amount of Reserved Capacity for each transaction scheduled as Non-Firm Local Point to Point Transmission Service as follows:

1) **Yearly reservation**: one-twelfth of the annual rate per kilowatt of Reserved Capacity per year.

2) **Monthly reservation**: one-twelfth of the annual rate per kilowatt of Reserved Capacity per month.

3) **Weekly reservation**: 1/52nd of the annual rate per kilowatt of Reserved Capacity per week.

4) **Daily reservation**: 1/7th of the weekly rate per kilowatt of Reserved Capacity per day.

5) **Hourly reservation**: 1/24th of the daily rate per kilowatt of Reserved Capacity per hour.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (4) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week The charges described in this schedule are subject to waiver under the circumstances and pursuant to the conditions described in Section 21.I.13 of this Schedule 21-CMP.

6) **Discounts**: Three principal requirements apply to discounts for Transmission Service as follows: (1) any offer of a discount made by Central Maine must be announced to all Eligible Customers solely by posting on the OASIS; (2) any customer-initiated requests for discounts (including requests for use by Central Maine's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, Central Maine must offer the same discounted Transmission Service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same Point(s) of Delivery on the Transmission System.

7) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to the resales of Transmission Service, compensation for which shall be governed by Schedule 21 § 11 (a).

SCHEDULE 12

Retail Access Transmission and Distribution Services

A. EXCEPTIONS TO OPEN ACCESS TRANSMISSION TARIFF:

The following applies only to Retail Network Transmission Service for both transmission-level and distribution level retail customers and Point-To-Point Transmission Service for transmission-level retail customers. For each unbundled retail Transmission Service, Central Maine specifies below the modifications to the ("OATT") terms and conditions necessary for retail access transmission and distribution services. The exceptions to the OATT specified below will apply to all customers that take service either directly under the following rate designations or pursuant to a targeted rate, Tariff or contract,[1] but for that targeted rate, Tariff or contract, the customer otherwise would take service under the following designations:

[1] Central Maine may change the price for distribution service that it charges customers pursuant to guidelines established by the Maine Public Utilities Commission. These price changes are normally done with targeted groups of customers or with one customer in order to retain sales or grow sales. The price changes are in the form of a rate or tariff or an individual contract

Transmission-Level [2] (1) LGS-ST-TOU; (2) LGS-T-TOU; (3) SB-LGS-T; and (4) SB-LGS-ST.

Distribution-Level [3] : (1) A; (2) A-LM; (3) A-TOU; (4); AL (5); IGS-P-TOU; (6) IGS-S-TOU (7) LGS-P-TOU; (8) LGS-S-TOU; (9) MGS-P; (10) MGS-P-TOU; (11) MGS-S; (12) MGS-S-TOU; (13) N (14) R; (15) R-TOU; (16) SB-IGS-P; (17) SB-IGS-S; (18) SB-LGS-P; (19) SB-LGS-S; (20) SL; (21) SGS; and (22) SGS-TOU.

1. Central Maine shall be the sole Designated Agent for arranging network service for its distribution-level retail customers. Central Maine shall be allowed to bill such retail customers directly for combined transmission and distribution services. Distribution-level retail customers shall take Local Network Transmission Service from Central Maine, acting as their agent under an Umbrella Service Agreement for Retail Local Network Transmission Service ("Umbrella Agreement"). Distribution-level retail customers also agree under the Umbrella Agreement that Central Maine will act as their Designated Agent for arranging and obtaining Regional Network Service and transmission related services on their behalf pursuant to the Tariff. Such individual distribution-level retail customers are not required to sign separate Transmission Service Agreements. Distribution-level retail customers agree to take Ancillary Services for Scheduling, System Control & Dispatch Service and Reactive Power & Voltage Support From Generating Resources Service from or through Central Maine, which Central Maine will procure on behalf of such customers. Central Maine agrees to perform services under the umbrella Agreement for an initial term of one year (commencing on March 1, 2000), that will continue from year-to-year unless terminated by Central Maine through a unilateral filing with FERC under section 205 of the FPA. Accordingly, Central Maine will transmit capacity and energy sufficient to serve all of its distribution-level retail customers as determined by the Maine Public Utilities Commission.

2. Transmission-level retail customers must sign a Local Point-To-Point Service Agreement or a Local Network Service Agreement and Network Operating Agreement for Retail Local Network Transmission Service ("Service Agreement"). Local Network Service will be supplied by Central Maine to these transmission-level retail customers for an initial term established pursuant to the Service Agreement. Transmission-level retail customers must also purchase Regional Network Service and

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[2] Transmission-level customers taking service under the specified rate schedules are required to purchase Transmission Services directly under this Schedule 21-CMP and the Tariff, except that transmission-level customers may designate CMP to act as their agent for arranging and obtaining service under the Tariff

[3] Distribution-level customers taking service under the specified rate schedules will purchase Transmission Services from CMP as their Designated Agent in a combined transmission and distribution rate.

transmission-related services under the Tariff or, at their discretion, designate Central Maine to act as their agent for obtaining and arranging Regional Network Service and transmission related services under the Tariff.

3. If specifically requested by Central Maine's transmission-level retail customers in the Service Agreement, Central Maine will also arrange and obtain Regional Network Service and related services under the Tariff, and arrange and obtain Ancillary Services for Scheduling, System Control & Dispatch Service and Reactive Power & Voltage Support From Generating Resources Service as provided under the OATT and will bill these retail transmission-level customers directly for Regional Network Service and applicable Ancillary Services. Central Maine shall charge transmission-level retail Customers, designating Central Maine as their agent, an administrative fee of $200 per month for arranging such services. The initial minimum term for such designation shall be 15 months from March 1, 2000 or the term of the Service Agreement, and thereafter shall be one (1) year. Transmission-level retail customers electing to change such designation must notify the manager of transmission services, in writing by May 1 of each year to be effective on the annual June 1 of that year, when the formula rates are updated pursuant to this Schedule 21-CMP.

4. Transmission-level retail customers designating Central Maine as the sole agent to arrange and obtain Regional Network Service and related services pursuant to the Tariff agree to pay in full to Central Maine any and all costs of such services, including costs incurred to arrange such services under the Tariff and for applicable Ancillary Services (including the $200 per month administrative fee (see A.3)).

5. An additional deposit beyond that required to obtain retail distribution service will not be required to accompany an Application for Transmission Service under this Schedule 21. Nevertheless, Central Maine will reserve the right to implement "commercially reasonable" deposit practices should market conditions or individual customer conditions warrant.

6. The reservation priority for existing firm service customers is modified to give retail customers the right to continue to take service.

7. [RESERVED]

8. Unless otherwise specified in their State of Maine Tariffs or in an agreement with Central Maine, the minimum term of service for retail transmission-level customers is one year. The minimum term for

retail distribution-level customers will be Central Maine’s monthly billing cycle. Thereafter, such retail distribution-level customers will continue to be responsible for transmission charges from typical monthly billing cycle to typical monthly billing cycle.

9. Retail customers taking Transmission Service under the aforementioned rate designations will abide by the MPUC ’s deposit, late payment, interest, and disconnection rules associated with the retail distribution service and will not be assessed additional charges covering these issues for Transmission Service under this Schedule 21.

B. TRANSMISSION RATE COMPONENTS OF CENTRAL MAINE’S DISTRIBUTION-LEVEL CUSTOMER RETAIL RATES:

The transmission rate components of Central Maine's distribution-level retail rates are determined as follows:

1. Allocate the transmission related charges[4] under the Tariff and the revenue requirement calculated pursuant to the Attachment G-R formula of this Schedule 21-CMP, including charges for system control and dispatch, to appropriate retail rate classes based upon historical test year 12 month average coincident peak data adjusted to reflect Behind-The-Meter Generation of transmission-level retail and wholesale customers, in accordance with Sections 21.II.7, 21.II.8.b and 21.II.8.c of this Schedule 21-CMP.

2. Divide the results of the allocation described in "1" above by the appropriate retail billing determinants for the same test year (kWh for customers that are not billed for demand, or kW for customers that are billed for demand) to determine the transmission prices for distribution-level customers associated with “1” above.

3. Beginning March 2000, Central Maine shall recover in distribution-level retail rates, the difference between actual Congestion costs billed pursuant to the Tariff, to the extent such Congestion costs are assessed on the basis of transmission reservations or load, and the level of Congestion costs reflected in transmission prices paid by Central Maine’s distribution-level retail customers. Any difference between Congestion costs incurred and those in distribution level retail rates, whether positive

[4] Charges incurred by Central Maine pursuant to the Tariff, including but not limited to congestion uplift costs, are considered transmission-related except for power supply related costs incurred under these regional arrangements. As a general rule, Central Maine defines transmission related charges as those regional charges allocated to Transmission Customers (or transmission owners taking Transmission Service under the Tariff as an agent for retail Transmission Customers) based on transmission billing determinants while power supply related charges are those regional charges associated with the Tariff that are allocated based on energy billing determinants.

or negative, will be accrued with interest calculated pursuant to Section 35.19a of the Commission's regulations, and shall be recovered or credited beginning with the next rate change for these customers.

Central Maine shall continue to be able to recover any differences (positive or negative) that exist between actual Congestion costs and that included in rates for recovery of current Congestion costs in subsequent transmission prices. Once recovery of past costs is complete, the amounts shall be removed from Central Maine's transmission prices.

Central Maine shall allocate such congestion costs to each rate class based on the same historical test year 12 month average coincident peak data used to allocate transmission-related charges under the Tariff, as described in "1" and "2" above. The amounts allocated to each rate class shall then be divided by the appropriate retail billing determinants as described in "2" above to determine the transmission prices associated with Congestion costs for distribution-level retail customers, and shall be in addition to the transmission prices for distribution-level retail customers determined in "1" and "2" above.

C. TIMING OF TRANSMISSION RATE CHANGES FOR DISTRIBUTION-LEVEL RETAIL CUSTOMERS:

1. To accommodate the timing difference between transmission price changes and distribution price changes, the retail transmission price changes for distribution-level retail customers will take effect contemporaneously with the annual changes to distribution rates. The transmission revenue effect of any difference (positive or negative) between when transmission price changes would normally occur (i.e. June 1) and when they actually occur will be accrued with interest, calculated pursuant to Section 35.19a of FERC's regulations and included in the next determination of transmission prices for distribution-level retail customers.

2. Transmission prices for distribution-level retail customers will not change each month to account for the crediting of wheeling out revenues that Central Maine receives from generators. Nor will transmission prices for distribution-level retail customers change each month to account for any revenue credits received from generators taking point-to-point service. Rather, Central Maine shall accrue with interest (calculated pursuant to Section 35.19a of FERC's regulations) the difference between the revenue credits properly assigned to distribution-level retail customers and that included in distribution-level

transmission rates, and include such accrued amounts in the next determination of distribution-level retail transmission prices.

3. The rates for Scheduling, System Control and Dispatch Service shall not change each month for distribution-level retail customers. To the extent such rates should change each month to reflect revenues associated with the Scheduling, System Control and Dispatch charges paid by generators, and CCS Charges paid by generators, Central Maine shall accrue with interest (calculated pursuant to Section 35.19a of FERC's regulations) the difference between the revenue credits properly assigned each month and the revenue credits actually used, such accrued amount to be incorporated into the next determination of rates under Schedule No. 1 for distribution-level retail customers.

D. TRANSMISSION RATES FOR CENTRAL MAINE'S TRANSMISSION-LEVEL CUSTOMERS:

1. Whether or not Central Maine's retail transmission-level customers designate Central Maine as their sole agent, Central Maine's retail transmission-level customers will be charged the applicable rate for Local Network Service pursuant to the formula in Attachment G-R of Schedule 21-CMP and Section (B) of this Schedule No. 12, and will be charged the applicable rate for Regional Network Service and applicable Ancillary Services in instances where the transmission-level customers designate Central Maine as their agent for acquiring services under the Tariff on their behalf pursuant to Section (B) of this Schedule No. 12.

2. The Local Network Load for each transmission-level retail customer with Behind-The-Meter Generation (not including those customers taking service over a Direct Assignment Facility that interconnects with PTF) shall be determined pursuant to Sections 21.II.7 and 21.II.8.b of this Schedule 21-CMP, except that Central Maine shall account for such Behind-the-Meter Generation in its calculations of Load Ratio Share using one of the following two methods: (a) by adding to the facility's monthly coincident peak demand (when the Behind-The-Meter Generation is in service), 22.5 percent of the additional load that would be placed on Central Maine's system when the Behind-The-Meter Generation is out of service; or (b) by using the monthly maximum 15 minute measured demand, occurring at any time during the month.

Customers taking service over a Direct Assignment Facility that interconnects with PTF shall pay the applicable charges for service over such Direct Assignment Facilities rather than the charge for Local

Network Service under this Schedule 21-CMP. The Load Ratio Share for such Customers shall be calculated using one of the following two methods: (a) by adding to the facility's monthly coincident peak demand (when the Behind-The-Meter Generation is in service), 22.5 percent of the additional load that would be placed on Central Maine's system when the Behind-the-Meter Generation is out of service; or (b) by using the monthly maximum 15 minute measured demand, occurring at any time during the month.

3. The treatment of behind-the-meter load, as described in this Schedule 21-CMP, shall not impact the manner in which Central Maine reports load to ISO, nor shall it impact any regional charges or rates assessed by ISO. Customers who do not designate Central Maine as their agent shall be billed or credited the difference between the amount billed directly by ISO for services and the allocation of costs that result from Central Maine's apportioning of the total charges under the Tariff using the Load Ratio Shares adjusted for Behind-The-Meter Generation pursuant to this Schedule 21-CMP. In the event ISO adopts any position on behind-the-meter load, any party shall be permitted to make a filing at FERC(under Section 205 of the FPA for Central Maine; under Section 206 of the FPA for all others), proposing a change to the treatment of behind-the-meter load in this Schedule 21-CMP to be consistent with ISO's treatment. Any party responding to such a filing is permitted to argue for no change to the terms of Central Maine's Schedule 21-CMP regarding behind-the-meter load.

4. Each load with Behind-The-Meter Generation shall select one of the two methods described in 2(a) or 2(b) above. Load is permitted to change its selection only once per year by sending written notice of such change to the Manager of Transmission Operations at Central Maine no earlier than May 1 of that year and no later than May 15 of that year. Upon proper notice, the requested change shall take effect on June 1 of that year.

5. Notwithstanding any other provision in this Schedule, the Local Network Load of a customer taking non-firm service under Rate O in any month shall be the load placed on the system by the customer at the time of Central Maine's monthly system peak for the load taken under Rate O, without regard for Behind-The-Meter Generation.

6. Nothing herein shall make a Behind-The-Meter Generator a designated Network Resource or prevent such generation from being designated by the generator itself as a Network Resource.

SCHEDULE 13
METER SERVICES

This formula sets forth the details for determining the annual revenue requirement related to providing Meter Services. The revenue requirement reflects the cost of owning, operating and maintaining Central Maine's Meters. The Revenue Requirement will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31, 2000, based on 1998 test year data, and updated thereafter each June 1, based on the previous calendar year's FERC Form 1 data, as shown below, using end-of-year balances for each rate base item, as further set forth below.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section 1 of Schedule 21-CMP and used in this formula have the following definitions:

A. ALLOCATION FACTORS

1. Wages and Salaries Allocation Factor shall equal the ratio of the Meter Direct Wages and Salaries to Total Direct Wages and Salaries excluding Administrative and General Wages and Salaries.

2. Meter Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Meter Plant and Meter Related General Plant to Total Plant in service.

B. TERMS

Administrative and General Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928, and 930.1.

Amortization of Investment Tax Credits shall equal Central Maine's credits as recorded in FERC Account No. 411.4.

Materials and Supplies shall equal Central Maine's balance as recorded in FERC Account No. 154.

Meter Depreciation Expense shall equal Central Maine's depreciation expense for Meter Plant as recorded in FERC Account No. 403.

Meter Direct Wages and Salaries shall equal Central Maine’s direct wages and salaries related to providing meter services as recorded in FERC Account Nos. 586 and 597.

Meter Operation and Maintenance Expense shall equal Central Maine’s expenses recorded in FERC Account Nos. 586 and 597.

Meter Plant shall equal Central Maine’s gross plant balances used for metering purposes as recorded in FERC Account No. 370.

Meter Plant Depreciation Reserve shall equal Central Maine’s depreciation reserve balance for Meter Plant as recorded in FERC Account No. 403.

General Plant shall equal Central Maine’s balance in FERC Account No. 389 – 399.

General Plant Depreciation Expense shall equal Central Maine’s depreciation expense for General Plant as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal Central Maine’s depreciation and amortization reserve balance for General Plant as recorded in FERC Account No. 108.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of Central Maine’s FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in Central Maine’s FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of Central Maine’s FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Central Maine’s FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in Central Maine’s FERC Account Nos. 408.1.

Prepayments shall equal Central Maine’s prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Central Maine's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and 190.

Total Municipal Tax Expense shall equal Central Maine's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal Central Maine's total gross plant balance as recorded in FERC Account Nos. 301-399.

II. CALCULATION OF TOTAL METER REVENUE REQUIREMENTS

The Meter Revenue Requirement shall equal the sum of the Meter related (A) Return and Associated Income Taxes, (B) Depreciation Expense, (C) Amortization of Investment Tax Credits, (D) Municipal Tax Expense, (E) Payroll Tax Expense, (F) Operations and Maintenance Expense, (G) Administrative and General.

A. **Return and Associated Income Taxes** shall equal the product of the Meter Investment Base and the Cost of Capital Rate reflected in Attachment G of Schedule 21-CMP.

1. **Meter Investment Base**

The Meter Investment Base will be the year end balances of Meter related: (a) Plant, plus (b) General Plant, less (c) Depreciation Reserve, less (d) Accumulated Deferred Taxes, plus (e) Other Regulatory Assets/Liabilities, plus (f) prepayments, plus (g) Materials and Supplies, plus (h) Cash Working Capital.

(a) Meter Related Plant shall equal the balance of Central Maine's Investment in Meter Plant.

(b) Meter Related General Plant shall equal the balance of Central Maine's General Plant multiplied by the Meter Wages and Salaries Allocation Factor.

(c) Meter Related Depreciation Reserve shall equal Central Maine's Meter Plant Depreciation Reserve plus the General Plant Depreciation Reserve multiplied by the Meter Wages and Salaries Allocation Factor.

(d) Meter Related Accumulated Deferred Taxes shall equal Central Maine's electric balance of Accumulated Deferred Income Taxes multiplied by the Meter Plant Allocation Factor.

(e) Meter Related Other Regulatory Assets/Liabilities shall equal Central Maine's electric balance of any deferred recovery of FAS 106 expenses multiplied by the Meter Wages and Salaries Allocation Factor, plus Central Maine's electric balance of FAS 109 multiplied by the Meter Plant Allocation Factor.

(f) Meter Related Prepayments shall equal Central Maine's electric balance of prepayments multiplied by the Meter Wages and Salaries Allocation Factor.

(g) Meter Related Materials and Supplies shall equal Central Maine's electric balance of Plant Materials and Supplies, multiplied by the Meter Plant Allocation Factor.

(h) Meter Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Meter Operation and Maintenance Expense and Meter Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Central Maine's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of:

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity, including unamortized discounts and premiums, and unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to Central Maine's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Central Maine's preferred stock then outstanding and the ratio that preferred stock is to Central Maine's total capital.

(iii) the return on equity component, which equals the product of Central Maine's Return on Equity of ~~10.57~~11.14% and the ratio that common equity is to Central Maine's total capital.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Meter Depreciation Expense, as defined in II.B., and D is Meter Investment Base, as determined in II.A.1., above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Meter Depreciation Expense, as defined in II.B., D is the Meter Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.1.(b) above.

B. **Meter Related Depreciation Expense** shall equal the sum of the Meter Plant Depreciation Expense and the Meter Related General Plant Depreciation Expense multiplied by the Meter Wages and Salaries Allocation Factor.

C. **<u>Meter Related Amortization of Investment Tax Credits</u>** shall equal Central Maine's electric Amortization of Investment Tax Credits multiplied by the Meter Plant Allocation Factor.

D. **<u>Meter Related Municipal Tax Expense</u>** shall equal Central Maine's total electric municipal tax expense multiplied by the Meter Plant Allocation Factor**.**

E. **<u>Meter Related Payroll Tax Expense</u>** shall equal Central Maine's total electric payroll tax expense multiplied by the Meter Wages and Salaries Allocation Factor.

F. **<u>Meter Operation and Maintenance Expense</u>** shall equal Central Maine's Operation and Maintenance Expenses recorded in FERC Account Nos. 586 and 597.

G. **<u>Meter-Related Administrative and General Expenses</u>** shall equal the sum of (1) Central Maine's Administrative and General Expenses multiplied by the Meter Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Meter Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments not otherwise directly assigned under Attachment G of this Schedule 21-CMP, multiplied by the Meter Plant Allocation Factor, plus any other Federal and State meter related expenses or assessments, plus specific meter related expenses included in Account 930.1**.**

III. CALCULATION OF THE MONTHLY METERING CARRYING CHARGE:

Each of the Schedule 13 Meter Investment Base and Meter Revenue Requirement formula components, II.A.1.(a) through II.A.1.(h), and II (A) through II (G), respectively, will be classified as either capital related or O&M related or related to both capital and O&M. Formula components related to both capital and O&M will be assigned based on the amount of gross plant classified to each category except for II.A.1.(a) Return and Associated Taxes. The capital related portion of Return and Associated Taxes shall equal the product of the sum of the capital related meter investment base components and the Cost of Capital Rate. The O&M related portion of Return and Associated Taxes shall equal the product of the sum of the O&M related meter investment base components and the Cost of Capital Rate.

Meter Investment Base formula components II.A.1.(a) and II.A.1.(c) excluding depreciation reserve associated with general plant are capital related, while II.A.1.(b), II.A.1.(c) less meter plant depreciation reserve, the FAS106 portion of II.A.1.(e), and components II.A.1.(f) through II.A.1.(h) are O&M related.

Meter Investment Base components II.A.1.(d) and the FAS 109 portion of II.A.1.(e), relate both to capital and O&M.

Meter Revenue Requirement component II.(B) excluding meter plant depreciation expense and components II(D) through II(G) are O&M related, while II(C), Amortization of Investment Tax Credits is related both to capital and O&M. The meter depreciation expense portion of II.(B) is excluded from the determination of the capital related carrying charge. Actual depreciation will be tracked for each Direct Assignment Facility and charged separately each month pursuant to this Schedule.

The annual capital related carrying charge is the sum of the capital related revenue requirement components expressed as a percentage of Central Maine's total net investment in Meter Plant. The monthly capital related carrying charge will be one-twelfth of the annual capital related carrying charge. The monthly capital related carrying charge will be applied to the net investment in Meter Plant directly assigned to the Transmission Customer to determine the monthly capital related charge. The monthly capital related charge plus the actual monthly depreciation for the Transmission Customers' Direct Assignment Facilities represents the total monthly charge for this service, and shall be in addition to any other applicable charges under this Schedule 21, including Ancillary Services.

The annual O&M related carrying charge is the sum of the O&M related revenue requirement components expressed as a percentage of Central Maine's total gross investment in Meter Plant. Gross investment in Meter Plant for purposes of this Schedule, shall reflect the investment in meter facilities for which Central Maine has received a contribution to capital or a contribution in aid of construction. Only the O&M related carrying charge is applicable in cases where the Transmission Customer has paid Central Maine for the capitalized cost of the meter plant.

The monthly O&M related carrying charge will be one-twelfth of the annual O&M related carrying charge. The monthly O&M related carrying charge will be applied to the gross investment in meter plant directly assigned to the Transmission Customer to determine the monthly charge for this service, and shall be in addition to any other applicable charges under this Schedule 21, including Ancillary Services.

SCHEDULE 14

MONTHLY CARRYING CHARGE FOR DIRECT ASSIGNMENT FACILITIES

Each of the Attachment G Transmission Investment Base and Transmission Revenue Requirement formula components, II.A.1.(a) through II.A.1.(i), and II (A) through II (G), respectively, will be classified as either capital related or O&M related or related to both capital and O&M. Formula components related to both capital and O&M will be assigned based on the amount of gross plant classified to each category except for II.A.1.(a) Investment Return and Associated Taxes. The capital related portion of Investment Return and Associated Taxes shall equal the product of the sum of the capital related investment base components and the Cost of Capital Rate. The O&M related portion of Investment Return and Associated Taxes shall equal the product of the sum of the O&M related investment base components and the Cost of Capital Rate.

Transmission Investment Base formula components II.A.1.(a), II.A.1.(c), and II.A.1.(d) excluding depreciation reserve and accumulated amortization associated with general and intangible plant are capital related, while II.A.1.(b), II.A.1.(d) less transmission plant depreciation reserve, the FAS106 portion of II.A.1.(f), and components II.A.1.(g) through II.A.1.(i) are O&M related. Transmission Investment Base components II.A.1.(e) and the FAS 109 portion of II.A.1.(f), relate both to capital and O&M.

Transmission Revenue Requirement component II.(B) excluding transmission depreciation expense and components II(D) through II(G) are O&M related, while II(C), Amortization of Investment Tax Credits is related both to capital and O&M. The transmission plant depreciation portion of II.(B) is excluded from the determination of the capital related carrying charge. Actual depreciation will be tracked for each Direct Assignment Facility and charged separately each month pursuant to this Schedule.

The annual capital related carrying charge is the sum of the capital related revenue requirement components expressed as a percentage of Central Maine's total net investment in Transmission plant, excluding the balance associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts for test periods beginning with the calendar year 1999 and thereafter. The monthly capital related carrying charge will be one-twelfth of the annual capital related carrying charge. The monthly capital related carrying charge will be applied to the net investment in transmission plant directly assigned to the Transmission Customer to determine the monthly capital related charge. The monthly capital related charge plus the actual monthly depreciation for the Transmission Customers' Direct Assignment Facilities represents the total monthly charge for this service, and shall be in addition to any other applicable charges under this Schedule 21, including Ancillary Services.

The annual O&M related carrying charge is the sum of the O&M related revenue requirement components expressed as a percentage of Central Maine's total gross investment in Transmission Plant, excluding the balance associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts for test periods beginning with the calendar year 1999 and thereafter. Gross investment in transmission plant for purposes of this Schedule, shall reflect the investment in transmission facilities for which Central Maine has received a contribution to capital or a contribution in aid of construction. Only the O&M related carrying charge is applicable in cases where the Transmission Customer has paid Central Maine for the capitalized cost of the transmission plant.

The monthly O&M related carrying charge will be one-twelfth of the annual O&M related carrying charge. The monthly O&M related carrying charge will be applied to the gross investment in transmission plant directly assigned to the Transmission Customer to determine the monthly charge for this service, and shall be in addition to any other applicable charges under this Schedule 21, including Ancillary Services.

When applicable, wholesale Transmission Customers will pay the carrying charge calculated as described above based on the Attachment G-W formula. The carrying charge for retail Transmission Customers will be calculated as described above based on the Attachment G-R formula, and, in addition to the O&M related revenue requirement components described above, will include Attachment G-R revenue requirement component II. (M) to reflect transmission related Customer Service and Informational Expenses and Sales Expenses.

ATTACHMENT C-CMP

Methodology To Assess Available Transfer Capability

1 Introduction

ISO is the regional transmission organization ("RTO"), serving the New England Control Area. ISO is responsible for the development, oversight, and fair administration of New England's wholesale market, management of the bulk electric power system and wholesale markets planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is comprised of PTF, Non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Provider of RNS and Through or Out Service over PTF, certain Participating Transmission Owners ("PTOs") also provide local Transmission Service over Non-PTF within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Service provided under Schedule 21. CMP is a Transmission Provider of Local Service under Schedule 21-CMP in accordance with the Transmission Operating Agreement ("TOA"). Pursuant to CFR§37.6(b) of the FERC Regulations which states the available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path. The Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path accordingly.

As stated in §37.6(b)(1)(i) Posted Path means any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.

Non-PTF facilities are primarily radial paths that provide Transmission Service directly to interconnected generators. It is possible, in the future that a particular path may interconnect more nameplate capacity generation than the path's TTC. However, for CMP's Non-PTF modeled by the ISO or the Local Control Center ("LCC"), the ISO or the LCC will only dispatch an amount of generation interconnected to such path so as not to incur a reliability violation on the subject path consistent with ISO's economic, security constrained dispatch methodology.

CMP does not currently have a Posted Path based on the above definition. However, should CMP have any Posted Path(s) in the future, CMP will calculate TTC using NERC MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to the following functions performed by CMP as the Transmission Provider of Local Point-to Point Transmission Service over Non-PTF pursuant to this Schedule 21-CMP, the TOA, and the ISO OATT:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)
- Use of Rollover Rights (ROR) in the calculation of ETC

As explained in Section 2, TTC and ATC are required to be calculated only for certain Non-PTF internal Posted Paths over which Local Point-to-Point Transmission Service is provided under Schedule 21-CMP. TTC and ATC is not calculated by CMP for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and advanced reservations are not required for network service.

2 Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point Transmission Service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the New England Control Area, out of the New England Control Area or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region. This process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF local facilities utilized for Local Network Service by generation or load. However, CMP provides service over Non-PTF over which advance Transmission Service reservations for firm or non-firm Transmission Service may be required. On those local facilities, the market participant must obtain a Transmission Service reservation under Schedule 21-CMP prior to delivery of energy into the New England Wholesale Market. This document addresses the calculation of ATC and TTC for the non-PTF internal paths.

3 Total Transfer Capability (TTC)

The Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected Transmission Systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule

21-CMP is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on the CMP OASIS site.

CMP will calculate and post TTC on OASIS for all Non-PTF Posted Paths that are eligible for Local Point-to-Point Transmission Service reservations. The TTC on CMP's Non-PTF eligible for Local Point-to-Point Transmission Service reservations are relatively static values. CMP thus calculates the TTC for Non-PTF Posted Paths equal to the rating of the particular transmission path.

4 Capacity Benefit Margin (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the load serving entities. The ISO does not set aside any CBM for use by the load serving entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load serving entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load serving entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of CMP's ATC calculation and because CBM for the New England Control Area is set to zero (0), CMP utilizes a zero (0) CBM value.

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservation (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

5 Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. CMP does not have any external interfaces, and therefore TRM for CMP's Non-PTF is zero.

6 Calculation of ATC for CMP's Local Facilities - General Description

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a Transmission Provider's ATC methodology. As a practical matter, the ratings of the Non-PTF radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, Transmission Services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for CMP's Non-PTF described above, as ATC is positive and listed as 9999. Transmission Customers are not restricted from reserving firm or non-firm Transmission Service on CMP's Non-PTF.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the Non-PTF in the New England market is almost always positive. With this simplified version of ATC, there is no detailed algorithm to be described or posted. Thus, for those Non-PTF facilities that serve as a path for the CMP Schedule 21-CMP Local Point-to-Point Transmission Customers, CMP has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Firm ATC (ATC_F)

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service over Schedule 21-CMP that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-CMP transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F.

6.1.2 Calculation of ATC_F in the Operating Horizon (OH)

For purposes of this Attachment C OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service over Schedule 21-CMP is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-CMP transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Firm Transmission Service is not offered in the Scheduling Horizon (SH) therefore ATC_F in the SH is zero.

6.2 Calculation of Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-CMP are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-CMP transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-CMP are zero. TRM_U, $counterflows_{NF}$ and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus $ETC_{F,}$ and ETC_{NF} plus postbacks $Postbacks_{NF}$.

6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, Transmission Services over these posted paths are considered to be always available. The Non-PTF facilities are primarily radial paths that provide Transmission Service to directly interconnected generators.

It is possible, in the future that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, for CMP's Non-PTF modeled by ISO or the LCC, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path consistent with ISO's economic, security constrained dispatch methodology. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

7 Posting of ATC

7.1 Location of ATC Posting

ATC values are posted on CMPs OASIS site in accordance with NAESB Standards.

7.2 Updates To ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

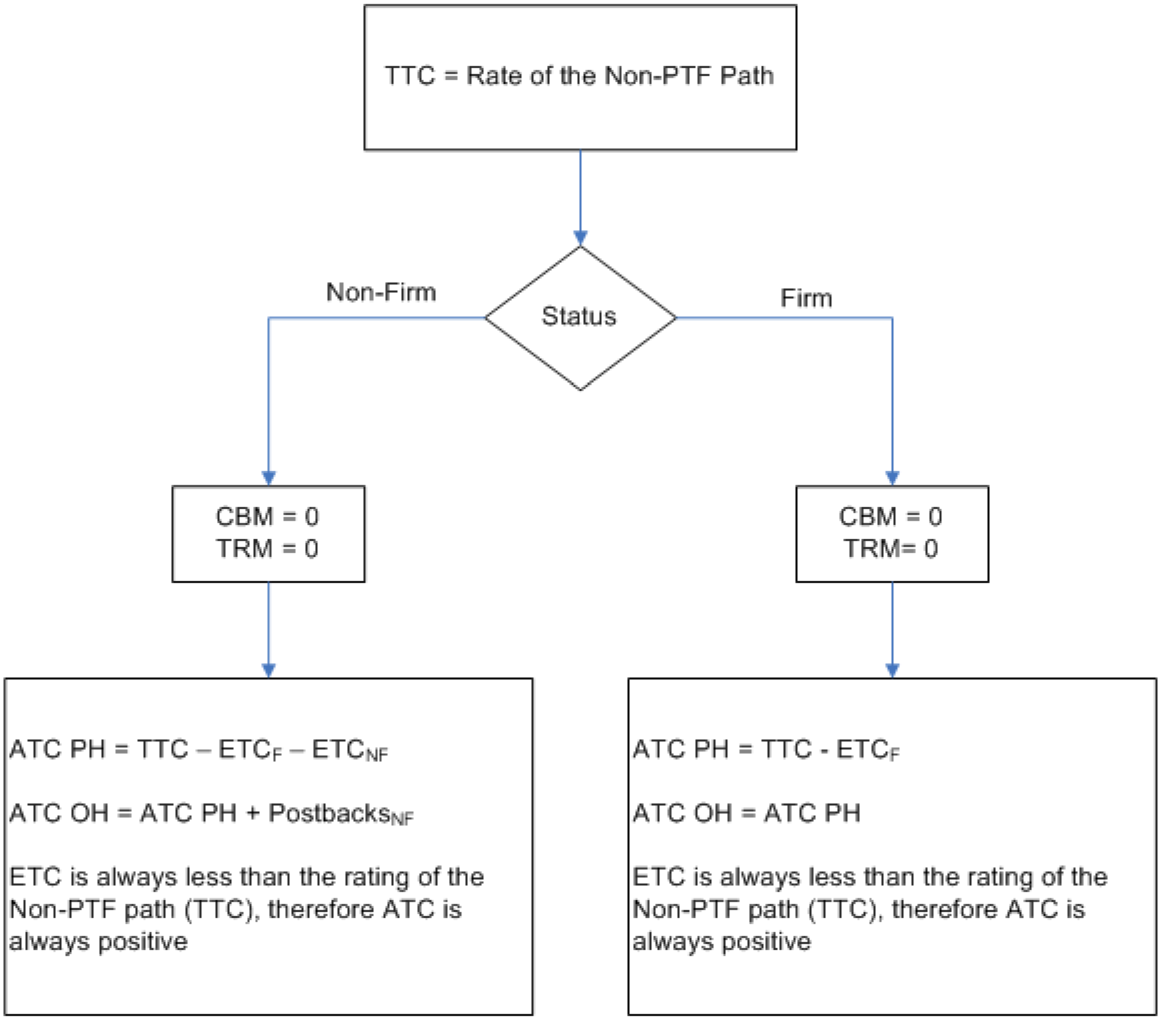
7.3 Coordination of ATC Calculations

Schedule 21-CMP non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms A link to the actual mathematical algorithm for the calculation of ATC for CMP's non-PTF internal interfaces is located on CMP's website at

http//www/cmpco.com/SuppliersAndPartners/TransmissionServices/CMPTransmissionSvc/CMPDownloads.html

Non-PTF Transmission Path ATC Process Flow Diagram



ATTACHMENT D

Methodology for Completing a System Impact Study

Central Maine (or its Designated Agent) may require System Impact Studies for the purpose of determining the feasibility of providing Transmission Service under this Schedule 21. All System Impact Studies will be coordinated with the Control Area Operator and completed using the same method employed by Central Maine to provide Transmission Service to its Affiliate customers. System Impact Studies associated with a request from an Eligible Generator Customer for Interconnection Service shall be performed at the direction of the Control Area Operator. Specifically, System Impact Studies will be performed by applying NPCC Criteria and the "Reliability Standards of ISO," or its successor, while assuring that Central Maine's Native Load Customers and those loads directly interconnected to the Central Maine Transmission System that are receiving Transmission Service can be served economically and reliably. All of the criteria, standards, and guidelines referenced above are included as part of the annual FERC Form 715 filing of Central Maine.

ATTACHMENT F

Local Network Operating Agreement

This Local Network Operating Agreement is part of Schedule 21 and is subject to and in accordance with all provisions of said Schedule 21. All definitions and terms and conditions of this Schedule 21-CMP are incorporated herein by reference.

1.0 General Terms and Conditions

Central Maine agrees to provide Local Network Transmission Service to the Transmission Customer subject to the Transmission Customer operating its facilities in accordance with applicable Central Maine, or its Affiliates, Control Area Operator, NERC and NPCC criteria, rules, standards, procedures or guidelines as they may be changed from time to time. In addition, service to the Transmission Customer is provided subject to the terms and conditions contained herein.

1.1 Character of Service

All Local Network Transmission Service shall be in the form of three-phase sixty (60) hertz alternating current at a delivery voltage agreed to by both parties.

1.2 Maintenance Scheduling

Central Maine shall consult the Transmission Customer regarding the timing of any scheduled maintenance of the Transmission System that would affect service to the Transmission Customer.

1.3 Information Requirements

The Transmission Customer shall be responsible for providing all information required by the Control Area Operator and Central Maine necessary for planning, operations, maintenance and regulatory filings. This information may include, but not be limited to:

Load related data:

- Ten (10) year forecast of Local Network Load at each delivery point.
- Power factor performance.
- Amount of interruptible load under contract, including interruption terms.
- Load shedding capability by delivery point.
- Capability to shift load between delivery points.

- Disturbance reports.
- Results of periodic metering and protection equipment tests and calibration.
- Planned changes to interconnection equipment.
- Voltage reduction capability.

Network Resources and interconnected generation:

- Resource operating characteristics, including ramp rate limits, minimum run times, etc.
- Ten year forecast of resource additions, retirements and capability changes.
- Generator reactive capability.
- Results of periodic metering and protection equipment tests and calibration.

Failure of the Transmission Customer to respond promptly and completely to Central Maine's reasonable request for information shall result in a fine of $100 per day payable to Central Maine. Continued failure to respond shall constitute default.

In addition to the types of information shown above, the Transmission Customer shall supply accurate and reliable operating information to Central Maine. Such information might include, but not be limited to, metered values for kWh, kW, KVAR, voltage, current, frequency, breaker status data and all other data necessary for reliable operation. Central Maine can require such information to be provided electronically using a method such as Supervisory Control And Data Acquisition (SCADA), Remote Terminal Units (RTU), remote access metering or be capable of interfacing directly with Central Maine's dispatch computer system. All equipment used for such purposes must be approved by Central Maine.

1.4 Operating Requirements

The Transmission Customer shall not conduct any switching or other activity likely to affect Central Maine's system without first contacting and receiving permission from Central Maine.

The Transmission Customer shall carry out all switching orders from Central Maine, the Control Area Operator, or a Designated Agent of either, in a timely manner.

The Transmission Customer shall operate all of its equipment and facilities connected to Central Maine's Transmission System, either directly or indirectly, in a safe, reliable and efficient manner. Such operations shall also conform to Good Utility Practice and all requirements and guidelines of Central Maine, the Control Area Operator, NERC and NPCC.

1.5 Discontinuance of Service

If at any point in time, it is Central Maine's judgment that the Transmission Customer is operating its equipment in a manner that would adversely impact the quality of service, reliability or safe operation of Central Maine's system, it may discontinue Transmission Service until the condition has been corrected.

If it is Central Maine's or the Control Area Operator's judgment that an emergency exists or that significant adverse impact is imminent, service to the Transmission Customer may be discontinued without notice. Otherwise, Central Maine or the Control Area Operator shall provide the Transmission Customer with reasonable notice of any intent to discontinue service. When practical, Central Maine will also allow suitable time for the Transmission Customer to correct the problem.

1.6 Required Equipment

The Transmission Customer will install, maintain and repair all interconnection equipment at its expense.

1.7 Emergency Operations

The Transmission Customer shall be subject to all applicable emergency operation standards and practices required of Central Maine to operate in an interconnected regional power pool. For Local Network Customers that are not members of ISO, Central Maine reserves the right to require such customers to provide their fair share of actions required under ISO Operating Procedure No 4: Action During a Capacity Deficiency, ISO Operating Procedure No. 7: Action in an Emergency and ISO Operating Procedure No. 14: Action During Extremely Light Load Conditions.

These actions might include, but are not limited to, running generation at maximum or minimum capability, voltage reduction, load shedding, transferring load between Points of Delivery, public appeals for load reduction, implementation of interruptible load programs and starting stand-by and idle generation.

2.0 Metering

Central Maine will provide Local Network Service to each Point of Delivery specified in the Transmission Customer's Service Agreement. Each Point of Delivery shall have a unique identifier, meter location and meter number.

2.1 Equipment

All metering equipment and installations used to measure energy and capacity delivered to the Transmission Customer must be approved by Central Maine. All Local Network Customers shall be required to have installed appropriate metering to determine such Backyard Generation. Central Maine may require the installation of telemetering equipment for the purposes of billing, power factor measurements and to allow Central Maine to operate its system reliably and efficiently. All such equipment will be installed and maintained at the Transmission Customer's expense.

All meters shall be capable of measuring the instantaneous kW within each hour, net flow in kWh and reactive power flow.

2.2 Seals

All meters shall be sealed, and the seals shall not be broken without prior approval by Central Maine.

2.3 Access

The Transmission Customer shall provide access, including telecommunications access, for a representative of Central Maine, to the meters at reasonable times for the purposes of reading, inspecting, and testing. Central Maine shall use its best efforts not to interfere with normal business operations.

2.4 Calibration and Maintenance

Unless otherwise mutually agreed, the meters shall not be tested or recalibrated or any of the connections, including those of the transformers, disturbed or changed except in the presence of duly authorized representatives of Central Maine and the Transmission Customer or under Emergency Conditions or unless either party, after reasonable notice fails or refuses to have its representatives present.

2.5 Testing

Central Maine will make tests of the metering equipment using Central Maine's standards of accuracy and procedures. Central Maine shall notify the Transmission Customer prior to conducting any metering tests, and the Customer may observe the test. If the meter is found to be inaccurate or otherwise defective, it shall be repaired, adjusted, or replaced at the Transmission Customer's expense.

3.0 Interconnection Equipment

The Transmission Customer's interconnection equipment shall meet all standards of Good Utility Practice.

3.1 Cost

Central Maine will not bear any costs of the interconnection, including any changes as required by this Agreement. The cost of Direct Assignment Facilities will be paid in accordance with this Schedule 21 and the Service Agreement. In the event that Central Maine would incur any expense in connection with the Direct Assignment Facilities, prior to Central Maine incurring any such expense, the Transmission Customer shall be responsible for forwarding to Central Maine funds sufficient to cover that expense, as estimated by Central Maine, including any tax liability for contribution in aid of construction. Central Maine will provide the customer with the actual expenses associated with the funding of Direct Assignment Facilities within sixty (60) days of completion of construction. Adjustments will be made within thirty (30) days thereafter.

3.2 Inspection

Central Maine may inspect the Transmission Customer's interconnection equipment to determine if all standards of Good Utility Practice are met. Central Maine shall not be required to deliver to, or receive electricity from, the Transmission Customer until those requirements are met.

3.3 New Resources

The Transmission Customer shall not connect any generators after the execution of this agreement without first informing Central Maine in writing one-hundred-twenty (120) days in advance of any such connection, except that any such generation not requiring approval the RTO-NE, shall not be connected without sixty (60) days prior notice in writing. Any third party generating facilities connected after the date of the execution of this agreement shall comply with Central Maine's then-existing Technical Interconnection Requirements for Non-Utility Generation as it applies to generation connected directly to the Central Maine system. The Transmission Customer shall be responsible to ensure compliance with these requirements.

In the event that the Transmission Customer or any third party generating facilities incorporate a synchronous generator after the date of the execution of this Local Network Operating Agreement, the Transmission Customer shall furnish, install and maintain equipment necessary to establish and maintain synchronism with Central Maine's system.

3.4 Protection Equipment

In order to protect Central Maine's system from damage, to minimize the likelihood of injury to operating personnel and third parties, and to allow Central Maine to maintain service to its non-generating customers in the event the Transmission Customer's system encounters operating difficulties, the Transmission Customer shall at its expense, provide, install, and maintain the following equipment insofar as required by Good Utility Practice and, after consultation with Central Maine:

A. A three-phase, gang-operated, load-break, lockable main disconnect switch that allows isolation of the Transmission Customer's facilities from Central Maine's system.

B. An automatic circuit breaker activated by a D.C. power source independent of both Central Maine's and the Transmission Customer's A.C. voltage source which can be tripped by the protective relay system under all system conditions. The circuit breaker must also be suitable for use in synchronizing generation on the Transmission Customer system to Central Maine's system.

C. Under-frequency and over-frequency protective relays to be used in conjunction with the required automatic circuit breaker.

D. Under-voltage and over-voltage protective relays to be used in conjunction with the required automatic circuit breaker.

E. Over-current protective relays to be used in conjunction with the required automatic circuit breaker.

F. Potential and current transformers to be used for the above relaying, sized and connected as approved by Central Maine.

G. Such other equipment as may be reasonably required by Good Utility Practice, as recommended by Central Maine.

H. The Transmission Customer shall provide to Central Maine complete documentation of the Transmission Customer's interconnection equipment, including, but not limited to, power one-line diagrams, relaying diagrams, plans, sectional and elevation views, grading plans, conduit plans, foundation plans, fence and grounding plans and detailed steel erection diagrams. In addition, the

Transmission Customer agrees to provide to Central Maine complete documentation of any changes to the Transmission Customer's Interconnection equipment.

I. The protective relay system required to detect faults on Central Maine's system and the breaker required to disconnect the Transmission Customer's generation to protect the general public and Central Maine's personnel must be approved by Central Maine. Central Maine shall provide relay settings and recommendations for design, equipment selection, and routine maintenance. The Transmission Customer shall purchase, install, and maintain the protective relay system, and maintain and make available to Central Maine all maintenance and test records. Central Maine shall perform functional test(s), at reasonable intervals, of the protective relay system to determine whether the system functions in a manner acceptable to Central Maine and shall notify the Transmission Customer in writing of the test results. The Transmission Customer shall bear the cost of this testing and any other assistance that may be requested of Central Maine before and after the system is made operational.

J. The Transmission Customer shall, at its own expense, repair and maintain its protective relay system and any other equipment owned or operated by the Transmission Customer.

3.5 Maintenance and Modifications To The Interconnection

A. The Transmission Customer shall repair and maintain during the term hereof all of the Transmission Customer's interconnection equipment on the Transmission Customer's side of the visible disconnect that isolates the Transmission Customer's facilities from Central Maine's system, in accordance with established practices and standards for the operation and maintenance of power system equipment.

B. The Transmission Customer shall maintain its own generation in accordance with Good Utility Practice. The Transmission Customer shall ensure that all third party generation facilities connected to the Transmission Customer system is maintained in accordance with Central Maine's Technical Interconnection Requirements for Non-Utility Generation.

C. The Transmission Customer shall arrange with Central Maine an initial functional testing and inter-tie inspection, to be completed prior to the effective date of this agreement. In addition, the Transmission Customer shall arrange with Central Maine for an annual, visual inspection of all interconnection facilities and associated maintenance records. Every two years, the Transmission

Customer shall arrange a relay calibration test and operational test of the Transmission Customer's interconnection equipment. The relay calibration test must be performed by a qualified contractor approved by Central Maine and acceptable to the Transmission Customer or by Central Maine itself. After the relay calibration tests are completed, Central Maine may perform a relay system functional test. The Transmission Customer shall bear the cost of any relay testing and any other assistance that may be requested by Central Maine before and after the system is made operational.

D. Before May 1 of each year, Central Maine shall provide the Transmission Customer with recommended dates for scheduling maintenance of the Transmission Customer's generating facilities and third party generating facilities greater than 5 MW and the Transmission Customer transmission facilities operating at 34.5 Kv or greater. The Transmission Customer shall provide to Central Maine on or before June 1 of each year a list of periods, in order of preference and in accordance with Central Maine's recommended dates, during which the Transmission Customer prefers to schedule maintenance during the subsequent calendar year. If Central Maine does not provide the Transmission Customer with recommended dates before May 1 of any year, the Transmission Customer shall nonetheless provide Central Maine on or before June 1 of that year, a list of periods, in order of preference, in which the Transmission Customer prefers to schedule maintenance during the subsequent calendar year, and Central Maine will attempt to accommodate the Transmission Customer's proposed schedule of maintenance periods if Central Maine can do so without adverse operational or economic effect on ISO, Central Maine or its customers. By July 1 of each year, the Transmission Customer and Central Maine will agree on maintenance periods for the interconnection equipment.

E. If Central Maine in its reasonable judgment determines that the Transmission Customer's interconnection equipment is, in any substantial respect, being maintained otherwise than in accordance with Good Utility Practice, Central Maine may so notify the Transmission Customer in writing. Within thirty (30) days of the date of notification, the Transmission Customer shall conform its maintenance practices to the requirements of Good Utility Practice and of this agreement. In the event that the Transmission Customer fails to bring its maintenance practices into conformance with the requirements of Good Utility Practice within that thirty (30) day period, Central Maine may de-energize the interconnection between the Transmission Customer and Central Maine until the Transmission Customer has conformed its maintenance practices as provided herein.

F. The Transmission Customer shall give Central Maine adequate written notice of any modification or replacement of the Transmission Customer's interconnection equipment. All additions, modifications or replacements must meet the requirements of this agreement and all standards of Good Utility Practice. If the Transmission Customer makes changes without notice to Central Maine, and if Central Maine has reasonable cause to believe that the changes may create dangerous conditions, Central Maine may de-energize the interconnection between the Transmission Customer and Central Maine.

G. The Transmission Customer, at its expense, shall change the Transmission Customer's interconnection equipment as may be reasonably required by Central Maine or as may otherwise be required to conform to Good Utility Practice to meet changing requirements of Central Maine's system.

H. In the event that de-energization of the interconnection is required by the provisions of this agreement, Central Maine will only de-energize the interconnection at the affected Point or Points of Delivery.

4.0 Power Factor

To prevent degradation of voltage to Central Maine's customers, to prevent unnecessary system losses, and to maintain Central Maine voltage levels and area reactive support, the Transmission Customer shall maintain a 97% or higher power factor. Should Central Maine be required to maintain a higher level than 97%, the Transmission Customer shall be required to do so as well. Failure by the Transmission Customer to maintain acceptable power factor may result in additional Direct Assigned Facilities charges associated with installing any equipment needed to maintain the designated power factor.

5.0 Voltage Control

The Transmission Customer's automatic voltage control equipment shall ensure that no more than a 3% instantaneous variation in voltage shall occur at the interconnection during connection or disconnection of a synchronous generator, an induction generator, or any motor load or capacitor.

6.0 Harmonics

The Transmission Customer must operate and maintain its system in a manner that avoids the generation of harmonic frequencies exceeding the limits established by the latest revision of IEEE-519 <u>Recommended Practices and Requirements for Harmonics Control in Electrical Power Systems</u>.

7.0 Default

The Transmission Customer’s failure to meet the terms and conditions of the agreement shall be deemed to be a default resulting in Central Maine seeking, consistent with FERC rules and regulations, immediate termination of service.

ATTACHMENT G-R

FORMULA FOR CALCULATING ANNUAL RETAIL TRANSMISSION REVENUE REQUIREMENTS
UNDER THE CENTRAL MAINE POWER COMPANY
LOCAL SERVICE SCHEDULE, Schedule 21-CMP

This formula sets forth the details for determining each year's Annual Transmission Revenue Requirement for Central Maine Power Company (Central Maine). The Transmission Revenue Requirement reflects Central Maine's cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to retail Transmission Customers under this Schedule 21-CMP. The Transmission Revenue Requirement will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31, 2000, based on 1998 test year data, and updated thereafter each June 1, based on the previous calendar year's FERC Form 1 data, and based on actual data in lieu of allocated data, if specifically identified in FERC Form 1, as shown below, using end-of-year balances for each rate base item, as further set forth below. The Annual Transmission Revenue Requirement calculated pursuant to this Attachment G-R shall include a Forecasted Transmission Revenue Requirement and Annual True-up as further set forth below and calculated in accordance with Attachment K to this Schedule 21-CMP. The Annual Transmission Revenue Requirement shall include an Incremental Return and Associated Income Taxes and shall incorporate the 125 basis point incentive ROE adder granted by the FERC in Docket No. EL08-74-000 for the Maine Power Reliability Program ("MPRP") on MPRP CWIP or any other MPRP transmission investments not otherwise recoverable as Pool-Supported PTF under Attachment F of this OATT. The data used in determining the Incremental Return and Associated Taxes shall be based on actual data specifically identified in Central Maine's accounting records.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section 1 of the Central Maine Schedule 21-CMP have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct wages and salaries not otherwise assigned under this Schedule 21-CMP, including

those of Affiliate companies, and the wages and salaries associated with the Transmission Related Customer Service and Information Expenses and Sales Expenses to Central Maine's total direct wages and salaries excluding administrative and general wages and salaries. The wages and salaries associated with the Transmission Related Customer Service and Informational Expenses and Sales Expenses shall exclude any wages and salaries associated with state-mandated programs, activities, and services.

2. <u>Transmission Network Allocation Factor</u> shall equal the ratio of Total Investment in Transmission Plant excluding the balance associated with generator leads and generator step up transformers in Central Maine's Transmission Plant for test periods beginning with calendar year 1999 and thereafter to Total Investment in Transmission Plant.

3. <u>Transmission Plant Allocation Factor</u> shall equal the ratio of the sum of Total Investment in Transmission Plant excluding the balance associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts for test period beginning with calendar year 1999 and thereafter, and Transmission Related General Intangible Plant to Total Plant in service.

4. <u>Customer Service and Informational Expenses and Sales Expenses Allocation Factor</u> shall initially equal the ratio of transmission revenue requirements (excluding such expenses) to the total company revenue requirements (excluding such expenses) Beginning with the 2001 test year, the allocation factor shall be the ratio of actual transmission revenues to total actual transmission and distribution revenues, including stranded costs.

B. TERMS

<u>Administrative and General Expense</u> shall equal Central Maine's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

<u>Amortization of Investment Tax Credits</u> shall equal Central Maine's credits as recorded in FERC Account No. 411.4.

Customer Service and Information Expenses and Sales Expenses shall equal Central Maine's expenses as recorded in FERC Account Nos. 901-916 reduced by the revenues that Central Maine receives for providing such services to energy service providers as recorded in FERC Account No. 456.

Depreciation Expense for Transmission Plant shall equal Central Maine's transmission depreciation expense as recorded in FERC Account No. 403 and shall not include any depreciation expense associated with generator leads and generator step-up transformers after March 31, 1999.

Intangible and General Plant shall equal Central Maine's gross plant balance as recorded in FERC Account Nos. 301-303 and 389-399.

Intangible and General Plant Depreciation Expense shall equal Central Maine's intangible and general expenses as recorded in FERC Account Nos. 403 and 404.

Intangible and General Plant Depreciation Reserve shall equal Central Maine's intangible and general reserve balance as recorded in FERC Account Nos. 108 and 111.

Maine Power Reliability Program Construction Work In Progress ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of Central Maine's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in Central Maine's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of Central Maine's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Central Maine's FERC Account No. 254.

Plant Held for Future Use shall equal Central Maine's balance in FERC Account No.105.

Prepayments shall equal Central Maine's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Central Maine's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and the deferred tax balance as recorded in FERC Account No. 190.

Total Municipal Tax Expense shall equal Central Maine's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal Central Maine's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal Central Maine's transmission reserve balance as recorded in FERC Account 108, and for test years beginning with 1999 and thereafter, shall exclude any reserve balance associated with generator leads and generator step-up transformers.

Transmission Operation and Maintenance Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564, the transmission-related portion of the Bolt Hill wheeling agreement as recorded in Account No. 565, and 566-573, excluding any HQ HVDC expenses booked to accounts 560 through 573 and any other expenses in support of other utilities' transmission facilities which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal Central Maine's Gross Plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal Central Maine's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of Central Maine's (A) Investment Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for MPRP), (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Investment Tax Credits, (D) Transmission Related Municipal Tax Expense, (E) Transmission Operation and Maintenance Expense, (F) Transmission Related Administrative and General Expenses, (G) Transmission Related Taxes and Fees, (H) Transmission Support Expense, minus (I) Transmission Support Revenue, minus (J) ISO Transmission Revenue, minus (K) Other Wheeling Revenue, minus (L) Transmission

Rents Received from Electric Property, plus (M) Transmission Related Customer Service and Informational Expenses and Sales Expenses, plus (N) Forecasted Transmission Revenue Requirement and Annual True-up. The Incremental Return and Associated Income Taxes for MPRP shall be calculated using the Transmission Investment Base components specifically identified in Section A.1 of the formula below.

A. <u>Investment Return and Associated Income Taxes</u> shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Investment Return and Associated Income Taxes for MPRP, Transmission Investment Base will only include Sections II.A.1.(a), (d), (e), and (j) in the manner indicated.

1. <u>Transmission Investment Base</u>

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Other Regulatory Assets/Liabilities, plus (g) Transmission Prepayments, plus (h) Transmission Materials and Supplies, plus (i) Transmission Related Cash Working Capital, plus (j) MPRP CWIP.

(a) <u>Transmission Plant</u> will equal the balance of Central Maine's Investment in Transmission Plant multiplied by the Transmission Network Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, MPRP Transmission Plant will be separately identified.

(b) <u>Transmission Related Intangible and General Plant</u> shall equal the sum of Central Maine's investment in Intangible and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation.

(c) <u>Transmission Plant Held for Future Use</u> shall equal the balance of Transmission-related Plant Held for Future Use.

(d) <u>Transmission Related Depreciation Reserve</u> shall equal the balance of Total Transmission Depreciation Reserve, plus the sum of the balance of Transmission Related Intangible and General Plant Depreciation Reserve. Transmission Related Intangible and General Plant

Depreciation Reserve shall equal the product of Intangible and General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, Transmission Depreciation Reserve associated with MPRP will be separately identified.

(e) Transmission Related Accumulated Deferred Taxes shall equal Central Maine’s electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, Transmission Related Accumulated Deferred Income Taxes associated with MPRP will be separately identified.

(f) Other Regulatory Assets/Liabilities shall equal Central Maine’s electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor, plus Central Maine’s electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(g) Transmission Prepayments shall equal Central Maine’s electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

(h) Transmission Materials and Supplies shall equal Central Maine’s electric balance of Plant Materials and Supplies, multiplied by the Plant Allocation Factor.

(i) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph J of the formula.

(j) MPRP CWIP shall equal Central Maine’s balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and not otherwise recoverable as Pool-Supported PTF under Attachment F of this OATT. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, MPRP CWIP will be separately identified.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Central Maine's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity, including any unamortized discounts and premiums, and unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to Central Maine's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Central Maine's preferred stock then outstanding and the ratio that preferred stock is to Central Maine's total capital.

(iii) the return on equity component, which equals the product of Central Maine's Return on Equity of ~~10.57~~11.14% and the ratio that common equity is to Central Maine's total capital. In order to calculate the Incremental Investment Return and Associated Income Taxes for MPRP, the incremental return on equity shall be the product of the MPRP incremental return on equity of 1.25% and the ratio that common equity is to Central Maine's total capital.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.C., below, C is the Equity AFUDC component of Transmission Depreciation Expense , as defined in Section II.B., and D is Transmission Investment Base, as determined in II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 - FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.C. below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., D is the Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. <u>Transmission Depreciation Expense</u> shall equal the sum of Depreciation Expense for Transmission Plant, plus an allocation of Intangible and General Plant Depreciation Expense calculated by multiplying Intangible and General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

C. Transmission Related Amortization of Investment Tax Credits shall equal Central Maine's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

D. Transmission Related Municipal Tax Expense shall equal Central Maine's total electric municipal tax expense multiplied by the Plant Allocation Factor.

E. Transmission Operation and Maintenance Expense shall equal Central Maine's Transmission Operation and Maintenance Expenses, multiplied by the Transmission Network Allocation Factor.

F. Transmission Related Administrative and General Expenses shall equal the sum of (1) Central Maine's Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments multiplied by Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments, and beginning June 1, 2007, minus the amortization of RTO formation and associated carrying costs included in Account 928, plus a pro forma amount of such costs expected to be amortized to Account 928 from June 1 through May 31 of the current rate year, plus specific transmission related expenses included in Account 930.1. The pro forma amount described above shall continue through May 31, 2011 and shall not be subject to the Annual True-up described in Attachment K of this Schedule 21-CMP.

G. Transmission Related Regulatory Assessments shall include any FERC assessments associated with Transmission Service provided under the OATT and Schedule 21, based on the FERC regulations in 18 C.F.R. § 382.201, and as recorded in FERC Account No. 408.1.

H. Transmission Support Expense shall equal Central Maine's electric expense for transmission support, excluding any support expenses associated with the non-PTF facilities as the Millstone power plant.

I. Transmission Support Revenues shall equal Central Maine's revenue received for transmission support, excluding, for test periods beginning in calendar year 1999 and thereafter, and support revenues associated with generator leads and step-up transformers in Central Maine's Transmission Plant accounts. To the extent that a customer had pre-paid Central Maine for O&M service performed during the test period associated with Direct Assignment Facilities, interconnection facilities, or grid upgrades, such prepayment shall not be credited to the revenue requirement described in this Attachment G-R. Rather, an annual amount of O&M service revenue shall be imputed to such service in accordance with Schedule No. 14 and credited for each test year during which such O&M service obligation continues.

J. ISO Transmission Revenues shall equal the revenues distributed to Central Maine, from ISO, for network, and through and out Transmission Service provided under the OATT excluding any incremental revenues associated with FERC-approved incentives for MPRP CWIP and the ROE adders for RTO participation and new transmission investment. These revenues will be based on historical test year data, except that for the duration of the transition period, Central Maine will use a pro forma amount for network service revenues expected to be received in the rate year.

K. Other Wheeling Revenues shall equal any revenues received by Central Maine for providing wheeling out services to Generators as well as any other short-term, non-firm, or penalty revenues received by Central Maine associated with the provision of Transmission Services under this Schedule 21-CMP, not otherwise reflected in Section II. J above. The credit for wheeling out revenues shall change from month to month based on the actual amounts received by Central Maine for the most recent month that data is available. The revenue requirement described in this Attachment G-R shall be revised each month to reflect the annualized amount of the credit. Revenues received by Central Maine pursuant to Transmission Service agreements that pre-dated Order No. 888, to the extent that the such transactions are treated as a revenue credit rather than in the determination of Load Ratio Share, will be prorated between this Attachment G-R and Schedule 1 of this Schedule 21-CMP on the basis of gross investment in plant for the services at issue.

L. Transmission Rents Received from Electric Property shall equal any Rents from electric property, associated with Transmission Plant as defined in Section II.A.1.(a) above, excluding, for test periods beginning in calendar year 1999 and thereafter, any rents associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts, but not otherwise reflected in Section II. I. above as Transmission Support Revenues.

M. Transmission-Related Customer Service and Informational Expenses and Sales Expenses shall equal Central Maine's expenses in FERC Account Nos. 901-916 less any State-mandated programs, activities and services multiplied by the Customer Service and Informational Expenses and Sales Expenses Allocation Factor.

N. Forecasted Transmission Revenue Requirement and Annual True-up shall equal Central Maine's estimated revenue requirements for forecasted transmission plant additions and any associated Annual True-up. The Forecasted Transmission Revenue Requirement and Annual True-up shall be calculated in accordance with Attachment K to this Schedule 21-CMP.

ATTACHMENT G -W
FORMULA FOR CALCULATING
ANNUAL WHOLESALE TRANSMISSION REVENUE REQUIREMENTS
UNDER THE CENTRAL MAINE POWER COMPANY
LOCAL SERVICE SCHEDULE
SCHEDULE 21-CMP

This formula sets forth the details for determining each year's Annual Transmission Revenue Requirement for Central Maine Power Company (Central Maine). The Transmission Revenue Requirement reflects Central Maine's cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to wholesale Transmission Customers under this Schedule 21-CMP. The Transmission Revenue Requirement will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31, 2000, based on 1998 test year data, and updated thereafter each June 1, based on the previous calendar year's FERC Form 1 data, and based on actual data in lieu of allocated data, if specifically identified in FERC Form 1, as shown below, using end-of-year balances for each rate base item, as further set forth below. The Annual Transmission Revenue Requirement calculated pursuant to this Attachment G-W shall include a Forecasted Transmission Revenue Requirement and Annual True-up as further set forth below and calculated in accordance with Attachment K to this Schedule 21-CMP. The Annual Transmission Revenue Requirement shall include an Incremental Return and Associated Income Taxes and shall incorporate the 125 basis point incentive ROE adder granted by the FERC in Docket No. EL08-74-000 for the Maine Power Reliability Program ("MPRP") on MPRP CWIP and on any MPRP transmission investments not otherwise recoverable as Pool-Supported PTF under Attachment F of this OATT. The data used in determining the Incremental Return and Associated Taxes shall be based on actual data specifically identified in Central Maine's accounting records.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section 1 of the Schedule 21-CMP have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct wages and salaries not otherwise assigned under this Schedule 21-CMP, including

those of Affiliate Companies to Central Maine's total direct wages and salaries including those of the Affiliate Companies and excluding administrative and general wages and salaries.

2. Transmission Network Allocation Factor shall equal the ratio of Total Investment in Transmission Plant excluding the balance associated with generator leads and generator step up transformers in Central Maine's Transmission Plant for test periods beginning with calendar year 1999 and thereafter to Total Investment in Transmission Plant.

3. Transmission Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Transmission Plant, excluding the balance associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts for test periods beginning with calendar year 1999 and thereafter, and Transmission Related General and Intangible Plant to Total Plant in service.

B. TERMS

Administrative and General Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

Amortization of Investment Tax Credits shall equal Central Maine's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal Central Maine's transmission depreciation expense as recorded in FERC Account No. 403 and shall not include any depreciation expense associated with generator leads or generator step up transformers for test years beginning with 1999 and thereafter.

Intangible and General Plant shall equal Central Maine's gross plant balance as recorded in FERC Account Nos. 301-303 and 389-399.

Intangible and General Plant Amortization and Depreciation Expense shall equal Central Maine's intangible and general expenses as recorded in FERC Account Nos. 404 and 403.

Intangible and General Plant Depreciation Reserve shall equal Central Maine's intangible and general reserve balance as recorded in FERC Account Nos. 111 and 108.

Maine Power Reliability Program Construction Work In Progress ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of Central Maine's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in Central Maine's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of Central Maine's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Central Maine's FERC Account No. 254.

Plant Held for Future Use shall equal Central Maine's balance in FERC Account No.105.

Prepayments shall equal Central Maine's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Central Maine's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and the deferred tax balance as recorded in FERC Account No. 190.

Total Municipal Tax Expense shall equal Central Maine's municipal tax expenses as recorded in FERC Account No. 408.1.

Total Plant in Service shall equal Central Maine's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal Central Maine's transmission reserve balance as recorded in FERC Account 108, and for test years beginning with 1999 and thereafter, shall exclude any reserve balance associated with generator leads and generator step-up transformers.

Transmission Operation and Maintenance Expense shall equal Central Maine's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564 and 566-573, excluding any HQ HVDC expenses booked to accounts 560 through 573 and any other expenses in support of other utilities' transmission facilities which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal Central Maine's Gross Plant balance as recorded in FERC Account Nos. 350-359 and for test years beginning with 1999 and thereafter, shall exclude any investment in generator leads and generator step up transformers.

Transmission Plant Materials and Supplies shall equal Central Maine's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of Central Maine's (A) Investment Return and Associated Income Taxes (including the Incremental Investment Return and Associated Income Taxes for MPRP), (B) Transmission Depreciation Expense, (C), Transmission Related Amortization of Investment Tax Credits, (D) Transmission Related Municipal Tax Expense, (E) Transmission Operation and Maintenance Expense, (F) Transmission Related Administrative and General Expenses, (G) Transmission Related Regulatory Assessments, (H) Transmission Support Expense, minus (I) Transmission Support Revenue, minus (J) ISO Transmission Revenue, minus (K) Other Wheeling Revenue, minus (L) Transmission Rents Received from Electric Property, and (M) Forecasted Transmission Revenue Requirement and Annual True-up. The Incremental Return and Associated Income Taxes for MPRP shall be calculated using the Transmission Investment Base components specifically identified in Section A.1 of the formula below.

A. Investment Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Investment Return and Associated Income Taxes for MPRP, Transmission Investment Base will only include Sections II.A.1.(a), (d), (e), and (j) in the manner indicated.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Other Regulatory Assets/Liabilities, plus (g) Transmission Prepayments, plus (h) Transmission Materials and Supplies, plus (i) Transmission Related Cash Working Capital, plus (j) MPRP CWIP.

(a) Transmission Plant will equal the balance of Central Maine's Investment in Transmission Plant multiplied by the Transmission Network Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, MPRP Transmission Plant will be separately identified.

(b) Transmission Related Intangible and General Plant shall equal the sum of Central Maine's investment in Intangible and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the balance of Transmission-related Plant Held for Future Use.

(d) Transmission Related Depreciation Reserve shall equal the balance of Total Transmission Depreciation Reserve, plus the sum of the balance of Transmission Related Intangible and General Plant Depreciation Reserve. Transmission Related Intangible and General Plant Depreciation Reserve shall equal the product Intangible and General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, Transmission Depreciation Reserve associated with MPRP will be separately identified.

(e) Transmission Related Accumulated Deferred Taxes shall equal Central Maine's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, Transmission Related Accumulated Deferred Income Taxes associated with MPRP will be separately identified.

(f) Other Regulatory Assets/Liabilities shall equal Central Maine's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor, plus Central Maine's electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(g) Transmission Prepayments shall equal Central Maine's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

(h) Transmission Materials and Supplies shall equal Central Maine's electric balance of Plant Materials and Supplies, multiplied by the Plant Allocation Factor.

(i) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph J of the formula.

(j) MPRP CWIP shall equal Central Maine's balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and not otherwise recoverable as Pool-Supported PTF under Attachment F of this OATT. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, MPRP CWIP will be separately identified.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Central Maine's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity, including any unamortized discounts and premiums, and unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to Central Maine's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Central Maine's preferred stock then outstanding and the ratio that preferred stock is to Central Maine's total capital.

(iii) the return on equity component, which equals the product of Central Maine's Return on Equity of ~~10.57~~11.14% and the ratio that common equity is to Central Maine's total capital. In order to calculate the Incremental Investment Return and Associated Income Taxes for MPRP, the incremental return on equity shall be the product of the MPRP incremental return on equity of 1.25% and the ratio that common equity is to Central Maine's total capital.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.C., below, C is the Equity AFUDC component of Transmission Depreciation Expense , as defined in Section II.B., and D is Transmission Investment Base, as determined in II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 - FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.C. below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., D is the

Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for MPRP, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Transmission Plant, plus an allocation of Intangible and General Plant Depreciation Expense calculated by multiplying Intangible and General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Transmission Network Allocation Factor.

C. Transmission Related Amortization of Investment Tax Credits shall equal Central Maine's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

D. Transmission Related Municipal Tax Expense shall equal Central Maine's total electric municipal tax expense multiplied by the Plant Allocation Factor.

E. Transmission Operation and Maintenance Expense shall equal Central Maine's Transmission Operation and Maintenance Expenses, multiplied by the Transmission Network Allocation Factor.

F. Transmission Related Administrative and General Expenses shall equal the sum of (1) Central Maine's Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Transmission Network Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments multiplied by Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments, and beginning June 1, 2007, minus the amortization of RTO formation and associated carrying costs included in Account 928, plus a pro forma amount of such costs expected to be amortized to Account 928 from June 1 through May 31 of the current rate year, plus specific transmission related expenses included in Account 930.1. The pro forma amount described above shall continue through May 31, 2011 and shall not be subject to the Annual True-up described in Attachment K of this Schedule 21-CMP.

G. Transmission Related Regulatory Assessments shall include any FERC assessments associated with Transmission Service provided under the OATT and Schedule 21, based on the FERC regulations in 18 C.F.R. § 382.201, and as recorded in FERC Account No 408.1.

H. Transmission Support Expense shall equal Central Maine's electric expense for transmission support, excluding any support expenses associated with the non-PTF portion of Millstone.

I. Transmission Support Revenues shall equal Central Maine's revenue received for transmission support, excluding, for test periods beginning in calendar year 1999 and thereafter, and support revenues associated with generator leads and step-up transformers in Central Maine's Transmission Plant accounts. To the extent that a customer had pre-paid Central Maine for O&M service performed during the test period associated with Direct Assignment Facilities, interconnection facilities, or grid upgrades, such prepayment shall not be credited to the revenue requirement described in this Attachment G-W. Rather, an annual amount of O&M service revenue shall be imputed to such service in accordance with Schedule No. 14 and credited for each test year during which such O&M service obligation continues.

J. ISO Transmission Revenues shall equal the revenues distributed to Central Maine, from ISO, for network, and through and out Transmission Service provided under the OATT excluding any incremental revenues associated with FERC-approved incentives for MPRP CWIP and the ROE adders for RTO participation and new transmission investment. These revenues will be based on historical test year data, except that for the duration of the transition period, Central Maine will use a pro forma amount for network service revenues expected to be received in the rate year.

K. Other Wheeling Revenues shall equal any revenues received by Central Maine for providing wheeling out services to generators as well as any other short-term, non-firm, or penalty revenues received by Central Maine associated with the provision of Transmission Services under this Schedule 21-CMP, not otherwise reflected in Section II . J above. The credit for wheeling out revenues shall change from month to month based on the actual amounts received by Central Maine for the most recent month that data is available, and this Attachment G-W revenue requirement will be revised each month to reflect the annualized amount of such monthly value, to account for the updated credit. Revenues received by Central Maine pursuant to Transmission Service agreements that pre-dated Order No. 888, to the extent that the such transactions are treated as a revenue credit rather than in the determination of Load Ratio Share, will be prorated between this Attachment G-W and Schedule 1 of this Schedule 21-CMP on the basis of gross investment in plant for the services at issue.

L. Transmission Rents Received from Electric Property shall equal any Rents from electric property, associated with Transmission Plant as defined in Section II.A.1.(a) above, excluding, for test periods beginning in calendar year 1999 and thereafter, any rents associated with generator leads and generator step-up transformers in Central Maine's Transmission Plant accounts, but not otherwise reflected in Section II. I. above as Transmission Support Revenues.

M. Forecasted Transmission Revenue Requirement and Annual True-up shall equal Central Maine's estimated revenue requirements for forecasted transmission plant additions and any associated Annual True-up. The Forecasted Transmission Revenue Requirement and Annual True-up shall be calculated in accordance with Attachment K to this Schedule 21-CMP.

ATTACHMENT H

Umbrella Service Agreement For Retail

Local Network Transmission Service

1.0 This Service Agreement, dated as of March 1, 2000 is entered into, by and between Central Maine Power Company, and Central Maine Power Company, as the Designated Agent for its distribution level retail access customers as determine by the Maine Public Utility Commission ("Transmission Customer"). Such retail customers are not required to sign a Service Agreement, but have designated the Central Maine as their agent to arrange and maintain Local Network Transmission Service under the Central Maine Power Company Local Service Schedule 21 and Regional Network Service under the OATT on their behalf.

2.0 Service under this agreement shall commence on March 1, 2000. The Service Agreement shall be effective for an initial term of one year. Thereafter, it will continue from year-to-year unless terminated by Central Maine through a unilateral filing with FERC under section 205 of the FPA. Unless otherwise specified in their State of Maine Tariffs or in their contract with Central Maine, retail distribution level customers taking service under this Service Agreement shall be responsible for transmission charges for the initial term of one of Central Maine's typical monthly billing cycles for retail customers. Thereafter, such customers will continue to be responsible for transmission charges from typical monthly billing cycle to typical monthly billing cycle.

3.0 Central Maine agrees to provide and the Transmission Customer agrees to take and pay for Local Network Service in accordance with the provisions of Part III of this Schedule 21-CMP, Schedule 12 and this Service Agreement. Retail customers shall continue to pay Maine Public Utility Commission ordered rates, including without limitation, stranded costs and other distribution-related costs, as applicable.

4.0 This Schedule 21 is incorporated herein and made a part hereof.

Specifications for Retail Local Network Transmission Service

1.0 Term of Transaction: The Service Agreement shall be effective for an initial term of one year. Thereafter, it will continue from year-to-year.

Start Date: March 1, 2000

2.0 General description of capacity and energy to be transmitted by Central Maine including the electric Control Area in which the transaction originates.

Central Maine will transmit capacity and energy sufficient to serve all of it retail distribution level customers as determined by the Maine Public Utility Commission.

3.0 Retail Local Network Service Customers agree to take the following Ancillary Services from Central Maine under the terms and conditions of the OATT and Central Maine's Local Service Schedule 21.

1. Scheduling, System Control and Dispatch.

Retail Local Network Customers agree to take the following Ancillary Services under the terms and conditions of the OATT and applicable ISO Market Rules through Central Maine or another entity acting as their Designated Agent.

1. Scheduling, System Control and Dispatch
2. Reactive Supply and Voltage Control Service
3. Regulation and Frequency Response Service (Automatic Generation Control)
4. Energy Imbalance Service
5. Ten Minute Spinning Reserve Service
6. Ten Minute Non-Spinning Reserve Service
7. Thirty Minute Operating Reserve Service

ATTACHMENT I

Service Agreement For Retail Local Network Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between Central Maine Power Company ("Central Maine"), and ____________________ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Central Maine to have a Completed Application for Local Network Transmission Service under Schedule 21.

3.0 By checking here , the Transmission Customer agrees to designate Central Maine as its sole agent, pursuant to Schedule 12, for arranging and obtaining Regional Network Service under the Tariff. The Transmission Provider agrees to bill the Transmission Customer directly for such services, and the Transmission Customer agrees to pay in full such bill for PTF service.

3.1 The Transmission Customer agrees to pay Central Maine any and all charges associated with the distribution component of the network service even if there is a dispute over charges associated with the transmission component of the network service. Central Maine reserves the right to terminate service for non-payment of charges for distribution service. Disputes concerning charges for distribution service will be subject to the rules of the Maine Public Utilities Commission. Disputes concerning Transmission Service will be subject to Federal Energy Regulatory Commission ("FERC") rules. Any partial payment by the Transmission Customer to Central Maine will applied first to any outstanding charges associated with Transmission Services provided by Central Maine to the Transmission Customer under the Tariff. Thereafter, any partial payment by the Transmission Customer to Central Maine will be applied to the outstanding charges associated with distribution services provided under Central Maine's Local Service Schedule.

4.0 Service under this agreement shall commence on the later of (1) __________________, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility additions or upgrades are completed, or (3) the date on which a Local Network Operating Agreement is executed and all requirements of said Agreement have been completed or (4) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on _____________________.

5.0 Central Maine agrees to arrange and to provide and the Transmission Customer agrees to take and pay for Local Network Service in accordance with the provisions of Part III of this Schedule 21-CMP and this Service Agreement.

6.0 Any notice or request made to or by either party regarding this Service Agreement shall be made to the representative of the other party as indicated below.

<u>Central Maine</u>:

____
____
____

<u>Transmission Customer</u>:

____
____
____

7.0 This Local Service Schedule is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Central Maine:

By:_________________________ _____________________ _________

Name Title Date

Transmission Customer:

By:_________________________ _____________________ _________

Name Title Date

Specifications For Local Network Transmission Service

1.0 Term of Transaction: ____

Start Date: ____

Termination Date: ____

2.0 General description of capacity and energy to be transmitted by Central Maine including the electric Control Area in which the transaction originates.

____

3.0 Detailed description and forecast of Local Network Load at each delivery point:

____

____

____

4.0 Detailed description of each Network Resource, including
any operating restrictions:____

____

____

5.0 Detailed description of the Transmission Customer's anticipated use of Central Maine's interfaces:

____

____

____

6.0 Description of any Transmission System owned or controlled by the Transmission Customer:____

____

____

____

7.0 Names(s) of any intervening Transmission Owners:

____

____

____

8.0 The Local Network Service Customer agrees to take the following Ancillary Services from Central Maine.

1. Scheduling, System Control and Dispatch _____Yes\No

The Local Network Customer agrees to take the following Ancillary Services from the ISO, a third party or agrees to self provide them.

		Yes/No	Source
1.	Reactive Supply and Voltage Control	____	* __________
2.	Regulation and Frequency Response	____	* __________
3.	Energy Imbalance	____	* __________
4.	Spinning Reserve	____	* __________
5.	Supplemental Reserve	____	* __________

9.0 Description of required Direct Assignment Facilities:

____

____

____

10.0 In addition to the charge for Transmission Service and charges for Ancillary Services as set forth in this Schedule 21, the customer will be subject to the following charges:

10.1 System Impact and/or Facilities Study Charge(s):

____

____

10.2 Direct Assignment Facilities Charges:______________________________________

____

____

10.3 Redispatch Charges:

____

____

10.4 Facility Additions or Upgrade Charges:

____

ATTACHMENT J

Form Letter of Credit

[BANK LETTERHEAD]

IRREVOCABLE LETTER OF CREDIT

[Date]

Irrevocable Letter of Credit No.

Central Maine Power Co.
Manager, Transmission Services
83 Edison Drive
Augusta, ME 04336

Dear Sirs:

At the request and on the instructions of our customer ________________________________ we hereby establish our irrevocable letter of credit No. ____________________ in your favor for the account of _______________________________________and authorize you to draw on ____ Bank an amount not to exceed ______________________Dollars ($_____________________).

Funds under this letter of credit are available to you against a sight draft on us, which must be marked "Drawn under ____ Bank Irrevocable Letter of Credit No. ________________ dated ____________________ ".

Each draft must be accompanied by: (1) a written statement by your duly authorized officer that there is then payable to you from ___________________________ an amount equal to the amount of such draft and specifying the section of the Power Purchase Agreement under which the amount is payable; and (2) the original of this letter of credit, which will be returned to you following notation hereon by the Bank of the amount of such draft, except that, if the amount of the draft is in the full amount of this letter of credit, then the letter of credit will be retained by the Bank.

Drafts so drawn and accompanied will be honored by this Bank if presented to our main office in ________________________, prior to the close of business on the expiration date. The expiration date of this letter of credit is ______________________________.

Upon the payment to you of any amount demanded hereunder, we shall be fully discharged on our obligation under this letter of credit with respect to such amount, and we shall not thereafter be obligated to make any further payments under this letter of credit in respect of such amount to you or to any other person.

If at any time prior to presentation for payment hereunder, we receive a certificate signed by an authorized officer of Central Maine stating that this Letter of Credit has been lost, stolen, mutilated or destroyed, we will, upon receipt of (i) the mutilated Letter of Credit, in the case of mutilation of the Letter of Credit, or (ii) in other cases, such proof of loss as we shall reasonably specify, issue to Central Maine a replacement Letter of Credit dated the same date, bearing the same number, in the same amount, and in all other respects identical to this Letter of Credit, as it may have been amended or reduced, except that the replacement Letter of Credit shall be marked "Duplicate" and shall contain a provision stating, "This duplicate Letter of Credit is issued to replace Letter of Credit No. _________; the beneficiary herein agrees to return promptly this duplicate Letter of Credit to [Bank]________________ in the event the original Letter of Credit is recovered."

This letter of credit sets forth in full our understanding and such understanding shall not in any way be modified, amended, amplified or limited by reference to any document, instrument or agreement referred to herein.

This letter of credit is subject to the Uniform Customs and Practice for Documentary Credits, 1983 Revision, ICC Publication No. 400 (the "Uniform Customs"). This letter of credit shall be deemed to be a contract made under the laws of the State of Maine and shall, as to matters not governed by the Uniform Customs, be governed by and construed in accordance with the laws of said State.

Very truly yours,

BANK

By:

Its:

ATTACHMENT K
FORECASTED TRANSMISSION REVENUE REQUIREMENTS FOR ATTACHMENT G-R AND ATTACHMENT G-W

I. DEFINITIONS

(i) **Annual True-up (ATU)**: shall be the difference between Central Maine's actual Annual Transmission Revenue Requirements for the most recently concluded calendar year and Central Maine's actual Annual Transmission Revenue Requirements for the calendar year prior to the most recently concluded calendar year (i.e., the revenue requirements used to calculate LNS rates effective June 1 of the most recently concluded calendar year), as adjusted to include interest pursuant to Part II below.

(ii) **Forecast Period**: The calendar year immediately following the calendar year for which the most recent FERC Form I data is available.

(iii) **Forecasted Transmission Plant Additions (FTPA)**: shall equal an estimate of Central Maine's transmission plant additions for the Forecast Period.

(iv) **Forecasted MPRP CWIP (FCWIP)**: shall equal CMP's estimated incremental change in MPRP CWIP for the Forecast Period.

(v) **Adjusted Carrying Charge Factor (ACCF)**: shall equal the sum of the Carrying Charge Factor and the quotient of (i) the Cost of Capital Rate multiplied by Central Maine's Transmission Related Accumulated Deferred Taxes associated with Post-1996 PTF Transmission Plant for the most recently concluded calendar year, and (ii) PTF Transmission Plant for the most recently concluded calendar year, as shown:

ACCF = CCF + [(COC * Transmission Related Accumulated Deferred Taxes associated with Post-1996 PTF Transmission Plant) ÷ PTF Transmission Plant]

(vi) **Carrying Charge Factor (CCF)**: shall reflect the most recent calendar year data used in determining Central Maine's Annual Transmission Revenue Requirements and shall equal the sum of Attachment G-R Sections II.A, excluding MPRP CWIP, through II.H plus II.M divided by Attachment G-

R Section II.A.1.(a) for Central Maine's retail Transmission Customers. The CCF for Central Maine's wholesale Customers shall equal the sum of Attachment G-W Sections II.A, excluding MPRP CWIP, through II.H divided by Attachment G-W Section II.A.1.(a).

(vii) **<u>Forecasted ADIT (FADIT)</u>**: shall equal Central Maine's projected change in Accumulated Deferred Income Taxes from the most recently concluded calendar year related to accelerated depreciation for the Forecast Period calculated in accordance with Treasury regulation Section 1.167(l)-1(h)(6).

(viii) **<u>Cost of Capital Rate (COC)</u>**: shall be determined in accordance with Attachment G-R Section II.A.2 and Attachment G-W Section II.A.2.

(ix) **<u>MPRP Cost of Capital Rate (MCOC)</u>**: shall be determined in accordance with Attachment G Section II.A.2.

(x) **<u>Forecasted Transmission Revenue Requirement (FTRR)</u>**: shall equal FTPA multiplied by the ACCF, less FADIT multiplied by the COC, plus FWCIP multiplied by the MCOC, as shown:

FTRR = (FTPA * ACCF) - (FADIT * COC) + (FCWIP * MCOC)

II. INTEREST ON ANNUAL TRUE-UPS

Interest on the Annual True-up amounts (i.e., interest applicable to any over or under collection) shall be calculated pursuant to the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii).

III. INFORMATIONAL FILINGS

Supporting documentation for the derivation and calculation of Section I (i) through (vii) of this Attachment K will be included as part of the Annual Informational Filing required pursuant to Section 10.2 of Schedule 21-CMP.

Schedule 21 – CMP

Attachment L

Creditworthiness Procedure

I. **General Information**

This Attachment L details the specific requirements for creditworthiness procedures of Schedule 21-CMP of the OATT for Central Maine Power Company ("CMP"). Any customer taking (i) any service under Schedule 21-CMP, the Local Service Schedule ("LSS") for CMP under the OATT or (ii) any Federal Energy Regulatory Commission ("Commission") regulated Interconnection Service from CMP (such a customer is referred to herein as a "Customer" and such services are referred to individually herein as a "Service" and collectively as "Services") must meet the terms of this Attachment L. The creditworthiness of each Customer must be established prior to receiving Service from CMP. A Customer will be evaluated at the time it's Application for such Service is provided to CMP or to ISO. A credit review shall be conducted for each Transmission Customer at least annually or upon reasonable request by the Transmission Customer. CMP may conduct a credit review any time there is a material change in a Customer's financial conditions as set forth in Section VIII.A. Any change in this Attachment L will be made in accordance with Section 10 and posted on CMP's OASIS.
All Customers must comply with the terms of this Attachment L. The Customer should refer to the Company's web site at www.cmpco.com or the Company's OASIS site, for the applicable contact representative at CMP.

Upon receipt of a Customer's Financial Information, CMP will review it for completeness and will notify the Customer if additional information is required. Upon completion of a credit evaluation of a Customer, CMP will notify the Customer of the results as well as of any Financial Assurance requirements. CMP will provide a written report of the credit evaluation, upon written or email request by the Customer.

II. **Financial Information**

- Customers requesting Service are required, at the sole discretion of CMP, to submit, if available, all current rating agency reports from Standard and Poor's ("S&P"), Moody's
- and/or Fitch of the Customer, its direct or indirect parent ("Parent"), or other credit provider, or
- Audited financial statements provided by a registered independent auditor for the two most recent years, or the period of its existence, if shorter, for the Customer, its Parent, or credit provider.

III. <u>Creditworthiness Requirements</u>

A. The Customer must meet at least one of the following quantitative criteria:

a) If rated, the Customer must have either for itself or for its outstanding debt the following:

- S&P's or Fitch rating of at least a **BBB-**, or
- Moody's rating of at least a **Baa3**.

Not withstanding any other provision of this Schedule L, a Customers credit will be limited as follows:

Rating (S&P / Moody's)	Credit Limit
A/A2	$30,000,000
A-/A3	$20,000,000
BBB+/Baa1	$15,000,000
BBB/Baa2	$10,000,000
BBB-/Baa3	$5,000,000

If ratings by different agencies are inconsistent, CMP will use the lowest rating.

b) If unrated or if rated below BBB-/Baa3, as stated in a), the Customer must meet all of the following:

- A Current Ratio of at least 1.0 times (current assets divided by all current liabilities);
- A Total Capitalization Ratio of less than 60% debt: total debt (including all short-term borrowing) divided by total shareholders' equity plus total debt:

c) If the Customer relies on the creditworthiness of a parent company; the Customer's parent company must meet the criteria set out in (a) or (b) above, and must provide to CMP a written guarantee, to CMP's satisfaction, that it will be unconditionally responsible for all financial obligations associated with the Customer's receipt of Transmission Service from CMP.

B. If the Customer does not meet the quantitative criteria in Section A of this Section III, the Customer will qualify for unsecured credit equivalent to two month Transmission Service charges, or for Interconnection Service, the credit equivalent of two months of the annual facilities charges and other ongoing charges, if the following qualitative criteria are met:

- The Customer has, on a rolling basis, 12 consecutive months of payments to CMP with no missed, late or defaults in payment.

IV. **Financial Assurance**

If the Customer does not meet the creditworthiness set out in Section III, then the Customer must either:

- Pay in advance for service an amount equal to the lesser of the total charge for Services or the charge for three months of Services not less than five (5) business days in advance of the commencement of service; or,
- Subject to prior approval by CMP, for Transmission Service of three (3) months or longer, prepay each month not less than (5) business days before the beginning of the month. Notwithstanding any other provision of this Attachment L, CMP will not pay interest for prepayment of the current month's service.
- For Interconnection Service, prepayment of three (3) months of the anticipated facilities construction and all construction related costs including but not limited to project planning, management and overheads, as specified and updated from time to time by CMP, not less than five (5) business days in advance of commencing work; or prepayment of all construction related costs according to a schedule to be included in the Interconnection Agreement or E&P Agreement. If a conflict arises between the Terms of this Schedule L and an Interconnection or E&P Agreement, the terms of Interconnection or E&P Agreement shall apply.
- Obtain Financial Assurance, to CMP's satisfaction in the form of (a) letter of credit, (b) performance bond, (c) a cash deposit, or (d) corporate guarantee equal to the equivalent of three (3) months of Transmission Service changes prior to receiving service.

If the Customer pays for service more than one month in advance or posts a cash deposit, CMP will pay the Customer interest on the amounts not yet due to CMP, computed in accordance with the Commission's regulations at 18 CRF 35.19a(a)(2)(iii).

V. **Credit Levels**

If the Customer meets the applicable criteria outlined in Section III, that Customer may receive unsecured credit equivalent to three (3) months of transmission charges or, for interconnections, the credit equivalent of three (3) months of the annual facilities charges and other ongoing charges.

VI. <u>Contesting Creditworthiness Determination</u>

The Customer may submit a written request for reconsideration within twenty (20) calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for reconsideration. CMP will review and respond to the request within twenty (20) calendar days.

VII. <u>Process for Changing Credit Requirements</u>

In the event that CMP plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, CMP shall submit such changes in a filing to the Commission under Section 205 of the Federal Power Act. CMP shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

A. General Notification Process

a) CMP shall provide written notification to ISO and stakeholders of any filing described above, at least thirty (30) days in advance of such filing.

b) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s).

c) CMP shall consult with interested stakeholders upon request.

d) Following Commission acceptance of such filing and upon the effective date, CMP shall revise its Attachment L Creditworthiness Procedures and an updated version of Schedule 21-CMP shall be posted on the ISO website.

B. Transmission Customer Responsibility

When there is a change in requirements, it is the responsibility of the Transmission Customers to forward updated financial information to the Company, to the address noted on CMP's OASIS site and indicate whether the change affects their ability to meet the requirements of Attachment L. In such cases where the Customer's status has changed, the Customer must take the necessary steps to comply with the revised requirements of Attachment L by the effective date of the change. Failure to meet the requirements of this Section VII (B) shall, at CMP's sole discretion, result in the requirement to post Financial Assurance immediately upon written or email notice by CMP.

VIII. <u>Posting Collateral Requirements</u>

A. Changes in Customer's Financial:

Each Customer must inform CMP in writing, within five (5) business days of any material change in its financial condition, and, if the Customer qualifies under Section IIIA. (c), that of its Parent. A material change in financial conditions may include, but not limited to, the following:

- Change in ownership direct or indirect, by way of merger, acquisition or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

Failure to meet the requirements of this Section VIII (A) shall, at CMP's sole discretion, result in the requirement to post Financial Assurance immediately upon written or email notice by CMP.

B. Change in Creditworthiness Status

A Customer who has been extended unsecured credit under this policy must provide Financial Assurance as set forth in Section IV, within three (3) business days, if one or more of the following conditions apply:

- The Customer no longer meets the applicable criteria for creditworthiness in item III;
- The Customer exceeds the amount of unsecured credit extended by CMP, in which case Financial Assurance equal to the amount of excess must be provided within three (3) business days; or

- The Customer has missed two or more payments for any of the Services offered by the Company's in the last 12 months.
- The Customer fails to meet the requirements of Sections VII (B) or VIII (A).

In the event that CMP determines that there is a change in the credit level or collateral requirements, the Customer may request a written explanation of the basis for this change. Such notification should be sent, in writing or via email, to the CMP contact indicated on the CMP OASIS site. CMP shall respond to such request within twenty (20) days of receipt of such notification.

Customers must post additional collateral within three (3) business days, from the date they are notified of the need for additional requirements.

IX. <u>Ongoing Financial Review</u>

Each Customer is required to submit to CMP annually or when issued, as applicable:

- Current rating agency report covering the Customer or its Parent;
- Audited financial statements of the Customer or its Parent from a registered independent auditor; and
- 10-Ks and 8-Ks, promptly upon their issuance.

X. <u>Suspension of Service</u>

CMP may, at its sole discretion, immediately suspend service (with notification to Commission) to a Customer, and may initiate proceedings with Commission to terminate service, if the Customer does not meet the terms described in items III through VII at any time during the term of service or if the customer's payment obligations to CMP exceed the amount of unsecured or secured credit to which it is entitled under this Attachment L. A Customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

SCHEDULE 21 - FG&E

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

LOCAL SERVICE SCHEDULE

SCHEDULE 21-FG&E

Fitchburg Gas and Electric Light Company Local Service Schedule

I. COMMON SERVICE PROVISIONS

Fitchburg Gas and Electric Light Company ("FG&E") is a participant in the New England Control Area and has agreed to provide transmission and ancillary services over PTF pursuant to the Tariff. The services provided under this Schedule 21-FG&E apply only to Non-PTF, except in the case of service to Network Customers that have all or part of their Network Load directly connected to the PTF in the Local Network. These Network Customers shall pay for Local Network Service pursuant to Attachment H to this Schedule 21-FG&E. Provisions of this Schedule 21-FG&E shall have priority over any conflicting provisions in the Tariff.

1 Definitions

1.0 Annual Transmission Costs: The total annual cost of the Local Network for purposes of Local Network Service shall be the amount specified in Attachment H until amended by FG&E or modified by the Commission.

1.1 Curtailment: A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

1.2 Load Ratio Share: Ratio of a Transmission Customer's Non-PTF Network Load to FG&E's total load computed in accordance with Sections II.10 and II.10(a) of this Schedule under Sections Supplementing Section 21 of the OATT and calculated on a rolling twelve month basis.

1.3.1 Local Network: The transmission facilities owned, controlled, or operated by FG&E that are used to provide transmission service under Schedule 21 of the OATT.

1.4 Local Network Service: The transmission service provided under Schedule 21 of the OATT and this Schedule.

1.5 Network Load: The load directly interconnected to the PTF or Non-PTF facilities of

FG&E. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Schedule 21 of the OATT for any Local Point-to-Point Service that may be necessary for such non-designated load. For purposes of establishing rates and charges under this Tariff, the Network Load will be subdivided into one of two categories:

A. PTF Network Load shall be the load over FG&E's PTF facilities and shall equal the load of Network Customers directly interconnected with FG&E's PTF or indirectly utilizing FG&E's PTF through Non-PTF facilities of FG&E.

B. Non-PTF Network Load shall be the load over FG&E's Non-PTF directly interconnected with FG&E's Non-PTF facilities.

1.6 **Network Upgrades**: Modifications or additions to transmission-related facilities that are integrated with and support FG&E's overall Local Network for the general benefit of all users of such Local Network.

1.7 **Parties**: FG&E and the Transmission Customer receiving service under this Schedule and the OATT.

SECTIONS SUPPLEMENTING THE BODY OF THE TARIFF

Preamble

The following provisions supplement the provisions of the Tariff. Provisions of this Schedule 21-FG&E shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-FG&E correspond to or are consecutive to the section numbers in the body of the Tariff that are affected by the additional provisions herein.

Sections Supplementing Section 1: General Terms and Conditions

1.7 **Creditworthiness**: For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, FG&E may require reasonable credit review procedures in accordance with Attachment L to Schedule 21-FG&E.

Sections Supplementing Section II of the Tariff: Open Access Transmission Tariff (OATT)

II.A. COMMON SERVICE PROVISIONS

II.4 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. FG&E is required to provide (or offer to arrange with the ISO as discussed below), and the Transmission Customer is required to purchase Scheduling, System Control and Dispatch Service.

The following Ancillary Services are available pursuant to Section II.4 of the Tariff only to the Transmission Customer serving load within the New England Control Area: (i) Reactive Supply and Voltage Control Service, (ii) Regulation and Frequency Response , (iii) Energy Imbalance, (iv) Ten-Minute Spinning Reserve Service, (v) Ten-Minute Non-Spinning Reserve Service and (vi) Thirty-Minute Operating Reserve Service.

II.8 Billing and Invoicing; Accounting

8.2 Invoicing: Within a reasonable time after the first day of each month, FG&E shall submit an invoice to the Transmission Customer for the charges for all services furnished under the OATT during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to FG&E, or by wire transfer to a bank named by FG&E.

8.4 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to FG&E on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after FG&E notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, FG&E may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between FG&E and the Transmission Customer, FG&E will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then FG&E may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

II.10.2 Stranded Cost Recovery

FG&E may seek to recover stranded costs from the Transmission Customer pursuant to this OATT in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, FG&E must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

SECTIONS SUPPLEMENTING SCHEDULE 21 OF THE OATT

I. Local Point-to-Point Service Over the Local Network Owned by FG&E

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-FG&E shall govern Local Point-To-Point transactions using the Local Network owned by FG&E. Provisions of this Schedule 21-FG&E shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-FG&E correspond to or are consecutive to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

To the extent not otherwise covered in the OATT, the then-current ISO New England Operating Documents, or the TOA, or the rules adopted thereunder, whenever FG&E implements least-cost redispatch procedures in response to a transmission constraint, FG&E and the Transmission Customer(s) taking Local Point-To-Point Service will each bear a proportionate share of the total redispatch cost.

3) Service Availability

b) Determination of Available Transfer Capability (ATC): A description of FG&E's specific methodology for assessing ATC is contained in Attachment C of this Schedule. In the event sufficient transfer capability may not exist to accommodate a service request, FG&E will respond by performing a System Impact Study.

g) Real Power Losses: Real power losses are associated with all transmission service. FG&E is not obligated to provide real power losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by FG&E. The applicable real power loss factors tabulated below will be applied to metered loads and Reserved Capacity amounts to account for losses on FG&E's system. The applicable real power loss factors are as follows:

Firm Local Point-to-Point Service = 0.72% at 69 kV subtransmission.

Non-firm Local Point-to-Point Service = 0.72% at 69 kV subtransmission.

6) Procedures for Arranging Non-Firm Local Point-To-Point Service

f) Determination of Available Transfer Capability: Following receipt of a tendered schedule FG&E will make a determination on a non-discriminatory basis of ATC pursuant to Attachment C of this Schedule. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service (during FG&E's normal business hours of 8:00 a.m. to 4:30 p.m., Monday to Friday).

11) Sale or Assignment of Local Point-to-Point Service

c) Information on Assignment or Transfer of Service: FG&E currently has waiver from the obligations of FERC Order No. 889 to maintain an OASIS. In the future, upon implementation of any FG&E OASIS site, resellers may use FG&E's OASIS site to post transmission capacity available for resale.

II. Local Network Service using Non-PTF Owned by FG&E

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-FG&E shall govern Local Network Service using Non-PTF owned by FG&E. Provisions of this Schedule 21-FG&E shall have priority over any conflicting provision in the Tariff. The section numbers of this Schedule 21-FG&E correspond to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

Local Network Service allows the Network Customer to integrate, economically dispatch, and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which FG&E utilizes its Non-PTF to serve its Native Load Customers. Local Network Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Schedule 21 of the OATT.

2) Availability of Local Network Service

f) Real Power Losses: The Network Customer is responsible for replacing losses associated with all transmission service as calculated by FG&E. The applicable real power loss factors tabulated below will be applied to metered loads and Reserved Capacity amounts to account for losses on FG&E's system. The applicable real power loss factors are as follows:

Local Network Service = 0.72% at 69 kV subtransmission.

8) Load Shedding and Curtailments

a) Procedures: Prior to the Service Commencement Date, FG&E and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to Section II.20 of the Tariff, with the objective of responding to contingencies on the Non-PTF. The Parties will implement such programs during any period when the ISO, the Local Control Center or FG&E determines that a system contingency exists and such procedures are necessary to alleviate such contingency. FG&E will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

b) Transmission Constraints: During any period when FG&E determines that a transmission constraint exists on the Local Network, and such constraint may impair the reliability of FG&E’s system, FG&E will take whatever actions, consistent with then-current ISO New England Operating Documents or the TOA, and the rules adopted thereunder, and with Good Utility Practice, that are reasonably necessary to maintain the reliability of FG&E’s system. To the extent ISO determines that the reliability of the ISO New England transmission system can be maintained by redispatching resources, FG&E will initiate procedures pursuant to the OATT, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder to redispatch all Network Resources and FG&E's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between FG&E's use of the Local Network on behalf of its Native Load Customers and any Network Customer's use of the Local Network to serve its designated Network Load.

c) Cost Responsibility for Relieving Transmission Constraints: To the extent not otherwise covered in the OATT, the then-current ISO New England Operating Documents, or the TOA, or the rules adopted thereunder, whenever FG&E implements least-cost redispatch procedures in response to a transmission constraint, FG&E and the Network Customer(s) will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

d) Curtailments of Scheduled Deliveries: If a transmission constraint on FG&E's Local Network cannot be relieved through the implementation of least-cost redispatch procedures and FG&E determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with Section II.22 of the Tariff.

e) Allocation of Curtailments: The ISO, the Local Control Center or FG&E shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by FG&E and Network Customers in proportion to their respective Load Ratio Shares. Neither the ISO, the Local Control Center, nor FG&E shall direct the Network Customer to Curtail schedules to an extent greater than either would Curtail FG&E's schedules under similar circumstances.

f) Load Shedding: To the extent that a system contingency exists on FG&E's Local Network and the ISO, the Local Control Center or FG&E determines that it is necessary for FG&E and the Network Customers to shed load, the Parties shall shed load in accordance with previously established procedures in accordance with Section II.22 of the Tariff, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder.

g) **System Reliability**: Notwithstanding any other provisions of this Schedule, FG&E reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on the part of FG&E for the purpose of making necessary adjustments to, changes in, or repairs on FG&E's lines, substations, and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the event of any adverse conditions or disturbances on FG&E's Local Network or on any other system(s) directly or indirectly interconnected with FG&E's Local Network, FG&E, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. FG&E will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will not be unduly discriminatory relative to FG&E's use of its Local Network on behalf of its Native Load Customers. FG&E shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

9) Rates and Charges

In addition to the above sections that correspond to sections in Schedule 21 of the OATT, the following additional provision shall apply to Local Network Service over FG&E's Local Network.

a) **Monthly Demand Charge**: The Network Customer shall pay a Monthly Demand Charge which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of FG&E's Annual Transmission Revenue Requirement as specified in Attachment H to this Schedule 21-FG&E.

10) Determination of Network Customer's Local Monthly Network Load: The Network Customer's local monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with FG&E under Section II.5(c) of Schedule 21 of the OATT) coincident with the FG&E's Monthly Local Network Peak. Monthly revenue requirements not otherwise paid for through charges to Eligible Customers for Local Point-to-Point Service will be allocated among FG&E's Network Customers receiving service under the tariff on the basis of their loads during the hour in the month in which the total connected load to the local network is at its maximum, without any adjustment for credits for generation.

In addition to the above sections that correspond to sections in Schedule 21 of the OATT, the following three provisions shall apply to Local Network Service over FG&E's local network.

10a) Determination of FG&E's Monthly Local Network Load: FG&E's monthly Local Network Load is FG&E's Monthly Local Network Peak minus the coincident peak usage of all firm Local Point-To-Point Service customers pursuant to Schedule 21 of the OATT plus the Reserved Capacity of all firm Local Point-To-Point Service customers.

10b) Recovery of PTF Transmission Revenue Requirements: The portion of FG&E's annual transmission revenue requirements with respect to PTF which is not recovered through the distribution of revenues from Regional Network Service or Local Point-to-Point Service shall be recovered from Eligible Customers taking Regional Network Service or Local Point-to-Point Service pursuant to Section II.12.2(b) of the Tariff.

SCHEDULE 1

Local Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into FG&E's Local Network Control Area. Local Scheduling, System Control and Dispatch Service is to be provided directly by FG&E and the ISO. The Transmission Customer must purchase this service from FG&E. The charges for FG&E's Local Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent that the ISO performs this service for FG&E, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to FG&E by the ISO.

Each firm Local Point-To-Point Service Customer under this Tariff will be charged for Local Scheduling, System Control and Dispatch Services for the total Reserved Capacity specified in each reservation for firm Local Point-To-Point Service made under the Tariff at the rates set forth in Appendix A of this Schedule 1.

Each Network Customer under this Tariff will be charged a monthly Local Scheduling, System Control and Dispatch Service Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Formula Requirements specified in Appendix B of this Schedule 1.

Each Transmission Customer with generation within the ISO's Control Area shall be required also to provide for Scheduling, System Control and Dispatch Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting with the ISO for these services on an unbundled basis. FG&E will make available Generation Scheduling, System Control and Dispatch Service at the rates set forth in Appendix C of this Schedule 1.

Each Transmission Customer with generation located outside of the ISO Control Area shall be required to provide for Scheduling, System Control and Dispatching Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting for these services from the provider of these services within the Control Area where the generation is located. FG&E shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule 1 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE 1

Appendix A

Determination Of

FG&E's Local Network Point-To-Point Formula Rate

For Local Scheduling, System Control And Dispatch Service

FG&E's Formula Rate for Point-To-Point Local Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{FORMULA RATE}_i = \frac{A_{i-1} - B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of FG&E for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule 1.

- B_{i-1} is the actual local scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual local scheduling and dispatch revenues shall be those recorded on the books of FG&E in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

- C_{i-1} is the single annual coincident peak transmission load (expressed in kilowatts) of FG&E for the calendar year prior to the Service Year, as reported in FERC Form No. 1.

Schedule 1

Appendix A

Exhibit 1

Determination of Annual Control Center Expenses

The rate formula for determination of the annual control center expenses revenue requirements for FG&E is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES = Sum of FG&E's (Account 556 System Control and Load Dispatching Expense) + (Account 557 Other Expense) X .50* for the calendar year prior to the Service Year.

* This factor reflects allocation to the transmission function of a portion (50 percent) of the costs recorded in Accounts 556 and 557 associated with dispatching transmission and generating facilities. This 50 percent allocation of control center costs is based on two functions performed by the control center (i) control of generation and (ii) control of transmission.

SCHEDULE 1

Appendix B

Determination of FG&E's
Network Formula Requirements
For Local Scheduling, System Control
And Dispatch Service

FG&E's formula requirements for Network Local Scheduling, System Control and Dispatch Service is determined from the following formula.

Formula Requirements_i = $A_{i-1} - B_{i-1}$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of FG&E for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to Appendix A of Schedule 1.

- B_{i-1} is the actual local scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual local scheduling, system control and dispatch revenues shall be those recorded on the books of FG&E in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

SCHEDULE 1

Appendix C

Determination Of FG&E's Formula Rate For Generation Scheduling, System Control And Dispatch Service

FG&E's Formula Rate for Generation Scheduling, System Control and Dispatch Service ("Formula Rate") shall be calculated using the Formula Rate for Point-to-Point Local Scheduling, System Control and Dispatch Service in Appendix A of Schedule 21 - FG&E.

SCHEDULE 7

Long-Term Firm Local and Short-Term Firm Local Point-to-Point Service

The Transmission Customer shall compensate FG&E each month for firm Reserved Capacity at the sum of the applicable charges set forth below:

1) Yearly delivery:

The Yearly Delivery Charge per kW shall be FG&E's Annual Transmission Revenue Requirement (determined in accordance with Attachment H of this Tariff) divided by FG&E's Total Peak Load for the corresponding calendar year. Total Peak Load, calculated based on the monthly average for the year, shall be FG&E's peak load, minus the coincident peak of all firm local point-to-point customers, plus the contract demand reservation for firm local point-to-point customers.

2) Monthly delivery:

The Monthly Delivery Charge per kW shall be determined by dividing the Yearly Delivery Charge by 12.

3) Weekly delivery:

The Weekly Delivery Charge per kW shall be determined by dividing the Yearly Delivery Charge by 52.

4) Daily delivery:

The Daily Delivery Charge per kW shall be determined by dividing the Yearly Delivery Charge by 365.

The total delivery charge in any week, pursuant to a reservation for daily delivery, shall not exceed the Weekly Delivery Charge specified in section (3) above times the highest amount in kilowatts of firm Reserved Capacity in any day during such week.

5) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by FG&E must be announced to all Eligible Customers solely by posting on Unitil.com, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on Unitil.com, and (3) once a discount is negotiated, details must be immediately posted on Unitil.com. For any discount agreed upon for service on a path from point(s) of receipt to point(s) of delivery, FG&E must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on FG&E's Local Network.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section I.11 (a) of Schedule 21 of the OATT.

SCHEDULE 8

Non-Firm Local Point-to-Point Service

The Transmission Customer shall compensate FG&E for non-firm Local Point-To-Point Service for non-firm Reserved Capacity up to the sum of the applicable charges set forth below:

1) Monthly delivery:

The Monthly Delivery Charge shall be determined by multiplying the Monthly Delivery Charge as described on Schedule 7 by .75.

2) Weekly delivery:

The Weekly Delivery Charge shall be determined by multiplying the Weekly Delivery Charge as described on Schedule 7 by .75.

3) Daily delivery:

The Daily Delivery Charge shall be determined by multiplying the Daily Delivery Charge as described on Schedule 7 by .75.

The total delivery charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the Weekly Delivery Charge specified in section (2) above times the highest amount in kilowatts of non-firm Reserved Capacity in any day during such week.

4) Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the Daily Delivery Charge specified in section (3) above divided by 24. The total delivery charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Delivery Charge specified in section (3) above times the highest amount in kilowatts of non-firm Reserved Capacity in any hour during such day. In addition, the total delivery charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Delivery Charge specified in section (2) above times the highest amount in kilowatts of non-firm Reserved Capacity in any hour during such week.

5) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by FG&E must be announced to all Eligible Customers solely by posting on Unitil.com, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on Unitil.com, and (3) once a discount is negotiated, details must be immediately posted on Unitil.com. For any discount agreed upon for service on a path from point(s) of receipt to point(s) of delivery, FG&E must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on FG&E's Local Network.

6) Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section I.11 (a) of Schedule 21 of the OATT.

SCHEDULE 9
DISTRIBUTION ADDER UNDER TARIFF

In the case where distribution facilities of FG&E are employed in providing service under Schedule 21 of the OATT, the Transmission Customer shall compensate FG&E for the use of such facilities. In addition to the charges contained in this Tariff, the compensation for such distribution facilities will be determined on a case-by-case basis.

All such charges shall be subject to appropriate regulatory approval.

ATTACHMENT C

Methodology To Assess Available Transfer Capability

1. Introduction

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, but does not include the transmission system in northern Maine (i.e., Aroostook and parts of Penobscot and Washington Counties) that is radially connected to New Brunswick and administered by the Northern Maine Independent System Administrator. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"). MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Service Provider for regional transmission service ("Regional Transmission Service") associated with Pool Transmission Facilities, the Participating Transmission Owners ("PTOs") provide local transmission service over Non-Pool Transmission Facilities within the RTOP footprint and are responsible for calculating TTC and ATC associated with Local Transmission Service provided under Schedule 21 pursuant to the Transmission Operating Agreement ("TOA"). Pursuant to CFR § 37.6(b)[5] of the FERC Regulations, Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. The ISO is not responsible for the calculation of these values.

Posted Path is defined as any control area to control area interconnection; any path for which service is

5 Section §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.[6]

FG&E does not currently have any Posted Paths based on the above definition. However, to the extent that FG&E does in the future have a Posted Path, FG&E will calculate TTC using the NERC Standard MOD-029 – Rated System Path Methodology ("MOD-029") as outlined below.

1.1 Scope of Document

The scope of this document is limited to those functions performed by FG&E as the Transmission Service Provider of Schedule 21-FG&E Point-to Point transmission service over Local Facilities pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT:

- Methodology for calculating Total Transfer Capability (TTC)
- Methodology for calculating Available Transfer Capability (ATC)
- Existing Transmission Commitment (ETC)
- Use of Transmission Reliability Margin (TRM)
- Use of Capacity Benefit Margin (CBM)
- Use of Rollover Rights (ROR) in the calculation of ETC

TTC and ATC are required to be calculated only for certain non-PTF internal Posted Paths over which Local Point-to-Point transmission service is provided under Schedule 21-FG&E. TTC and ATC is not calculated by FG&E for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and FG&E does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission pro forma OATT.

6 Section § 37.6(b)(1)(i).

The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the New England Control Area, out of the New England Control Area or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS or Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, FG&E owns Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those Local Facilities, the market participant may obtain a transmission service reservation from FG&E under Schedule 21-FG&E prior to delivery of energy into the Real-Time Energy Market.[7] This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. Schedule 21-FG&E Total Transfer Capability (TTC)

The TTC on FG&E’s non-PTF Local Facilities that require Point-to-Point transmission service reservations are relatively static values and are calculated using the NERC Standard MOD-029 – Rated System Path Methodology. TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines

7 See n - 2, 3 and 6, supra.

(or paths) between those areas under specified system conditions. FG&E calculates TTC according to this definition applying the process as described below.

3.1 Guidelines and Principles

When estimating TTC, FG&E will apply the following, as amended and/or adopted from time to time

- Good Utility Practice
- NERC criteria and guidelines
- ISO New England criteria, rules and reliability standards
- Northeast Power Coordinating Council (NPCC) criteria and guidelines
- Fitchburg Gas and Electric Light Company guides

3.2 Transmission System Model Representation

FG&E will estimate TTC using transmission system load flow models developed for FG&E's system. The models may include representations of other neighboring systems. FG&E will use system models that it deems appropriate for study of the request for firm transmission service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

3.3 Contingency Analysis

FG&E will perform, if necessary, power flow and transient stability analysis to ensure that the interface's physical limits will not be violated for credible system contingencies per NERC, NPCC and ISO reliability criteria. TTC, based on contingency analysis, is the incremental transfer capability of the transmission system following the loss of the most critical element while maintaining thermal, and stability performance of the system within acceptable regional practices and consistent with guidelines of Item 3.1 of this Attachment.

3.4 Posting TTCs

When necessary, FG&E will estimate TTC as outlined above and post on its website.

4. Capacity Benefit Margin (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the

Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of ATC calculation, CBM for the New England Control Area is set to zero (0).

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed firm transmission reservations (PTP_F) plus any rollover rights for firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed non-firm transmission reservations (PTP_{NF}). There are no allowances necessary for non-firm Network Integration Transmission Service ($NITS_{NF}$), non-firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. FG&E, under Schedule 21, does not have any external interfaces, and therefore, TRM for FG&E's non-PTF facilities is zero.

6. Calculation of ATC for FG&E's Local Facilities

General Description

This section defines the ATC calculations performed by FG&E pursuant to MOD-029 for its non-PTF internal interfaces. Consistent with the NERC definition, the equation for Available Transfer Capability is: ATC = (TTC – CBM – TRM – Existing Transmission Commitments + Postbacks + counterflows). As discussed above, the CBM and TRM for the PTF interfaces for which FG&E calculates ATC are zero (0). As consistent with the ISO calculation, the equations for firm and non-firm Available Transfer Capability are:

Firm ATC = (TTC – CBM – TRM – firm ETC)
Non-firm ATC = (TTC – CBM – TRM – firm and non-firm ETC)[8]

As discussed above, the TRM and CBM for FG&E's non-PTF paths are zero. The purpose of the Existing Transmission Commitments ("ETC") component of the ATC equation is for FG&E to reduce the amount of ATC by the amount of existing firm transmission commitments that are not otherwise included in CBM or TRM. There is no requirement to purchase transmission service in advance of flowing energy in Real-Time, and there is no MW amount set aside by FG&E on any interface. One such example is point-to-point service commitments. Point-to-point service commitments sharing common transmission paths would be combined through system modeling to calculate the net existing transmission capacity (ETC) impact. This ETC value is then used in the ATC calculation shown above. Therefore there are no Existing Transmission Commitments to be applied in the ATC equation. For this reason, ETC equals zero (0) for the purposes of ATC calculation. Because Postbacks and counterflows are related to ETC and ETC is zero (0), both Postbacks and counterflows also are equal to zero (0).

As described in Section 2, under Schedule 21-FG&E, FG&E requires the purchase of transmission service in advance of delivery of energy to the New England Wholesale Market over certain non-PTF paths, and those existing transmission commitments would be applied to the ATC equation for the specific posted path. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Entities submit their bids and offers to move energy into, out of and through the Energy Market through External Transactions. As Real-Time approaches, the ISO determines which of the submitted External Transactions will be scheduled in the coming hour in accordance with the rules set forth in the ISO New

8 Existing Transmission Commitments ("ETC")

England Operating Documents. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of External Transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF facilities that serve as a path for the FG&E's Schedule 21-FG&E Point-to-Point Transmission Customers, FG&E would post the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it would be posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Schedule 21-FG&E Firm ATC (ATC_F)

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C, PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-FG&E that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-FG&E transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

6.1.2 Calculation of ATC_F in the Schedule 21-FG&E Operating Horizon (OH)

For purposes of this Attachment C, OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily firm Transmission Service under Schedule 21-FG&E

is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-FG&E transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Because firm Schedule 21-FG&E transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

6.2 Calculation of Schedule 21-FG&E Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for non-firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), non-firm Postbacks ($Postbacks_{NF}$) and non-firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-FG&E are zero. Non-firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-FG&E transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-FG&E are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F, plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$).

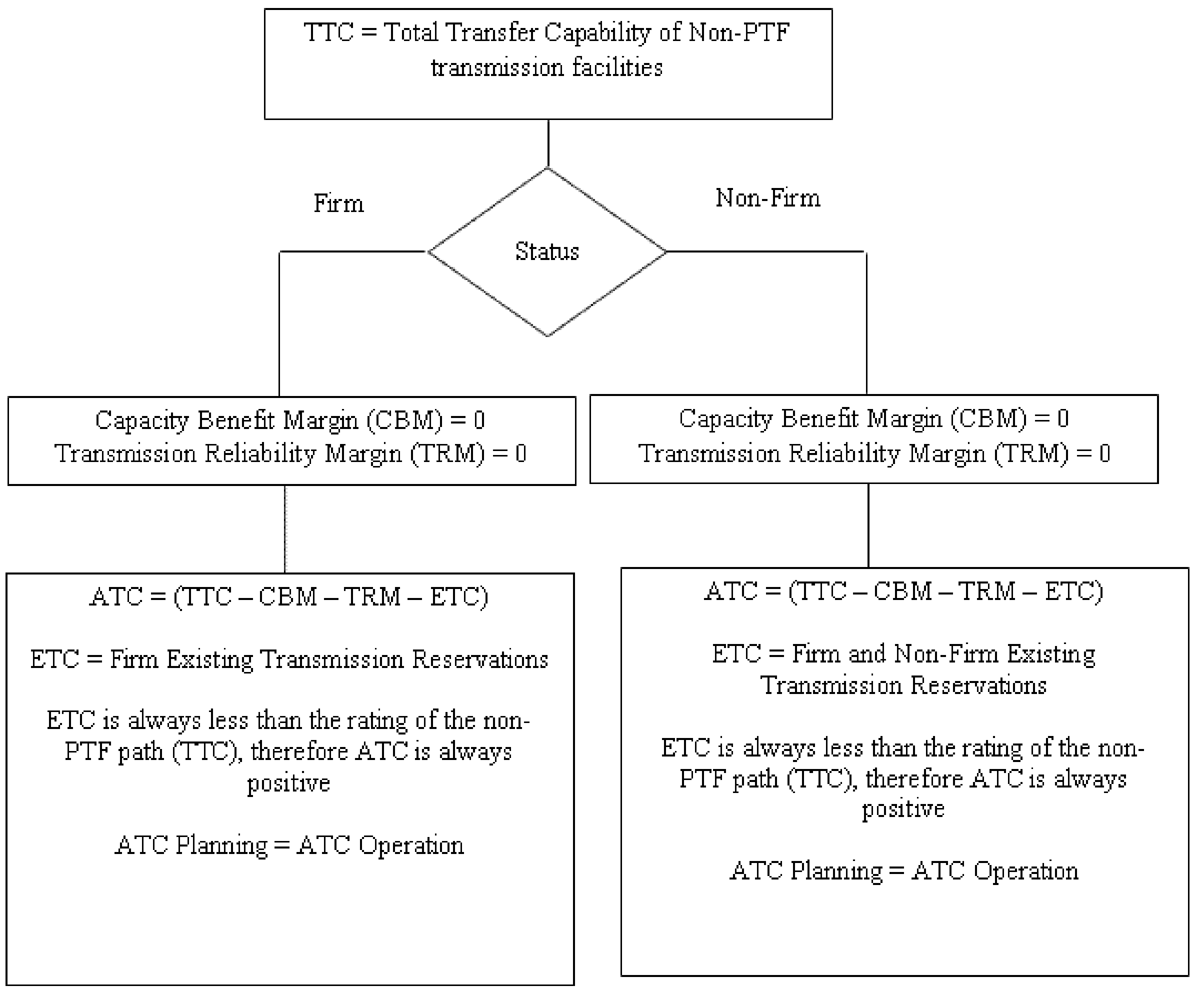
6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

As stated above, FG&E's non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators. It is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

ATC Process Flow Diagram for Non-PTF Interfaces

The process flow diagram illustrates the steps through which ATC is calculated both on an operating and planning horizon.



7. Posting of Schedule 21-FG&E ATC

7.1 Location of ATC Posting.

When necessary, FG&E will estimate ATC values for these internal paths as outlined above and post on its website, http://www.unitil.net/nepool/ma/pdf/atc_cbm_ttc_trm_fge.pdf.

7.2 Updates To ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

7.3 Coordination of ATC Calculations

Schedule 21-FG&E non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms

A link to the actual mathematical algorithm for the calculation of ATC for FG&E's non-PTF internal interfaces is located at http://www.unitil.com/sites/default/files/pdfs/fge_atc_algorithms_3_11.pdf.

ATTACHMENT D

Methodology for Completing a System Impact Study

FG&E will perform System Impact Studies for the purpose of determining the feasibility of integrating Network Load and Network Resources into FG&E's Local Network under Schedule 21 of the OATT, or for the purpose of determining the feasibility of providing Local Point-To-Point Service under this Tariff. All System Impact Studies will be completed using the same method employed by FG&E to integrate into FG&E's Local Network (i) generation resources owned or acquired to serve its Native Load Customers, and (ii) its Native Load Customers' load. Specifically, System Impact Studies will be performed by applying the applicable criteria, rules, standards and operating procedures. In addition to applying the applicable criteria, rules, standards and operating procedures, to determine the feasibility of providing service to Network Load and/or Local Point-To-Point Service, System Impact Studies will also be performed by applying Unitil Service Corp.'s "Electric System Planning Guide".

ATTACHMENT E

Index Of Local Point-To-Point Service Customers

Customer	Date of Service Agreement
Fitchburg Gas and Electric Light Company	September 10, 1996
Pinetree Power Fitchburg Inc.	March 9, 1999

ATTACHMENT H

Annual Transmission Revenue Requirement For Local Network Service

The Transmission Revenue Requirement for FG&E will reflect FG&E's costs with respect to transmission facilities not related to PTF ("Non PTF"). Except as provided below for the transitional implementation of this formula rate, the Transmission Revenue Requirement will be an annual calculation, effective June 1, based on the previous year's calendar data as reported in FG&E's FERC Form 1 report for that year, or other reasonable documentation, using end-of-year balances for each rate base item, as set forth below. The initial Transmission Revenue Requirement shall be effective October 1, 2003 through May 31, 2004 based on calendar year 2002 data as adjusted, as approved by the Commission. Further, the Transmission Revenue Requirement to be effective June 1, 2004, based on calendar year 2003 data, shall include an adjustment to annualize the impact on 2003 depreciation expense of revised depreciation rates effective October 1, 2003, as approved by the Commission. Depreciation expense shall be calculated according to Appendix A of this attachment, as approved by the Commission.

Beginning July 31, 2004, FG&E shall make an annual informational filing on or before July 31 of each year showing the Transmission Revenue Requirement in effect for the period beginning June 1 of that year through May 31 of the subsequent year. If there are corrections made to the information reflected in the informational filing after it has been submitted, FG&E will file corrections to the informational filing.

I. FORMULA

A. The Transmission Revenue Requirement for FG&E's Non-PTF shall equal the sum of the following: (A) Non-PTF Return and Associated Income Taxes, plus (B) Non-PTF Depreciation Expense, plus (C) Non-PTF Amortization of Intangible Plant and Other Regulatory Assets/Liabilities, plus (D) Non-PTF Amortization of Rate Case Expense, plus (E) Non-PTF Amortization of Loss on Reacquired Debt, minus (F) Non-PTF Amortization of Investment Tax Credits, plus (G) Non-PTF Property Tax Expense, plus (H) Non-PTF Payroll Tax Expense, plus (I) Non-PTF Transmission Operation and Maintenance Expense, plus (J) Non-PTF Customer Accounting Bad Debts Expense, plus (K) Non-PTF Administrative and General Expense, plus (L) Non-PTF Transmission Related Taxes and Fees Charge, minus (M) Non-PTF Transmission Rents Received from Electric Property, minus (N) Non-PTF Revenue for Through or Out Service.

B. Each of the components of A. above shall be calculated by subtracting the related PTF costs and revenues from the same calendar year, as included in ISO-NE's OATT, from the total transmission costs and revenues as described in Section III. Support Expense included in PTF shall only be included in this computation to the extent these costs are included in the determination of total transmission costs.

II. DEFINITIONS

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission–related direct wages and salaries to FG&E's total direct wages and salaries, excluding administrative and general wages and salaries.
2. Transmission Plant Allocation Factor shall equal the ratio of the sum of (1) Transmission Plant, (2) Transmission Related Intangible Plant, (3) Transmission Related General Plant, and (4) Transmission Related Common Plant, to Total Plant in Service.
3. Transmission Revenue Allocation Factor shall equal the ratio of Total Internal Transmission Revenue to Total Billed Revenue from Sales to Ultimate Customers.

B. TERMS

Administrative and General Expense shall equal FG&E's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

Amortization of Intangible Plant and Common Plant shall equal FG&E's expenses related to Intangible Plant and Common Plant as recorded in FERC Account No. 404.

Amortization of Investment Tax Credits shall equal FG&E's credits as recorded in FERC Account No. 411.4.

Amortization of Loss on Reacquired Debt shall equal FG&E's expenses as recorded in FERC Account No. 428.1.

Amortization of Other Regulatory Assets/Liabilities-FAS 109 shall equal FG&E's expenses related to Other Regulatory Assets/Liabilities–FAS 109 as recorded in FERC Account No. 407.

Amortization of Rate Case Expenses shall equal FG&E's expenses related to the deferred costs of regulatory rate proceedings related to transmission service as approved by FERC and as recorded in FERC Account No. 407.

Common Plant shall equal FG&E's gross balance of the plant common to both electric and gas operations as recorded in FERC Account Nos. 303, 310, 389-399, excluding capital leases.

Common Plant Amortization Reserve shall equal FG&E's Common Plant reserve balances as recorded in FERC Account No. 111.

Common Plant Depreciation Expense shall equal FG&E's Common Plant expenses as recorded in FERC Account No. 403.

Common Plant Depreciation Reserve shall equal FG&E's Common Plant reserve balance as recorded in FERC Account No. 108.

Customer Accounting Bad Debts Expense shall equal FG&E's expenses as recorded in FERC Account No. 904.

General Plant shall equal FG&E's gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation Expense shall equal FG&E's General Plant expenses as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal FG&E's General Plant reserve balance as recorded in FERC Account No. 108.

Intangible Plant shall equal FG&E's gross plant balance as recorded in FERC Account No. 303 (consisting of investments in computer systems and software).

Intangible Plant Amortization Reserve shall equal FG&E's Intangible Plant reserve balance as recorded in FERC Account No. 111.

Other Regulatory Assets/Liabilities–FAS 106 shall equal the net of FG&E's FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in FG&E's FERC Account No. 254.

Other Regulatory Assets/Liabilities–FAS 109 shall equal the net of FG&E's FAS 109 balance as recorded in FERC Account No. 182.3 and any FAS 109 balance as recorded in FG&E's FERC Account No. 254.

Payroll Tax Expense shall equal those payroll tax expenses as recorded in FG&E's FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal FG&E's balance in FERC Account No. 105.

Prepayments shall equal FG&E's electric prepayment balance as recorded in FERC Account No. 165. The electric portion shall be determined by multiplying the balance in FERC Account No. 165 by the ratio of electric utility plant to total utility plant as reported in FG&E's FERC Form 1.

Property Insurance Expense shall equal FG&E's expenses as recorded in FERC Account No. 924.

Property Tax Expense shall equal FG&E's property tax expenses as recorded in FERC Account Nos. 408.1 and 409.1.

Support Expense shall equal Transmission Support Expense as defined in the OATT Attachment F.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and FERC Account No. 190.

Total Billed Revenue from Sales to Ultimate Customers shall equal FG&E's total electric service revenues as recorded in FERC Account Nos. 440, 442, 444, 445, 446, 448, and 449.

Total Internal Transmission Revenue shall equal FG&E's internal transmission revenues as recorded in FERC Account Nos. 440, 442, 444, 445, 446, 448 and 449.

Total Loss on Reacquired Debt shall equal FG&E's expenses as recorded in FERC Account No. 189.

Total Plant in Service shall equal FG&E's total electric gross plant balance as recorded in FERC Account

Nos. 301-399 (inclusive of electric Common Plant).

Transmission Operation and Maintenance Expense shall equal FG&E's electric expenses as recorded in FERC Account Nos. 560-564 and 566-576.5 and shall exclude expenses already included in PTF Transmission Support Expense, costs billed to Select Energy, Inc. under a generation related entitlement sales agreement and Account Nos. 561.4 and 575.7.

Transmission Plant shall equal FG&E's gross plant balance as recorded in FERC Account Nos. 350-359 excluding joint owned unit costs.

Transmission Plant Depreciation Expense shall equal FG&E's Transmission Plant expenses as recorded in FERC Account No. 403 less joint owned unit costs.

Transmission Plant Depreciation Reserve shall equal FG&E's Transmission Plant reserve balance as recorded in FERC Account 108 less joint owned unit reserves.

Transmission Plant Held for Future Use shall equal the transmission-related balance of electric Plant Held for Future Use.

Transmission Plant Materials and Supplies shall equal FG&E's balance as assigned to transmission, as recorded in FERC Account No. 154.

Transmission Prepayments shall equal FG&E's Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Accumulated Deferred Income Taxes shall equal FG&E's electric balance of Total Accumulated Deferred Income Taxes multiplied by the Transmission Plant Allocation Factor.

Transmission Related Administrative and General Expense shall equal the sum of (1) electric Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus (2) electric Property Insurance Expense reduced by amounts billed to Select Energy Inc. under a generation related entitlement sales agreement and multiplied by the Transmission Plant Allocation Factor, plus (3) electric expenses included in FERC Account No. 928 related to FERC fees and assessments, plus (4) any other electric transmission related expenses included in FERC Account No. 928

plus (5) specific electric transmission related expenses included in FERC Account No. 930.1 and minus (6) any Administrative and General Expense amounts billed to Select Energy Inc. and not already deducted elsewhere, multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Amortization of Intangible Plant and Other Regulatory Assets/Liabilities shall equal the sum of (1) electric Amortization of Intangible Plant and Common Plant multiplied by the Transmission Wages and Salaries Allocation Factor and (2) electric Amortization of Other Regulatory Assets/Liabilities-FAS 109 multiplied by the Transmission Plant Allocation Factor. This component shall include additional regulatory assets/liabilities as established by regulatory authority and relevant to transmission services.

Transmission Related Amortization of Investment Tax Credits shall equal FG&E's electric Amortization of Investment Tax Credits multiplied by the Transmission Plant Allocation Factor.

Transmission Related Amortization of Loss on Reacquired Debt shall equal FG&E's electric Amortization of Loss on Reacquired Debt multiplied by the Transmission Plant Allocation Factor.

Transmission Related Cash Working Capital shall be 12.5% allowance (45 days/360 days) of the sum of Transmission Operation and Maintenance Expense, plus Transmission Related Customer Accounting Bad Debts Expense and plus Transmission Related Administrative and General Expense.

Transmission Related Common Plant shall equal FG&E's electric Common Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Customer Accounting Bad Debts Expense shall equal FG&E's electric Customer Accounting Bad Debts Expense multiplied by the Transmission Revenue Allocation Factor.

Transmission Related Depreciation & Amortization Reserve shall equal the sum of (1) Transmission Plant Depreciation Reserve plus (2) electric Intangible Plant and electric Common Plant Amortization Reserves multiplied by the Transmission Wages and Salaries Allocation Factor and (3) electric General Plant and electric Common Plant Depreciation Reserves multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Depreciation Expense shall equal the sum of (1) Transmission Plant Depreciation

Expense, (2) electric General Plant Depreciation Expense multiplied by the Transmission Wages and Salaries Allocation Factor and (3) electric Common Plant Depreciation Expense multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related General Plant shall equal FG&E's electric General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Intangible Plant shall equal FG&E's electric Intangible Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Loss on Reacquired Debt shall equal FG&E's electric balance of Total Loss on Reacquired Debt multiplied by the Transmission Plant Allocation Factor.

Transmission Related Other Regulatory Assets/Liabilities shall equal the sum of (1) FG&E's electric balance of Other Regulatory Assets/Liabilities-FAS 106 multiplied by the Transmission Wages and Salaries Allocation Factor, and (2) FG&E's electric balance of Other Regulatory Assets/Liabilities-FAS 109 multiplied by the Transmission Plant Allocation Factor. This component shall include additional regulatory assets/liabilities as established by regulatory authority and relevant to transmission services.

Transmission Related Payroll Tax shall equal FG&E's electric Payroll Tax Expense multiplied by the Transmission Wages and Salaries Allocation Factor.

Transmission Related Property Tax shall equal FG&E's electric Property Tax Expense, reduced by amounts billed to Select Energy, Inc. under a generation related entitlement sales agreement, multiplied by the Transmission Plant Allocation Factor.

III. CALCULATION OF TRANSMISSION REVENUE REQUIREMENT

This section describes the calculation of the components of the Transmission Revenue Requirement for FG&E's Non-PTF as provided in Section I.

A. Non-PTF Return and Associated Income Taxes shall equal the product of the Total Internal Transmission Investment Base and the Cost of Capital Rate, reduced by the amount recovered as PTF. For purposes of this computation, the PTF amount shall be calculated using the Cost of Capital Rate defined in III.A.2 below.

1. Total Internal Transmission Investment Base

The Total Internal Transmission Investment Base shall be the sum of the year end balances of the following items as defined in Section II.: (a) Transmission Plant, plus (b) Transmission Related Intangible Plant, plus (c) Transmission Related General Plant, plus (d) Transmission Related Common Plant, plus (e) Transmission Plant Held for Future Use, minus (f) Transmission Related Depreciation & Amortization Reserve, minus (g) Transmission Related Accumulated Deferred Income Taxes, plus (h) Transmission Related Loss on Reacquired Debt, plus (i) Transmission Related Other Regulatory Assets/Liabilities, plus (j) Transmission Prepayments, plus (k) Transmission Plant Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) FG&E's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of:

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of FG&E's long-term debt then outstanding and the ratio that long-term debt is to FG&E's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of FG&E's preferred stock then outstanding and the ratio that preferred stock is to FG&E's total capital.

(iii) the return on equity component, which equals the product of the cost of equity of 11.14~~10.57~~% and the ratio that common equity is to FG&E's total capital.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/])x\ FT}{1-FT}$$

Where FT is the Federal Income Tax Rate; A is the sum of the preferred stock component and the return on equity component, as determined in Sections III.A.2.(a)(ii) and (iii) above; B is Transmission Related Amortization of Investment Tax Credits, as defined in Section II above, C is the equity AFUDC component of Transmission Related Depreciation Expense, as defined in Section II above, and D is Total Internal Transmission Investment Base, as determined in Section III.A.1., above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax}) \times ST}{1-ST}$$

Where ST is the State Income Tax Rate; A is the sum of the preferred stock component and return on equity component as determined in Sections III.A.2. (a)(ii) and (iii) above; B is the Transmission Related Amortization of Investment Tax Credits as defined in Section II. above; C is the equity AFUDC component of Transmission Related Depreciation Expense, as defined in Section II above; D is the Total Internal Transmission Investment Base, as determined in Section III.A.1. above; and Federal Income Tax is the rate determined in Section III.A.2.(b) above.

B. Non-PTF Depreciation Expense shall equal FG&E's Transmission Related Depreciation Expense reduced by the amount recovered as PTF.

C. Non-PTF Amortization of Intangible Plant and Other Regulatory Assets/Liabilities shall equal FG&E's Transmission Related Amortization of Intangible Plant and Other Regulatory Assets/Liabilities reduced by the amount recovered as PTF.

D. Non-PTF Amortization of Rate Case Expenses shall equal the Amortization of Rate Case Expenses reduced by the amount recovered as PTF.

E. Non-PTF Amortization of Loss on Reacquired Debt shall equal FG&E's Transmission Related Amortization of Loss on Reacquired Debt reduced by the amount recovered as PTF.

F. Non-PTF Amortization of Investment Tax Credits shall equal FG&E's Transmission Related Amortization of Investment Tax Credits reduced by the amount recovered as PTF.

G. Non-PTF Property Tax Expense shall equal FG&E's Transmission Related Property Tax Expense reduced by the amount recovered as PTF.

H. Non-PTF Payroll Tax Expense shall equal FG&E's Transmission Related Payroll Tax Expense reduced by the amount recovered as PTF.

I. Non-PTF Transmission Operation and Maintenance Expense shall equal Transmission Operation and Maintenance Expenses reduced by the amount recovered as PTF.

J. Non-PTF Customer Accounting Bad Debts Expense shall equal the Transmission Related Customer Accounting Bad Debts Expense reduced by the amount recovered as PTF.

K. Non-PTF Administrative and General Expenses shall equal the Transmission Related Administrative and General Expenses reduced by the amount recovered as PTF.

L. Non-PTF Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided hereunder which is not specifically identified under any other section. This amount shall be reduced by the amount recovered as PTF.

M. Non-PTF Transmission Rents Received from Electric Property shall equal any amount in FERC Account No. 454, Rents from Electric Property, associated with Transmission Plant. This amount shall be reduced by the amount recovered as PTF.

N. Non-PTF Revenue for Through or Out Service shall equal distributions received by FG&E from ISO out of revenues paid for Through or Out Service (as defined in the OATT), pursuant to Section II.12.2(d) of the Tariff.

Appendix A

PTF and non-PTF Depreciation Rates

Account	Description	Depreciation Rates (%) Eff. January 1, 2011	Depreciation Rates (%) Eff. May 1, 2016
Transmission Plant			
351.00	Clearing Land and Rights of Way	1.27	1.27
352.00	Structures and Improvements	2.29	2.12
353.00	Station Equipment	4.11	3.92
355.00	Poles and Fixtures	5.38	6.13
356.00	Overhead Conductors and Devices	3.92	3.51
General Plant			
394.00	Tools, Shop and Garage Equipment	3.11	3.22
395.00	Laboratory Equipment	4.29	4.03
397.00	Communication Equipment	10.38	2.64
398.00	Miscellaneous Equipment	4.75	3.56
Common Plant			
390.00	Structures and Improvements	3.24	2.64
391.00	Office Furniture and Equipment	3.33	4.59
393.00	Stores Equipment	2.31	2.36
394.00	Tools, Shop and Garage Equipment	2.63	2.76
396.00	Power Operated Equipment	0.90	1.63
397.00	Communication Equipment	8.76	10.02
398.00	Miscellaneous Equipment	N/A	N/A

ATTACHMENT I

Index Of Local Network Service Customers

Customer	Date of Service Agreement
Fitchburg Gas and Electric Light Company	September 10, 1997
Massachusetts Bay Transportation Company	April 17, 2000

Attachment L

Creditworthiness Policy

1. Introduction

This guide establishes creditworthiness standards for transmission service and/or interconnection service customers ("Customers") entering into new or amended service agreements with Fitchburg Gas and Electric Light Company ("FG&E") under the ISO New England Open Access Transmission Tariff ("ISO-NE OATT").[9] In accordance with the Federal Energy Regulatory Commission's Policy Statement on Credit-Related Issues for Electric OATT Transmission Providers, Independent System Operators and Regional Transmission Organizations ("Policy Statement"), this Creditworthiness Policy is intended to make FG&E's credit-related practices more transparent and comprehensive. The following describes FG&E credit review procedures and the types of security that are acceptable to FG&E to protect against the risk of non-payment.

2. Creditworthiness

FG&E will evaluate the creditworthiness of Customers entering into new or amended transmission or interconnection service agreements with FG&E in order to assess a Customer's credit risk relative to the exposure of "Total Outstanding Obligation" as defined in Section 2.1 below, created by the transaction or transactions that FG&E has with the Customer. For purposes of determining the ability of a Customer to meet its obligations, FG&E may require the Customer to submit financial information for the credit review, including credit ratings, credit reports and audited financial statements for the last five years, including audited quarterly reports for the prior two years, if available. Further, the Customer will be expected to provide calculations of the following: Current Total Capitalization Ratio, Including Short-Term Debt; Tangible Net Worth for a period within sixty days of a Customer's request; Earnings Before Interest, Taxes, Depreciation and Amortization for twelve of the last fifteen consecutive months; and additional calculations and other information deemed necessary for the evaluation credit. In completing its evaluation, FG&E may consider other factors including but not limited to past billing history or the characteristics of service being requested.

2.1 Total Outstanding Obligation

The Customer's Total Outstanding Obligation to FG&E will be the sum total of the following

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9 *See* ISO New England Inc., ISO New England Inc. Transmission, Markets and Services Tariff, Section II. This policy is applicable to transmission or interconnection service agreements established from time-to-time under Schedules 21 - FG&E of the ISO-NE OATT and to individually negotiated agreements for similar transmission or interconnection services.

components:

2.1.1 If the Customer is making payments to FG&E for ongoing expenses (including, but not limited to, O&M expenses related to interconnections or other monthly charges such as monthly transmission charges under Schedule 21 – FG&E) the Customer will be required to provide security pursuant to Section 2.2 below, for four months' worth of the Customer's average payment obligation for such charges.

2.1.2 In accordance with the provisions of the ISO-NE OATT, a Customer will pay a Contribution in Aid of Construction ("CIAC") or transfer ownership of facilities to FG&E for transmission or interconnection facilities that are to be constructed on behalf of a Customer at the Customer's sole expense. If FG&E determines in good faith that the receipt of CIAC payments or property from the Customer are non-taxable, FG&E will require a form of security from the customer pursuant to Section 2.2 below for the amount of the potential tax liability to FG&E that would occur if such facilities were deemed taxable.

2.1.3 In accordance with the provisions of Schedule 21 – FG&E to the ISO-NE OATT, a Customer will pay a formula rate over time for return of and on the cost of capital incurred by FG&E on behalf of a Customer at the Customer's sole expense. The Customer will also be required to provide security pursuant to Section 2.2 below, for the unamortized balance of plant in service reserved for the sole use of the Customer.

2.2 Creditworthiness Requirements

A Customer will be considered creditworthy upon satisfying at least one of the following conditions or a combination of those conditions at the time that the customer enters into a transmission or interconnection service agreement and for so long as the Customer maintains satisfaction of at least one of these conditions for any outstanding obligations thereunder:

2.2.1 The Customer maintains a minimum credit rating from Standard & Poor's Long-term Issuer Credit Rating of BBB- or better or Moody's Investors Service Long-term Issuer Credit Rating of Baa3 or better so long as the Customer's Total Outstanding Obligation plus any other unsecured obligations with FG&E does not exceed the Credit Limits discussed in Section 4 below. When FG&E reviews a Customer's rating from two or more rating agencies and a split rating is present, the lower debt rating will apply. In the event that the Customer has no rating from either Standard & Poor's or Moody's Investors Service, a rating from Fitch may also be used with acceptable ratings equivalent to those from either Standard and Poor's or Moody's Investors Service. If unrated, the Customer's financial statements will be reviewed to determine an equivalent rating based on the Customer's unsecured credit limits and/or financial statements.

If, at any time, the Customer's rating falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify FG&E within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to FG&E, as described in this Section 2.2.

2.2.2 The Customer provides and maintains in effect during the term of and until full and final payment and performance of the service agreement an unconditional and irrevocable standby letter of credit for the Total Outstanding Obligation in the form and substance and issued by a bank reasonably acceptable to FG&E. A draft, acceptable form letter of credit is attached. Any such bank must satisfy the creditworthiness criteria described in 2.2.1 above.

If, at any time, the bank's rating falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify FG&E within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to FG&E, as described in this Section 2.2.

2.2.3 If the Customer's parent or an affiliate company satisfies the creditworthiness criteria described in 2.2.1 above and, subject to the Credit Limits stated in Section 4 below, such company submits to FG&E and maintains in effect a letter of guaranty reasonably acceptable to FG&E as to amount, form and substance for the term of and until full and final payment and performance of the service agreement.

If, at any time, the credit rating of the Customer's parent or affiliate providing the guaranty falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify FG&E within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to FG&E, as described in this Section 2.

2.2.4 The Customer makes an advance payment to FG&E in immediately available funds for the Total Outstanding Obligation.

3. Customer Costs Requiring Prepayment

In accordance with the provisions of the ISO-NE OATT, a Customer will pay a Contribution in Aid of Construction ("CIAC") for transmission or interconnection facilities to be constructed by FG&E on behalf of a Customer at the Customer's sole expense. The Customer will have the option to (i) prepay the CIAC in immediately available funds to FG&E, or (ii) make periodic CIAC progress payments, as defined in the Customer's service agreement, to prepay in increments capital costs scheduled to be incurred by FG&E. If FG&E determines in good faith that such payments or property transfers made by the Customer should be reported as income subject to taxation, the Customer shall also prepay all costs associated with the cost consequences of the current tax liability imposed on FG&E by those facilities (the "Tax Gross- up").

4. Determination of Credit Limits

FG&E reserves the right to limit the total amount of unsecured credit extended to a Customer under 2.2.1 and 2.2.3 above such that the sum of all unsecured credit that such Customer has with FG&E, including the Total Outstanding Obligation, shall not exceed the Credit Limits defined below. Such limitations are based on an assessment of the Customer's or its Guarantor's credit rating and the net worth of the Customer's or its Guarantor's assets.

Standard and Poor's (or Equivalent) Rating	Unsecured Credit Limit as Percent of Customer's or Guarantor's Tangible Net Worth
A and above	1.0%
A-	0.5%
BBB+	0.3%
BBB	0.2%
BBB-	0.1%

Once FG&E has evaluated or reevaluated and determined the maximum Credit limits for each Customer, it will inform the prospective Customer of the amount of such credit limits. A customer may request in writing a reevaluation of the maximum Credit limits, within 14 days from the date that they were informed by FG&E of such limits. Justification for such a reevaluation should be contained in the request. All requests for reevaluation must be submitted directly to the FG&E Contract Administrator.

From time to time, principally due to unknown factors such as changing market, economic, banking or other financial conditions, but not solely limited to these factors, FG&E may find it necessary to modify or amend its creditworthiness policies and guidelines after a 15 day notice period and require that present and future Transmission Customers fulfill any additional conditions contained in the modified Creditworthiness Guide. Transmission Customers will have 30 days after the notice period to cure any deficiency.

FORM LETTER OF CREDIT

_____________________________________ Bank

____

(address)

IRREVOCABLE STANDBY LETTER OF CREDIT

DATE: ______________________

AMOUNT U.S. $________________

____

FOR INTERNAL IDENTIFICATION PURPOSES ONLY

____

Our Number:

Beneficiary: Applicant:

____________________________ ___________________________

____________________________ ___________________________

____________________________ ___________________________

____________________________ ___________________________

Attn: At the request of:

____

Ref:____

LADIES AND GENTLEMEN;

WE HEREBY ESTABLISH THIS IRREVOCABLE, AND UNCONDITIONAL, EXCEPT AS STATED HEREIN, LETTER OF CREDIT NUMBER _____________ (LETTER OF CREDIT), BY ORDER OF, FOR THE ACCOUNT OF, AND ON BEHALF OF [CUSTOMER NAME] (ACCOUNT PARTY) IN FAVOR OF FITCHBURG GAS AND ELECTRIC LIGHT COMPANY (BENEFICIARY) FOR DRAWINGS, IN ONE OF MORE DRAFTS, UP TO AN AGGREGATE AMOUNT NOT EXCEEDING U.S. $_______________ EFFECTIVE IMMEDIATELY. THE TERM 'BENEFICIARY' INCLUDES ANY SUCCESSOR OF THE NAMED BENEFICIARY.

THIS LETTER OF CREDIT CANNOT BE AMENDED, MODIFIED OR REVOKED WITHOUT THE PRIOR WRITTEN CONSENT OF BOTH THE BANK AND THE BENEFICIARY. THE BENEFICIARY SHALL NOT BE DEEMED TO HAVE WAIVED ANY RIGHTS UNDER THIS LETTER OF CREDIT, UNLESS AN OFFICER OF THE BENEFICIARY SHALL HAVE SIGNED A WRITTEN WAIVER EXPRESSLY REFERENCING THE RIGHT TO BE WAIVED. NO SUCH WAIVER SHALL BE EFFECTIVE AS TO ANY TRANSACTION THAT OCCURS SUBSEQUENT TO THE DATE OF THE WAIVER, NOT AS TO ANY CONTINUANCE OF A BREACH AFTER THE WAIVER.

WE HEREBY UNDERTAKE TO PROMPTLY HONOR YOUR DRAFT(S) DRAWN ON US, INDICATING OUR LETTER OF CREDIT NUMBER __________ IS ISSUED, PRESENTABLE AND PAYABLE AND WE GUARANTY TO THE DRAWERS, ENDORSERS, AND BONA FIDE HOLDERS OF THIS LETTER OF CREDIT, THAT DRAFTS UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT WILL BE HONORED. THIS LETTER OF CREDIT MAY NOT BE TRANSFERRED OR ASSIGNED BY US.

SUBJECT TO THE EXPRESS TERMS AND CONDITIONS HEREIN, FUNDS UNDER THIS LETTER OF CREDIT ARE AVAILABLE TO YOU BY PRESENTATION AT OUR OFFICES LOCATED AT [_______________] OF BENEFICIARY'S DRAWING CERTIFICATE ISSUED SUBSTANTIALLY IN THE FORM OF ANNEX 1 ATTACHED HERETO AND WHICH FORMS AN INTEGRAL PART HEREOF, DULY COMPLETED AND PURPORTEDLY BEARING THE ORIGINAL SIGNATURE OF AN OFFICER OF THE BENEFICIARY. PRRESENTATION OF ANY

DRAWING CERTIFICATE UNDER THIS LETTER OF CREDIT MAY BE MADE IN PERSON TO US OR MAY BE SENT TO US BY TELEX TO [_________________] OR BY FACSIMILE TRANSMISSION TO FACSIMILE TELEPHONE NUMBER [_______________].

ALL COMMISSIONS AND CHARGES WILL BE BORNE BY THE ACCOUNT PARTY. IF DOCUMENTS, IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT, ARE RECEIVED BEFORE 10:00 AM (EASTERN TIME) ON A BUSINESS DAY, PAYMENT WILL BE EFFECTED ON OR BEFORE 5:00 PM (EASTERN TIME) ON THE NEXT BUSINESS DAY. IF DOCUMENTS, IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT ARE RECEIVED AFTER 10:00 AM ON A BUSINESS DAY, PAYMENT WILL BE EFFECTED ON OR BEFORE 5:00 PM ON THE SECOND BUSINESS DAY FOLLOWING SUCH DATE OF RECEIPT.

EXCEPT AS EXPRESSLY STATED HEREIN, THIS UNDERTAKING IS NOT SUBJECT TO ANY AGREEMENT, CONDITION OR QUALIFICATION. THIS LETTER OF CREDIT DOES NOT INCORPORATE, AND SHALL NOT BE DEEMED MODIFIED OR AMENDED BY REFERENCE TO ANY DOCUMENT, INSTRUMENT OR AGREEMENT (A) THAT IS REFERRED TO HEREIN (EXCEPT FOR THE UNIFORM CUSTOMS, AS DEFINED BELOW), OR (B) IN WHICH THIS LETTER OF CREDIT IS REFERRED TO OR TO WHICH THIS LETTER OF CREDIT RELATES.

OUR OBLIGATION UNDER THIS LETTER OF CREDIT SHALL BE OUR INDIVIDUAL OBLIGATION AND IS IN NO WAY CONTINGENT UPON THE REIMBURSEMENT WITH RESPECT THERETO, OR UPON OUR ABILITY TO PERFECT ANY LIEN, SECURITY INTEREST OR ANY OTHER REIMBURSEMENT.

THIS LETTER OF CREDIT EXPIRES WITH OUR CLOSE OF BUSINESS ON [364 days from effective date]; HOWEVER, IT IS A CONDITION OF THIS LETTER OF CREDIT THAT IT SHALL BE DEEMED AUTOMATICALLY EXTENDED WITHOUT AMENDMENT FOR 364 DAYS FROM THE PRESENT OR ANY FUTURE EXPIRATION DATE HEREOF, UNLESS AT LEAST SIXTY (60) DAYS BEFORE ANY SUCH EXPIRATION DATE WE NOTIFY YOU BY REGISTERED MAIL ADDRESSED TO: [address of beneficiary, ATTN: _______________], THAT WE ELECT NOT TO RENEW THIS LETTER FOR SUCH ADDITIONAL PERIOD.

THIS LETTER OF CREDIT IS SUBJECT TO THE UNIFORM CUSTOMS AND PRACTICE FOR DOCUMENTARY CREDITS (1993 REVISION) INTERNATIONAL CHAMBER OF COMMERCE,

PUBLICATION NO. 500. IF THIS LETTER OF CREDIT EXPIRES DURING THE INTERRUPTION OF BUSINESS AS DESCRIBED IN ARTICLE 17 THEREOF WE HEREBY SPECIFICALLY AGREE TO EFFECT PAYMENT IF THE LETTER OF CREDIT IS DRAWN AGAINST WITHIN 30 DAYS AFTER THE RESUMPTION OF BUSINESS.

ANNEX 1 TO [BANKNAME]
IRREVOCABLE LETTER OF CREDIT NO. _____________

[INSERT DATE]

[BANK NAME]
[ATTENTION]
[BANK ADDRESS 1]
[BANK ADDRESS 2]

LADIES AND GENTLEMEN:

THE UNDERSIGNED _________________________________, A DULY ELECTED AND ACTING OFFICER OF FITCHBURG GAS AND ELECTRIC LIGHT COMPANY (THE "BENEFICIARY"), HEREBY CERTIFIES TO [INSERT BANK NAME] (THE "BANK"), WITH REFERENCE TO IRREVOCABLE LETTER OF CREDIT NO. _________ DATED _______________, ISSUED BY THE BANK IN FAVOR OF THE BENEFICIARY (THE "LETTER OF CREDIT"), AS FOLLOWS AS OF THE DATE THEREOF:

1. THE BENEFICIARY IS A PARTY TO THAT CERTAIN [INTERCONNECTION AGREEMENT], EFFECTIVE _______________, BETWEEN THE BENEFICIARY AND [CUSTOMER NAME] (THE "AGREEMENT").

2. BENEFICIARY IS MAKING A DRAWING UNDER THE LETTER OF CREDIT IN THE AMOUNT OF $___________ BECAUSE [CHECK APPLICABLE PROVISION]:

[____] (A) THERE CURRENTLY EXIST ONE OR MORE UNPAID AMOUNTS WHICH [CUSTOMER NAME] IS OBLIGATED TO PAY PURSUANT TO THE TERMS OF THE AGREEMENT.

[____] (B) THE BENEFICIARY HAS RECEIVED NOTICE FROM THE BANK OF ITS INTENTION NOT TO RENEW THE LETTER OF CREDIT BEYOND THE CURRENT EXPIRATION DATE AND [CUSTOMER NAME] HAS FAILED, PRIOR TO THE CLOSE OF BUSINESS ON

________________ [INSERT DATE WHICH IS NOT MORE THAN THIRTY (30) DAYS BEFORE THE PRESENT EXPIRATION DATE], TO DELIVER TO BENEFICIARY A REPLACEMENT LETTER OF CREDIT SATISFYING THE REQUIREMENTS OF THE AGREEMENT.

3. BASED UPON THE FOREGOING, THE BENEFICIARY HEREBY MAKES DEMAND UNDER THE LETTER OF CREDIT FOR PAYMENT OF U.S. DOLLARS _________________ AND _____/100THS (U.S. $______________).

4. FUNDS PAID PURSUANT TO THE PROVISIONS OF THE LETTER OF CREDIT SHALL BE WIRE TRANSFERRED TO THE BENEFICIARY IN ACCORDANCE WITH THE FOLLOWING INSTRUCTIONS:

____
____
____

UNLESS OTHERWISE PROVIDED HEREIN, CAPITALIZED TERMS WHICH ARE USED AND NOT DEFINED HEREIN SHALL HAVE THE MEANING GIVEN EACH SUCH TERM IN THE LETTER OF CREDIT.

IN WITNESS WHEREOF, THIS CERTIFICATE HAS BEEN DULY EXECUTED AND DELIVERED ON BEHALF OF THE BENEFICIARY BY ITS DULY ELECTED AND ACTING OFFICER AS OF THIS _____ DAY OF ___________, _____.

BENEFICIARY: FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

____
NAME:

____
TITLE

SCHEDULE 21 - NEP

NEW ENGLAND POWER COMPANY
LOCAL SERVICE SCHEDULE

I. COMMON SERVICE PROVISIONS

1 Definitions

Whenever used in this Schedule, in either the singular or plural number, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Schedule that are not defined in this Schedule shall have the meanings set forth in the Tariff or customarily attributed to such terms by the electric utility industry in New England.

1.0 New England Affiliate: New England Affiliate means Massachusetts Electric Company, Nantucket Electric Company, The Narragansett Electric Company and Granite State Electric Company.

1.1 Annual Peak Load: The highest Network Load of the Network Customer during a calendar year.

1.2 Contract Termination Charge (CTC): New England Power Company's stranded cost charge to certain wholesale requirements customers, as defined and described in the Stipulations and Agreements and as calculated pursuant to Appendix 1 of the Offer of Settlement filed with the Commission in Docket Nos. ER97-678-000 and ER97-680-000.

1.3 Contribution in Aid of Construction (CIAC): A contribution in aid of construction pursuant to Section 118(b) of the Internal Revenue Code of 1986.

1.4 Distribution System: Distribution System means the facilities owned or supported by NEP or its New England Affiliates that do not constitute PTF or Non-PTF and are used for Transmission Service under the Tariff for Transmission Customers other than end-use customers.

1.5 [Reserved]

1.6 IRS Notice 87-82: Internal Revenue Service Notice 87-82, Providing guidance with Respect to the Treatment of CIACs (received by regulated public utilities) After Enactment of New Section 118(b) of the Internal Revenue Code.

1.7 IRS Notice 90-60: Internal Revenue Service Notice 90-60, Contribution in Aid of Construction, issued September 10, 1990.

1.7.1 Load Interconnections: Any load facility desiring to interconnect with NEP's electrical system or modify an existing interconnection, as further set forth in the Local Service Agreement in Schedule 21-Attachment A. In addition, Attachment C, D, E, F and H of Schedule 21-NEP shall apply.

1.8 Load Power Factor: The ratio of the load measured in kW to the same load measured in kVA during a one-hour period.

1.9 Load Ratio Share: Ratio of a Transmission Customer's monthly PTF Network Load occurring coincident with NEP's Total Monthly Peak Load, to NEP's Total Monthly Peak Load, calculated on a monthly basis.

1.10 [Reserved]

1.11 Monthly Transmission Expenses: The total monthly cost of the Transmission System as specified in Attachment RR to this Schedule until amended by NEP or modified by the Commission.

1.12 NEP: NEP means New England Power Company, a Transmission Owner under the Tariff

1.13 NEPOOL Tariff: The predecessor NEPOOL Open Access Transmission Tariff as filed with the Commission on December 31, 1996 and as amended and in effect from time to time.

1.14 NERC: North American Electric Reliability Council

1.15 Network Load: The load interconnected (not reduced for any generation behind the meter) to the PTF, Non-PTF or Distribution Facilities of NEP or its New England Affiliates either directly or through Distribution Facilities or Non-PTF Facilities of other entities that a Network Customer designates to receive Local Network Service under Schedule 21 and this Schedule.

For purposes of establishing rates and charges under this Schedule, the Network Load will be subdivided into one of three categories:

A. **PTF Network Load** shall be the load over NEP's Local Network and shall equal the load of Network Customers directly interconnected with NEP's PTF or indirectly utilizing NEP's PTF through Non-PTF or Distribution Facilities of NEP or its New England Affiliates.

B. **Non-PTF Network Load** shall be the load over NEP's Non-PTF either directly interconnected with NEP's Non-PTF or indirectly utilizing NEP's Non-PTF through Distribution Facilities of NEP or its New England Affiliates.

C. **Distribution Facilities Network Load** shall be the load interconnected to the Distribution Facilities of NEP, its New England Affiliates or other entities.

1.16 **Network Upgrades:** Modifications or additions to transmission-related facilities that are integrated with and support NEP's overall Transmission System for the general benefit of all users of such Transmission System or to reliably integrate a generating unit with the Transmission System or to interconnect to outside control areas.

1.17 **Non-PTF Load Ratio Share:** Ratio of a Transmission Customer's monthly Non-PTF Network Load occurring coincident with NEP's Total Monthly Non-PTF Peak Load, to NEP's Total Monthly Non-PTF Peak Load.

1.18 **NPCC:** Northeast Power Coordinating Council, a regional reliability governing body.

1.19 **Own Use Energy:** Energy consumed by NEP's transmission facilities for purposes including but not limited to station service and sleet thawing, but excluding losses incurred on the Transmission System.

1.20 **Parties:** NEP and the Transmission Customer receiving service under this Schedule and the Tariff.

1.21 **Payment Schedule:** The payment schedule attached to a Local Service Agreement containing estimated milestones and estimated costs.

1.22 Policy and Practices for Protection Requirements for New or Modified Load Interconnections: NEP's policy concerning protection requirements for new or modified interconnections to loads, are included in the associated attachments of the Transmission Customer's Local Service Agreement.

1.23 Project: The substation and all facilities ancillary and appurtenant thereto, which the Transmission Customer requests to interconnect to the Transmission System, as more fully described in associated attachments to this Schedule 21-NEP and Attachment A to Schedule 21, Local Transmission Service.

1.24 Qualified Bidders List: A list of contractors and vendors qualified by NEP to work on interconnection facilities.

1.25 REMVEC: The Rhode Island, Eastern Massachusetts, Vermont Energy Control, which operates as a Local Control Center to the ISO.

1.26 Taxable Event: An event taxable to NEP resulting from transfers made by the Transmission Customer to NEP for services provided under this Schedule and Schedule 21 with respect to construction and installation of new Direct Assignment Facilities or improvements.

1.27 Total Monthly Peak Load: For each month, the highest hourly sum of the coincident peaks of deliveries to all PTF Network Loads under this Schedule, plus the loads of customers served under New England Power Company's (NEP) FERC Electric Tariff, Original Volume No. 1, connected directly to NEP's PTF or indirectly utilizing NEP's PTF through Non-PTF or Distribution Facilities of NEP, its New England Affiliates or other entities, including losses and NEP's Own Use Energy.

1.28 Total Monthly Non-PTF Peak Load: For each month, the highest hourly sum of the coincident peaks of deliveries to all Non-PTF Network Loads under this Schedule plus the loads of customers served under NEP's FERC Electric Tariff, Original Volume No. 1, that would otherwise qualify as Non-PTF Network Load, including losses and NEP's Own Use Energy.

1.29 Transformation Facilities: One or more transformers in a substation that step the voltage from the transmission voltage level to the distribution voltage level.

1.30 Transmission Service: Service provided under the OATT.

1.31 Transmission System: Transmission System means the facilities owned, controlled or operated by NEP that are used to provide Transmission Service.

2 Purpose of This Schedule

The OATT provides for a two-tier transmission arrangement integrating regional transmission service over PTF and Local Service over Non-PTF. The arrangement is designed and shall be operated in such a manner as to encourage and promote competition in the electric market to the benefit of ultimate users of electric energy. The OATT is intended to provide for comparable, non-discriminatory treatment of all similarly situated Transmission Owners and all Eligible Customers that are transmission users, and it shall be construed in the manner which best achieves this objective.

This Schedule functions in conjunction with the OATT to offer Transmission Services and Ancillary Services not provided pursuant to the other sections of the OATT, and to provide for the recognition of payments by and credits to NEP under the OATT. The rates, terms and conditions of this Schedule supplement and, where applicable, replace the rates, terms and conditions of the OATT and Schedule 21 with respect to Local Service; however Local PTP Service is not offered by NEP. In the event of a conflict between the terms of this Schedule and the terms of Schedule 21 with respect to Local Service, the terms of this Schedule shall govern.

Pursuant to this Schedule and to Schedules 22 and 23, NEP: (a) offers access to its Transmission Facilities for Excepted Transactions; (b) offers access to its Non-PTF in conjunction with the purchase of Transmission Service under the OATT; (c) provides rates, terms and conditions for the interconnection of new network load to the Transmission System and Distribution System for wholesale transactions; (d) reflects in the charges for Transmission Service and Ancillary Services amounts paid by NEP or credited to NEP in accordance with the OATT; and (e) provides for the recovery of costs associated with the Transmission Facilities and Ancillary Services that are not recovered pursuant to the OATT.

3 Ancillary Services

Ancillary Services are needed with Transmission Service to maintain reliability within and among the Control Areas affected by the Transmission Service. NEP is required to provide and the Network Customer or the Transmission Customer taking service in accordance with this Schedule and the OATT is required to purchase Local Scheduling, System Control and Dispatch Service in accordance with the rates and/or methodology described in Attachment S-1 and Attachment OCC to this Schedule.

4 Billing and Payment

4.1 Billing Procedure: Within a reasonable time after the first day of each month, NEP or its designee shall submit an invoice to the Transmission Customer for the charges for all services furnished by NEP under this Schedule and Schedule 21 during the preceding month. The invoice shall be paid by the Transmission Customer within twenty-five (25) days of issuance. All payments shall be made in immediately available funds payable to NEP, or by wire transfer to a bank named by NEP.

4.2 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to NEP on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after NEP notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, NEP may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between NEP and the Transmission Customer, NEP will continue to provide service under the Local Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then NEP may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

4.3 After Termination or Cancellation: The applicable provisions of the OATT, Schedule 21, this Schedule and any Local Service Agreement shall continue in effect after termination or cancellation thereof to the extent necessary to provide for final billings, billing adjustments and payments and with respect to liability and indemnification from acts or events that occurred while the Local Service Agreement was in effect. Notwithstanding the above, if the OATT, Schedule 21, this Schedule or any Local Service Agreement is terminated prior to the end of its initially contemplated term, for reasons other than breach by NEP, the Transmission Customer shall reimburse NEP for all unrecovered costs applicable to facilities installed pursuant to the provisions of the OATT, Schedule 21, this Schedule or any Local Service Agreement.

4.4 Audits of Accounts and Records: Within two (2) years following a calendar year, NEP and the Transmission Customer shall have the right to audit each other's accounts and records at the offices where such accounts and records are maintained during normal business hours; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service for said calendar year. The party being audited will be entitled to review the audit report and any supporting materials. The independent auditor performing such audit shall be subject to a confidentiality agreement between the auditor and the party being audited. To the extent that audited information includes confidential information, the auditing party shall designate an independent auditor to perform such audit. For the purpose of this provision, confidential information is proprietary information supplied by a Transmission Customer or a provider of Ancillary Services to NEP, which the Transmission Customer or a provider of Ancillary Services requests NEP not to disclose. NEP will treat such information as confidential except to the extent that disclosure of this information is required by the OATT, by regulatory or judicial order for reliability purposes pursuant to Good Utility Practice, pursuant to the Commission's Final Order 889 in Docket No. RM95-9-000, or as required under the ISO New England Information Policy. NEP will not disclose such information to its power marketing Affiliate or others.

5 Creditworthiness

For the purpose of determining the ability of a Transmission Customer to meet its obligations related to service hereunder, NEP may require reasonable credit review procedures. Applicable creditworthiness procedures are specified in Attachment L of this Schedule.

6 Dispute Resolution Procedures

6.1 Interpretation: The interpretation of and performance under this Schedule shall be according to and controlled by the laws of the Commonwealth of Massachusetts when not in conflict with or pre-empted by the Federal Power Act.

6.2 Indemnification: In cases where the Transmission Customer enjoys limitation of its liability under the Massachusetts Tort Claims Act, G.L. c. 258, §§1 and 2, as amended from time to time, NEP will have a similar limitation on its liability under the OATT, Schedule 21 and this Schedule.

II. LOCAL NETWORK SERVICE

The rates, terms and conditions set forth below supplement and, where applicable, replace the rates, terms and conditions of Local Network Service set forth in Schedule 21. In the event of a conflict between the terms of this Schedule and the terms of Schedule 21, the terms of this Schedule shall govern.

19 Real Power Losses

Real Power Losses are associated with all Transmission Service. NEP is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all Transmission Service as calculated by NEP. The applicable Real Power Loss factors tabulated in Attachment I to this Schedule will be applied to metered loads to account for losses on the Non-PTF System and/or Distribution System that are not otherwise accounted for and allocated. Determination of losses across NEP's PTF system will be according to the procedure set by the ISO. In cases where the ISO or the Tariff does not allocate PTF losses, PTF losses will be assigned at 3%. When a load interconnects to the Transmission System at a Non-PTF point, the Real Power Loss factors in Attachment I to this Schedule will be applied to metered load amounts to reflect the losses incurred between the metering point and the PTF. Application of appropriate loss compensation to the meter would negate the need to apply the Real Power Loss factors. The Real Power Loss factors vary, depending upon the system voltage level at the interconnection point. If multiple voltage levels intervene between the PTF and the interconnection point/metering point, the Real Power Loss factors for each of the intervening voltage levels are additive. Any Non-PTF losses not allocated under Attachment I to this Schedule will be allocated to Non-PTF Network Load on the basis of Non-PTF Load Ratio Share.

20 Metering and Power Factor Correction at Point(s) of Delivery

20.1 Power Factor: The Network Customer's cumulative Load Power Factor for all Point(s) of Delivery in an area as defined by the ISO shall be maintained within a range, as required by

NEP, the ISO, and/or REMVEC, in accordance with Good Utility Practice. This range will be reviewed periodically and is subject to change. The Network Customer shall be notified of such changes. If the Network Customer's cumulative Load Power Factor does not fall within the required range, and NEP has existing means of providing the deficient reactive power NEP will charge the Network Customer a Power Factor Penalty in accordance with Attachment OCC to this Schedule. The Power Factor Penalty charge will be suspended if the customer corrects the Load Power Factor or, if during periods when the range may be changed, the customer's Load Power Factor is within the prescribed range. If NEP cannot provide the deficient reactive power from existing facilities, NEP will install, at the Customer's sole expense, the appropriate equipment to bring the customer's power factor within the required range. NEP will file with the Commission the cost support for such installations.

21 Network Resources

21.1 [Reserved]

21.2 Designation of New Network Resources: Each designation of a Network Resource shall be effective as of the beginning of a month, shall remain in effect for at least one full month, and shall only be terminated at the end of a month.

22 Construction of Facilities Associated with Interconnection of New Network Load

22.1 Basic Understandings: In cases in which the Transmission Customer intends to interconnect new network load to the Transmission System or Distribution System, the interconnection: (i) shall require the construction of interconnection facilities and associated equipment and (ii) may require the construction or installation of facilities and/or associated equipment in addition to the interconnection facilities on the Transmission System or Distribution System or the transmission system of another utility. These interconnection facilities and additional facilities shall be the financial responsibility of the Transmission Customer, to the extent consistent with Commission policy.

Subject to the following terms and conditions, NEP or its New England Affiliate shall, at the Transmission Customer's expense, build the facilities or make preparations so that this construction can be submitted for written bids to parties on the Qualified Bidders List. NEP shall have the right to supervise any construction undertaken by qualified outside contractors at the Transmission Customer's expense and to reject any construction work which fails to meet its requirements.

22.2 General Considerations: NEP or its New England Affiliate or another party selected pursuant to this Section shall construct the facilities at the Transmission Customer's expense. NEP or its New England Affiliate shall design, own, and maintain the facilities. NEP and the Transmission Customer shall mutually agree upon a schedule for construction and final interconnection. NEP shall use due diligence to fulfill its obligations under this Schedule in order to permit the interconnection of the Project in a timely manner. NEP reserves the exclusive right to make the final interconnection between the Project and NEP's Transmission System. NEP shall use, or specify that the Transmission Customer's selected contractor use, standard equipment customarily employed by NEP or its New England Affiliate for its own system in accordance with Good Utility Practice in making the final interconnection.

The Transmission Customer shall pay NEP for all reasonable costs and fees required to enable NEP to fulfill its obligations, including any tax liability, the costs and fees of all permits, licenses, franchises or regulatory or other approvals necessary for the construction and operation of the facilities. NEP shall consult with Transmission Customer on decisions involving substantial additional costs to be incurred by NEP in fulfillment of its obligations.

22.3 Tax Security Arrangements: The Transmission Customer shall acknowledge that under IRS Notice 87-82, transfers made by the Transmission Customer to NEP for services provided hereunder with respect to the construction and installation of new facilities or improvements may, under certain circumstances cause a Taxable Event to NEP. The Transmission Customer agrees to assure NEP recovery of all potential tax costs, both state and federal, including all interest and penalty claims, if a Taxable Event occurs.

The Transmission Customer shall expressly agree to indemnify and save NEP harmless from and against any and all federal and/or state income tax, interest or penalty claims, or liability related to any tax gross-up incurred as a result of the work performed for and the services rendered to the Transmission Customer.

22.4 Security: In addition to the security provided for in Section 5 of this Schedule, the Transmission Customer shall agree to provide NEP with security for the potential tax liability for a term and in a form acceptable to NEP. Such security shall cover an amount calculated in accordance with the terms of Section 22.5 of this Schedule. If the Transmission Customer fails to provide NEP with satisfactory security within thirty (30) days of notice by NEP, NEP may cease all work related to the Transmission Customer's request until such security is in place.

NEP reserves the right to require the Transmission Customer to increase the value of the security to reflect changed circumstances including, but not limited to, an increase in the taxable value of the Direct Assignment Facilities or changes in tax law which affect NEP's tax position vis-à-vis the construction and installation of new or modified facilities. The Transmission Customer shall provide NEP with the security as well as any periodic renewals that may be required by NEP. Such security shall have a minimum term of one (1) year and, in the case of a letter of credit, shall designate NEP as beneficiary with authority to draw drafts on the issuer for the secured amount in accordance with this Schedule. Such security shall also provide that NEP may draw the full amount of the security in the event it has not been renewed, extended or replaced on or before thirty (30) days prior to the expiration date of such security.

If at any time during the term of the Transmission Customer's Service Agreement with NEP there is a change in federal law tax which, in NEP's view, mitigates or eliminates its tax liability under applicable law or regulation, NEP shall agree, to the extent it deems appropriate, to release to the Transmission Customer any security determined to be in excess of NEP's potential tax liability.

22.5 Determination of Secured Amount: The Transmission Customer agrees that if a Taxable Event occurs, NEP's tax liability will be based upon the fair market value of the facilities constructed, installed or modified hereunder. The Transmission Customer agrees that the fair market value of the facilities is deemed to be the depreciated replacement cost of such facilities at the time of the transfer, as prescribed by IRS Notice 90-60.

The Transmission Customer shall secure an amount equal to the product of the depreciated replacement cost of the facilities times NEP's gross-up tax factor (net federal and state tax rate). NEP shall provide an initial estimate of the amount to be secured, based upon its facilities construction, installation or modification estimate. These projected figures, however, are subject to adjustment for actual construction costs when they become known.

The Transmission Customer shall agree to increase the secured amount to reflect any other adjustments as required by NEP to ensure that the existing security is sufficient to cover NEP's potential tax liability. The Transmission Customer shall agree to increase the secured amount within thirty (30) days of receipt of notice from NEP of any such adjustment to these costs. In the event that the Transmission Customer fails to do so, NEP shall have the right to seek termination of its service to the Transmission Customer until it increases the secured amount to the level specified by NEP.

22.6 Payment of Tax and Reconciliation: In the event that a Taxable Event occurs, NEP may exercise its rights under the security arrangement and draw upon all amounts necessary to pay the applicable taxes. If, in NEP's judgment, there are insufficient funds from such security to pay the applicable taxes, the Transmission Customer agrees to provide NEP with the balance of the funds needed within fifteen (15) days notice from NEP of such insufficiency. Any excess funds covered by security shall remain at NEP's disposal until NEP has received a final determination from the taxing authorities on the amounts payable as a result of the Taxable Event.

Upon such final determination, there shall be a reconciliation of the taxes payable by NEP, including any interest or penalties, and amounts provided by the Transmission Customer, in the form of security or otherwise. If the funds provided by the Transmission Customer prove insufficient to cover NEP's tax liability, the Transmission Customer shall pay NEP the amount of the underpayment within fifteen (15) days notice from NEP of the additional amount owed. If NEP receives a refund from the taxing authorities of any amounts paid due to the Taxable Event, NEP shall refund to the Transmission Customer such amount refunded to NEP. If taxes had not as yet been paid by NEP, in the form of estimated tax payments or otherwise, NEP shall refund the amount paid by the Transmission Customer in excess of NEP's actual tax liability. Interest on such amounts shall accrue, from the applicable following date: (a) the date the refund is received by NEP; (b) the date of recovery of estimated taxes previously paid by NEP (i.e., the due date of the tax payment following the determination); or (c) the date of final payment by the Transmission Customer under this Schedule, to the date NEP refunds such amount to the Transmission Customer. Once the Transmission Customer has fulfilled all of its obligations with respect to the final determination of the tax amounts payable, NEP shall release the Transmission Customer from all obligations under this Section. Interest, however, will not apply when a Letter of Credit is used as security.

22.7 IRS Private Letter Ruling. In the case of a Contribution in Aid of Construction ("CIAC") amounting to at least $100,000 and upon written request by a Transmission Customer, NEP will request a Private Letter Ruling from the Internal Revenue Service on the taxable nature of the Transmission Customer's CIAC. The Transmission Customer must submit such written request to NEP, with payment for the estimated costs of obtaining such ruling, within 30 days of the Commission's acceptance of the transmission Customer's Service Agreement (or its amendment) covering construction under this Schedule. Payment shall be sufficient to cover NEP's estimated expenses in retaining outside tax counsel with expertise in such matters, all regulatory, filing and application fees and any other reasonable expenses, including salary and overhead costs, deemed appropriate and necessary for preparing, managing and obtaining the ruling.

The Transmission Customer shall be responsible for all costs that NEP incurs in pursuing the Private Letter Ruling. If NEP's costs in pursuing the Private Letter Ruling exceed the estimated costs shown, it shall so notify the Transmission Customer and the Transmission Customer shall reimburse or pay the estimated additional cost, as the case may be, within thirty (30) days of notification. NEP shall not be responsible for pursuing or continuing to pursue the Private Letter Ruling if the Transmission Customer has not complied with these payment provisions.

The Transmission Customer agrees that the selection and retention of outside tax counsel in this regard shall be exclusively determined by NEP. Furthermore, the Transmission Customer understands that NEP cannot predict or guarantee the outcome of the Private Letter Ruling and, should the Internal Revenue Service deem the CIAC taxable to NEP, the Transmission Customer must meet its financial obligations to NEP to cover federal and state taxes.

The Transmission Customer shall cooperate in the preparation and provision of information, documents and other materials needed by NEP and its outside counsel for the Private Letter Ruling application and its supporting description and analysis. As soon as practicable after NEP's receipt of the Private Letter Ruling from the IRS, it shall provide the Transmission Customer with a copy of the document. The parties agree that the decision of the IRS as to the taxable status of the CIAC shall be binding upon the parties, their successors and/or assigns.

22.8 Land Interests: The Transmission Customer recognizes that acquisition of the land interests necessary for the interconnection facilities may require individual agreements between NEP or its New England Affiliate and the landowners. The Transmission Customer agrees to pay NEP all its reasonable costs associated with these acquisition agreements in advance of their execution. In the event the Transmission Customer acquires the land, permits, licenses, franchises or regulatory or other approvals necessary for the construction and operation of the interconnection facilities, NEP has the right, at the Transmission Customer's expense, to approve or reject any terms and conditions related thereto prior to the acceptance of the interconnection facilities.

22.9 Construction: If the Transmission Customer does not request that the construction of the interconnection facilities be submitted for written bids as described below, NEP or its New England Affiliate shall construct the interconnection facilities and the Transmission Customer shall pay NEP the total costs associated with the construction of the interconnection facilities. The estimated costs (exclusive of any regulatory approval costs and/or fees) and the schedule for the Transmission Customer's payments to NEP will be shown the Service Agreement.

The Transmission Customer shall pay NEP following the close of the Transmission Customer's construction financing (if any) in accordance with the Payment Schedule shown in the Service Agreement. The Payment Schedule contains estimated milestones and estimated costs. NEP shall invoice the Transmission Customer for costs, on an estimated basis.

Within a reasonable period of time following completion of the interconnection facilities, NEP shall provide the Transmission Customer with a report of actual construction costs sufficient to allow identification of all major cost components. Upon completion of the interconnection facilities, the Transmission Customer and NEP agree to make a final adjustment to correct for any overpayment or underpayment of the construction costs.

22.10 Construction by Third-Party: The Transmission Customer may request that the construction of the interconnection facilities be submitted for written bids by NEP-approved contractors having the capability and skill to perform the work in accordance with the terms and conditions contained herein. The Transmission Customer shall assume all risks and consequences associated with the decision to use such bidding process.

The Transmission Customer understands that if a contractor other than NEP or its New England Affiliate constructs the interconnection facilities, the RFP process and interconnection facilities construction may require more time than if NEP or its New England Affiliate constructed the interconnection facilities. Notwithstanding the foregoing, the Transmission Customer understands and agrees that all construction work on existing facilities shall be done by NEP or its New England Affiliate. Such work shall not be included in the work submitted for bid by the Transmission Customer to outside contractors.

If the Transmission Customer requests that the construction of the interconnection facilities be submitted for written bids in accordance with the preceding paragraph, NEP shall prepare RFPs for construction of the interconnection facilities which, at a minimum, shall include construction drawings, steel structure specifications, bid drawings and specifications, materials specifications, and construction specifications. NEP shall also prepare the Qualified Bidders List. Materials, including steel structures, shall be obtained from suppliers listed in the Qualified Bidders List. The Transmission Customer shall seek NEP's prior approval with respect to any additions to the Qualified Bidders List or substitution of equal items of material from approved suppliers. The Transmission Customer shall reimburse NEP for its reasonable costs of preparing the RFPs and the Qualified Bidders List.

Upon the Transmission Customer's acceptance of the RFPs and the Qualified Bidders List, the Transmission Customer shall issue the RFPs to the contractors on the Qualified Bidders List. NEP and its New England Affiliates shall have the right to respond to the RFPs. The Transmission Customer shall review the responses to the RFPs and select a contractor to construct the interconnection facilities. Selection of the contractor shall be at the Transmission Customer's sole discretion, but subject to the limitations and criteria contained herein. The contractor selected by this process shall contract directly with the Transmission Customer for this construction. In no event shall NEP become legally or financially obligated to the selected contractor for construction of the interconnection facilities or any other related work.

If NEP or its New England Affiliate is not the successful bidder, NEP shall have the ongoing right to monitor, at the Transmission Customer's expense, and approve or reject the contractor's construction of the interconnection facilities to ensure that the contractor's performance satisfies NEP's specifications and the criteria set forth in this Schedule and all appendices, exhibits, and attachments hereto. NEP shall have the right to make a final inspection and acceptance of the completed interconnection facilities. NEP's evaluation and acceptance of the interconnection facilities shall be based on compliance with the contract specifications; Good Utility Practice; the National Electric Safety Code as in effect during the time of construction; the appropriate state rules and regulations; NEP's Policy and Practices for Protection Requirements for New or Modified Load Interconnections; and other practices, procedures, specifications, and applicable standards developed by NEP's New England Affiliate. Any part of the work which NEP reasonably finds unsatisfactory shall be corrected prior to its acceptance of the completed interconnection facilities.

If the Transmission Customer selects a contractor other than NEP or its New England Affiliate, within thirty days following completion of the interconnection facilities, the Transmission Customer shall provide NEP with all detailed construction cost data that NEP needs to meet construction cost unitizing requirements under the Federal Power Act and relevant regulations.

22.11 Delivery and Measurement of Electricity:

22.11.1 Voltage Level: All electricity across the interconnection point shall be the form of three-phase sixty-hertz alternating current at a voltage class determined by mutual agreement of the parties.

22.11.2 Machine Reactive Capability: The Transmission Customer will be required to provide reactive capability to regulate and maintain system voltage at the interconnection point. NEP and the ISO shall establish a scheduled range of voltages to be maintained by the Project. The reactive capability requirements shall be reviewed during the System Impact Study and Facilities Study.

22.11.3 Metering and Related Equipment: The Transmission Customer shall be responsible for the cost of installing and maintaining compatible metering and communication equipment at or distant from the Project which measures steam flow, if the Project is a generating source (as applicable and where necessary), as well as electricity flows between NEP and Transmission Customer and determines the status of switching equipment. The Transmission Customer shall be responsible for communicating to NEP accurate information on capacity and energy being transmitted. Instrument transformers shall be approved by NEP before the design is finalized. In cases where it may be appropriate for the metering equipment to be installed at the Transmission

Customer’s property, NEP reserves the right to inspect, commission and witness test such meters. NEP shall also have access to read such meters remotely and locally to facilitate measurements and billing.

The Transmission Customer shall provide suitable space within its facilities for installation of the metering, telemetering, environmental control, and communication equipment at no cost to NEP.

The Transmission Customer shall be responsible for providing all necessary leased telephone lines and any necessary protection for leased lines and shall furthermore be responsible for all communication required by the ISO, or its designee. The Transmission Customer shall maintain all telemetering and transducer equipment on the Project in accordance with applicable criteria, rules, standards and operating procedures. At the Transmission Customer's expense, NEP shall purchase, own and maintain all telemetering equipment located on NEP’s facilities. The Transmission Customer shall be responsible for the cost of installing NEP-approved or NEP-specified test switches in the transducer circuits.

If the metering equipment, the interconnection point and the Point(s) of Receipt are not at the same location, the metering equipment shall record delivery of electricity in a manner that accounts for losses occurring between the metering point and the Point(s) of Receipt or between the metering point and the interconnection point, as appropriate. Accounting for transmission losses between the metering point and the Point(s) of Receipt or between the metering point and the interconnection point shall be pursuant to the rates, terms and conditions of this Schedule and the OATT.

All metering equipment may be routinely tested by NEP at the Transmission Customer's expense, in accordance with applicable criteria, rules, standards and operating procedures. If, at any time, any metering equipment is found to be inaccurate by a margin greater than that allowed under applicable criteria, rules, standards and operating procedures, NEP shall cause such metering equipment to be made accurate or replaced at the Transmission Customer's expense. Meter readings for one-half the period extending back to the last successful meter test shall be adjusted so far as the same can be reasonably ascertained. Each party shall comply with any reasonable request of the other concerning the sealing of meters, the presence of a representative of the other party when the seals are broken and the tests are made, and other matters affecting the accuracy of the measurement of electricity delivered from the Project. If either party believes that there has been a meter failure or stoppage, it shall immediately notify the other.

The Transmission Customer shall be responsible for the cost of purchasing and installing software, hardware and/or other technology that may be required to read billing meters.

The Transmission Customer shall be responsible for the costs of all metering and related equipment pursuant to Attachment OCC to this Schedule and/or Attachment DAF to this Schedule, as applicable.

22.12 Notice Provisions: If at any time, in the reasonable exercise of NEP's judgment, operation of the Project adversely affects the quality of service to other customers or interferes with the safe and reliable operation of the Transmission System or Distribution System, NEP may discontinue service to the Transmission Customer until the condition has been corrected. Unless an emergency exists or the risk of one is imminent, NEP shall give the Transmission Customer reasonable notice of its intention to discontinue service and, where practical, allow suitable time for the Transmission Customer to remove the interfering condition. NEP's judgment with regard to discontinuance of deliveries or disconnection of facilities under this paragraph shall be made in accordance with Good Utility Practice. In the case of such discontinuance, NEP shall immediately confer with the Transmission Customer regarding the conditions causing such discontinuance and its recommendation concerning the timely correction thereof.

22.13 Access and Control: Properly accredited representatives of NEP or its New England Affiliates shall at all reasonable times have access to the Project to make reasonable inspections and obtain information required in connection with this Schedule. At the Project, such representatives shall make themselves known to the Transmission Customer's personnel, state the object of their visit, and conduct themselves in a manner that will not interfere with the construction or operation of the Project. NEP or its New England Affiliates will have control such that it may open or close the circuit breaker or disconnect and place safety grounds at the Point(s) of Receipt, or at the station, if the Point(s) of Receipt is (are) remote from the station.

22.14 Insurance Requirements: The Transmission Customer shall be subject to the insurance requirements specified in the Local Service Agreement.

23 Load Shedding and Curtailments

23.1 Transmission Constraints: During any period when NEP determines that a transmission constraint exists on the Non-PTF, and such constraint may impair the reliability of the New England Transmission System, NEP will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the system. To the extent NEP determines that the reliability of the New England Transmission System can be maintained by redispatching resources, NEP will initiate procedures pursuant to contracts with owners of the identified resources to redispatch all Network Resources and NEP's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this Section may not unduly discriminate between NEP's use of the Non-PTF on behalf of its Native Load Customers and any Network Customer's use of the Non-PTF to serve its designated Network Load.

23.2 Cost Responsibility for Relieving Transmission Constraints: Whenever NEP implements least-cost redispatch procedures in response to a transmission constraint, NEP and the Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

23.3 System Reliability: A Network Customer that fails to respond to established load shedding and curtailment procedures will be deemed by NEP of making unauthorized use of the Transmission System. If unauthorized use occurs, NEP will charge and the Transmission Customer will be obligated to pay a penalty equal to twice the standard rate for such a transaction, as described more fully in Section 24.15 of this Schedule. In all cases of unauthorized use of the Transmission System, the service will be considered non-firm and NEP will be under no obligation to provide any services for such use.

24 Compensation for Local Network Service

The following rates and charges may apply to Local Network Service as specified below. Charges under this Section shall include any applicable PTF costs not otherwise recovered under the OATT. To the extent that NEP enters into an incentive rate plan(s), the incentive rate terms shall be reflected in a separate filing with the Commission under Section 205 of the Federal Power Act. Additionally, all costs and revenues under such incentive rate plan(s) shall be excluded from NEP's PTF and Non-PTF Transmission Revenue Requirement. However, liquidated damages mandated by the Commission in

Docket No. RM02-1-000 shall be reflected in NEP's costs and included in its PTF and Non-PTF Transmission Revenue Requirement calculations.

24.1 Monthly Demand Charge: Any Network Customer utilizing NEP's PTF facilities either directly or indirectly shall pay a Monthly Demand Charge as calculated in accordance with Attachment OCC to this Schedule.

24.2 Monthly Non-PTF Demand Charge: Any Network Customer with Network Load qualifying as Non-PTF Network Load, shall pay a Monthly Non-PTF Demand Charge determined in accordance with Attachment OCC to this Schedule.

24.3 Transformer Surcharge: In the event that a Network Customer does not own the stepdown transformation from 69 kV or greater voltage to distribution voltage level, where it utilizes NEP's Transformation Facilities, the Network Customer will be subject to a Transformer Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.4 Meter Surcharge: If the Network Customer neither owns nor supports metering equipment necessary for provision of Local Network Service, that customer will be subject to a Meter Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.5 Power Factor Penalty: Pursuant to the requirements of Section 20.1 of this Schedule, the Network Customer may be subject to a Power Factor Penalty calculated in accordance with Attachment OCC to this Schedule.

24.6 Direct Assignment Facility Charge: The Direct Assignment Facility Charge compensates NEP for the annual costs of the facilities, expansions and upgrades that may be directly assigned by NEP or by the ISO, as appropriate, to the Transmission Customer. These costs may include, but are not limited to, the capital carrying cost, income tax, depreciation, operation and maintenance, administrative and general expenses and property tax. The Direct Assignment Facility Charge shall be calculated as specified in Attachment DAF to this Schedule. In no event shall the Direct Assignment Facilities Charge be less than $1,000.00 per year. If NEP enters into an agreement for use and support of facilities owned by other entities on behalf of a Transmission Customer, any charges incurred by NEP will be directly assigned to the Transmission Customer.

The Direct Assignment Facilities Charge in each year shall be billed based on forecast data for that year and shall be adjusted for experienced costs as soon as practicable after the close of the year. The charge so calculated shall commence on the date the facilities, expansions or upgrades are placed in service.

24.7 Distribution Service:

24.7.1 Specific Distribution Surcharge: Any Network Customer listed in Attachment OCC, VI, to this Schedule, which relies on the specific distribution facilities of NEP's New England Affiliate, Massachusetts Electric Company, as provided to NEP under the Integrated Facilities provision of NEP's FERC Electric Tariff No. 1 (Tariff No. 1), will be subject to a Specific Distribution Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.7.2 Rolled-In Distribution Surcharge: To the extent that a Network Customer listed in Attachment OCC, VI, to this Schedule, utilizes distribution facilities in addition to the specific facilities identified in NEP's Tariff No. 1 (as of February 28, 1998), the Network Customer will pay the Rolled-In Distribution Surcharge calculated in accordance with Attachment DS to this Schedule for delivery service to load. To the extent that distribution service to a new Network Customer is subject to the direct jurisdiction of the Federal Energy Regulatory Commission, the provision of distribution service to that customer on or after March 1, 1998 shall be reflected in the Network Customer's Local Service Agreement.

In the event that the integrated distribution facilities under NEP's FERC Electric Tariff No. 1 are otherwise eliminated or superseded, the customers listed in Attachment OCC, VI, to this Schedule, will take distribution service entirely under the Rolled-In Distribution Surcharge calculated in accordance with Attachment DS to this Schedule.

24.8 Ancillary Services: Any Network Customer with Network Load qualifying as PTF Network Load will be subject to the Network Load Dispatch Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.9 OASIS Charges: Identifiable usage-dependent costs of OASIS may be charged to the specific user in accordance with the Commission's Final Order 889 in Docket No. RM95-9-000, and any subsequent amendments thereto.

24.10 [Reserved]

24.11 EPRI Credit: The Network EPRI Credit, calculated in accordance with Attachment OCC to this Schedule, shall apply to any wholesale Network Customer, which is not also an Affiliate of NEP.

24.12 Pre-1997 RNS Revenue Credit: Pursuant to the compliance filing made by NEP in FERC Docket Nos. EC99-70-00 and ER99-2832-000 (Not Consolidated), Taunton Municipal Lighting Plant, Middleborough Gas and Electric Department and Pascoag Fire District will receive a credit in their monthly bill under this Schedule calculated in accordance with Attachment OCC to this Schedule.

24.13 Network Upgrade Charge: If network upgrades are required in association with a new load, the Network Customer shall be required to pay a Network Upgrade Charge. The monthly Network Upgrade charge shall be the higher of (i) the allocated Monthly Transmission Expenses for Local Network Service with the New Network Upgrades rolled-in; or (ii) an incremental monthly charge for service based upon the total costs of the Network Upgrades for which the Transmission Customer is responsible as determined by the formula in Attachment DAF to this Schedule.

24.14 Redispatch Charge: Pursuant to Section 23.2 of this Schedule, the Transmission Customer may be subject to charges for generation redispatch.

24.15 Unauthorized Use Penalty: Pursuant to Section 23.3 of this Schedule, the Transmission Customer may be subject to a penalty equal to twice the standard rate for unauthorized use of the Transmission System, based on the period of unauthorized use.

The annual standard rate per KW for unauthorized use of the Transmission System shall be derived from (i) the previous calendar year's annual transmission expenses as calculated in

Attachment RR, excluding any revenue credits associated with Section 24.1 of this Schedule divided by (ii) the average of the twelve Total Monthly Peak Loads from the previous year.10

The monthly standard rate per KW shall equal one-twelfth of the annual standard rate; the weekly standard rate per KW shall equal one-fifty-second of the annual standard rate; and the daily standard rate per KW shall equal one-fifth of the weekly standard rate.

The unauthorized use penalty charge for a single hour of unauthorized use shall be based on the daily standard rate, and more than one assessment for a given duration (e.g., daily) results in an increase of the penalty period to the next longest duration (e.g., weekly). The unauthorized use penalty charge for multiple instances of unauthorized use (i.e., more than one hour) within a day will be based on the daily standard rate. The unauthorized use penalty charge for multiple instances of unauthorized use isolated to one calendar week would result in a penalty based on the weekly standard rate. The unauthorized use penalty charge for multiple instances of unauthorized use during more than one week during a calendar month will be based on the monthly standard rate.

[10] The standard rate is analogous to the former Firm Local Point-To-Point Service rate that was eliminated from Schedule 21-NEP (Attachment J) effective November 1, 2007; *see Docket No. ER07-1323-000*.

ATTACHMENT C

Form of System Impact Study Agreement

This Agreement dated __________, is entered into by ____________ (the Transmission Customer) and New England Power Company (NEP), for the purpose of setting forth the terms, conditions and costs for conducting a System Impact Study relative to _________________________________.

1. The Transmission Customer agrees to provide, in a timely and complete manner, all required information and technical data necessary for NEP to conduct the System Impact Study. The Transmission Customer understands that it must provide all such information and data prior to NEP's commencement of the Study. Such information and technical data is specified in Exhibit 1 to this Agreement.

2. All work pertaining to the System Impact Study that is the subject of this Agreement will be approved and coordinated only through designated and authorized representatives of NEP and the Transmission Customer. Each party shall inform the other in writing of its designated and authorized representative.

3. NEP will advise the Transmission Customer of any additional studies as it may in its sole discretion deem necessary. Any such additional studies shall be conducted only if required by Good Utility Practice and shall be subject to the Transmission Customer's consent to proceed, such consent not be unreasonably withheld.

4. NEP contemplates that it will require _______ to complete the System Impact Study. Upon completion of the Study by NEP, NEP will provide a report to the Transmission Customer based on the information provided and developed as a result of this effort. If, upon review of the Study results, the Transmission Customer decides to pursue ___________, NEP will, at the Transmission Customer's direction, tender a Facilities Study Agreement within thirty (30) days. The System Impact and Facilities Studies, together with any additional studies contemplated in Paragraph 3, shall form the basis for the Transmission Customer's proposed use of NEP's transmission system and shall be furthermore utilized in obtaining necessary third-party approvals of any interconnection facilities and requested transmission services. The Transmission Customer understands and acknowledges that any use of study results by the Transmission Customer or their agents, whether in preliminary or final form, prior to application approval pursuant to Section I.3.9 of the Tariff, is completely at the Transmission Customer's risk and that NEP

will not guarantee or warrant the completeness, validity or utility of study results prior to application approval pursuant to Section I.3.9 of the Tariff.

5. The estimated costs contained within this Agreement are NEP's good faith estimate of its costs to perform the System Impact Study contemplated by this Agreement. NEP's estimates do not include any estimates for wheeling charges that may be associated with the transmission of facility output to third parties or with rates for station service. The actual costs charged to the Transmission Customer by NEP may change as set forth in this Agreement. Prepayment will be required for all study, analysis, and review work performed by NEP or its Designated Agent, all of which will be billed by NEP to the Transmission Customer in accordance with Paragraph 6 of this Agreement.

6. The payment required is $______ from the Transmission Customer to NEP for the primary system analysis, coordination, and monitoring of the System Impact Study. NEP will, in writing, advise the Transmission Customer in advance of any cost increases for work to be performed if total amount increases by 10% or more. Any such changes to NEP's costs for the study work shall be subject to the Transmission Customer's consent, such consent not to be unreasonably withheld. The Transmission Customer shall, within thirty (30) days of NEP's notice of increase, either authorize such increases and make payment in the amount set forth in such notice, or NEP will suspend the System Impact Study and this Agreement will terminate if so permitted by the Federal Energy Regulatory Commission.

In the event this Agreement is terminated for any reason, NEP shall refund to the Transmission Customer the portion of the above credit or any subsequent payment to NEP by the Transmission Customer that NEP did not expend in performing its obligations under this Agreement. Any additional billings under this Agreement shall be subject to an interest charge computed in accordance with the provisions of the OATT. Payments for work performed shall not be subject to refunding except in accordance with Paragraph 7 below.

7. If the actual costs for the work exceed prepaid estimated costs, the Transmission Customer shall make payment to NEP for such actual costs within thirty (30) days of the date of NEP's invoice for such costs. If the actual costs for the work are less than those prepaid, NEP will credit such difference toward NEP costs unbilled, or in the event there will be no additional billed expenses, the amount of the overpayment will be returned to the Transmission Customer with interest computed as stated in Paragraph 6 of this Agreement, from the date of reconciliation.

8. Nothing in this Agreement shall be interpreted to give the Transmission Customer immediate rights to wheel over or interconnect with NEP's Transmission or Distribution System. Such rights shall be provided for under separate agreement and in accordance with the OATT.

9. Within one (1) year following NEP's issuance of a final bill under this Agreement, the Transmission Customer shall have the right to audit NEP's accounts and records at the offices where such accounts and records are maintained, during normal business hours; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service under this Agreement. NEP reserves the right to assess a reasonable fee to compensate for the use of its personnel time in assisting any inspection or audit of its books, records or accounts by the Transmission Customer or their Designated Agent.

10. Each party agrees to indemnify and hold the other party and its Affiliates, including affiliated trustees, directors, officers, employees, and agents of each of them, harmless from and against any and all damages, costs (including attorney's fees), fines, penalties and liabilities, in tort, contract, or otherwise (collectively "Liabilities") resulting from claims of third parties arising, or claimed to have arisen as a result of any acts or omissions of either party under this Agreement. Each party hereby waives recourse against the other party and its Affiliates for, and releases the other party and its Affiliates from, any and all Liabilities for or arising from damage to its property due to a performance under this Agreement by such other party.

11. If either party materially breaches any of its covenants hereunder, the other party may terminate this Agreement by filing a notice of intent to terminate with the Federal Energy Regulatory Commission and serving notice of same on the other party to this Agreement.

12. This agreement shall be construed and governed in accordance with the laws of the Commonwealth of Massachusetts and with Part II of the Federal Power Act, 16 U.S.C. §§824d et seq., and with Part 35 of Title 18 of the Code of Federal Regulations, 18 C.F.R. §§35 et seq.

13. All amendments to this Agreement shall be in written form executed by both parties.

14. The terms and conditions of this Agreement shall be binding on the successors and assigns of either party.

15. This Agreement will remain in effect for a period of up to two years from its effective date as permitted by the Federal Regulatory Commission, and is subject to extension by mutual agreement. Either party may terminate this Agreement by thirty (30) days' notice except as is otherwise provided herein. If this Agreement expires by its own terms, it shall be NEP's responsibility to make such filing.

NEP:

By:______________________ _______________ ______________
Name Title Date

Transmission Customer:

By:______________________ _______________ ______________
Name Title Date

System Impact Study Agreement

EXHIBIT 1

Information to be Provided to NEP
by the Transmission Customer for System Impact Study

1.0 Facilities Identification

1.1 Requested capability in MW and MVA; summer and winter

1.2 Site location and plot plan with clear geographical references

1.3 Preliminary one-line diagram showing major equipment and extent of Transmission Customer ownership

1.4 Auxiliary power system requirements

1.5 Back-up facilities such as standby generation or alternate supply sources

2.0 Major Equipment

2.1 Power transformer(s): rated voltage, MVA and BIL of each winding, LTC and or NLTC taps and range, Z1 (positive sequence) and Z0 (zero sequence) impedances, and winding connections. Provide normal, long-time emergency and short-time emergency thermal ratings.

2.2 Generator(s): rated MVA, speed and maximum and minimum MW output, reactive capability curves, open circuit saturation curve, power factor (V) curve, response (ramp) rates, H (inertia), D (speed damping), short circuit ratio, X1 (leakage), X2 (negative sequence), and X0 (zero sequence) reactances and other data:

	Direct Axis	Quadrature Axis
saturated synchronous reactance	Xdv	Xqv

	Direct Axis	Quadrature Axis
unsaturated synchronous reactance	Xdi	Xqi
saturated transient reactance	X'dv	X'qv
unsaturated transient reactance	X'di	X'qi
saturated subtransient reactance	X"dv	X"qv
unsaturated subtransient reactance	X"di	X"qi
transient open-circuit time constant	T'do	T'qo
transient short-circuit time constant	T'd	T'q
subtransient open-circuit time constant	T"do	T"qo
subtransient short-circuit time constant	T"d	T"q

2.3 Excitation system, power system stabilizer and governor: manufacturer's data in sufficient detail to allow modeling in transient stability simulations.

2.4 Prime mover: manufacturer's data in sufficient detail to allow modeling in transient stability simulations, if determined necessary.

2.5 Busses: rated voltage and ampacity (normal, long-time emergency and short-time emergency thermal ratings), conductor type and configuration.

2.6 Transmission lines: overhead line or underground cable rated voltage and ampacity (normal, long-time emergency and short-time emergency thermal ratings), Z1 (positive sequence) and Z0 (zero sequence) impedances, conductor type, configuration, length and termination points.

2.7 Motors greater than 150 kW 3-phase or 50 kW single-phase: type (induction or synchronous), rated hp, speed, voltage and current, efficiency and power factor at ½, 3/4 and full load, stator resistance and reactance, rotor resistance and reactance, magnetizing reactance.

2.8 Circuit breakers and switches: rated voltage, interrupting time and continuous, interrupting and momentary currents. Provide normal, long-time emergency and short-time emergency thermal ratings.

2.9 Protective relays and systems: ANSI function number, quantity manufacturer's catalog number, range, descriptive bulletin, tripping diagram and three-line diagram showing AC connections to all relaying and metering.

2.10 CT's and VT's: location, quantity, rated voltage, current and ratio.

2.11 Surge protective devices: location, quantity, rated voltage and energy capability.

3.0 Other

3.1 Additional data to perform the System Impact Study will be provided by the Transmission Customer as requested by NEP.

3.2 NEP reserves the right to require specific equipment settings or characteristics necessary to meet the applicable criteria and standards.

ATTACHMENT D

Form of Facilities Study Agreement

This agreement dated __________, is entered into by ____________ (the Transmission Customer) and New England Power Company (NEP), for the purpose of setting forth the terms, conditions and costs for conducting a Facilities Study Agreement relative to ______________________________________. The Facilities Study will determine the detailed engineering, design and cost of the facilities necessary to satisfy the Transmission Customer's request for service over NEP's Transmission System.

1. The Transmission Customer agrees to provide, in a timely and complete manner, all required information and technical data necessary for NEP to conduct the Facilities Study. Where such information and technical data was provided for the System Impact Study, it should be reviewed and updated with current information, as required.

2. All work pertaining to the Facilities Study that is the subject of this Agreement will be approved and coordinated only through designated and authorized representatives of NEP and the Transmission Customer. Each party shall inform the other in writing of its designated and authorized representative.

3. NEP will advise the Transmission Customer of additional studies as may be deemed necessary by NEP. Any such additional studies shall be conducted only if required by Good Utility Practice and shall be subject to the Transmission Customer's consent to proceed, such consent not to be unreasonably withheld.

4. NEP contemplates that it will require ___ days to complete the Facilities Study. Upon completion of the study by NEP, NEP will provide a report to the Transmission Customer based on the information provided and developed as a result of this effort. If, upon review of the study results, the Transmission Customer decides to pursue its transmission service request, the Transmission Customer must sign a supplemental Service Agreement with NEP. The System Impact and Facilities Studies, together with any additional studies contemplated in Paragraph 3, shall form the basis for the Transmission Customer's proposed use of NEP's Transmission System and shall be furthermore utilized in obtaining necessary third-party approvals of any facilities and requested transmission services. The Transmission Customer understands and acknowledges that any use of the study results by the Transmission Customer or their agents, whether in preliminary or final form, prior to application approval

pursuant to Section I.3.9 of the Tariff, is completely at the Transmission Customer's risk and that NEP will not guarantee or warrant the completeness, validity or utility of the study results prior to application approval pursuant to Section I.3.9 of the Tariff.

5. The estimated costs contained within this Agreement are NEP's good faith estimate of its costs to perform the Facilities Study contemplated by this Agreement. NEP's estimates do not include any estimates for wheeling charges that may be associated with the transmission of facility output to third parties or with rates for station service. The actual costs charged to the Transmission Customer by NEP may change as set forth in this Agreement. Prepayment will be required for all study, analysis, and review work performed by NEP's or its Designated Agent's personnel, all of which will be billed by NEP to the Transmission Customer in accordance with Paragraph 6 of this Agreement.

6. The payment required is $____ from the Transmission Customer to NEP for the primary system analysis, coordination, and monitoring of the Facilities Study to be performed by NEP for the Transmission Customer's requested service. NEP will, in writing, advise the Transmission Customer in advance of any cost increases for work to be performed if the total amount increases by 10% or more. Any such changes to NEP's costs for the study work to be performed shall be subject to the Transmission Customer's consent, such consent not to be unreasonably withheld. The Transmission Customer shall, within thirty (30) days of NEP's notice of increase, either authorize such increases and make payment in the amount set forth in such notice, or NEP will suspend the study and this Agreement will terminate if so permitted by the Federal Energy Regulatory Commission. In the event this Agreement is terminated for any reason, NEP shall refund to the Transmission Customer the portion of the above credit or any subsequent payment to NEP by the Transmission Customer that NEP did not expend in performing its obligations under this Agreement. Any additional billings under this Agreement shall be subject to an interest charge computed in accordance with the provisions of the OATT. Payments for work performed shall not be subject to refunding except in accordance with Paragraph 7 below.

7. If the actual costs for the work exceed prepaid estimated costs, the Transmission Customer shall make payment to NEP for such actual costs within thirty (30) days of the date of NEP's invoice for such costs. If the actual costs for the work are less than that prepaid, NEP will credit such difference toward NEP costs unbilled, or in the event there will be no additional billed expenses, the amount of the overpayment will be returned to the Transmission Customer with interest computed in accordance with the provisions of the OATT.

8. Nothing in this Agreement shall be interpreted to give the Transmission Customer immediate rights to interconnect to or wheel over NEP's Transmission or Distribution System. Such rights shall be provided for under separate agreement.

9. Within one (1) year following NEP's issuance of a final bill under this Agreement, the Transmission Customer shall have the right to audit NEP's accounts and records at the offices where such accounts and records are maintained during normal business hours; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service under this Agreement. NEP reserves the right to assess a reasonable fee to compensate for the use of its personnel time in assisting any inspection or audit of its books, records or accounts by the Transmission Customer or their Designated Agent.

10. Each party agrees to indemnify and hold the other party and its Affiliates, including affiliated trustees, directors, officers, employees, and agents of each of them, harmless from and against any and all damages, costs (including attorney's fees), fines, penalties and liabilities, in tort, contract, or otherwise (collectively "Liabilities") resulting from claims of third parties arising, or claimed to have arisen as a result of any acts or omissions of either party under this Agreement. Each party hereby waives recourse against the other party and its Affiliates for, and releases the other party and its Affiliates from, any and all Liabilities for or arising from damage to its property due to performance under this Agreement by such other party.

11. If any party materially breaches any of its covenants hereunder, the other party may terminate this Agreement by filing a notice of intent to terminate with the Federal Energy Regulatory Commission and serving notice of same on the other party to this Agreement.

12. This agreement shall be construed and governed in accordance with the laws of the Commonwealth of Massachusetts and with Part II of the Federal Power Act, 16 U.S.C. §§824d et seq., and with Part 35 of Title 18 of the Code of Federal Regulations, 18 C.F.R. §§35 et seq.

13. All amendments to this Agreement shall be in written form executed by both parties.

14. The terms and conditions of this Agreement shall be binding on the successors and assigns of either party.

15. This Agreement will remain in effect for a period of up to two years from its effective date as permitted by the Federal Energy Regulatory Commission, and is subject to extension by mutual agreement.

Either party may terminate this Agreement by thirty (30) days' notice except as is otherwise provided herein. If this Agreement expires by its own terms, it shall be NEP's responsibility to make such filing.

NEP:

By:______________________ _______________ ______________

Name Title Date

Transmission Customer:

By:______________________ _______________ ______________

Name Title Date

ATTACHMENT E

Local Service Agreement

Policy and Practices for Protection Requirements
For New or Modified Load Interconnections

Any load facility, hereafter called a LF, desiring to interconnect with NEP's electrical system or modify an existing interconnection must meet the technical specifications and requirements set forth in this Policy and Practices. Once interconnected, NEP, in keeping with Good Utility Practice and in its sole discretion, may disconnect the LF if the LF departs from the technical specifications and requirements of this Policy and Practices. The LF must return to full compliance with this Policy prior to reconnecting with NEP's electrical system.

If it is possible for the LF to be a significant source of current flow into NEP's lines due to generation sources within the LF system then NEP may determine the LF to be considered a Generation Facility and the Policy and Practices for Protection Requirements for Generation Interconnections shall apply as set forth in the New England ISO OATT.

This document is divided into the following sections:

1. Protection Information Required from the LF for All Interconnections
2. General Protection Requirements for All LF Interconnections
3. Protection Equipment Requirements for All LF Interconnections
4. Requirements for Protection of NEP's System
5. Requirements for Protection of NEP's System: Facilities Having Sources
6. Requirements for Emergency Load Reduction
7. Protection System Testing and Maintenance
8. Changes to the LF's Protection System

1.) PROTECTION INFORMATION REQUIRED FROM THE LF FOR ALL INTERCONNECTIONS

A. The following information must be submitted by the LF for review and acceptance by NEP prior to finalizing the LF's protection design:

- A station one-line drawing.
- A one-line drawing showing the relays and metering including current transformer (CT) and voltage transformer (VT) connections and ratios.
- A three-line drawing showing the AC connections to the relays and meters.
- The LF’s transformer nameplate information including rated voltage, rated KVA, positive and zero sequence impedances and winding connections.
- A list of protective relay equipment proposed to be furnished to conform with this Policy and Practices including: relay types, styles, manufacturer's catalog numbers, ranges and descriptive bulletins.
- Schematic drawings showing the control circuits for the interconnection breaker(s) or equivalent interrupting device(s).
- Equipment specifications for CTs and VTs relevant to the interconnection.
- Interconnection breaker or equivalent interrupting device operating time.
- Other information that may be determined by NEP as required for a specific interconnection.

B. Relay settings for all LF protective relays that affect the interconnection with NEP’s system must be submitted by the LF for review and acceptance by NEP at least four weeks prior to the scheduled date for setting the relays.

C. If, due to the interconnection of the LF to the line, the fault interrupting, continuous, momentary or other rating of any of NEP's equipment or the equipment of others connected to NEP's system is exceeded, NEP shall have the right to require the LF to pay for the purchase, installation, replacement or modification of equipment to eliminate the condition. Where such action is deemed necessary by NEP, NEP will, where possible, permit the LF to choose among two or more options for meeting NEP’s requirements as described in this Policy and Practices.

2.) GENERAL PROTECTION REQUIREMENTS FOR ALL LF INTERCONNECTIONS

A. A circuit breaker, or other fault interrupting method acceptable to NEP, shall be installed to isolate the LF from NEP's system. This will hereafter be called the "interconnection breaker". If there is more than one interconnection breaker, the requirements of this Policy and Practices apply to each one individually.

B. NEP will review the relay settings as submitted by the LF to assure adequate protection for NEP's facilities. NEP shall not be responsible for the protection of the LF's facilities. Providing the relaying is installed and maintained as reviewed, the LF shall not be responsible for the protection of NEP's facilities. The LF shall be responsible for protection of its system against possible damage resulting from interconnection with NEP.

If requested by the LF, NEP will provide system protection information for the line terminal(s) directly related to the interconnection. This protection information is provided exclusively for use by the LF in evaluating protection of the LF's facilities during parallel operation.

C. NEP shall specify whether the transformer, if any, between NEP's voltage and the LF's distribution voltage, hereafter called the "LF's transformer", is to be grounded or ungrounded at NEP's voltage.

3.) PROTECTION EQUIPMENT REQUIREMENTS FOR ALL LF INTERCONNECTIONS

A. The interconnection breaker control circuits shall be DC powered from a station battery.

B. The LF shall provide a switch at the Interconnection Point with NEP that can be opened for isolation. NEP shall have the right to open the interconnection during emergency conditions or with due notice to the LF at other times. NEP shall exercise such right in accordance with Good Utility Practice. The switch shall be gang operated, have a visible break when open, and be capable of being locked open, tagged and grounded on NEP side by NEP personnel. The switch shall be of a manufacture and type generally accepted for use by NEP.

C. Protective relaying control circuits shall be DC powered from a station battery. Solid state relays shall be self powered or DC powered from a station battery.

D. CT ratios and accuracy classes shall be chosen such that secondary current is less than 100 amperes and transformation errors are less than 10% under maximum fault conditions.

E. All protective relays required by this Policy and Practices shall meet ANSI/IEEE standard C37.90 and be of a manufacture and type generally accepted for use by NEP.

F. Protective relays provided by the LF as required per this Policy and Practices shall be sufficiently redundant and functionally separate so as to provide adequate protection, as determined by NEP, upon the failure of any one component. The use of a single all-inclusive relay package is not acceptable.

G. NEP may require the LF to provide two independent, redundant relaying systems in accordance with NPCC Criteria for the Protection of the Bulk Power System if the interconnection is to the Bulk Power System or if it is determined that delayed clearing of faults within the LF adversely affects the Bulk Power System.

H. A direct transfer tripping system, if provided, shall use equipment generally accepted for use by NEP and shall, at the option of NEP, use dual channels.

4.) REQUIREMENTS FOR PROTECTION OF THE TRANSMISSION SYSTEM

A. The LF must provide protective relays to detect any faults, whether phase-to-phase or phase-to-ground within the LF, and isolate the LF from NEP's line(s) such that the following criteria are met, as determined by NEP:

- The existing sensitivity of fault detection is not substantially degraded.
- The existing speed of fault clearing is not substantially degraded.
- The coordination margin between relays is not substantially reduced.
- The sustained unfaulted phase voltage during a line-to-ground fault is not increased beyond 1.25 times the normal phase-to-ground voltage. (This value may be further reduced if required to coordinate with existing system insulation levels and overvoltage protection.)
- Non-directional line relays will not operate for faults external to the line due to the LF's contribution.
- Proper settings for existing relays are achievable within their ranges.

NEP may perform engineering studies to evaluate the LF's protection compliance with respect to the above and may make recommendations to the LF on methods to achieve compliance.

If, due to the interconnection of the LF to NEP's system, any of the above criteria are violated for NEP's facilities or for the facilities of others connected to NEP's system, NEP shall have the right to require the

LF to pay for the purchase, installation, replacement or modification of protective equipment to eliminate the violation and restore the level of protection existing prior to the interconnection. This may include the addition of pilot relaying systems involving communications between all terminals. Where such action is deemed necessary by NEP, NEP will, where possible, permit the LF to choose among two or more options for meeting NEP's requirements as described in this Policy and Practices.

B. The LF is responsible for procuring any communications channels necessary between the LF and NEP's stations and for providing protection from transients and overvoltages at all ends of these communication channels.

C. The LF may be required to use high speed protection if time-delayed protection would result in degradation in the existing sensitivity or speed of the protection systems on NEP's lines.

D. The LF may be required to provide local breaker failure protection which may include direct transfer tripping to NEP's line terminal(s) in order to detect and clear faults within the LF that cannot be detected by NEP's back-up protection.

5.) REQUIREMENTS FOR PROTECTION OF THE TRANSMISSION SYSTEM: FACILITIES HAVING SOURCES

If it is possible for the LF to be a source of current flow into NEP's system, either due to generation within the LF system or due to connections within the LF system to other sources, the LF must provide protective relays to detect any faults, whether phase-to-phase or phase-to-ground on NEP's lines or within the LF, and isolate the LF from NEP's line(s) per the requirement of Section 4 above and the following:

A. A control interlock scheme that detects voltage on NEP's line(s) shall be used to prevent an interconnection breaker from closing to energize NEP's line(s).

B. A voltage transformer shall be provided by the LF, connected to NEP side of the interconnecting breaker. The voltage from this VT shall be used in the interlock as specified in Section 5A above. If the LF's connection is ungrounded at NEP voltage, this VT shall be a single three-phase device or three single-phase devices connected from each phase to ground, rated for phase-to-phase voltage and provided with two secondary windings. One winding shall be connected in open delta, have a loading resistor to prevent ferroresonance, and be used for the relay specified in Section 5C below.

C. If the LF's connection to NEP’s system is un-grounded, the LF shall provide a zero sequence overvoltage relay fed from the open delta of the three phase VT specified in Section 5B above.

D. NEP's lines generally have automatic reclosing following a trip with reclosing times as short as five seconds and without regard to whether the LF is keeping the circuit energized. The LF is responsible for protecting its equipment from being reconnected out of synchronism with NEP's system by an automatic line reclosure operation. The LF may choose to install additional equipment such as direct transfer tripping from NEP's station(s) to insure the LF is off the line prior to the line reclosing.

6.) REQUIREMENTS FOR EMERGENCY LOAD REDUCTION

A. The LF shall provide a manual load shed lockout relay to trip and block closing of selected load feeders. This relay shall be operated via a signal sent from an area dispatching center to a remote terminal unit (RTU) provided by the LF and shall be manually reset. The selection of feeders to trip shall be in conformance with NPCC Emergency Operation Criteria and determined by the area control authority. Alternatively, the LF may elect to provide compensatory load reduction through contractual arrangements with other area customers or by other means.

B. During system conditions where local area load exceeds generation, NPCC Emergency Operation Criteria requires a program of phased automatic underfrequency load shedding of up to 25% of area load to assist in arresting frequency decay and to minimize the possibility of system collapse. In conformance to these criteria, the LF shall provide an underfrequency relay with a lockout function to trip and block closing of selected load feeders. Feeders so shed shall not be re-energized without the express permission of the area control authority. If desired, the LF may use the RTU specified in Section 6A above to receive a signal sent from an area dispatching center that would reset the lockout function and permit automatic restoration of the feeders. The underfrequency settings and the selection of feeders shall be in conformance with these Criteria and determined by the area control authority. Alternatively, the LF may elect to provide compensatory load reduction to conform with the requirements of this Section through contractual arrangements with other area customers or by other means.

C. The LF shall provide a voltage reduction function to reduce the feeder voltage regulation set point by 5% for all load feeders. This function shall be operated via a signal sent from an area dispatching center to an RTU provided by the LF and shall be remotely reset from the dispatching center or self reset in 4 hours.

D. Depending on the point of connection of the LF to NEP's system, NEP may require a dead station tripping function to disconnect the LF from NEP's lines following six minutes of de-energized NEP lines in order to assist in restoration of service following an area or system wide shutdown.

7.) PROTECTION SYSTEM TESTING AND MAINTENANCE

A. NEP shall have the right to witness the testing of protective relays and control circuits required by this Policy and Practices at the completion of construction and to receive a copy of all test data. The LF shall provide NEP with at least a one week notice prior to the final scheduling of these tests. Testing shall consist of:

- CT and CT circuit polarity, ratio, insulation, excitation, continuity and burden tests.
- VT and VT circuit polarity, ratio, insulation and continuity tests.
- Relay pick-up and time delay tests.
- Functional breaker trip tests from protective relays.
- Relay in-service test to check for proper phase rotation and magnitudes of applied currents and voltages.
- Breaker closing interlock tests.
- Other relay commissioning tests typically performed for the relay types involved.

B. The protective relays shall be tested and maintained by the LF on a periodic basis but not less than once every four years or as determined by NEP. The results of these tests shall be summarized by the LF and reported in writing to NEP.

For relays installed in accordance with the NPCC Criteria for the Protection of the Bulk Power System, maintenance intervals shall be in accordance with the NPCC Maintenance Criteria for Bulk Power System Protection. The status of conformance with the NPCC Maintenance Criteria for Bulk Power System Protection shall be reported in writing to NEP annually.

8.) CHANGES TO THE LF'S PROTECTION SYSTEM

The LF must provide NEP with reasonable advance notice of any proposed changes to be made to the protective relay system, relay settings, operating procedures or equipment that affect the interconnection. NEP will determine if such proposed changes require re-acceptance of the interconnection per the requirements of this Policy and Practices.

In the future, should NEP implement changes to the system to which the LF is interconnected, the LF will be responsible at its own expense for identifying and incorporating any necessary changes to its protection system. Those changes to the LF's protection system are subject to review and approval by NEP.

ATTACHMENT F

Local Service Agreement

Insurance Requirements

During the term of this Agreement, the interconnecting Transmission Customer, at its own cost and expense, shall procure and maintain insurance in the forms and amounts acceptable to NEP at the following minimum levels of coverage:

1) Statutory coverage for workers' compensation, and Employer's Liability Coverage with a limit no less than $500,000.00 per accident;

2) Comprehensive General Liability Coverage including Operations, Contractual Liability and Broad Form Property Damage Liability written with limits no less than $5,000,000.00 combined single limit for Bodily Injury Liability and Property Damage Liability; and

3) Automobile Liability for Bodily Injury and Property Damage to cover all vehicles used in connection with the work with limits no less than $1,000,000.00 combined single limit for Bodily Injury and Property Damage Injury.

Prior to commencing the work, the interconnecting Transmission Customer shall have its insurer furnish to NEP certificates of insurance evidencing the insurance coverage required above and the interconnecting Transmission Customer shall notify and send copies to NEP of any policies maintained hereunder written on a "claims-made" basis. NEP may at its discretion require the interconnecting Transmission Customer to maintain tail coverage for five years on all policies written on a "claims-made" basis.

Every contract of insurance providing the coverages required in this provision shall contain the following or equivalent clause: "No reduction, cancellation or expiration of the policy shall be effective until thirty (30) days from the date written notice thereof is actually received by the interconnecting Transmission Customer. Upon receipt of any notice of reduction, cancellation or expiration, the interconnecting Transmission Customer shall immediately notify NEP.

NEP and its Affiliates shall be named as additional insureds, as their interests may appear, on the Comprehensive General Liability and Automobile Liability policies described above.

The interconnecting Transmission Customer shall waive all rights of recovery against NEP for any loss or damage covered by said policies. Evidence of this requirement shall be noted on all certificates of insurance provided to NEP.

ATTACHMENT H

Methodology for Completing System Impact Study

When New England Power Company ("NEP") determines on a non-discriminatory basis that a System Impact Study is needed because its Transmission System will be inadequate to accommodate a request for service, the following outlines the study methodology that NEP will employ to estimate the transmission system impact of a request for firm Transmission Service and/or any Costs for System Redispatch, Direct Assignment Facilities or Network Upgrades that would be incurred in order to provide the requested transmission service.

1. **System Impact** will be estimated based on consideration of reliability requirements to

- meet obligations under agreements that predate the OATT;
- meet obligations of existing and pending Valid Requests under the OATT; and
- maintain thermal, voltage and stability system performance within acceptable regional practices

2. **Guidelines and Principles followed by NEP -** NEP is a Participating Transmission Owner under the TOA and the Tariff and a member of the NPCC. When performing the System Impact Study, NEP will apply the following, as amended and/or adopted from time to time.

- Good Utility Practice;
- Criteria rules and reliability standards applicable to the New England Transmission System;
- NPCC criteria and guidelines; and
- New England Power Service Company (or its successor) guides

3. **Transmission System Model Representation -** The Transmission System Model will be based on a library of loadflow cases prepared by the ISO for studies of the New England area. The models may include representations of other NPCC and neighboring systems. These loadflow cases include individual system model representations provided by members of the ISO and represent forecasted system conditions for up to ten years in to the future. This library of loadflow cases is maintained and updated as appropriate by the ISO, and is consistent with information filed under FERC Form 715. NEP will use system models that it deems appropriate for study of the Request for Service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of loadflow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

4. System Conditions - Loading of all transmission system elements shall be less than normal ratings for precontingency conditions and less than long-term emergency (LTE) ratings for post-contingency conditions. Post-contingency loading above LTE rating and less than short-term emergency (STE) rating may be allowed where demonstrated that loading can be reduced below the LTE rating within 15 minutes.

Transmission system voltages shall be within the applicable design ratings of connected equipment for normal and emergency conditions. Normal and post-contingency voltages shall be in accordance with NEP and ISO standards.

5. Short Circuits - Transmission system short circuit currents shall be within the applicable equipment design ratings.

6. Study Analysis - System impact of the integration of new generators will be evaluated to meet the requirements of design, identified in the guidelines and principles under Item 2, to provide sufficient transmission capability to maintain stability and to maintain thermal and voltage levels of lines and equipment within applicable limits. The same applies to the evaluation of transmission and delivery service under this tariff.

7. Loss Evaluation - The impact of losses on the Transmission System will be taken into account in the System Impact Study to ensure Good Utility Practice in the design and operation of its system.

8. System Protection - Protection requirements will be evaluated by NEP.

9. Approvals - NEP will conduct the System Impact Study to ensure compliance with its planning and design policies and practices. However, the actions to be taken by the Parties to implement the recommendations of the System Impact Study are subject to approval under the ISO New England Operating Procedures or Section I.3.9 of the Tariff, as amended and/or adopted from time to time.

10. Study Scope and Reporting - The study will determine the impacts and identify changes required, if any, to NEP's existing Transmission System. NEP will provide the Eligible Customer with a written report of the physical interconnection alternative(s), required NEP system additions and/or modifications, if any, associated study grade cost estimates (+/-25%) and the results of the analysis.

ATTACHMENT I

Real Power Losses Factors

Voltage Class kV	Losses as a % of Energy Delivered
Stepdown transformer*	1.00
69	1.25**
34.5	1.98
23	2.61
15	4.18
5	4.34
Dist. Secondary	0.52

*The transformer that steps the voltage from the transmission level to the delivery level.

**The loss factor for the 69 kV level applies only when the Point of Delivery is not directly interconnected with the PTF.

Note: When multiple voltage levels are present between the Point of Delivery and the metering point, the loss factors are additive.

ATTACHMENT DAF

Direct Assignment Facilities

This Attachment applies to all transactions that utilize any Direct Assignment Facilities or any other charges specifically assigned to a customer by NEP under this Schedule or the OATT. The formula set forth in this Attachment, as it may be amended from time to time, represents the Direct Assignment Facilities Charge which a Transmission Customer or Network Customer (together, "Transmission Customer") will pay in addition to the other applicable charges specified herein.

The determination of the annual Direct Assignment Facilities Charges chargeable to a specific Transmission Customer or group of Transmission Customers shall be calculated by the Annual Facility Charge formulas set forth below for transmission and distribution facilities. In no event will the Annual Facilities Charge be less than $1,000 per calendar year.

TRANSMISSION

Determination of Annual Facilities Charges for Transmission Facilities

The basis for this charge is data of NEP. The Annual Facilities Charge for NEP and its New England Affiliates shall equal the product of the year-end Gross Plant Investment associated with the facility and the average Annual Transmission Carrying Charge, for the life of the facility.

The Gross Plant Investment will be the investment from the plant accounting records associated with the facility.

The average Annual Transmission Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of total transmission plant investment determined in accordance with Attachment RR, Section I. (A) (1) (a) to this Schedule.

To the extent that the Transmission Customer provides a Contribution in Aid of Construction the average Annual Transmission Carrying Charge calculation will be modified to exclude Sections I. (A) (1) (a), I. (A) (1) (d), I. (A) (1) (e), I. (A) (1) (f), I. (B), and I. (C) of Attachment RR to this Schedule.

If the Transmission Customer permanently terminates service prior to the normal expiration of its Service Agreement, the Transmission Customer may, at its option, close out its continuing obligation to pay the Annual Facilities Charge by paying NEP a lump sum payment equal to the net present value of the Return and Depreciation Expense on the net book value of the facility at the time of termination that would have been collected over the remaining life of the facility, plus any cost of removal if applicable. The return shall be equal to that found in Attachment RR, Section I. (A)(2) to this Schedule, in the year of termination. Depreciation Expense shall be based on a straight-line method. The discount rate in the net present value calculation shall be equal to the interest rate pursuant to Section 35.19(a) of the Commission's regulations effective at the time of termination.

Billings shall initially be based upon estimates calculated based on actual costs in the preceding year, such estimates being adjusted to actual as soon as practicable after such costs become known. The source of the data shall be NEP's accounting records.

DISTRIBUTION

Determination of the Annual Facilities Charge for Distribution Facilities

The basis for this charge is data of NEP's New England Affiliate(s) or any other Affiliate that shall assume ownership over the Facilities included under this attachment.

The Annual Facilities Charge shall equal the product of the year-end Gross Plant Investment associated with the facility and the average Annual Distribution Carrying Charge, for the life of the facility.

The Gross Plant Investment will be the investment from the plant accounting records associated with the facility.

The average Annual Distribution Carrying Charge shall be the Annual Distribution Revenue Requirement as determined in Attachment RR, Exhibit 1 to this Schedule, divided by the year-end balance of total distribution plant investment determined in accordance with Attachment RR, Exhibit 1, Section I. (A) (1) (a) to this Schedule.

To the extent that the Transmission Customer provides a Contribution in Aid of Construction the average Annual Distribution Carrying Charge calculation will be modified to exclude Sections I. (A) (1) (a), I. (A) (1) (d), I. (A) (1) (e), I. (A) (1) (f), I. (B), and I. (C) of Attachment RR, Exhibit 1 to this Schedule.

If the Transmission Customer permanently terminates service in advance of the term of its Service Agreement, the Transmission Customer may, at its option, close out its continuing obligation to pay the Annual Facilities Charge by paying NEP a lump sum payment equal to the net present value of the Return and Depreciation Expense on the net book value of the facility at the time of termination that would have been collected over the remaining life of the facility, plus any cost of removal if applicable. The return shall be equal to that found in Attachment RR, Exhibit 1, Section I.(A)(2) to this Schedule, in the year of termination. Depreciation Expense shall be based on a straight-line method. The discount rate in the net present value calculation shall be equal to the interest rate pursuant to Section 35.19(a) of the Commission's regulations effective at the time of termination.

Billings in accordance with this Schedule shall initially be based upon estimates calculated based on actual costs in the preceding year, such estimates being adjusted to actual as soon as practicable after such costs become known. The source of the data shall be NEP's or its applicable New England Affiliate's accounting records.

METERS

Determination of Annual Metering Charges

The Meter Maintenance Charge shall equal the product of NEP's installed metering costs for the customer and the Meter Carrying Charge determined in Attachment OCC, Exhibit 3 to this Schedule.

In accordance with the Meter Carrying Charge referenced above, the Annual Metering Charges will be updated on May 31 each year to reflect costs from the prior calendar year.

If the customer makes a CIAC, then the carrying charge in Attachment OCC, Exhibit 3 to this Schedule, will be adjusted accordingly.

ATTACHMENT DS

Rolled-In Distribution Surcharge

The monthly Rolled-in Distribution Surcharge shall be (i) the monthly cost per kilowatt of $2.77, multiplied by (ii) the annual peak load of the Transmission Customer on the distribution system of NEP’s applicable New England Affiliate(s) from the prior calendar year. Notwithstanding the foregoing, this provision will not apply to the Transmission Customer’s Network Load taking service under the Specific Distribution Surcharge.

ATTACHMENT OCC

Other Charges & Credits

The following charges and credits may apply to a Transmission Customer or Network Customer, as applicable:

I. Monthly Demand Charge:

Pursuant to Section 24.1 of this Schedule, the Network Customer will pay a monthly charge determined by multiplying its Load Ratio Share by the NEP's Monthly Local Network Transmission Expense as calculated in accordance with Exhibit 2 of this Attachment.

II. Monthly Non-PTF Demand Charge:

Pursuant to Section 24.2 of this Schedule, the Network Customer will pay a monthly charge determined by multiplying its Non-PTF Load Ratio Share by the Monthly Non-PTF Transmission Expense calculated in accordance with Attachment RR to this Schedule.

III. Transformer Surcharge:

Pursuant to Section 24.3 of this Schedule, the Transmission Customer or Network Customer will pay a monthly surcharge computed in accordance with Exhibit 1 of this Attachment.

This charge shall be multiplied by the Network Customer's Annual Peak Load, from the prior calendar year (coinciding with the calendar year used to calculate the Transformer Surcharge) in Exhibit 1 of this Attachment.

IV. Meter Surcharge:

The monthly meter surcharge shall be computed in accordance with Exhibit 3 of this Attachment multiplied by the number of NEP meters necessary to measure the delivery of transmission service to the Transmission Customer or Network Customer.

V. Power Factor Penalty:

Pursuant to Section 20.1 of this Schedule, a Network Customer or Transmission Customer will pay a Monthly Power Factor Penalty of $0.62 multiplied by the customer's deficient kilovars.

VI. Specific Distribution Surcharge:

The monthly Specific Distribution Surcharge shall be available to the following Network Customers
Georgetown Municipal Light Dept.
Ipswich Municipal Light Dept.
Princeton Electric Light Dept.
Hull Municipal Lighting Plant
Granite State Electric
Green Mountain Power Corp.
Groveland Municipal Light Dept.
Merrimac Municipal Light Dept.
Rowley Municipal Light Dept.

The monthly Specific Distribution Surcharge shall equal $.70 per KW month multiplied by the customer's Annual Peak Load from the prior calendar year.

VII. Network Load Dispatch Surcharge:

The monthly Network Load Dispatch Surcharge shall equal the monthly Dispatching Expense, Account 561, as defined in Attachment RR, Section I.G. to this Schedule, less any revenue received by NEP from the ISO for load dispatching services, multiplied by the Network Customer's Load Ratio Share.

VIII. [Reserved]

IX. Network EPRI Credit:

The Network EPRI Credit shall be determined by multiplying the Monthly Transmission-Related EPRI Expenses by the customer's Non-PTF Network Load Ratio Share.

The Monthly Transmission-Related EPRI Expenses shall equal themonthly EPRI Expenses as recorded in Account 930.

X. [Reserved]

XI. Pre-1997 RNS Revenue Credit:

The Pre-1997 RNS Revenue Credit will apply in the subsequent month's billing for the period June 1, 2001 through March 1, 2008, unless the transitional arrangements for the period prior to March 1, 2008 are otherwise amended.

ATTACHMENT OCC

EXHIBIT 1

Transformer Surcharge

I. No later than May 31 of each calendar year, the Transformer Surcharge will be calculated based on the prior calendar year's annual costs. The annual costs for Transformation Facilities service shall be the year-end balance of transmission plant investment in transformers included in Attachment RR, Section I. (A)(1)(a) to this Schedule multiplied by the Average Annual Carrying Charge.

II. The Average Annual Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of total transmission plant investment included in Attachment RR, Section I. (A)(1)(a) to this Schedule.

III. To determine the monthly Transformer Surcharge rate, the annual costs for transformation service will be divided by the Annual Peak Loads of that portion of all Transmission Customers' or Network Customers' load receiving such transformation service under this Schedule, and further divided by 12.

ATTACHMENT OCC
EXHIBIT 2

Monthly Local Network Transmission Expense

I. The Monthly Local Network Transmission Expense shall be the monthly balance of PTF Transmission Plant investment included in Attachment RR, Section I. (A)(1)(a) to this Schedule multiplied by the Monthly Carrying Charge, less any revenue received from the ISO associated with transmission-related services provided under the OATT.

II. The Monthly Carrying Charge shall be the Monthly Transmission Revenue Requirement as determined in accordance with Attachment RR to this Schedule, excluding any revenue credits associated with Transmission-related revenues from the ISO and revenues under Section 24.1 of this Schedule and as specified in Attachment RR, Section I.(G) and (J) to this Schedule, divided by the monthly balance of Transmission Plant determined in accordance with Attachment RR, Section I.(A)(1)(a) to this Schedule.

ATTACHMENT OCC
EXHIBIT 3

Meter Surcharge

I. No later than May 31 of each calendar year, the Meter Surcharge will be calculated based on the prior calendar year's annual costs. The annual costs for metering service shall be the year-end balance of plant investment in meters included in Attachment RR, Section I. (A) (1) (a) to this Schedule multiplied by the Average Annual Carrying Charge.

II. The Average Annual Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of transmission plant investment included in Attachment RR, Section I.(A) (1) (a) to this Schedule.

III. To determine the monthly Meter Surcharge rate, the annual costs for meter service will be divided by the number of NEP-Owned Billing Meters and further divided by twelve. The number of NEP-Owned billing meters shall equal the total number of meters owned by NEP and used for billing purposes under NEP's tariffs for wholesale all requirements and firm and non-firm transmission services.

ATTACHMENT OCC

EXHIBIT 4

Pre-1997 RNS Revenue Credit

The respective Pre-1997 RNS Revenue Credit to Taunton Municipal Lighting Plant, Middleborough Gas and Electric Department and Pascoag Fire District will be equal to

$$\left[1- \frac{\text{EUA RNS Rate}}{\text{Combined RNS Rate}}\right] * [\text{customer's payment for RNS}]$$

Where:

EUA RNS Rate is former Montaup's 1999 Pre-1997 RNS rate as calculated under the NEPOOL Tariff.

Combined RNS Rate is equal to:

(A*B) + (C*D) / (B+D)

Where:

A = EUA's 1999 Pre-1997 RNS Rate as calculated under the NEPOOL Tariff.

B = EUA's 1999 12 CP Network Load (MW) as calculated under the NEPOOL Tariff.

C = NEP's 1999 Pre-1997 RNS Rate as calculated under the NEPOOL Tariff.

D = NEP's 1999 12 CP Network Load (MW) as calculated under the NEPOOL Tariff.

ATTACHMENT RR

Transmission Revenue Requirements

The Transmission Revenue Requirement will be determined based on the calculation shown below. In determining the rate for Local Network Service, the Revenue Requirement calculation as set forth below will be determined on a monthly basis.

I. The Transmission Revenue Requirement shall equal the sum of NEP's (A) Return and Associated Income Taxes, (B) Transmission Depreciation Expense, (C) Transmission-Related Amortization of Loss on Reacquired Debt, (D) Transmission-Related Amortization of Investment Tax Credits, (E) Transmission-Related Amortization of FAS 109, (F) Transmission-Related Municipal Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission-Related Administrative and General Expense, (I) Transmission-Related Integrated Facilities Credit, (J) Transmission Revenue Credit, (K) Distribution-Related Integrated Facilities Credit, and plus (L) Billing Adjustments; plus (M) Reactive Power Expense; plus (N) Bad Debt Expense.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be (a) Transmission Plant, plus (b) Transmission-Related General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) Transmission-Related Construction Work in Progress, less (e) Transmission-Related Depreciation Reserve, less (f) Transmission-Related Accumulated Deferred Taxes, plus (g) Transmission-Related Loss on Reacquired Debt, plus (h) Other Regulatory Assets, less (i) Allowance for Funds Used During Construction (AFUDC) Regulatory Liability, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission-Related Cash Working Capital.

(a) Transmission Plant will equal the balance of NEP's Total Investment in Transmission Plant, plus NEP's Total Investment in Distribution Plant excluding NEP's capital leases in the Hydro-Quebec DC facilities (HQ leases). NEP's investment in PTF transmission plant and step-down transformers beyond NEP's Point of Delivery, including associated equipment, shall be included but stated separately. NEP's investment in wholesale metering, including associated equipment, shall also be included but stated separately.

(b) Transmission-Related General Plant shall equal NEP's balance of investment in General Plant excluding General Plant related to NEP's generation facilities as specifically identified in NEP's CTC.

(c) Transmission Plant Held for Future Use shall equal the balance of investment in FERC Account 105.

(d) Transmission-Related Construction Work In Progress shall equal the portion of NEP's investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.

(e) Transmission-Related Depreciation Reserve shall equal the balance of Total Depreciation Reserve, excluding any generation-related depreciation reserve associated with assets identified in NEP's CTC.

(f) Transmission-Related Accumulated Deferred Taxes shall equal NEP's balance of Total Accumulated Deferred Income Taxes, excluding any Accumulated Deferred Taxes associated with non-utility assets or generation facilities as identified in the CTC.

(g) Transmission-Related Loss on Reacquired Debt shall equal NEP's balance of Total Loss on Reacquired Debt excluding losses associated with NEP Generation as specifically identified in the CTC, or any generation-related losses associated with pollution control bonds.

(h) Other Regulatory Assets shall equal NEP's balance of FAS 109 excluding FAS 109 balances associated with NEP Generation as specifically identified in the CTC.

(i) AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on NEP's Transmission-related projects as recorded in FERC Account 254 consistent with Commission orders.

(j) Transmission Prepayments shall equal NEP's balance of prepayments excluding any prepayments related to NEP's ongoing generation-related activities.

(k) **Transmission Materials and Supplies** shall equal NEP's balance of Transmission-related Materials and Supplies.

(l) **Transmission-Related Cash Working Capital** shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense and Transmission-Related Administrative and General Expense.

2. **Cost of Capital Rate**

The Cost of Capital Rate will equal (a) NEP's Weighted Cost of Capital, plus (b) the Yankee Adjustments plus (c) Federal Income Tax plus (d) State Income Tax.

(a) **The Weighted Cost of Capital** will be calculated based upon the capital structure at the end of each month and will equal the sum of:

(i) **the long-term debt component**, which equals the product of the actual weighted average embedded cost to maturity of NEP's long-term debt excluding any debt associated with pollution control bonds then outstanding and the ratio that long-term debt is to NEP's total capital less the end-of-year investment in Yankee Units.

(ii) **the preferred stock component**, which equals the product of the actual weighted average embedded cost to maturity of NEP's preferred stock then outstanding and the ratio that preferred stock is to NEP's total capital less the end-of-year investment in Yankee Units.

(iii) **the return on equity component (ROE),** which equals the product of the allowed based ROE of 11.14~~10.57~~% and the ratio that common equity is to NEP's total capital less the end-of-year investment in Yankee Units.

For purposes of implementing the exclusion of the FERC-approved adders from Section J. below, the following ROEs will be applied to the corresponding investment:

post-2003 to pre-2009 PTF transmission plant investment in Regional System Plan approved by ISO-NE	12.64~~11.74%~~%

remaining PTF transmission plant investment	11.64~~11.07~~%
remaining transmission plant investment	11.14~~10.57~~%

plus any ROE incentive approved by the FERC under Order No. 679 for other plant investments.[11]

(b) **The Yankee Adjustment** shall be calculated in accordance with FERC Opinion Nos. 49 and 49(a) issued in NEP's R-10 rate case and FERC Opinion No. 158 issued in NEP's W-3 rate case.

(c) **Federal Income Tax** shall equal

$$\frac{A \text{ x } FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Section (I)(A)(2)(a)(ii), and Section (I)(A)(2)(a)(iii) above.

(d) **State Income Tax** shall equal

$$\frac{(A + \text{Federal Income Tax}) \text{ x } ST}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and Federal Income Tax is the rate determined in Section (I)(A)(2)(c) above.

B. **Transmission Depreciation Expense** shall equal the Depreciation Expense associated with the Transmission Plant, Transmission-Related General Plant and Transmission Plant Held for Future Use as described in Sections I.A.(a)(1), (b) and (c), less the amortization of AFUDC regulatory credit as recorded in FERC Account 407.4.

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[11] FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679

C. **Transmission-Related Amortization of Loss on Reacquired Debt** shall equal NEP's Amortization of the balance on Loss on Reacquired Debt as defined in Section I.A.(1)(f).

D. **Transmission-Related Amortization of Investment Tax Credits** shall equal NEP's Amortization of Investment Tax Credits, excluding any ITC credits specifically identified as generation-related in NEP's CTC.

E. **Transmission-Related Amortization of FAS 109** shall equal the Amortization of NEP's Balance of FAS 109, as identified in Section I.A.(1)(q) over a ten-year period beginning on the Divestiture Date of NEP's Generating Assets as defined in the CTC.

F. **Transmission-Related Municipal Tax Expense** shall equal NEP's total municipal tax expense excluding specifically identified generation-related municipal taxes or payments in lieu of such generation-related municipal taxes.

G. **Transmission Operation and Maintenance Expense** shall equal all expenses charged to FERC Account Numbers 560 through 598. Account Number 565, Transmission by Others, shall only include those expenses in support of facilities that are integrated with NEP's Transmission System or other transmission systems. Transmission Operation and Maintenance Expense shall include any expenses associated with transmission-related administrative services provided by the ISO and the expenses associated with providing Transmission Customers with the Pre-1997 Revenue Credit as described in Attachment OCC to this Schedule.

H. **Transmission-Related Administrative and General Expenses** shall equal NEP's Administrative and General Expenses, less Production-related Administrative and General Expense associated with joint-owned production units, plus Payroll Taxes,

I. **Transmission-Related Integrated Facilities Credit** shall equal NEP's transmission payments to its New England Affiliates for use of the integrated transmission facilities of those New England Affiliates.

J. **Transmission Revenue Credit** shall equal NEP's total transmission revenue, FERC Account Number 456, transmission-related sub-accounts of 447, and those revenues received from the ISO associated with the provision of transmission services under the OATT excluding the revenue received under the terms set forth in Section 24.2 of this Schedule, excluding any revenue received for the Hydro-Quebec DC facilities, excluding any revenue directly credited to Network Customers under Section 24.11 of this Schedule, excluding distribution revenues associated with expenses that have been excluded from NEP's Transmission Revenue Requirement, and excluding any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment~~ in accordance with Section II.A.2.(a)(iii) of Attachment F under the OATT~~. To the extent that NEP's transmission-related revenue under FERC Electric Tariff No. 1 is not reflected in the above-reference accounts on or after July 9, 1996, such revenue will be imputed under the formula set forth in the OATT and included in the Transmission Revenue Credit in accordance with the above specifications. Any Transmission Revenue Credit related to Section 24.1 of this Schedule shall be stated separately. Any revenue from the ISO associated with the provision of transmission service under the OATT, shall also be included but stated separately.

K. Distribution-Related Integrated Facilities Credit shall be equal to the credit applied to the purchased power bill of Massachusetts Electric Company under NEP's Tariff No. 1 for use of its distribution facilities used in support of wholesale transactions.

L. Billing Adjustments shall be plus or minus any billing adjustments from the prior transmission billing periods, including ISO adjustments. Billing adjustments shall include, but not be limited to, adjustments due to metering errors, corrections to any value included in this Attachment RR, or the Load Ratio Share. Such adjustments may be corrected prospectively. However, if the error is substantial, or substantially affects an individual Network or Transmission Customer, NEP reserves the right to credit and rebill customers for each affected billing month in which the error occurred.

M. Reactive Power Expense shall be set at zero as of the Second Effective Date, as defined in the NEPOOL Agreement.

N. Bad Debt Expense shall be the bad debt expense as reported in Account 904 related to transmission billing.

O. Miscellaneous Provisions In the event that the FERC accounts listed above are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts.

EXHIBIT 1

Distribution Cost of Service

Pursuant to Attachment DAF to this Schedule, the Distribution Cost of Service shall be calculated as follows for the applicable New England Affiliate:

I. The Primary Distribution System Cost of Service shall equal the sum of (A) Return and Associated Income Taxes, (B) Primary Depreciation Expense, (C) Primary Related Amortization of Loss on Reacquired Debt, (D) Primary Related Amortization of Investment Tax Credits, (E) Primary Related Municipal Tax Expense, (F) Primary Operation and Maintenance Expense, (G) Primary Related Administrative and General Expense, and (H) Primary Revenue Credit.

A. Return and Associated Income Taxes shall equal the product of the Primary Investment Base and the Cost of Capital Rate.

(1) Primary Investment Base will be (a) Total Primary Distribution Plant, plus (b) Primary Related General Plant, plus (c) Primary Plant Held for Future Use, less (d) Primary Depreciation Reserve, less (e) Primary Related Accumulated Deferred Income Taxes, plus (f) Primary Related Loss on Reacquired Debt, plus (g) Other Regulatory Assets, plus (h) Primary Materials and Supplies, plus (i) Primary Related Prepayments, plus (j) Primary Related Cash Working Capital.

(a) Total Primary Distribution Plant shall equal the New England Affiliate's Plant Accounts 360 to 373 multiplied by allocation factors from the Distribution Engineering Study.

(b) Primary Related General Plant shall equal the New England Affiliate's Investment in General Plant, multiplied by the Primary Wages & Salaries Allocation Factor. The Primary Wages & Salaries Allocation Factor shall equal the ratio of Total Distribution Wages & Salaries to the Total New England Affiliate's Wages & Salaries excluding A&G, multiplied by the ratio of Primary Distribution related O&M to Total Distribution O&M (Primary O&M Allocation Factor).

(c) Primary Plant Held for Future Use shall equal the New England Affiliate's Account 105, multiplied by the Primary Land Allocation Factor from the Distribution Engineering Study.

(d) Primary Depreciation Reserve shall equal the New England Affiliate's Depreciation Reserve multiplied by the ratio of Primary Depreciable Distribution Plant to Total Depreciable Distribution Plant (Primary Depreciable Plant Allocation Factor), plus an allocation of average General Plant Depreciation Reserve calculated by multiplying beginning and end of year General Plant Depreciation Reserve by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

(e) Primary Related Accumulated Deferred Income Taxes shall equal the Total Accumulated Deferred Income Taxes, multiplied by the ratio of average Primary Plant in Service to average Total Plant in Service excluding General Plant (Primary Plant Allocation Factor).

(f) Primary Related Loss on Reacquired Debt shall equal the Total Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

(g) Other Regulatory Assets shall equal the New England Affiliate's balance of FAS 106, multiplied by the Primary Wages and Salaries Allocator described in Section (I)(A)(1)(b), plus the New England Affiliate's balance of FAS 109, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(c) above.

(h) Primary Materials and Supplies shall equal the New England Affiliate's Distribution Plant Materials and Supplies, multiplied by the Primary O&M Allocation Factor as described in Section (I)(A)(1)(b) above.

(i) Primary Related Prepayments shall equal the New England Affiliate's Prepayments, multiplied by the Primary Wages and Salaries Allocator described in Section (I)(A)(1)(b) above.

(j) Primary Related Cash Working Capital shall be a 45 day allowance or 12.5% of Primary Operation and Maintenance Expense and Primary Related Administrative and General Expense.

(2) Cost of Capital Rate will equal (a) the New England Affiliate's Weighted Cost of Capital, plus (b) Federal Income Tax, plus (c) State Income Tax.

(a) **The Weighted Cost of Capital** will be calculated based upon the capital structure at the end of each year and will equal the sum of:

i) **the long-term debt component**, which equals the product of the actual dollar weighted average embedded cost to maturity of the New England Affiliate's long-term debt then outstanding and the ratio that long-term debt is to the New England Affiliate's total capital.

ii) **the preferred stock component**, which equals the product of the actual weighted average embedded cost to maturity of the New England Affiliate's preferred stock then outstanding and the ratio that preferred stock is to the New England Affiliate's total capital.

iii) **the return on equity component**, which equals the product of 11.14~~10.57~~% and the ratio that common equity is to the New England Affiliate's total capital.

(b) **Federal Income Tax** shall equal

$$\frac{A \times FT}{1\text{-}FT}$$

where FT is the Federal Income Tax Rate and A the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above.

(c) **State Income Tax** shall equal

$$\frac{(A + \text{Federal Income Tax}) \times ST}{1\text{-}ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and Federal Income Tax is Federal Income Tax as determined in Section (I)(A)(2)(b) above.

B. **Primary Depreciation Expense** shall equal Depreciation Expense for Distribution Plant, multiplied by the Primary Depreciable Plant Allocation Factor as described in Section (I)(A)(1)(d) above, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

C. Primary Related Amortization of Loss on Reacquired Debt shall equal the New England Affiliate's Amortization of Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

D. Primary Related Amortization of Investment Tax Credits shall equal the New England Affiliate's Amortization of Investment Tax Credits, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

E. Primary Related Municipal Tax Expense shall equal a pro-rata share of the New England Affiliate's total municipal taxes allocated by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

F. Primary Operation and Maintenance Expense shall the sum of all expenses charged to FERC Account Numbers 580 through 598, allocated to Primary as indicated by the Distribution Engineering Study.

G. Primary Related Administrative and General Expenses shall equal the New England Affiliate's Administrative and General Expenses, plus Payroll Taxes, multiplied by the Primary Wages & Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

ATTACHMENT L

Creditworthiness Policy

1. Introduction & Applicability

This policy establishes creditworthiness standards for transmission service and/or interconnection service customers ("Customers") entering into new, amended or assigned service agreements with NEP under the ISO-NE OATT. The following describes NEP's qualitative and quantitative credit review procedures and the types of security that are acceptable to NEP to protect against the risk of default.

2. Information Requirements

For purposes of determining the ability of a Customer to meet its obligations, NEP may require the Customer to submit financial information for the credit review, including credit ratings, credit reports and audited financial statements. In addition, the following factors may be considered in evaluation of the Customer's creditworthiness: applicant's history; nature of organization and operating environment; management; contractual obligations; governance, financial / accounting policies, risk management and credit policies; market risk including price exposures, credit exposures, and operational exposures; and event risk. All information required under this Attachment should be forwarded to the NEP account manager as specified on the NEP OASIS website.

3. Creditworthiness Evaluation

NEP will evaluate the creditworthiness of Customers entering into new or amended transmission or interconnection service agreements with NEP in order to assess a Customer's credit risk relative to the exposure or "Total Outstanding Obligation" as defined in Section 3.1 below, created by the transaction or transactions that NEP has with the Customer.

3.1 Total Outstanding Obligation

The Customer's Total Outstanding Obligation to NEP will be the sum total of the following components:

3.1.1 If the Customer is making payments to NEP for ongoing expenses (including, but not limited to, O&M expenses related to interconnections or other monthly charges such as monthly transmission charges under Schedule 21-NEP of the ISO-NE OATT) the Customer will be required to provide security pursuant to Section 3.2 below, for four months' worth of the Customer's average payment obligation for such charges

3.1.2 Whenever, in accordance with the provisions of the ISO-NE OATT, a Customer pays a Contribution in Aid of Construction ("CIAC") or transfers ownership of facilities to NEP for transmission or interconnection facilities that are to be constructed on behalf of a Customer at the Customer's sole expense, and NEP determines in good faith that the receipt of CIAC payments or property from the Customer are non-taxable, NEP will require a form of security from the Customer pursuant to Section 3.2 below for the amount of the potential tax liability to NEP that would occur if such facilities were deemed taxable.

3.1.3 Whenever, in accordance with the provisions of the ISO-NE OATT, a Customer pays a formula rate over time for return of and on the cost of capital incurred by NEP on behalf of a Customer at the Customer's sole expense, the Customer will be required to provide security pursuant to Section 3.2 below, for the unamortized balance of plant in service reserved for the sole use of the Customer.

3.2 Creditworthiness Requirements

A Customer will be considered creditworthy upon satisfying at least one of the following conditions, or a combination of those conditions, at the time that the Customer enters into a transmission or interconnection service agreement and for so long as the Customer maintains satisfaction of at least one of these conditions for any outstanding obligations thereunder:

3.2.1 The Customer maintains a minimum credit rating of BBB from Standard & Poor's Long-term Issuer Credit Rating or Baa2 from Moody's Investors Service Long-term Issuer Credit Rating, so long as the Customer's Total Outstanding Obligation plus any other unsecured obligation with NEP and its Affiliates does not exceed the Credit Limits discussed in Section 5 below.[12] If unrated, the Customer's financial statements will be reviewed to determine an equivalent rating based on the Customer's unsecured credit limits and/or financial statements.

3.2.2 The Customer provides and maintains in effect during the term of and until full and final payment and performance of the service agreement an unconditional and irrevocable Letter of Credit for the Total Outstanding Obligation in the form and substance and issued by a bank acceptable to NEP. A draft, acceptable form letter of credit is posted on OASIS. Any such bank must satisfy the creditworthiness criteria described in 3.2.1 above.

3.2.3 The Customer's parent or an Affiliate company satisfies the creditworthiness criteria described in 3.2.1 above and, subject to the Credit Limits stated in Section 4 below, such company submits to NEP and maintains in effect a Letter of Guaranty acceptable to NEP as to amount, form and substance for the term of and until full and final payment and performance of the service agreement.

3.2.4 The Customer is a municipal that is a member of the Massachusetts Municipal Wholesale Electric Cooperative (MMWEC). In such instances, MMWEC must meet the criteria set out in 3.2.1 or 3.2.2 above and provide to NEP a Letter of Guaranty that MMWEC will be unconditionally responsible for all financial obligations associated with the Customer's receipt of transmission or interconnection service from NEP.

3.2.5 The Customer makes an advance payment to NEP in immediately available funds for the Total Outstanding Obligation.

If, at any time, the credit rating of the Customer, Customer's bank, or Customer's parent or Affiliate providing the Guaranty as set out in 3.2.1, 3.2.2 or 3.2.3 above falls below investment grade (BBB- from Standard and Poor's and or Baa3 from Moody's), the Customer will be required to provide (i) notification to NEP within 10 days and, (ii) another form of security acceptable to NEP, as described in this Section 3.2, within 30 days.

4. Customer Costs Requiring Prepayment

[12] When NEP reviews a Customer's rating from two or more rating agencies and a split rating is present, the lower debt rating will apply. In the event that the Customer only has a rating from either Standard & Poor's or Moody's Investors Service, a rating from Duff & Phelps or Fitch and Weiss may also be used with acceptable ratings equivalent to those from either Standard and Poor's or Moody's Investors Service.

Whenever, in accordance with the provisions of the ISO-NE OATT, a Customer pays a CIAC for transmission or interconnection facilities to be constructed by NEP on behalf of a Customer at the Customer's sole expense, the Customer will have the option to (i) prepay the CIAC in immediately available funds to NEP, or (ii) make periodic CIAC progress payments, as defined in the Customer's service agreement, to prepay in increments capital costs scheduled to be incurred by NEP. If NEP determines in good faith that such payments or property transfers made by the Customer should be reported as income subject to taxation, the Customer shall also prepay all costs associated with the cost consequences of the current tax liability imposed on NEP by those facilities (the "Tax Gross- up").

5. Credit Limits

NEP reserves the right to limit the total amount of unsecured credit extended to a Customer under 3.2.1 and 3.2.3 above such that the sum of all unsecured credit that such Customer has with NEP and its Affiliates, including the Total Outstanding Obligation, shall not exceed the Credit Limits defined below. Such limitations are based on an assessment of the Customer's or its Guarantor's credit rating and the net worth of the Customer's or its Guarantor's assets.

Standard and Poor's (or Equivalent) Rating	Unsecured Credit Limit as Percent of Customer's or Guarantor's Tangible Net Worth
A and above	1.0%
A-	0.5%
BBB+	0.2%
BBB	0.1%
BBB-	0.0%

6. Contesting Creditworthiness Determinations

A Customer may contest NEP's determination of creditworthiness by submitting a written request to NEP for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate the Customer's creditworthiness. NEP will review and respond to the request within 20 calendar days.

7. Process for Changing Credit Requirements

In the event that NEP plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, NEP shall submit such changes in a filing to the Federal Energy Regulatory Commission ("Commission") under Section 205 of the Federal Power Act. NEP shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

7.1 General Notification Process

7.1.1 NEP shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing. Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Policy. NEP shall consult with interested stakeholders upon request.

7.1.2 Following Commission acceptance of such filing and upon the effective date, NEP shall revise its Attachment L Creditworthiness Policy and an updated version of Schedule 21-NEP shall be posted on the ISO-NE website.

7.2 Customer Responsibility

7.2.1 Upon the effective date of any revision to these creditworthiness requirements or upon the date of the Commission's order accepting such revisions, whichever is later, the Customer shall have 30 days to forward updated financial information to NEP and indicate whether the revised creditworthiness requirements impair the Customer's ability to comply with the revised requirements. In such cases, the Customer must take all reasonable steps to comply with the revised requirements of the Creditworthiness Policy within 45 days of the effective date of the change.

7.3 Notification for Active Customers

7.3.1 Active Customers are defined as any current Customer that has a Service Agreement currently in effect and has posted an irrevocable letter of credit, letter of guaranty or prepayment in accordance with Sections 3.2.2, 3.2.3, 3.2.4, or 3.2.5, above.

7.3.2 All Active Customers will be served with copies of any filing submitted to the Commission to modify the NEP's creditworthiness requirements.

8. Suspension of Service

NEP may, immediately suspend service (with notification to Commission) to a customer, and may initiate proceedings with Commission to terminate service, if the customer does not meet the terms described in this Attachment. A customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

ATTACHMENT S-1

Local Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area over Non-PTF. The Transmission Customer or Network Customer must purchase this service from NEP. The charges for Scheduling, System Control and Dispatch Service shall be based on the Local Network Load Dispatch Surcharge set forth in Attachment OCC to this Schedule. To the extent the ISO performs this service for NEP, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to NEP by the ISO.

SCHEDULE 21-NHT

Local Service Schedule

New Hampshire Transmission, LLC

I. COMMON SERVICE PROVISIONS

This Local Service Schedule, designated Schedule 21-NHT, governs the terms and conditions of service taken by Transmission Customers over the Local Network Transmission System who are not otherwise served under transmission service agreements with NHT that are still in effect. In the event of a conflict between the provisions of this Schedule 21-NHT and other provisions of the Tariff the provisions of this Schedule 21-NHT shall control.

1. Definitions

Whenever used in this Schedule 21-NHT, in either the singular or plural number, the following capitalized terms shall have the meanings specified in the Definition Sections of this Part I. Terms used in this Schedule 21-NHT but not defined in this Definition Section shall have the meanings specified in Section 1 of the Tariff. Terms used in this Schedule 21-NHT but not defined in this Definition Section shall have the meanings customarily attributed to such terms by the electric utility industry in New England. Sections or Attachments referred to in this Schedule 21-NHT shall mean a section in or attachment to this Schedule 21-NHT unless otherwise stated.

1.1 Annual Transmission Revenue Requirements ("ATRR"):

The annual revenue requirements of NHT's Local Network Transmission System for purposes of this Schedule 21-NHT shall be the amount calculated pursuant to the formula in Attachment G to this Schedule 21-NHT as updated each June 1, or until amended by NHT or modified by the Commission.

1.2 Backyard Generation (or Behind-the-Meter Generation):

Generation which interconnects directly with a customer's facilities that will offset all or a portion of a customer's electric load requirements. Any generation used to supply any portion of Local Network Load will not qualify for demand credits associated with Backyard Generation. Such credits shall only be applicable to load not designated as Local Network Load. In such instances, the customer shall be responsible for taking and paying for an appropriate level of Local Point-To-Point Transmission Service pursuant to this Schedule 21-NHT.

1.3 Control Area Operator:

ISO, or any successor organization or entity, that is responsible for the continued operation of the New England Control Area and the administration of the Tariff, subject to regulation by the

Commission.

1.4 Designated Agent:

Any entity that performs actions or functions required under this Schedule 21-NHT or the Tariff on behalf of NHT, an Eligible Customer, or a Transmission Customer.

1.5 Direct Assignment Facilities:

Facilities or portions of facilities that are constructed by or for NHT for (1) the sole use/benefit of a particular Transmission Customer requesting service under this Schedule 21-NHT or (2) the use by an owner or developer of a generating station requesting to be interconnected to the Local Network Transmission System. Direct Assignment Facilities shall be specified in the Service Agreement or interconnection agreement that in addition to the applicable terms and conditions of this Schedule 21-NHT or the OATT governs service to the Transmission Customer; and shall be subject to Commission acceptance.

1.6 NHT

New Hampshire Transmission, LLC.

1.7 NHT-Owned Interconnection Facilities:

Facilities and equipment, or portions thereof, owned by NHT that are necessary to interconnect a customer with the Local Network Transmission System.

1.8 Generator or Generator Owner:

The owner, in whole or in part, of a generating unit whether located within or outside the New England Control Area.

1.9 Interconnection Agreement:

An agreement between NHT and an Eligible Customer for Interconnection Service.

1.10 Interconnection Service:

Those services required to electrically connect Transmission Customer's or Generator Owner's facilities to the Local Network Transmission System. Interconnection Service includes, but is not limited to, the identification, design, and construction of facilities required to establish and maintain such electrical connection as identified by a completed System Impact Study and

Facilities Study. The customer's and NHT's contractual obligations associated with Interconnection Service shall be specified in an Interconnection Agreement which shall be executed and filed with the Commission prior to the commencement of such service.

1.11 LNS Service:

The service provided by NHT over its Local Network pursuant to this Schedule 21-NHT.

1.12 Load Ratio Share:

Ratio of a Transmission Customer's Local Network Load to NHT's total Local Network Load computed in accordance with Sections 22.2 and 22.3 of the Local Network Service under Part III of this Schedule 21-NHT.

1.13 Local Network (Local Network Transmission System):

The transmission facilities owned or operated by NHT within the New England Control Area that are used to provide transmission service.

1.14 Local Network Load:

The load that a Local Network Customer designates for Local Network Transmission Service under Part III of this Schedule 21-NHT. The Local Network Customer's Local Network Load shall include all load served by the output of any Network Resources designated by the Local Network Customer (including losses) and shall not be credited or reduced for any Backyard Generation. All Local Network Customers shall be required to have installed appropriate metering to determine such Backyard Generation, in accordance with the Network Operating Agreement. A Local Network Customer may elect to designate less than its total load as Local Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Local Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of this Schedule 21-NHT for any Local Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.15 Network Operating Agreement:

An executed agreement that contains the terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Part III of this Schedule 21-NHT.

1.16 Part I:

The sections of this Schedule 21-NHT containing the definitions and common service provisions.

1.17 Part II:

The sections of this Schedule 21-NHT pertaining to Local Point-To-Point Transmission Service in conjunction with the applicable common service provisions of Part I and appropriate Schedules and Attachments.

1.18 Part III:

The sections of this Schedule 21-NHT pertaining to Local Network Transmission Service in conjunction with the applicable common service provisions of Part I and appropriate Schedules and Attachments.

1.19 Parties:

NHT and the Transmission Customer receiving service under this Tariff.

1.20 Transmission Service:

Transmission service provided over NHT's Local Network, designated as Local Network Service or Local Point-To-Point Service that is provided pursuant to this Schedule 21-NHT.

2. Purpose of This Schedule 21-NHT

This Schedule 21-NHT is only applicable for service over NHT's transmission facilities located within the New England Control Area. It is intended to provide Transmission Service as a complement to the regional service to be provided under the OATT and is designed to ensure cost recovery by NHT of its ATRR as determined in accordance with the formula specified in Attachment G hereto.

The OATT contemplates a two-tier transmission arrangement integrating regional service which is provided under Part B of the OATT, and LNS Service, including Local Network Service and Local Point-To-Point Transmission Service, including, without limitation, service over NHT-Owned Interconnection Facilities as provided under this Schedule 21-NHT.

3. RESERVED

4. Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within the New England Control Area.

4.1 Ancillary Services supporting transmission service over the Local Network Transmission System:

Ancillary Services to support transmission service over the Local Network Transmission System will be provided pursuant to the OATT.

5. Billing and Payment

5.1 Billing Procedure:

Within a reasonable time after the first day of each month, NHT shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Schedule 21-NHT during the preceding month. In accordance with the formula rate contained in Attachment G of this Schedule 21-NHT, such monthly invoices for transmission service shall reflect an estimate of the monthly revenues NHT expects to receive associated with NHT's share of regional transmission service revenues collected pursuant to the OATT, with such estimated monthly amounts being reconciled with interest pursuant to Section 35.19(a) of the Commission's Regulations to actual monthly revenues received in subsequent billing months when such actual amounts are known by NHT. The invoice shall be paid by the Transmission Customer within ten (10) days of receipt. All payments shall be made, in accordance with the procedure specified by NHT in immediately available funds payable to NHT, or by wire transfer to a bank named by NHT.

5.2 Interest on Unpaid Balances:

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in 18 C.F.R. § 35.19a(a)(2)(iii) of the Commission's regulations. Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by NHT.

5.3 Customer Default:

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to NHT on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after NHT notifies the Transmission Customer to cure such failure, or if the Transmission Customer violates any provision of its Service Agreement, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, NHT may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between NHT and the Transmission Customer, NHT will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then NHT may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with applicable Commission rules and regulations, and may proceed with such suspension.

6.0 Accounting for the PTO's Use of this Schedule-21-NHT.

NHT will record the following amounts, as outlined below.

6.1 Transmission Revenues:

Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Part II of this Schedule 21-NHT.

6.2 Study Costs and Revenues:

Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the PTO conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including Third-Party Sales, if any, under this Schedule 21-NHT or at the direction of the Control Area Operator; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in a Transmission Customer's billing under this Schedule 21 or at the direction of the Control Area Operator.

7. Regulatory Filings

7.1 Rights Under The Federal Power Act

Nothing contained in this Schedule 21-NHT or any Service Agreement shall be construed as affecting in any way the right of NHT unilaterally to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation.

Nothing contained in this Schedule 21-NHT or any Service Agreement shall be construed as affecting in any way the ability of a Transmission Customer receiving service under this Schedule 21-NHT or for an Excepted Transaction to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

8. Force Majeure and Indemnification

8.1 Force Majeure:

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, any order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither NHT nor the Transmission Customer will be considered in default as to any obligation under this Schedule 21-NHT if prevented from fulfilling the obligation due to an event of Force Majeure; provided that no event of Force Majeure shall excuse any payment obligation hereunder or under a Service Agreement. However, a Party whose performance under this Schedule 21-NHT is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Schedule 21-NHT, and shall promptly notify NHT or the Transmission Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure.

8.2 Indemnification:

The Transmission Customer shall at all times indemnify, defend, and save the Transmission Owner harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Owner's performance of its obligations under this Schedule

21-NHT on behalf of the Transmission Customer, except in cases of gross negligence or intentional wrongdoing by the Transmission Owner.

9. Creditworthiness

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, NHT may require reasonable credit review procedures in accordance with Attachment L of this Schedule 21- NHT. This review shall be made in accordance with standard commercial practices. In addition, NHT may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under this Schedule 21-NHT, or an alternative form of security proposed by the Transmission Customer and acceptable to NHT and consistent with commercial practices established by the Uniform Commercial Code that protects NHT against the risk of non-payment.

10. Dispute Resolution Procedures

10.1 Internal Dispute Resolution Procedures:

Any dispute between a Transmission Customer and NHT involving Transmission Service under this Schedule 21-NHT (excluding applications for rate changes or other changes to this Schedule 21-NHT, or to any Service Agreement entered into under this Schedule 21-NHT, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of NHT and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days or such other period as the Parties may agree upon by mutual agreement, such dispute may be submitted to mediation and/or arbitration and resolved in accordance with the arbitration procedures set forth in Section I.6 of the Tariff.

10.2 Rights Under The Federal Power Act:

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission, or seek any other available remedy, under relevant provisions of the Federal Power Act.

II. LOCAL POINT-TO POINT TRANSMISSION SERVICE

Preamble

NHT will provide Firm and Non-Firm Local Point-To-Point Transmission Service over its Local Network pursuant to the applicable terms and conditions of this Schedule 21-NHT. Local Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

NHT will provide Interconnection Service to owners and developers of generating units directly interconnected to the Local Network Transmission System in accordance with the provisions of Schedule 22 of the ISO Tariff for generators with generating capacity of more than 20MW, and Schedule 23 of the ISO Tariff for generators with generating capacity of 20MW or less. Transmission services provided over PTF and Interconnection Service to interconnect directly with PTF are governed by the OATT.

11. Unauthorized use of the Transmission System

Any use of the Local Network Transmission System that exceeds a) the Transmission Customer's firm Reserved Capacity at any Point of Receipt or Point of Delivery or b) the Transmission Customer's non-firm capacity reservation, will be deemed an unauthorized use of the Local Network Transmission System. In the event that a Transmission Customer exceeds its firm reserved capacity or non-firm capacity reservation at any Point of Receipt or Point of Delivery, it shall pay an amount equal to 200% of the otherwise applicable charge firm point to point transmission service for each Kilowatt of the excess, exclusive of any discounts offered to any other Eligible Customer. Such charge shall apply for the length of the reservation period, not to exceed one month. In all cases of unauthorized use of the Local Network Transmission System, the service will be considered non-firm and NHT will be under no obligation to provide any services for such use.

12. Service Availability

12.1 Determination of Available Transmission Capability:

Determinations regarding availability and capabilities of the PTF are made by the Control Area Operator. NHT's specific methodology for assessing ATC over its non-PTF is posted on the OASIS and is contained in Attachment C of this Schedule 21-NHT. In the event sufficient Local Network transmission capability may not exist to accommodate a service request, NHT will, at the request of an Eligible Customer, respond by performing a System Impact Study as described in the following sections.

12.2 Initiating Service in the Absence of an Executed Service Agreement:

If NHT and the Transmission Customer requesting Firm or Non-Firm Local Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Local Point-To-Point Service Agreement, the ISO, acting as agent for NHT, shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification to NHT and the ISO directing the ISO acting as agent for NHT to file, an unexecuted Local Point-To-Point Service Agreement containing terms and conditions deemed appropriate by NHT for such requested Transmission Service. If the Transmission Customer refuses, or otherwise does not make such a request, the ISO acting as agent for NHT, may make such a filing prior to the commencement of service. NHT shall commence providing Transmission Service and the Transmission Customer shall be obligated to (i) compensate NHT at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of this Schedule 21-NHT including posting appropriate security deposits in accordance with the terms of Section I.5.c of the Common Provisions of Schedule 21 to the OATT.

12.3 Real Power Losses:

Real Power Losses are associated with all transmission service. NHT is not a Control Area Operator and is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by NHT or the Control Area Operator.

12.4 Load Shedding:

To the extent that system contingency exists on the Local Network Transmission System, and NHT determines shedding of load is necessary, the Parties shall shed load in accordance with procedures under the Service Agreement, the Tariff, and the rules adopted thereunder, or in accordance with other mutually agreed to provisions.

13. Transmission Customer Responsibilities

13.1 Conditions Required of Transmission Customers:

Local Point-To-Point Transmission Service and Interconnection Service shall be provided by NHT only if the following conditions are satisfied by the Transmission Customer:

(a) The Transmission Customer has pending a Completed Local Application for service with the ISO or in the case of Interconnection Service, has a Completed Application for service with the Control Area Operator and satisfied all other requirements of the Tariff or of this Schedule 21-NHT, as applicable;

(b) The Transmission Customer meets the creditworthiness criteria set forth in Section 9;

(c) The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to NHT's Local Network Transmission System prior to the time service under Part II of this Tariff commences;

(d) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of this Tariff, whether or not the Transmission Customer takes service for the full term of its reservation; and

(e) The Transmission Customer has executed a Local Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 12.2 of this Schedule 21-NHT.

14. Metering and Power Factor Correction at Receipt and Delivery Points(s)

14.1 Transmission Customer Obligations:

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of this Schedule 21-NHT and to communicate the information to NHT. Unless otherwise agreed, such equipment shall remain the property of NHT.

14.2 Power Factor:

The Transmission Customer is required to maintain a power factor within a range as specified by NHT pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable. Where a Transmission Customer fails to maintain a power factor within the specified range, NHT may make whatever improvements or repairs are required to restore or maintain the power factor, and charge the Transmission Customer accordingly.

15. Compensation for Local Point-To-Point Transmission Service

Rates for Firm and Non-Firm Local Point-To-Point Transmission Service are provided in the Schedules appended to this Schedule 21-NHT: Firm Local Point-To-Point Transmission Service (Schedule 7); and Non-Firm Local Point-To-Point Transmission Service (Schedule 8).

16. Interconnection Service

Any entity proposing to interconnect with NHT's transmission facilities, that is not party to an agreement executed on or before July 9, 1996, in which Interconnection Service is addressed, that (1) proposes to site a new generating unit and directly interconnect to the Local Network Transmission System, or (2) proposes to materially change electrical characteristics or increase the capacity of an existing generating unit and remain connected to the Local Network Transmission System, shall submit an application for Interconnection Service to the Control Area Operator and comply with all applicable requirements of the Tariff, including but not limited to Schedule 22 of the ISO Tariff for generators with generating capacity of more than 20MW, and Schedule 23 of the ISO Tariff for generators with generating capacity of 20MW or less.

III. LOCAL NETWORK SERVICE

17. Real Power Losses

Real Power Losses are associated with all transmission service. NHT is not a Control Area Operator and is not obligated to provide Real Power Losses. The Local Network Customer is responsible for replacing losses associated with all transmission service as calculated by NHT or the Control Area Operator.

18. Initiating Service

18.1 Condition Precedent for Receiving Service:

Subject to the terms and conditions of Part III of this Schedule 21-NHT, NHT will provide Local Network Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under the OATT, (ii) the Eligible Customer and NHT complete the technical arrangements for such service, (iii) the Eligible Customer executes a Service Agreement for service under Part III of this Schedule 21-NHT or requests in writing that the ISO, acting as agent for NHT, file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Local Network Operating Agreement with NHT.

18.2 Application Procedures:

An Eligible Customer requesting service under Part III of this Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the ISO acting as agent for NHT as far as possible in advance of the month in which service is to commence in accordance with Section II. 3) a) of the common service provisions of Schedule 21 of the OATT.

18.3 Operation of Network Resources:

The Local Network Customer shall not operate its designated Network Resources, which are not subject to central dispatch by the Control Area Operator, such that the output of those facilities exceeds its designated Local Network Load, plus non-firm sales delivered pursuant to Part II of this Schedule 21-NHT, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of the ISO or NHT to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Local Network Transmission System.

18.4 Transmission Arrangements for Network Resources Not Physically Interconnected With NHT's Local Network:

The Local Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with NHT's Local Network Transmission System. NHT will undertake reasonable efforts to assist the Local Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice. The customer shall be obligated to reimburse NHT for all costs NHT incurs in assisting the customer in obtaining such arrangements. Upon the customer's request, NHT shall provide the transmission customer an estimate of such costs before they are incurred. Upon the customer's request, NHT shall provide reasonable itemization of such costs along with any invoice related to those costs.

18.5 Limitation on Designation of Network Resources:

The Local Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Local Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of this Schedule 21-NHT.

18.6 Use of Interface Capacity by the Local Network Customer:

There is no limitation upon a Local Network Customer's use of NHT's Local Network Transmission System at any particular interface to integrate the Local Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, a Local Network Customer's use of the NHT's total interface capacity with other transmission systems may not exceed the Local Network Customer's Load.

18.7 Local Network Customer Owned Transmission Facilities:
The Local Network Customer that owns existing transmission facilities that are integrated with NHT's Local Network Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Local Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of NHT to serve its power and Transmission Customers. For facilities constructed by the Local Network Customer subsequent to the Service Commencement Date under Part III of this Schedule 21-NHT, the Local Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with NHT. Calculation of the credit shall be addressed in either the Local Network Customer's Service Agreement or any other agreement between the Parties.

19. Designation of Load

19.1 Network Load Not Physically Interconnected with NHT's Local Network:
This Section applies to both initial designation and the subsequent addition of new Local Network Load not physically interconnected with NHT's Local Network. To the extent that the Local Network Customer desires to obtain Local Network transmission service for a load outside NHT's Local Network Transmission System, the Local Network Customer shall have the option of (1) electing to include the entire load as Local Network Load for all purposes under Part III of this Schedule 21-NHT and designating Local Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Transmission Service under Part II of this Schedule 21-NHT. To the extent that the Local Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this Section, the request must be made through a modification of service pursuant to a new Application. NHT shall include such load as part of a Transmission Customer's Local Network Load only if a scheduling and interconnection agreement acceptable to NHT is in effect with the Control Area in which the load

is located.

20. Additional Study Procedures For Local Network Transmission Service Requests

20.1 Notice of Need for System Impact Study:

When applicable, a description of NHT's methodology for completing a System Impact Study is provided in Attachment D of this Schedule 21-NHT.

21. Load Shedding and Curtailments

21.1 Procedures:

Prior to the Service Commencement Date, NHT and the Local Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Local Network Operating Agreement with the objective of responding to contingencies on the Local Network Transmission System. The Parties will implement such programs during any period when NHT determines that a system contingency exists and such procedures are necessary to alleviate such contingency. NHT will notify all affected Local Network Customers in a timely manner of any scheduled Curtailment.

21.2 Transmission Constraints:

During any period when NHT determines that a transmission constraint exists on the Local Network Transmission System, and such constraint may impair the reliability of NHT's system, NHT will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of NHT's system. To the extent either NHT or the Control Area Operator determine that the reliability of the Transmission System can be maintained by redispatching resources, NHT can initiate procedures pursuant to the Local Network Operating Agreement, the Tariff, and other Control Area Operator rules and procedures including, without limitation, the Market Rules. Any redispatch under this Section may not unduly discriminate between NHT's use of the Local Network Transmission System on behalf of its Native Load Customers and any Local Network Customer's use of the Local Network Transmission System to serve its designated Local Network Load

21.3 Curtailments of Scheduled Deliveries:

If a transmission constraint on NHT's Local Network Transmission System cannot be relieved through the implementation of redispatch procedures and the Control Area Operator determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with any applicable provisions of the Local Network Operating Agreement, the Tariff and any Control Area Operator rules and procedures including, without limitation, the Market Rules.

21.4 Load Shedding:

To the extent that a system contingency exists on NHT's or the New England Transmission System and NHT or the ISO determines that it is necessary for NHT and the Local Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement, or in accordance with other mutually agreed to provisions.

22. Rates and Charges

The Local Network Customer shall pay NHT for any Direct Assignment Facilities and applicable study costs, consistent with Commission policy, along with the following:

22.1 Monthly Demand Charge:

The Local Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of NHT's Annual Transmission Revenue Requirement. The Annual Transmission Revenue Requirement is calculated pursuant to Attachment G of this Schedule 21-NHT.

22.2 Determination of Local Network Customer's Monthly Local Network Load:

The Local Network Customer's monthly Local Network Load is its hourly load (including its designated Local Network Load not physically interconnected with NHT's Local Network under Section 19.1) coincident with NHT's Monthly Local Network Transmission System Peak.

22.3 Determination of NHT's Monthly Local Network Transmission System Load:

NHT's monthly Local Network Transmission System load is NHT's Monthly Local Network Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Transmission Service customers pursuant to Part II of this Schedule 21-NHT plus the Reserved Capacity of all Firm Local Point-To-Point Transmission Service customers.

22.4 Redispatch Charge:

All costs associated with redispatch of resources shall be charged and allocated in accordance with the Tariff and any Control Area Operator rules and procedures including, without limitation, the Market Rules.

22.5 Stranded Cost Recovery:

NHT may seek to recover stranded costs from the Local Network Customer pursuant to this Schedule 21-NHT in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, NHT must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

23. Operating Arrangements

23.1 Operation under The Local Network Operating Agreement:

The Local Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement. If NHT and the Local Network Customer agree in the Interconnection Agreement, the Interconnection Agreement can serve as a Local Network Operating Agreement.

23.2 Local Network Operating Agreement:

The terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of this Schedule 21-NHT shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Local Network Customer within NHT's Local Network Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between NHT and the Local Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside NHT's Local Network Transmission System, interchange schedules, unit outputs for redispatch required under Section 21, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of this Schedule 21-NHT, including scheduling protocols. The Local Network Operating Agreement will recognize that the Local

Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Control Area Operator for all required Ancillary Services or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services which may be provided by another entity, by contracting with another entity, consistent with Good Utility Practice, which satisfies any applicable requirements imposed by NERC, the NPCC, NHT or the Control Area Operator. For those Ancillary Services that may be provided by another entity, NHT shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services.

SCHEDULE 7

Long and Short Term Firm Local Point-To-Point Transmission Service

Each Transmission Customer who takes Firm Local Point-to-Point Transmission Service shall pay NHT each month on the basis of the highest amount of Reserved Capacity for each transaction reserved as Firm Local Point to Point Transmission Service. Except as provided otherwise below, the charges will be re-determined annually on June 1 of each year, and shall be in effect for the succeeding twelve months. The rate per kilowatt for each month is one-twelfth of the annual rate determined by dividing the Annual Transmission Revenue Requirement calculated pursuant to the Attachment G formula, by NHT's average monthly Local Network Transmission System Load (as defined in Section 22.3) for the prior calendar year.

Each Transmission Customer taking Firm Local Point to Point Transmission Service shall pay the firm local point-to-point rate on the basis of the highest amount of Reserved Capacity for each transaction reserved as Firm Local Point to Point Transmission Service as follows:

1) Yearly reservation: one-twelfth of the annual rate per kilowatt of Reserved Capacity per year.

2) Monthly reservation: one-twelfth of the annual rate per kilowatt of Reserved Capacity per month

3) Weekly reservation: 1/52nd of the annual rate per kilowatt of Reserved Capacity per week.

4) Daily reservation: 1/7th of the weekly rate per kilowatt of Reserved Capacity per day.
Provided that the total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NHT must be announced to all Eligible Customers solely by posting on the OASIS; (2) any customer-initiated requests for discounts (including requests for use by NHT's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, NHT must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same Point(s) of Delivery on the Transmission System.

6) Exceeding Capacity Reservations and Unreserved Use: In the event the Transmission Customer exceeds the Capacity Reservation specified in the customer's transmission Service Agreement as determined by NHT, the Transmission Customer shall be retroactively charged an amount equal to 200% of the rates specified above without any discount, if one is in place at the time, for any capacity exceeding the amount reserved. Such charge shall apply for the length of the period of unreserved use of NHT's transmission system, except that: i) unreserved uses for any single hour period shall be based on 200% of the applicable rate for daily firm point-to-point transmission service, and ii) multiple unauthorized uses of any given duration (e.g., daily) occurring during any single billing month shall be subject to a penalty charge of 200% of the rate that is applicable to the next longest duration of service, (e.g. weekly).

7) Resale: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Section I.11.a of Schedule 21.

SCHEDULE 8

Non-Firm Local Point-To-Point Transmission Service

Each Transmission Customer who takes Non-Firm Local Point-to-Point Transmission Service shall pay NHT each month on the basis of the highest amount of Reserved Capacity for each transaction reserved as Non-Firm Local Point to Point Transmission Service. The charges will be re-determined annually on June 1 of each year, and shall be in effect for the succeeding twelve months. The rate per kilowatt for each month is one-twelfth of the annual rate determined by dividing the Local Network Service Annual Transmission Revenue Requirement calculated pursuant to the Attachment G formula, by NHT's average monthly Local Network Transmission System Load (as defined in Section 22.3) for the prior calendar year.

Each Transmission Customer taking Non-Firm Local Point to Point Transmission Service shall pay the non-firm local point-to-point rate on the basis of the highest amount of Reserved Capacity for each transaction scheduled as Non-Firm Local Point to Point Transmission Service as follows:

1) **Yearly reservation:** one-twelfth of the annual rate per kilowatt of Reserved Capacity per year.

2) **Monthly reservation:** one-twelfth of the annual rate per kilowatt of Reserved Capacity per month.

3) **Weekly reservation:** 1/52nd of the annual rate per kilowatt of Reserved Capacity per week.

4) **Daily reservation:** 1/7th of the weekly rate per kilowatt of Reserved Capacity per day.

5) **Hourly reservation:** 1/24th of the daily rate per kilowatt of Reserved Capacity per hour.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (4) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

6) Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NHT must be announced to all Eligible Customers solely by posting on the OASIS; (2) any customer-initiated requests for discounts (including requests for use by NHT's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, NHT must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same Point(s) of Delivery on the Transmission System.

7) Exceeding Capacity Reservations and Unreserved Use: In the event the Transmission Customer exceeds the Capacity Reservation specified in the customer's transmission Service Agreement as determined by NHT, the Transmission Customer shall be retroactively charged an amount equal to 200% of the rates specified for Long and Short Term Firm Point to Point Transmission Service as specified in Schedule 7 of this Schedule 21-NHT without any discount, if one is in place at the time, for any capacity exceeding the amount reserved.

8) Resale: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Section I.11.a of Schedule 21.

ATTACHMENT C

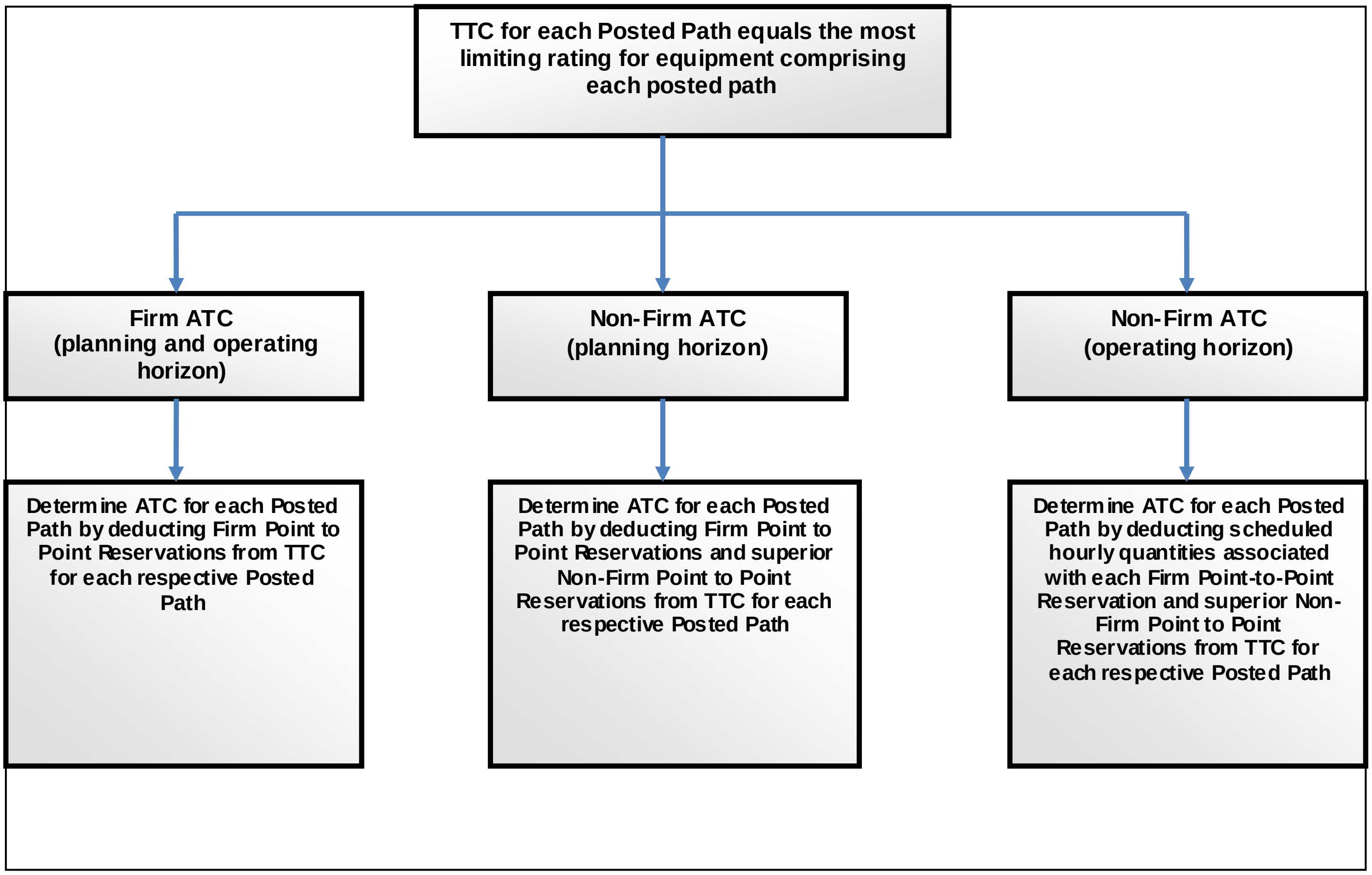
Methodology To Assess Available Transmission Capability

NHT will respond to a valid request for Local Network and Local Point-To-Point Transmission Service by determining whether sufficient transfer capability is available to grant the request. All valid requests will be assigned a priority as set forth in the OATT. The Available Transmission Capability will be calculated based on a Contract Path Methodology, taking into account Total Transfer Capability, Transmission Reliability Margin, capacity reserved by NHT to serve projected native load, existing and confirmed long-term firm transactions and all other requests consistent with the Tariff.

Total Transfer Capacity will be forecasted by NHT and/or the Control Area Operator for posted paths using system models, load flow analysis and other engineering analyses, and in accordance with the NHT Facilities Rating Methodology posted on the NHT OASIS.

In determining Available Transmission Capacity NHT will use Good Utility Practice, comply with applicable Control Area Operator criteria, rules and standards, utilize NPCC and NERC criteria and guidelines, and guidelines established by NHT. The process used by NHT to determine its Available Transmission Capacity is depicted by the following process flow diagram.

Process Used by NHT to Calculate the TCC and ATC for Posted Paths



Notes:

1. TCC and ATC are calculated in accordance with NHT's Facilities Ratings Methodology as posted on NHT's OASIS.
2. NHT has provided its Facilities Ratings Methodology and Facilities Ratings to ISO-NE.
3. TCC and ATC for Posted Paths relate to Point to Point Transmission Service taken over NHT's Non-Pool Transmission Facilities.
4. TCC and ATC are not calculated and posted over Pool Transmission Facilities because Point-to-Point Transmission Service internal to New England is part of Regional Network Service and was eliminated from the ISO-NE Tariff as a stand-along distinct service
5. ISO-NE administers transmission service over all Pool Transmission Facilities.

The algorithm used by NHT to calculate its Available Transmission Capacity is as follows:

NHT Local Service Available Transfer Capability (ATC)
Firm/Non-Firm ATC = TTC (Total Transfer Capability); minus CBM (Capacity Benefit Margin); minus TRM (Transmission Reliability Margin); minus Transmission Service Capacity Reservation(s).

Calculation of TTC shall equal: $\sqrt{3}$; times (operating voltage); times (ampere rating of the transmission facility).

No Local Service capacity reservation is set aside on any non-PTF path for CBM or TRM.

Local Service on non-Pool Transmission Facilities is currently provided for Seabrook Station Service only when there is no net generation out of the Seabrook Plant or upon failure of Generation Step Up Transformer (GSU).

Total Existing Local Service Capacity Reservations for Seabrook Station Service: 6/1/04 through current = 50 MW. Such Local Service is provided over non-PTF paths: Path 1) Seabrook 345 kV Bus No. 5 to Seabrook Station Service; and Path 2) Seabrook 345 kV Bus No. 3 to 345 kV-GSU. These non-PTF paths are not available for additional Point-to-Point Service Requests, except to meet the needs of the Seabrook Station (e.g., increase in Station Service Requirements) due to the physical limitations of access to these specific 345 kV transmission facilities.

Firm TTC (Total Transfer Capability)/Non-Firm TTC (hourly, daily, weekly, monthly, yearly) over each Path 1 and Path 2, respectively, is: 1793 MWA/1793 MW [TTC = $\sqrt{3}$ X 345 kVX 3000A]

Firm ATC/Non-Firm ATC (hourly, daily, weekly, monthly, yearly) over each Path 1 and Path 2, respectively, is: 1743 MVA/1743 MW [ATC = TTC ($\sqrt{3}$X 345 kV X 3000A); minus CBM (0); minus TRM (0); minus Transmission Service Capacity Reservations (50 MW)]

Paths available for non-PTF Point-to-Point Service are:

Path 3) Seabrook 345 kV Switch Nos. 2201-2901 to Future Unit #2; and
Path 4) Seabrook Sub. 345 kV Bus 1 to Future Tie – RAT Transformer

Firm TTC/Non-Firm TTC over each path, respectively, (3 & 4, above) (hourly, daily, weekly, monthly, yearly) is: 1793 MVA/1793 MW [TTC = $\sqrt{3}$ X 345 kV X 3000A]

Firm ATC/Non-Firm ATC (hourly, daily, weekly, monthly, yearly) over each path, respectively, (3 & 4, above) is: 1793 MVA/1793 MW [ATC = TTC ($\sqrt{3}$ X 345 kV X 3000A) – CBM (0) – TRM (0) – Transmission Service Capacity Reservations (0)]

Note: At present, there are no Transmission Service Capacity Reservations over Path 3) or Path 4).

ATTACHMENT D

Methodology for Completing a System Impact Study

NHT (or its designated agent) may require System Impact Studies for the purpose of determining the feasibility of providing Transmission Service under this Tariff. All System Impact Studies will be coordinated with the Control Area Operator and completed using the same method employed by NHT to provide Transmission Service to its affiliated customers. System Impact Studies associated with a request from an Eligible Customer for Interconnection Service shall be performed at the direction of the Control Area Operator pursuant to Schedule 22 of the ISO Tariff for generators with generating capacity of more than 20MW, and Schedule 23 of the ISO Tariff for generators with generating capacity of 20MW or less. System Impact Studies will be performed by applying NPCC Criteria and the "Reliability Standards of the New England Power Pool," or its successor, while assuring that NHT's Native Load Customers and those loads directly interconnected to the Local Network Transmission System that are receiving transmission service can be served economically and reliably. All of the criteria, standards, and guidelines referenced above are included as part of the annual FERC Form 715 filing.

ATTACHMENTS E AND F

[RESERVED FOR FUTURE USE]

ATTACHMENT G

FORMULA FOR CALCULATING ANNUAL WHOLESALE TRANSMISSION REVENUE REQUIREMENTS
UNDER NEW HAMPSHIRE TRANSMISSION LLC'S SCHEDULE 21

This formula sets forth the details for determining each year's Annual Transmission Revenue Requirement for New Hampshire Transmission, LLC ("NHT"). The Transmission Revenue Requirement reflects NHT's cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to wholesale transmission customers in the New England Control Area under this Schedule 21-NHT and the OATT. The Transmission Revenue Requirement will be an annual formula rate calculation. Initially, cost data reflecting costs as incurred by NHT'S Affiliate, FPL-NED, for owning, operating and maintaining the transmission facilities located in the New England Control Area for January 1, 2009 through May 31, 2010 shall be used, and NHT's costs will be used for June 1, 2010 through December 31, 2010. Thereafter, NHT's ATRR will be updated each June 1, based on NHT's costs incurred during the previous calendar year as recorded in NHT's FERC Form 1, data, and based on actual data in lieu of allocated data, if specifically identified in FERC Form 1, using end-of-year balances for each rate base item, as further set forth below.

Notwithstanding the aforementioned, until such time as FPL-NED has completed the transfer of the transmission facilities to NHT for which this Schedule 21-NHT pertains, NHT's ATRR shall continue to be based on the cost incurred by FPL-NED for owning, operating and maintaining the transmission facilities located in the New England Control Area. As such, all references to costs, expenses and investments attributable to NHT contained in this formula, shall be deemed to refer to costs, expenses and investments attributable to NHT or FPL-NED, as applicable, to coincide with the date of such transfer. To facilitate the use of FPL-NED's costs, expenses and investments for the purpose of deriving NHT's ATRR pursuant to this Attachment G, all such FPL-NED costs used in the determination of NHT's ATRR shall be recorded in a format consistent with the FERC Uniform System of Accounts.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section 1 of this Schedule 21- NHT have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of NHT's Transmission-related direct wages and salaries not otherwise assigned under this tariff, to NHT's total direct wages and salaries excluding administrative and general wages and salaries.

2. Transmission Plant Allocation Factor shall be designed to ensure that no costs associated with the Seabrook Nuclear Generating Station properly functionalized as production costs or expenses are included in NHT's ATRR, and therefore, prior to the Asset Transfer Date, shall equal the ratio of the sum of (1) Total Investment in Transmission Plant attributable to NHT including the investment in the Generator Step-up Transformer, recorded in such Transmission Plant accounts, and (2) the balance of Transmission Related General and Intangible Plant attributable to NHT, to Total Plant in Service attributable to NHT, including the investment in the Generator Step-up Transformer. After the Asset Transfer Date, this Transmission Plant Allocation Factor shall be 1.00

3. LNS Plant Allocation Factor shall be designed to ensure that no costs associated with the Generator Step-up Transformer are included in NHT's ATRR and shall equal the ratio of the sum of Total Investment in Transmission Plant attributable to NHT, excluding the investment in the Generator Step-up Transformers, and the balance of Transmission Related General and Intangible Plant attributable to NHT, to Total Transmission Plant in Service attributable to NHT, including the investment in the Generator Step-up Transformer.

B. GENERAL TERMS

1. Administrative and General Expense shall equal expenses attributable to NHT as recorded in FERC Account Nos. 920-935, excluding Property Insurance recorded in FERC Account No. 924, Regulatory Commission Expense recorded in FERC Account No. 928 and General Advertising Expense recorded in FERC Account No. 930.1.

2. Amortization of Investment Tax Credits shall equal any credits attributable to

NHT as recorded in FERC Account No. 411.4.

3. Asset Transfer Date shall be the date upon which FPL-NED transfers its ownership in the Seabrook Transmission Substation to NHT.

4. Depreciation Expense for Transmission Plant shall equal the transmission depreciation expense attributable to NHT as recorded in FERC Account No. 403. Annual Depreciation Expense for Transmission Plant shall be based on an annual rate of 3.12 percent per year for its initial year's revenue requirements and any change shall require Commission acceptance or approval.

5. Generator Step-up Transformers shall equal the investment in the generator step-up transformers used to interconnect the Seabrook Nuclear Generating Station to the Local Network Transmission System. Notwithstanding the transfer of said Generator Step-up Transformers from FPL-NED to NHT reflecting that a contribution of capital was paid to FPL-NED by NextEra Energy Seabrook, LLC (formerly FPL Energy Seabrook, LLC) resulting in NHT recording such at zero cost net book basis, for purposes of deriving the Transmission Plant Allocation Factor and the LNS Plant Allocation Factor, the investment in the Generator Step-up Transformers shall be equal to the original cost of said Generator Step-up Transformers as recorded by NextEra Seabrook, LLC and shall reflect any changes in that investment (i.e. retirements, replacements, additions, etc.) on a going-forward basis. Any future additional investment in the Generator Step-up Transformers shall be paid for as a direct assignment charge to NextEra Seabrook, LLC or its successors such that the net investment basis as recorded by NHT shall continue to be zero.

6. Intangible and General Plant shall equal the gross plant balances attributable to NHT as recorded in FERC Account Nos. 301-303 and 389-399.

7. Intangible and General Plant Amortization and Depreciation Expense shall equal any intangible and general plant amortization and depreciation expenses attributable to NHT as recorded in FERC Account Nos. 404 and 403.

8. Intangible and General Plant Depreciation Reserve shall equal any intangible and general plant reserve balances attributable to NHT as recorded in FERC Account Nos. 111 and 108.

9. **Other Regulatory Assets/Liabilities -** FAS 106 shall equal the net of FAS106 balance attributable to NHT as recorded in FERC Account 182.3 and any FAS 106 balance attributable to NHT as recorded in FERC Account No. 254.

10. **Other Regulatory Assets/Liabilities -** FAS 109 shall equal the net of FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance in FERC Account 254 attributable to NHT.

11. **Payroll Taxes** shall equal those payroll expenses attributable to NHT as recorded in FERC Account Nos. 408.1.

12. **Plant Held for Future Use** shall equal the balance recorded in FERC Account No.105 attributable to NHT.

13. **Prepayments** shall equal any prepayment balance attributable to NHT as recorded in FERC Account No. 165.

14. **Property Insurance** shall equal expenses attributable to NHT as recorded in FERC Account No. 924.

15. **Total Accumulated Deferred Income Taxes** shall equal the net of deferred tax balance attributable to NHT as recorded in FERC Account Nos. 281-283 and the deferred tax balance attributable to NHT as recorded in FERC Account No. 190.

16. **Total Municipal Tax Expense** shall equal the municipal tax expenses attributable to NHT as recorded in FERC Account No. 408.1.

17. **Total Plant in Service** shall equal the total gross plant balance attributable to NHT as recorded in FERC Account Nos. 301-399.

18. **Total Transmission Depreciation Reserve** shall equal the transmission reserve balance attributable to NHT as recorded in FERC Account 108

19. **Transmission Operation and Maintenance Expense** shall equal the expenses attributable to NHT as recorded in FERC Account Nos. 560 through 576.5, excluding those expenses for Load Dispatching in FERC Account 561 and excluding any amounts recorded in FERC Account No. 565 relating solely to NEPOOL & ISO Expense, and amounts recorded in FERC Account Nos. 566-576.5, excluding any expenses in support of other utilities' transmission facilities, i.e. Transmission Support Expenses, and excluding any operation and maintenance expenses associated with the Generator Step-up Transformers, which may be included in FERC Account Nos. 560-576.5.

20. **Transmission Plant** shall equal the Gross Plant balance attributable to NHT as recorded in FERC Account Nos. 350-359.

21. **Transmission Plant Materials and Supplies** shall equal the balance as assigned to transmission and that is attributable to NHT, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of the following cost components attributable to NHT: (A) Investment Return and Associated Income Taxes, plus (B) Transmission Depreciation Expense, plus (C) Transmission Related Amortization of Investment Tax Credits, plus (D) Transmission Related Municipal Tax Expense, plus (E) Transmission Related Payroll Tax Expense, plus (F) Transmission Operation and Maintenance Expense, plus (G) Transmission Related Administrative and General Expenses, plus (H) Transmission Related Regulatory Assessments, plus (I) Transmission Support Expense, plus (J) NEPOOL & ISO Expense minus (K) Transmission Support Revenue, minus (L) ISO Revenues, minus (M) Other Wheeling Revenue, and minus (N) Transmission Rents Received from Electric Property.

A. **Investment Return and Associated Income Taxes** shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. **Transmission Investment Base**

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation Reserve, less (e) Transmission Related

Accumulated Deferred Taxes, plus (f) Other Regulatory Assets/Liabilities, plus (g) Transmission Prepayments, plus (h) Transmission Materials and Supplies, plus (i) Transmission Related Cash Working Capital.

(a) **Transmission Plant** will equal the balance of the Investment in Transmission Plant attributable to NHT less any investment in the Generator Step-up Transformers. At December 31, 2003, Transmission Plant balance is $28,195,111.

(b) **Transmission Related Intangible and General Plant** shall equal the sum of the investment in Intangible and General Plant attributable to NHT multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the LNS Plant Allocation Factor. At December 31, 2003, Transmission Related Intangibles and General Plant Balances are zero.

(c) **Transmission Plant Held for Future Use** shall equal the balance of Transmission-related Plant Held for Future Use attributable to NHT. To the extent any such amount relating to the Generator Step-up Transformers exist in said balance of Total Plant Held for Future Use, such amounts shall be excluded by further multiplying said balance by the LNS Plant Allocation Factor. At December 31, 2003, the balance of Transmission Plant Held For Future Use is zero.

(d) **Transmission Related Depreciation Reserve** shall equal the balance of Total Transmission Depreciation Reserve, plus the sum of the balance of Transmission Related Intangible and General Plant Depreciation Reserve, that are attributable to NHT. To the extent any such amount relating to the Generator Step-up Transformers exists in said balance of Total Transmission Depreciation Reserve, such amounts shall be excluded by further multiplying said balance by the LNS Plant Allocation Factor. Transmission Related Intangible and General Plant Depreciation Reserve shall equal the product of Intangible and General Plant Depreciation Reserve attributable to NHT multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the LNS Plant Allocation Factor. At December 31, 2003, Transmission Related Depreciation Reserve Balance is $8,249,858.

(e) **Transmission Related Accumulated Deferred Taxes** shall equal the balance of Total

Accumulated Deferred Income Taxes attributable to NHT. To the extent any such amount relating to the Generator Step-up Transformer exist in said balance of Total Accumulated Deferred Income Taxes, such amounts shall be excluded by further multiplying said balance of Transmission Related Accumulated Deferred Taxes by the LNS Plant Allocation Factor. At December 31, 2003, Transmission Related Accumulated Deferred Taxes is $295,398.

(f) **Other Regulatory Assets/Liabilities** shall equal the balance of any deferred rate recovery of FAS 106 expenses attributable to NHT multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the LNS Allocation Factor, plus the balance of FAS 109 attributable to NHT multiplied by the LNS Plant Allocation Factor. At December 31, 2003, Other Regulatory Assets/Liability is zero.

(g) **Transmission Prepayments** shall equal the electric balance of prepayments attributable to NHT multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the LNS Allocation Factor. At December 31, 2003, Transmission Prepayments is $1,374.

(h) **Transmission Materials and Supplies** shall equal the electric balance of Plant Materials and Supplies attributable to NHT multiplied by the Transmission Plant Allocation Factor. To the extent any such amount relating to the Generator Step-up Transformers exist in said balance of Transmission Materials and Supplies, such amounts shall be excluded by further multiplying said balance of Transmission Materials and Supplies by the LNS Plant Allocation Factor. At December 31, 2003, Transmission Materials and Supplies balance is zero.

(i) **Transmission Related Cash Working Capital** shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph K of the formula, as such expenses and revenues are attributable to NHT.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) FPL's Weighted Cost of Capital, plus (b) Federal

Income Tax plus (c) State Income Tax.

(a) **The Weighted Cost of Capital** will be calculated in accordance with the methodology specified in Section 35.13(h)(22) of Part 18 of the Code of Federal Regulations, i.e. Statement AV, based upon the capital structure for FPL at the end of each year and will equal the sum of:

(i) **the long-term debt component**, which equals the product of the actual weighted average embedded cost to maturity, including any unamortized discounts and premiums, and unamortized losses and gains on reacquired debt, and the ratio that long-term debt is to FPL's total capital.

(ii) **the preferred stock component**, which equals the product of the actual weighted average embedded cost to maturity of FPL's preferred stock then outstanding and the ratio that preferred stock is to FPL's total capital.

(iii) **the return on equity component**, which equals the product of the Return on Equity ~~("ROE") of 10.57 percent (which is the base ROE exclusive of any incentive ROE adder(s) per FERC Opinion No. 531-A issued October 16, 2014 in Docket No. EL11-66-001, and FERC Opinion 531-B issued March 3, 2015 in Docket No. EL11-66-002 and EL11-66-003)~~of 11.14 (10.4+.74 adder per Rehearing Order issued March 24, 2008 in Docket ER04-157-014) percent and the ratio that common equity is to FPL's total capital.

(b) **Federal Income Tax** shall equal

$$\frac{(A+[(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.C. below, C is the Equity AFUDC component of Transmission Depreciation Expense , as defined in Section II.B., and D is Transmission Investment Base, as determined in II.A.1., above.

(c) **State Income Tax** shall equal

$$\underline{(A+[(C+B)/D] + \text{Federal Income Tax}) \times ST}$$

1 - ST

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.C. below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., D is the Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Transmission Plant attributable to NHT, plus an allocation of Intangible and General Plant Depreciation Expense attributable to NHT. To the extent any such amount relating to the Generator Step-up Transformers exist in said balance of Transmission Depreciation Expense, such amounts shall be excluded by further multiplying said balance of Transmission Depreciation Expense by the LNS Plant Allocation Factor. The allocated portion of Intangible and General Plant Depreciation Expense shall be calculated by multiplying Intangible and General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor and further multiplied by the LNS Plant Allocation Factor.

C. Transmission Related Amortization of Investment Tax Credits shall equal the electric Amortization of Investment Tax Credits attributable to NHT, multiplied by the Transmission Plant Allocation Factor. To the extent any such amount relating to the Generator Step-up Transformers exist in said balance of Transmission Related Amortization of Investment Tax Credits, such amounts shall be excluded by further multiplying said balance of Transmission Related Amortization of Investment Tax Credits by the LNS Plant Allocation Factor.

D. Transmission Related Municipal Tax Expense shall equal the total electric municipal tax expense attributable to NHT multiplied by the Transmission Plant Allocation Factor and further multiplied by the LNS Plant Allocation Factor.

E. Transmission Related Payroll Tax Expense shall equal the total payroll tax expense attributable to NHT multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the LNS Transmission Plant Allocation Factor.

F. Transmission Operation and Maintenance Expense shall equal the Transmission Operation and Maintenance Expenses attributable to NHT and excluding any operation and maintenance expenses associated with the Generator Step-up Transformers, which may be included in FERC Account Nos. 560-576.5.

G. Transmission Related Administrative and General Expenses shall equal the sum of (1) the Administrative and General Expenses attributable to NHT multiplied by the Transmission Wages and Salaries Allocation Factor, (2) the Property Insurance attributable to NHT multiplied by the Transmission Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Regulatory Commission Expense attributable to NHT multiplied by the Transmission Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments attributable to NHT, plus specific transmission related General Advertising Expense included in Account 930.1 attributable to NHT. The sum of these components (1) through (3) shall then be multiplied by the LNS Plant Allocation Factor.

H. Transmission Related Regulatory Assessments shall include any FERC assessments associated with transmission service provided under the NHT Tariff, based on the FERC regulations in 18 C.F.R. § 382.201, and as recorded in FERC Account No 408.

I. Transmission Support Expense shall equal the expense for transmission support as incurred by NHT.

J. NEPOOL & ISO Expense shall equal NHT's expense associated with charges assessed NHT pursuant to the Tariff and/or the Restated NEPOOL Agreement.

K. Transmission Support Revenues shall equal NHT's revenue received for transmission support, excluding support revenues associated with generator step-up transformers included in Transmission Plant accounts attributable to NHT, if any.

L. ISO Revenues shall equal the revenues distributed to NHT from the ISO, for network integration transmission service, internal point to point transmission service, and through and out transmission service provided under the OATT, but excluding any incremental revenues associated with FERC-approved ROE adders for RTO participation and for new transmission investment. Such amounts shall be reflected as forecast amounts in each monthly billing statement and shall be reconciled to such actual monthly revenues received by NHT in the billing statement following the month in which such actual monthly revenues are received by NHT, and shall be reconciled with interest as calculated pursuant to

Section 35.19(a) of the Code of Federal Regulations for any over or under estimated amounts.

M. Other Wheeling Revenues shall equal any revenues received by NHT for providing wheeling out services to generators as well as any other short-term, non-firm, or unauthorized use penalty revenues received by NHT associated with the provision of transmission services under this Tariff, not otherwise reflected in Section II . K above.

N. Transmission Rents Received from Electric Property shall equal any Rents from electric property associated with Transmission Plant attributable to NHT as defined in Section II.A.1.(a) above, not reflected in Section II. I. above as Transmission Support Revenues, and excluding support revenues associated with generator step-up transformers included in Transmission Plant accounts attributable to NHT, if any.

ATTACHMENT L TO SCHEDULE 21
NHT CREDITWORTHINESS GUIDE

A. Credit Review: For the purpose of determining the ability of a Transmission Customer to fulfill its financial obligations pursuant to the Tariff, the Transmission Provider shall require commercially reasonable credit review procedures. A creditworthiness review shall be conducted for each Transmission Customer upon its initial request for Transmission Service, and thereafter generally annually, or upon the anniversary of the Transmission Customer's Service Commencement Date, or upon reasonable request by the Transmission Customer. Provided, however, any time that a Transmission Customer experiences any credit downgrade that may place it below the standards specified in Section B, the Transmission Provider reserves the right to re-evaluate the Transmission Customer's creditworthiness pursuant to this Attachment L. Further, if in accordance with Section C.3, the Transmission Provider determines that financial assurances that a Transmission Customer has previously provided pursuant to this Attachment L have become insufficient to protect the Transmission Provider against the risk of non-payment, Transmission Provider can require the Transmission Customer to increase such financial assurances.

B. Creditworthiness: Both new and existing Transmission Customers that, upon their application for Transmission Service and throughout the term of their Service Agreements, satisfy the criteria delineated in this Section B will be considered creditworthy by the Transmission Provider. Such Transmission Customers will not be required to submit financial assurances (including, with respect to new customers, the application deposits that would otherwise be required pursuant to either Sections 17.3 or 29.2 of the Tariff) in order to protect the Transmission Provider from the risk of non-payment. Pursuant to this Section B, if applicable, a Transmission Customer is creditworthy if it has not, pursuant to Section 7.3, Defaulted more than once in the last twelve (12) months and:

B.1. has a Standard and Poor's ("S&P") Long-Term Issuer Credit Rating of BBB- (or better); or a Moody's Investor Service, Inc. ("Moody's") Long-Term Issuer Credit Rating of Baa3 (or better). In the event that a Transmission Customer or its guarantor is rated by both S&P and Moody's, then the Transmission Provider will use the lower of the two ratings; or

B.2. is a borrower from the Rural Utilities Service ("RUS") and has a "Times Interest Earned Ratio" of 1.05 (or better) and a "Debt Service Coverage Ratio" of 1.00 (or better) in the most recent calendar year, or is maintaining the Times Interest Earned Ratio and Debt Service Coverage Ratio as established in the Transmission Customer's RUS Mortgage. The Transmission

Customer must provide appropriate documentation annually, or as agreed-upon by both parties; or

B.3. is a federal agency and its financial obligations under the Tariff are backed by the full faith and credit of the United States; or

B.4. is a municipal or state agency, or a rural electric cooperative (without RUS Debt) that:

B.4.i. if applicable, has been taking Transmission Service for one (1) year and has provided documentation that its financial obligations under the Tariff are backed by the full faith and credit of the municipality or state in which it is established; or

B.4.ii. has provided documentation that under the applicable laws of the state in which it is established, that its financial obligations under the Tariff are deemed to be operating expenses and that the agency or the electric cooperative is required by such applicable laws to devote its revenues first to the payment of its operating and maintenance expenses and the principal and interest of its outstanding obligations prior to payment of all other obligations; or

B.5. the Transmission Customer provides a letter of unconditional and continuing guaranty from its parent company. Such letter of guaranty must be acceptable to the Transmission Provider as to form and substance and can be used only if the guarantor meets, at the time of execution and maintains during the life of the applicable Service Agreement, a minimum credit rating as stated in Section B1. However, to the extent that the guarantor is placed on watch for possible downgrade and has: i) a S&P Long-Term Issuer Credit Rating of BBB (or below); or ii) a Moody's Long- Term Issuer Credit Rating of Baa2 (or below), then the Transmission Customer will be required to provide additional financial assurances as provided in this Attachment L. A draft, acceptable form of a continuing guaranty shall be posted on OASIS; or

B.6. the Transmission Customer has been in business for at least one (1) year and provides its most recent audited financial statements to the Transmission Provider which demonstrate that the Transmission Customer meets standards that are at least equivalent to the standards underlying a S&P Long-Term Issuer Credit Rating of BBB- (or better) or a Moody's Long-Term Issuer Credit Rating Baa3 (or better); provided that if the Transmission Customer is not found to be creditworthy pursuant to this Section B.6, then pursuant to Section C.5, the Transmission

Provider will inform the Transmission Customer of the reasons for that determination.

C. Creditworthiness Procedures: The Transmission Provider shall require financial assurances in accordance with the procedures set forth below:

C.1. New Transmission Service: Upon its execution of a Transmission Service Agreement, a new Transmission Customer (or an existing Transmission Customer requesting new service) that does not meet the creditworthiness requirements established in Section B shall either:

C.1.i. provide an unconditional and irrevocable standby letter of credit, or an alternative form of security identified in Section E, in an amount equal to two (2) times the estimated charges for transmission and ancillary services including losses (rounded to the nearest thousand dollar increment) for an average month for that type of service.

C.1.i.a. Provided, however, uncreditworthy customers applying for Non-Firm Point-to-Point Transmission Service shall provide an unconditional and irrevocable standby letter of credit, or an alternative form of security identified in Section E, in an amount equal to three (3) times the estimated charges for transmission and ancillary services including losses (rounded to the nearest thousand dollar increment) for an average month for that type of service.

C.1.i.b. The estimated average monthly charge for Long-Term Firm Point-to-Point and Network Integration Transmission Service shall be based on the Long-Term Firm Point-to-Point Transmission Service rate for the reserved capacity or the load being served, respectively. Any letter of credit provided by a Transmission Customer must be acceptable to the Transmission Provider and consistent with the Commercial practices established by the Uniform Commercial Code. All costs associated with the issuance and maintenance of a letter of credit shall be paid by the Transmission Customer. A draft, acceptable form of a letter of credit shall be posted on OASIS; or

C.1.ii. arrange to prepay for Transmission Service as follows:

C.1.ii.a. For requests with a term greater than one month, the prepayment for the first month must be made when the Transmission Customer makes its reservation for that Transmission Service request, and no later than five (5) business days before the commencement of service. Prepayments for the subsequent months of service must be made no later than five (5) business days prior to the beginning of each month;

C.1.ii.b. For service for one (1) month or less, the Transmission Customer shall pay the total charge for service when it makes the request, and no later than five (5) business days prior to the commencement of service. For Network Integration Transmission Service customers, the advance payment for each month shall be based on a reasonable estimate by the Transmission Provider of the charge for that month. The Transmission Provider shall pay interest on any prepayments made pursuant to this Section C.1(ii) at the rates established in 18 C.F.R.§ 35.19a(2)(iii).

Where applicable, all uncreditworthy customers applying for new service that fail to meet Section B's creditworthiness criteria shall also pay the application deposits required by either Sections 17.3 or 29.2 of the Tariff.

C.2. Existing Transmission Customers: Any Transmission Customer that originally meets the creditworthiness requirements of Section B and subsequently fails to meet those requirements after it requests Transmission Service but before termination of that service shall:

C.2.i. Within five (5) business days of receipt of a notice from the Transmission Provider, provide the Transmission Provider an acceptable form of financial assurance permitted by this Attachment L that is equal to the Transmission Customer's average monthly Transmission Services charge for the applicable Transmission Service; and

C.2.ii. Within thirty-five (35) calendar days of such notification, provide the Transmission Provider either: (a) an unconditional and irrevocable letter of credit that is equal to two (2) times the Transmission Customer's average monthly Transmission Services charge for the applicable Transmission Service, including losses; or (b) an equivalent alternate form of financial assurance pursuant to Section E; or

C.2.iii. arrange to prepay for Transmission Service in accordance with the procedures set forth in Section C.1(ii). Provided, however, the Transmission Customer must provide the Transmission Provider payment for all outstanding Transmission Service charges no later than five (5) business days prior to the beginning of the next month.

C.3. The average monthly Transmission Service charge for Sections C.2 (i) and (ii) will be based on the Transmission Customer's charges during the preceding twelve (12) months for the applicable Transmission Service. If the Transmission Customer has not yet been purchasing service for twelve (12) months, then the average will be the higher of either: (a) the average of the monthly cost of service to date; or (b) the average value specified in Section C.1.

C.4. Right to Protect Against Additional Risk of Non-payment: All financial assurances calculated and collected pursuant to Sections C.1 and C.2 must be sufficient to protect the Transmission Provider from the risk of non-payment with respect to an uncreditworthy Transmission Customer during the entire term of such customer's Transmission Service Agreement. Accordingly, after an uncreditworthy customer has provided the Transmission Provider financial assurances pursuant to Sections C.1 or C.2, the Transmission Provider will monitor the amount of such customer's Transmission Services charges to ensure that it has provided a sufficient amount of security to protect the Transmission Provider against the risk of non-payment. If a Transmission Customer is not in Default pursuant to Section 7.3, then the Transmission Customer shall provide the adjusted amount of financial assurances required pursuant to this Section C.3 within thirty-five (35) calendar days of receipt of a notice from the Transmission Provider. A Transmission Customer will not be required to adjust its financial assurances pursuant to this Section C.3 more than twice every twelve (12) months.

C.4.i. Adjustment of Financial Assurances Provided Pursuant to Section C.1: If a Transmission Customer provided security when initially applying for service pursuant to Section C.1 and the Transmission Provider determines that the Transmission Customer's actual average monthly Transmission Services charges over any subsequent twelve (12) month period exceed the original average estimated charges for transmission and ancillary services upon which a financial assurance initially was based, then the Transmission Customer must increase its financial assurance to be equal to three (3) times its current actual average monthly purchases of Transmission Service. The value of the actual average monthly purchases of Transmission Services evaluated pursuant to this Section C.3.i will be based on the preceding twelve (12) month period as measured from the date immediately prior to the Transmission Provider's credit re-evaluation. Pursuant to Section C.1, the sum of any required security will include, where applicable, any application deposits required pursuant to Sections 17.3 or 29.2.

C.4.ii. Adjustment of Financial Assurances Provided Pursuant to Section C.2: If a Transmission Customer provided security pursuant to Section C.2 and the Transmission Provider determines that the customer's actual average monthly purchases of Transmission Services over a subsequent twelve (12) month period exceed the original monthly average for charges for transmission and ancillary services upon which the amount of a financial assurance initially was based, then the Transmission Customer must increase the amount of its financial assurance to be equal to three (3) times its actual average purchases of Transmission Service. The value of the actual average monthly purchases of Transmission Services evaluated pursuant to this Section C.3.ii will be based on the preceding twelve (12) month period as measured from the date immediately prior to the Transmission Provider's credit reevaluation.

C.4.iii. Transmission Customer Right To Request A Credit Reevaluation: Transmission Customers may make reasonable requests for the Transmission Provider to re-evaluate their creditworthiness pursuant to the relevant standard established in either Section C.4.i or C.4.ii. Based on such a re-evaluation, if appropriate, the Transmission Provider will reduce the amount of financial security requested from a Transmission Customer if an analysis of its transmission usage over the preceding twelve (12) month period indicates that the customer has provided security in excess of that required by this Attachment L.

C.4.iv. Right to Draw Upon Financial Assurances Upon Default: The Transmission Provider has the right to liquidate, or draw upon, all or a portion of a Transmission Customer's form of financial assurance(s) in order to satisfy a Transmission Customer's total net obligations to the Transmission Provider upon a Default pursuant to Section 7.3 of the Tariff. A Transmission Customer shall replace any liquidated, or drawn-upon, financial assurances pursuant to the timeframe delineated in Section C.2.

C.5. Notice: The Transmission Provider's notification to a Transmission Customer will inform the Transmission Customer:

C.5.i. that it is not creditworthy pursuant to this Attachment L, or in accordance with Section C.3, that it must adjust previously provided financial assurances;

C.5.ii. why it is not creditworthy or why it must adjust previously provided financial assurances;

C.5.iii. that it must provide any required financial assurances by the deadlines specified in the notice; and

C.5.iv. that the Transmission Provider may take corrective actions, including suspension of service pursuant to Section D, if the Transmission Customer fails to provide the required financial assurances by the specified deadlines.

All notices sent to a Transmission Customer pursuant to this Section C.5 shall be in writing and shall be sent to the Transmission Customer by telefax or overnight courier at the respective telephone number or courier address specified in the Transmission Customer's application for Transmission Service (or such other address as the Transmission Customer may have designated in writing to the Transmission Provider) and shall become effective upon actual receipt as evidenced by telefax confirmation sheet or tracking information provided by the overnight courier, as the case may be.

D. **Suspension of Service:** The Transmission Provider may suspend Transmission Service if:

D.1. a Transmission Customer that is not in Default pursuant to Section 7.3 of this Tariff fails to provide the entirety of three (3) months of required financial assurances (or the entirety of any additional financial assurances required pursuant to Section C.3 or C.4) within thirty-five (35) calendar days after Transmission Provider's notification to such Transmission Customer pursuant to Section C.3. Transmission Provider will provide at least thirty (30) calendar days written notice to the Commission before suspending Transmission Service; or

D.2. a Transmission Customer that is in Default pursuant to Section 7.3 of this Tariff fails to provide the entirety of the one month's requested financial assurance within five (5) business days after the Transmission Provider's notification to such Transmission Customer pursuant to Section C. Transmission Provider will provide five (5) calendar days written notice to the Commission before suspending Transmission Service. Any notices sent to the Transmission Customer and to the Commission pursuant to this Section D may be telefaxed/mailed concurrently. The suspension of service shall continue only for as long as the circumstances that entitle the Transmission Provider to suspend service continue. A Transmission Customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

E. Alternative Forms of Financial Assurance: Transmission Customer may provide the following as acceptable alternative forms of financial assurance in the amounts specified in Sections C.1 or C.2:

E.1. Cash Deposit: The Transmission Customer may provide a cash deposit that will be retained during the term of (and until full and final payment and performance of) any relevant Service Agreement. If a Transmission Customer has submitted multiple requests for Transmission Service, then the Transmission Provider may require a cash deposit for each Service Agreement. Cash deposits submitted as a form of financial assurance will be held by the Transmission Provider and the Transmission Customer will be paid an interest rate that is equal to the interest rate earned on the escrow account in which the cash deposit is held. The cash deposit can be made by wiring immediately available funds to the Transmission Provider's account.

E.2. Surety Bond: The Transmission Customer may provide, and maintain in effect during the term of (and until full and final payment and performance of) the applicable Service Agreement, a surety bond issued by a financial institution acceptable to Transmission Provider. If a Transmission Customer has submitted multiple requests for Transmission Service, then the Transmission Provider may require a surety bond for each Service Agreement. All costs associated with the issuance and maintenance of a surety bond shall be paid by the Transmission Customer. A draft, acceptable form of a surety bond shall be posted on OASIS.

F. Return of Financial Assurances upon Re-establishment of Creditworthiness: If a Transmission Customer re-establishes creditworthiness pursuant to Section B, then upon verification by Transmission Provider, all financial assurances will be returned (or terminated, if applicable) to the Transmission Customer with interest (if applicable), upon payment of all past due balances to the Transmission Provider pursuant to the Tariff.

SCHEDULE 21 - NSTAR

NSTAR ELECTRIC COMPANY

LOCAL SERVICE SCHEDULE

I COMMON SERVICE PROVISIONS

1.0 DEFINITIONS

Whenever used in this Local Service Schedule, in either the singular or plural number, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Local Service Schedule that are not defined in this Local Service Schedule shall have the meanings set forth in the Tariff or customarily attributed to such terms by the electric utility industry in New England. Where there is a conflict between this Local Service Schedule and the Tariff, the terms here shall apply.

1.1 Annual Transmission Revenue Requirements

The total annual cost of the Transmission System shall be the amount specified in Attachment D until amended by NSTAR or modified by the Commission.

1.2 Annual True-Up

The reconciliation to actual costs of the estimated costs used for billing purposes under Section 4.0 of this Local Service Schedule for any Service Year.

1.3 Designated Agent

Any entity that performs actions or functions on behalf of NSTAR, an Eligible Customer, or the Transmission Customer required under the Local Service Schedule.

1.4 Firm Local Point-To-Point Service

Transmission service under this Local Service Schedule that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to this Local Service Schedule.

1.5 Load Ratio Share

Ratio of a Transmission Customer's most recently reported Monthly Network Load in the case of Network Customers and including, where applicable, the Reserved Capacity of Transmission Customers taking Firm Local Point-To-Point Service, to the total load of Network Customers and the Reserved Capacity of Transmission Customers taking Firm Local Point-To-Point Service.

1.6 Local Network

All transmission facilities constituting NSTAR's non-Pool Transmission Facilities (Non-PTF), excluding the Phase I/II HVDC-TF, which is defined in Schedule 20A of this OATT.

1.7 Local Network Load

The load that a Network Customer designates for Local Network Service under this Local Service Schedule. The Network Customer's Local Network Load shall include all load designated by the Network Customer, (including losses). A Network Customer may elect to designate less than its total load as Local Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete Points of Delivery as Local Network Load, the Eligible Customer is responsible for making separate arrangements under this Local Service Schedule for any Local Point-To-Point Service that may be necessary for such non-designated load.

1.8 Local Network Service

The transmission service provided under this Local Service Schedule over NSTAR's Local Network.

1.9 Local Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support NSTAR's overall Transmission System for the general benefit of all users of such Transmission System.

1.10 Local Point-To-Point Service

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under this Local Service Schedule over NSTAR's Local Network.

1.11 Long-Term Firm Local Point-To-Point Service

Firm Local Point-To-Point Service provided under this Local Service Schedule with a term of one year or more.

1.12 Monthly Network Load

A Network Customer's hourly load (including its designated Local Network Load not physically interconnected with NSTAR under Section 15.2 of this Local Service Schedule) coincident with NSTAR's Monthly Transmission System Peak.

1.13 Native Load Customers

The wholesale and retail power customers of NSTAR on whose behalf NSTAR, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate NSTAR's system to meet the reliable electric needs of such customers.

1.14 NERC

North American Electric Reliability Council, the Electric Reliability Organization of the United States.

1.15 Non-Firm Local Point-To-Point Service

Local Point-To-Point Service under this Local Service Schedule that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in this Local Service Schedule. Non-Firm Local Point-To-Point Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.16 NPCC

Northeast Power Coordinating Council, a regional reliability council of NERC.

1.17 NSTAR

NSTAR Electric Company, a Massachusetts Corporation with offices located at 800 Boylston Street, Boston, Massachusetts 02199. NSTAR owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides service pursuant to the rates, terms and conditions of this Local Service Schedule and the applicable terms and conditions of this Local Service Schedule.

1.18 NSTAR's Monthly Transmission System Load

NSTAR's Monthly Transmission System Peak minus the coincident peak usage of all Firm Local

Point-To-Point Service customers pursuant to Part II of this Local Service Schedule plus the Reserved Capacity of all Firm Local Point-To-Point Service customers.

1.19 NSTAR's Monthly Transmission System Peak

The maximum firm usage of NSTAR's Transmission System in a calendar month.

1.20 Parties

NSTAR and the Transmission Customer receiving service under this Local Service Schedule.

1.21 Point(s) of Delivery

Point(s) on NSTAR's Transmission System where capacity and energy transmitted by NSTAR will be made available to the Receiving Party under this Local Service Schedule. The Point(s) of Delivery shall be specified in the Transmission Service Agreement.

1.22 Point(s) of Receipt

Point(s) of interconnection on NSTAR's Transmission System where capacity and energy will be made available to NSTAR by the Delivering Party under this Local Service Schedule. The Point(s) of Receipt shall be specified in the Transmission Service Agreement.

1.23 Service Year

The calendar year in which the Transmission Customer is receiving service under this Local Service Schedule.

1.24 Short-Term Firm Local Point-To-Point Service

Firm Local Point-To-Point Service under this Local Service Schedule with a term of less than one year.

1.25 Transmission System

The facilities owned, controlled or operated by NSTAR that are used to provide transmission service under this Local Service Schedule.

2.0 ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. NSTAR is required to provide and the Transmission Customer is required to purchase the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Supplemental End-Use Reactive Support Service.

In addition, the Transmission Customer is required to purchase additional Ancillary Services under the terms and conditions of the Tariff. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve. NSTAR shall also assess a penalty for any unauthorized use of Ancillary Services by the Transmission Customer, based on the amount of transmission service it used but did not reserve, using the rate shown for such Ancillary Service.

The prices and/or compensation methods for Local System Control and Dispatch Services and Supplemental End-Use Reactive Support Service are described in Attachment D and Schedule 2, respectively, attached to and made a part of this Local Service Schedule. Three principal requirements apply to discounts for Ancillary Services provided by NSTAR in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on NSTAR's system.

3.0 CREDITWORTHINESS

NSTAR's creditworthiness procedures are specified in Attachment L to this Local Service Schedule.

4.0 BILLING AND PAYMENT

4.1 Billing Procedure

Within a reasonable time after the first day of each month, NSTAR shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Local Service Schedule during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to NSTAR, or by wire transfer to a bank named by NSTAR.

Billings hereunder shall be based on cost estimates made by NSTAR subject to Annual True-up when actual costs for the Service Year are known. Such Annual True-up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-up relates. To the extent bill adjustments are required pursuant to the Annual True-up, such adjustments shall bear interest calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

(i) The Annual True-Up shall be performed by recalculation of the costs for the Service Year based on actual cost and load information as reported in the FERC Form 1 for that Service Year and shall develop thereby an Embedded Cost Charge, defined in Section 16.1, to be used in the said Annual True-Up. The Annual True-Up shall also include the CWIP Supplement referred to in clause (ix).

(ii) The Annual True-Up will be filed with FERC by NSTAR in an informational filing on or before May 31 of the year following the Service Year and posted on NSTAR's website. The Annual True-Up so filed and posted shall include the actual report showing the basis for the computation of the Postretirement Benefits Other Than Pensions ("PBOP") component of "Administrative and General Expense" and shall also show the basis for the allocation of the PBOP expense to the service provided under this Local Service Schedule; provided that the information so filed and posted shall not include confidential information. The informational filing shall include a Benefits Labor Loader showing the basis for such allocation of both PBOP and prepaid pension costs. On request, NSTAR shall provide any Network Customer the Annual

True-Up by May 31 of the year following the Service Year. Any difference between the estimated Embedded Cost Charge and the actual Embedded Cost Charge shall be collected from or refunded to the Network Customer in the month of June of the calendar year following the Service Year.

(iii) The Annual True-Up provided pursuant to Section 4.1(ii) shall include an attestation by a Company officer that "to the best of the affiant's knowledge, information and belief the data employed in the Annual True-Up reflect NSTAR's per book costs for the Service Year, conform to NSTAR's FERC Form 1 Report for the Service Year, conform in all material respects to the FERC Uniform System of Accounts, and have been developed in accordance with the provisions of this rate schedule."

(iv) The Annual True-Up shall also be accompanied by supplementary information which shall (i) detail any data used in the Annual True-Up not directly taken from NSTAR's FERC Form 1 Report and (ii) identify any FERC Form 1 Account used to record expenses during the Service Year that was not used in the preceding Service Year. The supplementary information shall be certified by an officer of NSTAR.

(v) There shall be an "Audit Period" that will extend from July 1 through September 30 of the year following the Service Year; provided that NSTAR and the Network Customer may agree to extend the Audit Period beyond September 30 by their mutual written agreement. During the Audit Period, any Network Customer shall have the right to conduct an audit or other inspection of the actual data used in the Annual True-Up and/or request additional information not included with the Annual True-Up. NSTAR shall not withhold information, including PBOP information, on grounds of confidentiality, but is entitled to make such information available pursuant to a confidentiality agreement and to restrict access to non-competitive duty personnel and to other personnel whose receipt of the information would not be in violation of the Standards and/or Code of Conduct as prescribed by FERC. During the Audit Period, NSTAR shall exercise all commercially reasonable efforts to provide the Network Customer, within 10 business days, such additional information as the Network Customer may request in order to understand the Annual True-Up. To the extent requested, NSTAR shall meet with any Network Customer to provide such additional information, explanation, and/or clarification regarding the Annual True-Up as the Network Customer may request.

(vi) During the Audit Period, the Network Customer shall have the right to request NSTAR to adjust the Annual True-Up, and any refunds it received or payments it made, pursuant to the Annual True-Up to the extent of any discrepancy between the data employed by NSTAR in performing the Annual True-Up and the actual data for the Service Year or in the event NSTAR developed the Annual True-Up in a manner that is inconsistent with this rate schedule.

(vii) If NSTAR does not agree to the Network Customer's request, as set forth in subparagraph (vi), and if NSTAR and the Network Customer are in disagreement as to any component of the Annual True-Up, the Network Customer within thirty days following the conclusion of the Audit Period may request and NSTAR shall agree to non-binding dispute resolution either conducted with the FERC Staff or otherwise at the Network Customer's choice. The Network Customer may file a complaint with the Commission within thirty days following completion of the audit period or the dispute resolution process and shall specify in that complaint the component or components of the Annual True Up that the Network Customer disputes. In the event such a complaint is filed, the disputed component or components of the Annual True Up shall be subject to refund as of the first day of the Service Year pending the results of the Commission investigation instituted as a result of such complaint. If the Network Customer fails to object to the Annual True-Up within thirty days following conclusion of the Audit Period, NSTAR's costs for the Service Year shall be deemed final, and its revenues from the Network Customer for the Service Year shall not be subject to refund; provided that the deadline for such an objection shall (i) be extended for ninety days following the date NSTAR makes any subsequent change to its Form 1 data for the Service Year that affects the Annual True-Up and (ii) shall not apply if the Commission prior to December 31st of the calendar year following the Service Year institutes its own investigation of NSTAR's Service Year costs.

(viii) Subject to the limitation that the Massachusetts Attorney General does not make or receive transmission payments or refunds, the Massachusetts Attorney General shall have the same procedural rights under this Section 4.0 as a Network Customer. This in no way obligates the Massachusetts Attorney General to the dispute resolution or arbitration procedures outlined in Sections 5.1 and 5.2.

(ix) The Annual True-Up shall include a CWIP Supplement, which shall apply to the Service Year, shall be filed with FERC by NSTAR in an informational filing on or before June 30 of the year following the Service Year and posted on NSTAR's website to the extent it does not include critical energy infrastructure information or other confidential information. The CWIP Supplement shall include NSTAR Electric's most recent annual construction forecast. The CWIP Supplement shall provide for each project included in rate base during the Service Year the actual amounts of CWIP recorded for each project, the related accounts, such as AFUDC and regulatory liability, inclusive of all subaccounts, and the resulting effect on the CWIP revenue requirement in line item detail. The CWIP Supplement shall also identify any changes in NSTAR's accounting practices related to the accrual of AFUDC and the inclusion of CWIP in rate base or related to ensuring that AFUDC is not accrued on CWIP balances that have been included in rate base.

For each "new project" (a project that is estimated to enter rate base for the first time in the Service Year), the CWIP Supplement shall provide, to the extent not included in the construction forecast, a detailed statement of the reasons for undertaking the project, the benefits to be derived from the project, and the alternatives to or consequences of not undertaking the project. For each "pre-existing project" (a project that entered rate base prior to the Service Year), the CWIP Supplement shall include an update on the status of the project including any material change regarding the estimated cost of the project, the estimated in-service date and/or project timelines, and whether there is any change in the need for the project or in alternatives to the project. CWIP associated with a project cannot be included in the rate base for a Service Year unless it is included in the CWIP Supplement applicable to the Service Year.

The CWIP Supplement applicable to a Service Year shall include a CWIP Work Order/Project Reference Aid ("Reference Aid") that distinguishes between new projects and pre-existing projects and that provides for each project, whether new or pre-existing, ISO information, to the extent such information is available and applies to a project, and NSTAR information. The ISO information shall include a short description of the project, the year the project was approved through the ISO process, and the project identification number for ISO purposes. The NSTAR information shall include reference to the most recent NSTAR construction planning forecast in which the project appeared, the page of the plan at which the project description begins, the NSTAR numeric project designation, the NSTAR description of the project, the work order or work orders associated with the project, and a description of each work order. The Reference Aid shall present this information in a format so that the ISO information related to a project can be correlated with the NSTAR information related to a project. The Reference Aid, as described above, is based on current ISO and NSTAR tracking systems for projects under or proposed for construction and is to be modified to present equivalent information if and to the extent the ISO and/or NSTAR tracking system is modified.

The 50% of transmission-related CWIP included in rate base is subject to the Annual True-Up and dispute resolution provisions of this Section 4.1 regarding differences between actual and estimated costs. In addition, the CWIP included in rate base for a project shall be subject to refund as provided below to the extent the Commission makes a finding that the inclusion of such CWIP in rate base is unjust and unreasonable. In the case of a new project, the refund amount shall be the CWIP actually recovered from customers from the date of collection to the date of refund. In any proceeding regarding a new project, NSTAR shall bear the burden of proving that inclusion of CWIP related to the new project in rate base is just and reasonable. In the case of a pre-existing project, the refund amount shall be for the CWIP actually recovered from customers from the prospective refund effective date specified by the Commission pursuant to the provisions of Section 206 of the Federal Power Act to the date of refund. All refunds shall include interest at the rate specified in 18 C.F.R. § 35.19a(a)(2)(iii). Any customer and/or the Massachusetts Attorney General can request that the Commission institute an investigation into the justness and reasonableness of including CWIP for any project in rate base and the Commission may institute such an investigation sua sponte.

Nothing in this Clause (ix) authorizes the inclusion in rate base of more than 50% of the CWIP balance attributable to a project. Absent a Commission finding of imprudence, NSTAR shall be entitled to accrue AFUDC as to any CWIP that is excluded from rate base. The Commission's institution of an investigation as to the justness and reasonableness of including CWIP associated with a project in rate base does not affect the timing or the finality of other components of the Annual True-Up as established by clause (vii) hereof.

With the exception of curtailment penalty charges pursuant to Section 16.2 and Schedule 3, paragraph 5 and Schedule 4, paragraph 6, any Annual True-Up rendered under this Local Service Schedule and any other monthly bill to which the Annual True-Up relates shall be binding on both Parties one (1) year from the date of NSTAR's Annual True-Up, unless previously disputed pursuant to this section or Section 4.3 of this Local Service Schedule.

4.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by NSTAR.

4.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to NSTAR on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after NSTAR notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, NSTAR may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request.

In the event of a billing dispute between NSTAR and the Transmission Customer, NSTAR will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then NSTAR may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5.0 DISPUTE RESOLUTION PROCEDURES

5.1 Internal Dispute Resolution Procedures

Any dispute between a Transmission Customer and NSTAR involving transmission service under this Local Service Schedule (excluding applications for rate changes or other changes to this Local Service Schedule, or to any Service Agreement entered into under this Local Service Schedule, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of NSTAR and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

5.2 External Arbitration Procedures

Any arbitration initiated under this Local Service Schedule shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or ISO rules.

5.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Local Service Schedule and any Service Agreement entered into under this Local Service Schedule and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

5.4 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(a) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(b) one half the cost of the single arbitrator jointly chosen by the Parties.

5.5 Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

II LOCAL POINT-TO-POINT SERVICE

6.0 NATURE OF FIRM LOCAL POINT-TO-POINT SERVICE

6.1 Curtailment of Firm Local Point-To-Point Service

In the event a Transmission Customer (including Third-Party Sales by NSTAR) fails to curtail a transaction when requested to do so by NSTAR, the Local Control Center and/or ISO, as appropriate and pursuant to this Section, NSTAR shall assess a penalty charge to the Transmission Customer. Said penalty charge will be determined in accordance with this Local Service Schedule.

In the event NSTAR, the Local Control Center or ISO exercises their rights to effect a Curtailment, in whole or in part, of Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the Transmission Customer.

6.2 Classification of Firm Local Point-To-Point Service

(a) The Transmission Customer taking Firm Local Point-To-Point Service may, (1) change its Points of Receipt and Delivery to obtain service on a non-firm basis consistent with the terms of Part I, Section 10(a) of Schedule 21 of the OATT or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Part I, Section 10(b) of Schedule 21 of the OATT; provided that NSTAR continues to be compensated for any costs associated with the construction or upgrading of facilities associated with the original firm service.

(b) In the event that a Transmission Customer's use of the Transmission System (including Third-Party Sales by NSTAR) exceeds that Transmission Customer's Reserved Capacity at any Point of Receipt or Point of Delivery in any hour, NSTAR will charge the Transmission Customer a penalty charge in accordance with Section 10 and Schedule 3 of this Local Service Schedule.

(c) Under no circumstance will NSTAR be obligated to provide Control Area Ancillary Services to the Transmission Customer in support of any excess capacity (i.e., capacity in excess of Transmission Customer's Reserved Capacity).

7.0 NATURE OF NON-FIRM LOCAL POINT-TO-POINT SERVICE

7.1 Classification of Non-Firm Local Point-To-Point Service

In the event that a Transmission Customer's use of the Transmission System (including Third-Party Sales by NSTAR) exceeds that Transmission Customer's non-firm Reserved Capacity at any Point of Receipt or Point of Delivery, NSTAR will charge the Transmission Customer a penalty charge in accordance with Section 10 and Schedule 4 of this Local Service Schedule for such excess. Under no circumstance will NSTAR be obligated to provide Control Area Ancillary Services to the Transmission Customer in support of any excess capacity (i.e., capacity in excess of Transmission Customer's Reserved Capacity).

7.2 Curtailment or Interruption of Service

In the event a Transmission Customer (including Third-Party Sales by NSTAR) fails to implement a Curtailment or Interruption when requested to do so by NSTAR, the Local Control Center and/or ISO, as appropriate and pursuant to this Section, NSTAR shall assess a penalty charge. Said penalty charge will be determined in accordance with Section 10 and Schedule 4 of this Local Service Schedule.

In the event NSTAR, the Local Control Center and/or ISO exercises its rights to effect a Curtailment, in whole or part, of Non-Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the Transmission Customer.

In the event NSTAR, the Local Control Center and/or ISO exercises its rights to effect an Interruption, in whole or part, of Non-Firm Local Point-To-Point Service, the charge payable by the Transmission Customer shall be computed as if the term of service actually rendered were the term of service reserved; provided that an adjustment of the charge shall be made only when the Interruption is initiated by NSTAR, the Local Control Center and/or ISO, not when the customer fails to deliver energy to NSTAR.

8.0 SERVICE AVAILABILITY

8.1 Real Power Losses

Real power losses associated with transactions on NSTAR's Local Network shall be determined based on estimated average system losses for metering points on NSTAR's Local Network; the loss factor will be three and one tenth percent (3.1%).

8.2 Load Shedding

To the extent that a system contingency exists on the NSTAR Transmission System or the New England Transmission System and NSTAR, the Local Control Center or ISO, as appropriate, determines that it is necessary to shed load, the Parties shall shed load in accordance with the procedures specified by NSTAR, the Local Control Center and/or ISO.

9.0 METERING

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under the Local Service Schedule and to communicate the information to NSTAR. However, NSTAR reserves the right to determine and approve any and all metering equipment and the metering installation design, such approval not to be unreasonably withheld.

All meters, including any recording devices or telemetry equipment must be operated and maintained in accordance with ISO Operating Procedures. Unless otherwise agreed, such equipment shall remain the property of NSTAR.

If at any time any metering equipment owned by NSTAR (or the Transmission Customer, if so agreed) is found to be inaccurate in excess of two percent (2%), up or down, the owner of the metering equipment shall cause it to be made accurate or replaced and the meter readings and rate computation for the period of inaccuracy shall be adjusted to correct such inaccuracy so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the next preceding month shall be made except by agreement of the Parties. In addition to an annual routine test, the owner of the metering equipment shall cause such equipment to be tested at any time upon written request of the other Party. If such equipment proves accurate within two percent (2%), up or down, the expense of the test shall be borne by the Party requesting the test. The determination of percent accuracy shall be in accordance with the weighted average percent registration as described in ANSI C12.1-1988, Section 6.1.8.1. The owner of the metering equipment shall comply with any reasonable request of the other Party concerning the sealing of meters, the presence of a representative when the seals are broken and tests are made, and other matters affecting the accuracy of the measurement of electricity hereunder.

10.0 COMPENSATION FOR LOCAL POINT-TO-POINT SERVICE

Rates for Firm and Non-Firm Local Point-To-Point Service shall be determined as set forth in the Schedules appended to this Local Service Schedule: Firm Local Point-To-Point Service (Schedule 3) and Non-Firm Local Point-To-Point Service (Schedule 4). Such rates shall be determined on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that

Service Year, and an appropriate billing adjustment shall be made pursuant to Section 4 of this Local Service Schedule.

NSTAR shall use this Local Service Schedule to make its Third-Party Sales to be transmitted as Local Point-To-Point Service. NSTAR shall account for such use at the applicable rates, pursuant to Section II.8.5 of the Tariff.

11.0 STRANDED COST RECOVERY

NSTAR may seek to recover stranded costs from the Transmission Customer pursuant to this Local Service Schedule in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, NSTAR must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

III LOCAL NETWORK SERVICE

12.0 NATURE OF LOCAL NETWORK SERVICE

12.1 Real Power Losses

Real power losses associated with transactions on Non-PTF shall be determined based on estimated average system losses for metering points on NSTAR's Local Network; the loss factor will be three and one tenth percent (3.1%).

12.2 Metering

Unless agreed otherwise, all meters, including any recording devices or telemetry equipment shall be owned, operated, maintained and tested by NSTAR or its Designated Agent in accordance with ISO Operating Procedures at the Transmission Customer's expense. NSTAR shall provide access to metering data, including telephone line access, which may reasonably be required to facilitate measurement and billing under a Service Agreement at the requesting Party's expense.

NSTAR reserves the sole right to determine appropriate metering installations. When new metering equipment is required, it shall be supplied by NSTAR, at the Transmission Customer's expense, including applicable taxes, and overhead costs, in conformity with ISO Operating Procedures.

If at any time any metering equipment owned by NSTAR (or Transmission Customer, if so agreed) is found to be inaccurate in excess of two percent (2%), up or down, the owner of the metering equipment shall cause it to be made accurate or replaced and the meter readings and rate computation for the period of inaccuracy shall be adjusted to correct such inaccuracy so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the next preceding month shall be made except by agreement of the Parties. In addition to an annual routine test, the owner of the metering equipment shall cause such equipment to be tested at any time upon written request of the other Party.

If such equipment proves accurate within two percent (2%), up or down, the expense of the test shall be borne by the Party requesting the test. The determination of percent accuracy shall be in accordance with the weighted average percent registration as described in ANSI C12.1-1988, Section 6.1.8.1. The owner of the metering equipment shall comply with any reasonable request of the other Party concerning the sealing of meters, the presence of a representative when the seals are broken and tests are made, and other matters affecting the accuracy of the measurement of electricity hereunder.

13.0 NETWORK RESOURCES

13.1 Operation of Network Resources

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or NSTAR's Control Area such that the output of those facilities exceeds its designated Local Network Load, plus Non-Firm Sales delivered pursuant to Part II of this Local Service Schedule, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of NSTAR to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System.

13.2 Transmission Arrangements for Network Resources Not Physically Interconnected With

NSTAR

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with NSTAR's Transmission System. NSTAR will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

13.3 Use of Interface Capacity by the Network Customer

Unless otherwise provided under the Tariff, there is no limitation upon a Network Customer's use of NSTAR's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, unless otherwise provided by the Tariff, a Network Customer's use of NSTAR's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

13.4 Network Customer Owned Transmission Facilities

The Network Customer that owns existing transmission facilities that are integrated with NSTAR's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of NSTAR to serve its power and transmission customers. For facilities constructed by the Network Customer subsequent to the Service Commencement Date under this Local Service Schedule, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with NSTAR. Calculation of the credit shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

14.0 DESIGNATION OF LOCAL NETWORK LOAD

14.1 Local Network Load

The Network Customer must designate the individual Local Network Loads on whose behalf NSTAR will provide Local Network Service. The Local Network Loads shall be specified in the Service Agreement.

14.2 Local Network Load Not Physically Interconnected with NSTAR

This section applies to both initial designation pursuant to Section 15.1 and the subsequent addition of new Local Network Load not physically interconnected with NSTAR. To the extent that the Network Customer desires to obtain transmission service for a load outside NSTAR's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Local Network Load for all purposes under this Local Service Schedule and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Service under this Local Service Schedule.

To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this section, the request must be made through a modification of service pursuant to a new Application.

15.0 LOAD SHEDDING AND CURTAILMENTS

15.1 Procedures

Prior to the Service Commencement Date, NSTAR and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the OATT with the objective of responding to contingencies on the Transmission System. The Parties will implement such programs during any period when NSTAR, the Local Control Center or ISO, as appropriate, determines that a system contingency exists and such procedures are necessary to alleviate such contingency. NSTAR will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

15.2 Allocation of Curtailments

NSTAR shall, on a non-discriminatory basis, effect a Curtailment of the transaction(s) that effectively relieves the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by NSTAR and Network Customer in proportion to their respective Load Ratio Shares. NSTAR shall not direct the Network Customer to effect a Curtailment of schedules to an extent greater than NSTAR would effect a Curtailment of NSTAR's schedules under similar circumstances.

15.3 Load Shedding

To the extent that a system contingency exists on NSTAR's Transmission System and ISO, the Local Control Center or NSTAR, as appropriate, determines that it is necessary for NSTAR, Local Point-to-Point Customers and Network Customers to shed load, the Parties shall shed load in accordance with the OATT.

15.4 System Reliability

Any Curtailment of Local Network Service will be not unduly discriminatory relative to NSTAR's use of the Transmission System on behalf of its Native Load Customers. In the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures, NSTAR shall assess a penalty charge. Said penalty charge will be determined in accordance with Section 16.2.

16.0 RATES AND CHARGES

Rates for Local Network Service shall be determined as set forth in this Section 16 on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and all appropriate billing adjustments shall be made pursuant to Section 4 of this Local Service Schedule.

The Network Customer shall pay NSTAR for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

16.1 Monthly Demand Charge

The Network Customer shall pay a Monthly Demand Charge which shall be the Embedded Cost Charge. The Embedded Cost Charge shall be determined by multiplying the Network Customer's Load Ratio Share by one twelfth (1/12) of NSTAR's Annual Transmission Revenue Requirements, as determined in accordance with Attachment D of this Local Service Schedule and as subject to an Annual True-up pursuant to Section 4. The Embedded Cost Charge is based on NSTAR's system average embedded cost. In the event NSTAR seeks to apply a rate based on a methodology other than average embedded cost to all or any part of a Network Customer's service, either already being provided or proposed to be provided, NSTAR shall provide the affected Network Customer thirty days advance written notice of any filing with the Commission seeking to implement such a rate and shall comply with all applicable requirements of the Commission and the Tariff. Any dispute as to NSTAR's position concerning proposed cost allocation shall be addressed as provided in Section II.7(g) of Schedule 21-Local Service to Section II of the Tariff; provided that nothing in this provision prevents NSTAR from filing with the Commission at any time to establish new rates pursuant to the provisions of Section 205 of the FPA or a Network Customer from opposing such a filing, and nothing in this provision is intended to reflect a Network Customer's agreement that NSTAR has the rights set out in this Section 16.1 or is intended to prevent the affected Network Customer from filing a complaint with the Commission at any time pursuant to the provisions of Section 206 of the FPA or NSTAR from opposing such a filing.

16.2 Curtailment Penalty Charge

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the transmission system, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the Monthly Demand Charge for Local Network Service, as calculated in accordance with Section 16.1 of this Local Service Schedule, for the month in which such service was not curtailed or interrupted.

16.3 [Reserved]

16.4 Taxes and Fees Charge

16.4.1 If NSTAR incurs tax liability currently for which it will in subsequent years receive tax benefits (for example, a taxable contribution in aid of construction) then Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years. Sections 16.4.1 and 16.4.2 are intended to apply to those Transmission Customers for whom Direct Assignment Facilities are constructed pursuant to this Local

Service Schedule and to any Transmission Customer's appropriate share of the cost of any required Local Network Upgrades to the extent that any such Local Network Upgrade is identified pursuant to the study procedures outlined in Schedule 21-Local Service, Section II.7(d) and permitted or required by Commission ruling to be paid as a contribution in aid of construction.

16.4.2 If NSTAR takes a position that any particular transaction under any section of the Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above, but additionally taking into account any interest assessment required to be paid by NSTAR.

16.4.3 At its effective date, this Section 16.4 applies only to contributions in aid of construction ("CIAC"). NSTAR reserves the right to file under Section 205 of the FPA to modify this provision to apply to items other than CIAC and the Network Customer reserves the right to oppose any such filing.

17.0 OPERATING ARRANGEMENTS

17.1 Operating Requirements

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of this Local Service Schedule shall be specified in the OATT. The OATT shall provide for the Parties to:

(i) operate and maintain equipment necessary for integrating the Network Customer within NSTAR's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment),

(ii) transfer data between NSTAR and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside NSTAR's Transmission System, interchange schedules, unit outputs for redispatch required under Section 15, voltage schedules, loss factors and other real time data),

(iii) use software programs required for data links and constraint dispatching,

(iv) exchange data on forecasted loads and resources necessary for long-term planning, and

(v) address any other technical and operational considerations required for implementation of this Local Service Schedule, including scheduling protocols.

The OATT will recognize that the Network Customer shall either:

(i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO), as defined in 18 CFR 38.1, and ISO,

(ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with NSTAR, or

(iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO and ISO. NSTAR shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services.

17.2 Network Operating Committee

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the OATT. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 2

SUPPLEMENTAL END-USE REACTIVE SUPPORT SERVICE

In the event that power factor levels and reactive supply requirements set forth in the service agreement or other associated operating or interconnect agreement are not maintained by the Delivering Party (or, as appropriate, the Receiving Party), in accordance with applicable ISO standards and practices then NSTAR shall charge the Transmission Customer to take corrective action. The Transmission customer shall compensate NSTAR for installing the necessary equipment, whether in the form of generating units or other non-generating resources, such as demand resources, to correct the incremental difference between the Transmission Customer's lowest (or highest) power factor level and that which is an acceptable level in accordance with ISO standards and practices. The charges will be based upon the necessary level of reactive power supply required to correct the deficiency in the power factor level.

For the KVAR demand supplied to the Transmission Customer, the charge shall be the greater of a) the market price of installing leading reactive power supply expressed in terms of $/KVAR or b) $50/KVAR of installed (leading) reactive power reflecting current NSTAR cost.

For the KVAR demand absorbed by NSTAR the charge shall be the greater of a) the market price of installing lagging reactive power supply expressed in terms of $/KVAR or b) $22.5/KVAR of installed (lagging) reactive power reflecting current NSTAR cost.

SCHEDULE 3

LONG-TERM FIRM AND SHORT-TERM FIRM

LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall compensate NSTAR for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following charges as applicable:

1) Annual Rate

The Annual Rate for Firm Local Point-To-Point Service shall consist of the higher of (i) the Embedded Cost Charge or (ii) the Incremental Cost Charge, as set forth below:

(i) The Embedded Cost Charge shall be determined by dividing NSTAR's Annual Transmission Revenue Requirements (determined in accordance with Attachment D of this Local Service Schedule) by the maximum amount of NSTAR's Monthly Transmission System Load during such Service Year.

(ii) The Incremental Cost Charge shall be determined from the total costs of all Local Network Upgrades plus other incremental costs incurred provided for in the Service Agreement application to a transaction. If the Incremental Cost Charge is higher, the Transmission Customer shall pay for the facilities necessary to provide it with service during an amortization period, with the Transmission Customer paying the Embedded Cost Charge upon completion of the amortization. Such amortization period shall be coterminous with the Service Agreement.

2) Firm Local Point-To-Point Service for Monthly Transactions or Longer Term Transactions

The charge for each month applicable to a monthly transaction or longer term transaction (the "Monthly Rate") shall be determined as the product of: (a) NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Service Agreement for such month, expressed in kilowatts.

3) Firm Local Point-To-Point Service for Less Than One Month

NSTAR's Weekly Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by fifty-two (52) weeks. NSTAR's Daily Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by three hundred and sixty-five (365) days. NSTAR's Hourly Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by eight thousand seven hundred and sixty (8,760) hours.

The Transmission Customer shall pay the Weekly, Daily or Hourly Rate, as applicable, times the Reserved Capacity set forth in the Transmission Customer's Applicable Service Agreement.

4) Penalty

When the Transmission Customer exceeds its Reserved Capacity or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved (Excess Incident), NSTAR will charge the Transmission Customer 200% of the rate determined as follows for each kilowatt of the Excess Incident:

- The unreserved use penalty for a single hour of unreserved use shall be based on the rate for daily Firm Point-to Point Transmission Service.

- If there is more than one assessment for a given duration (e.g., daily) for the Transmission Customer, the penalty shall be based on the next longest duration (e.g., weekly).

- The unreserved penalty charge for multiple instances of unreserved use (i.e., more than one hour) within a day shall be based on the daily rate for Firm Point-To-Point Transmission Service.

- The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week shall be based on the charge for weekly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month shall be based on the charge for monthly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one month during a calendar year shall be based on the charge for yearly Firm Point-To-Point Transmission Service.

All Excess Incidents will be recorded by NSTAR, and if in any calendar year more than ten (10) Excess Incidents occur in connection with service for the Transmission Customer, then NSTAR may require the Transmission Customer to apply for additional Firm Local Point-To-Point Service under this Local Service Schedule in the amount equal to the highest Excess Incident during that Service Year. Charges for such additional transmission service will relate back to the first day of the month following the month of NSTAR's notice.

5) Curtailment Penalty Charge

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the Transmission System, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the Monthly Rate for Firm Local Point-To-Point Service for the month in which such service was not curtailed or interrupted.

6) Taxes and Fees Charge

A) If any governmental authority requires the payment of any fee or assessment not specifically provided for in any of the charge or rate provisions under this Local Service Schedule or imposes a sales, gross revenue, or other form of tax with respect to payments made for service provided under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. NSTAR will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's Regulations.

B) If NSTAR incurs tax liability currently for which it will, in subsequent years, receive tax benefits (for example, a taxable contribution in aid of construction), the Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years.

C) If NSTAR takes a position that any particular transaction under any section of this Local Service

Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation, or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above but additionally taking into account any interest assessment required to be paid by NSTAR.

7) <u>Regulatory Expense Charge</u>

NSTAR shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreement(s).

8) <u>Customer-Related Expense Charge</u>

NSTAR shall charge the Transmission Customer, in addition to the other charges assessed pursuant to this Local Service Schedule, and as set forth in its Service Agreement for those costs attributable to the billing, meter reading, record keeping, (all from FERC Uniform System of Accounts Nos. 901-905) and an allocation of administrative and general expenses (FERC Uniform System of Accounts Nos. 920-935) associated with each of these costs, all of which are related to the Transmission Customer's Local Point-To-Point Service and allocated on the basis of the total number of customers served by NSTAR.

9) <u>Exchanges</u>

With respect to any transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a transmission charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

10) <u>Discounts</u>

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, NSTAR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

11) Resales

The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

SCHEDULE 4

NON-FIRM LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall compensate NSTAR for any Ancillary Services and for Non-Firm Local Point-To-Point Service up to the sum of the applicable charges set forth below:

1) The Annual Rate for Non-Firm Local Point-To-Point Service shall be NSTAR's Annual Transmission Revenue Requirements (determined in accordance with Attachment D of this Local Service Schedule) for the Service Year divided by NSTAR's Monthly Transmission System Load during such Service Year.

2) Non-Firm Local Point-To-Point Service for Monthly Transactions or Longer Term Transactions
The charge for each month applicable to a monthly transaction or longer term transaction (the "Monthly Rate") shall be determined as the product of: (a) NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Service Agreement for such month, expressed in kilowatts.

3) Non-Firm Local Point-To-Point Service for Less Than One Month
NSTAR's Weekly Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by fifty-two (52) weeks.

NSTAR's Daily Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by three hundred and sixty-five (365) days. NSTAR's Hourly Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by eight thousand seven hundred and sixty (8,760) hours.

The Transmission Customer shall pay the Weekly, Daily or Hourly Rate, as applicable, time the Reserved Capacity set forth in the Transmission Customer's Applicable Service Agreement.

4) Credit to the Transmission Charge
Whenever service provided hereunder is interrupted or curtailed by NSTAR, or its Designated Agent

including ISO, the Transmission Charges to the Transmission Customer calculated pursuant to Sections 2 and 3 of this Schedule 4 shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service. The credit to the Transmission Customer for each hour of interruption or curtailment shall be calculated as the product of (a) NSTAR's Hourly Rate and (b) the kilowatts of service interruption or curtailment during such hour.

5) Penalty

When the Transmission Customer exceeds its Reserved Capacity or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved (Excess Incident), NSTAR will charge the Transmission Customer 200% of the rate determined as follows for each kilowatt of the Excess Incident:

- The unreserved use penalty for a single hour of unreserved use shall be based on the rate for daily Firm Point-to Point Transmission Service.

- If there is more than one assessment for a given duration (e.g., daily) for the Transmission Customer, the penalty shall be based on the next longest duration (e.g., weekly).

- The unreserved penalty charge for multiple instances of unreserved use (i.e., more than one hour) within a day shall be based on the daily rate for Firm Point-To-Point Transmission Service.

- The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week shall be based on the charge for weekly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month shall be based on the charge for monthly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one month during a calendar year shall be based on the charge for yearly Firm Point-To-Point Transmission Service.

All Excess Incidents will be recorded by NSTAR, and if in any calendar year more than ten (10) Excess

Incidents occur in connection with service for the Transmission Customer, then NSTAR may require the Transmission Customer to apply for additional Non-Firm Local Point-To-Point Service under this Local Service Schedule in the amount equal to the highest Excess Incident during that Service Year. Charges for such additional Non-Firm Local Point-To-Point Service will relate back to the first day of the month following the month of NSTAR's notice.

6) Curtailment Penalty Charge.

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the Transmission System, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the monthly demand charge for Non-Firm Local Point-To-Point Service for the month in which such service was not curtailed or interrupted.

7) Taxes and Fees Charge

A) If any governmental authority requires the payment of any fee or assessment not specifically provided for in any of the charge or rate provisions under this Local Service Schedule or imposes a sales, gross revenue, or other form of tax with respect to payments made for service provided under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. NSTAR will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's Regulations.

B) If NSTAR incurs tax liability currently for which it will, in subsequent years, receive tax benefits (for example, a taxable contribution in aid of construction), the Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years.

C) If NSTAR takes a position that any particular transaction under any section of this Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation, or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above but additionally taking into account any interest assessment required to be paid by NSTAR.

8) Regulatory Expense Charge

NSTAR shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreement(s).

9) Customer-Related Transaction Charge

NSTAR shall charge the Transmission Customer, in addition to the other charges assessed pursuant to this Local Service Schedule, and as set forth in its Service Agreement for those costs attributable to the billing, meter reading, record keeping, (from FERC Uniform System of Accounts Nos. 901-905) and an allocation of administrative and general expenses (Nos. 920-935) associated with each of these costs, all of which are related to the Transmission Customer's Local Point-To-Point Service and allocated on the basis of the total number of customers served by NSTAR.

10) Exchanges

With respect to any transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a transmission charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

11) Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, NSTAR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

12) <u>Resales</u>

The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

ATTACHMENT A

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

1. Introduction

ISO is the regional transmission organization ("RTO"), serving the New England Control Area. ISO is responsible for development, oversight, and fair administration of New England's wholesale market and management of bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is interconnected to three neighboring Balancing Authority Areas: New Brunswick System Operator Area ("NBSO Area"), New York Independent System Operator Area ("NYISO Area"), and Hydro-Québec TransÉnergie Area ("HQTÉ Area").

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission-approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the transmission provider for transmission service associated with PTF, the Participating Transmission Owners (PTOs) under the Transmission Operating Agreement, such as NSTAR, provide local transmission service over Non-Pool Transmission Facilities within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Service provided under Schedule 21. Pursuant to CFR § 37.6(b)[1] of the Commission's regulations, NSTAR as a Transmission Provider is obligated to calculate and post ATC and TTC for certain local facilities over which Point-to-Point transmission service is provided under Schedule 21-NSTAR. These are primarily radial paths that provide transmission service to directly interconnected generators.

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[1] §37.6(b) Posting transfer capability. The available transfer capability (ATC) on the Transmission Provider's system and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as

set forth in this section.

Posted Path is defined as any control area-to-control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which serviced was denied, curtailed or interrupted. §37.6(b)(1)(i).

NSTAR does not currently have any Posted Paths based on the above definition. However, to the extent that NSTAR does in the future have any Posted Path(s), NSTAR will calculate ATC and TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to the following functions which are performed or utilized by NSTAR in order to provide Local Point-to Point Service under Schedule 21-NSTAR: Total Transfer Capability (TTC) methodology; Available Transfer Capability (ATC) methodology; Existing Transmission Commitment (ETC); Use of Transmission Reliability Margin (TRM); Use of Capacity Benefit Margin (CBM); and Use of Rollover Rights (ROR) in the calculation of ETC.

TTC and ATC are required to be calculated only for certain non-PTF internal paths over which Local Point-to-Point Service is provided under Schedule 21-NSTAR. TTC and ATC are not calculated by NSTAR for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and NSTAR does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the open access transmission tariff for New England, the process by which generation located inside New England supplies energy and/or capacity to the bulk electric system has differed from the Commission's pro forma open access transmission tariff. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time

Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit energy transactions that move into the New England Control Area, out of the New England Control Area or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast LMPs and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of economic External Transactions is greater than the transfer capability of the associated external interface, the ExternalTransactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through-or-Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the New England Control Area, and non-PTF where utilized for Local Network Service by generation or load. However, NSTAR owns local transmission facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those facilities, Market Participants may obtain a transmission service reservation from NSTAR under Schedule 21-NSTAR prior to delivery of energy and/or capacity into the New England markets pursuant to Schedule 18, 20A or 20B of the Tariff. This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. NSTAR Total Transfer Capability (TTC)

TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21-NSTAR is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on the NSTAR OASIS site.

The TTC on NSTAR's Non-PTF that requires Local Point-to-Point Service reservations are relatively static values. NSTAR calculates the TTC for Posted Paths as the rating of the particular radial transmission path.NSTAR will calculate and post TTC on its OASIS site for all non-PTF Posted Paths that are eligible for Local Point-to-Point Service reservations. TTC is calculated as the transfer capability rating of the particular radial transmission path less the most limiting element within the PostedPath.

4. Capacity Benefit Margin (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a Transmission Provider for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents, and in any event, ISO's determination of CBM does not apply directly to the determination of ATC for Local Service. Load Serving Entities operating with the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with the Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of NSTAR's ATC calculation and because CBM for the New England Control Area is set to zero (0), NSTAR utilizes a zero (0) CBM value.

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. As NSTAR does not have any external interfaces, TRM for its non-PTF facilities is presently set to zero.

6. Existing Transmission Commitments

6.1 Existing Transmission Commitments, Firm (ETC_F)

ETC_F are confirmed Firm Local Point-To-Point Transmission Service reservations (PTP_F) plus any exercised rollover rights for Firm Point-To-Point Transmission Service reservations (ROR_F). There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F), and other services, contracts or agreements

(OS_F) to be considered in the ETC_Fcalculation.

6.2 Existing Transmission Commitments, Non-Firm (ETC_{NF})

ETC_{NF} are confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}), or other services, contracts or agreements (OS_{NF}).

7. Calculation of ATC for NSTAR's Transmission System

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a Transmission Provider's ATC methodology. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the Non-PTF assets, as ATC is positive and listed as 9999. Transmission Customers are not restricted from reserving Firm or Non-Firm Point-to-Point Service on Non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time Energy Market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of net energy and/or capacity transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF that serve as a path for NSTAR's Transmission Customers taking Local Point-to-Point Service, NSTAR has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

7.1 Calculation of Schedule 21-NSTAR Firm ATC (ATC_F)

7.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment A, PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$. As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-NSTAR that is available in the PH includes: Yearly, Monthly, Weekly and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NSTAR transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F.

7.1.2 Calculation of ATC_F in the Operating Horizon (OH)

For purposes of this Attachment A, OH begins noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses, the total hours remaining in the OH decrease until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$. As discussed above, TRM and CBM are zero. Daily Firm Transmission Service under Schedule 21-NSTAR is the only firm service offered in the OH. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NSTAR transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

7.1.3 Calculation of ATC_F in the Scheduling Horizon (SH)

Because Firm Schedule 21-NSTAR transmission service is not offered in the SH, ATC_F in the SH is zero.

7.2 Calculation of Schedule 21-NSTAR Non-Firm ATC (ATC_{NF})

7.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$). As discussed above, the TRM and CBM for Schedule 21-NSTAR are zero. ATC_{NF} available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-NSTAR transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

7.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly. As discussed above, the TRM and CBM for Schedule 21-NSTAR are zero. TRM_U, $counterflows_{NF}$ and ETC_{NF} of Schedule 21-NSTAR transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F plus postbacks of PTP_F in the OH as PTP_{NF} ($Postbacks_{NF}$).

7.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available. As also stated above, NSTAR's Non-PTF are primarily radial paths that provide transmission service to directly interconnected generators. It is possible that in the future a particular radial path may interconnect more nameplate capacity generation than the path's TTC. For the local facilities modeled by ISO, and consistent with ISO's economic, security-constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH could become zero, but will never be negative.

8. Posting of Schedule 21-NSTAR ATC

8.1 Location of ATC Posting

ATC values are posted on the NSTAR OASIS site.

8.2 Updates to ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

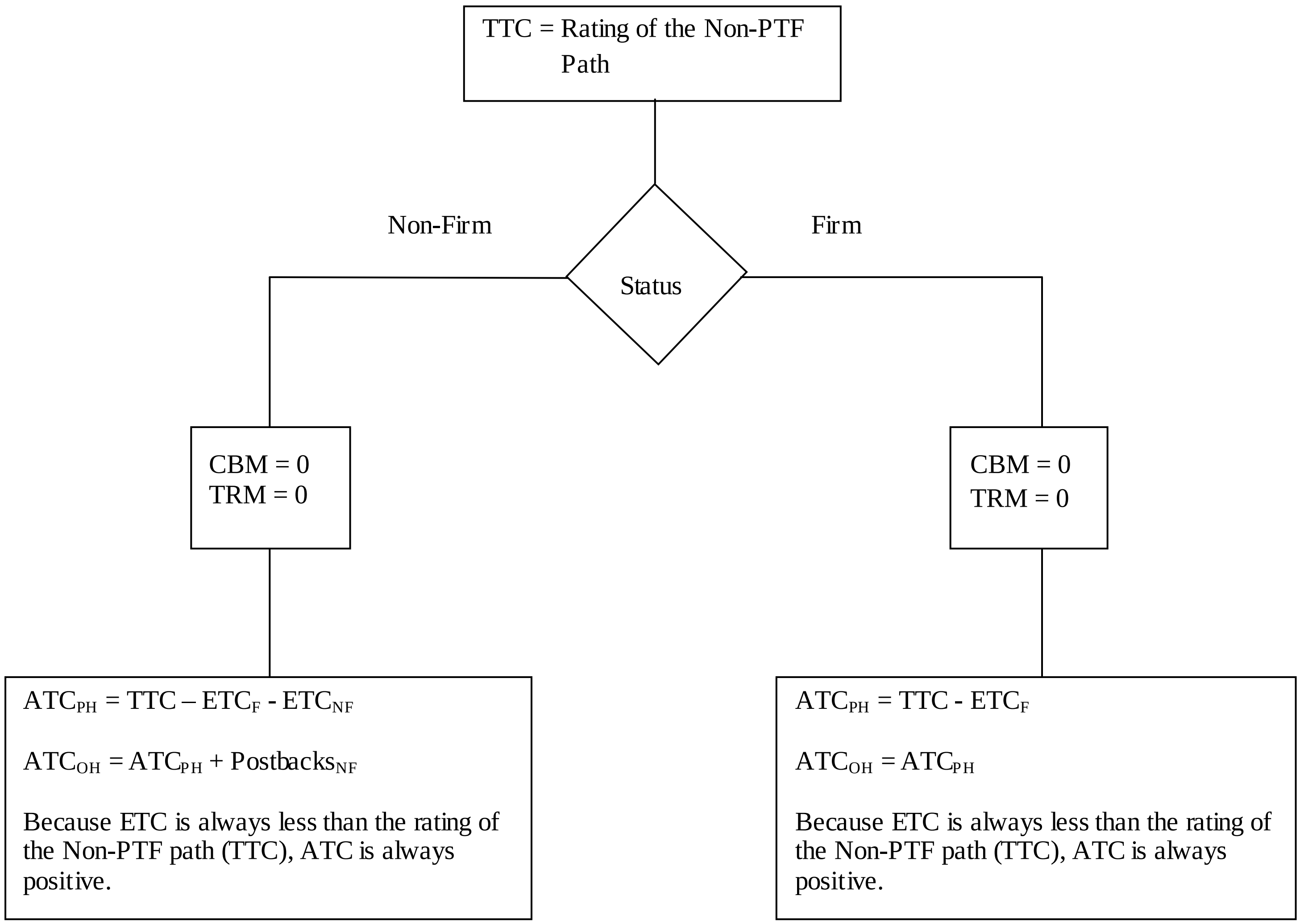
8.3 Coordination of ATC Calculations

NSTAR's Non-PTF has no external interfaces. Therefore, it is not necessary to coordinate the values.

8.4 Mathematical Algorithms

The mathematical algorithms for the calculation of ATC can be found on NSTAR's web site at http://www.nstar.com/business/rates_tariffs/open_access/docs/ATC_Algorithm-Sch_21.pdf

Non-PTF Transmission Path ATC Process Flow Diagram



ATTACHMENT B

METHODOLOGY FOR COMPLETING A SYSTEM IMPACT STUDY

When NSTAR determines on a non-discriminatory basis that a System Impact Study is needed because its Transmission System will be inadequate to accommodate a Completed Application for service, the following outlines the study methodology that NSTAR will employ to estimate the Transmission System impact of a Completed Application for Firm Local Point-To-Point Service, Network Integration Service and/or any costs associated with Direct Assignment Facilities and/or Local Network Upgrades that would be incurred in order to accommodate the service requested in the Completed Application.

1. System Impact will be estimated based on consideration of reliability requirements to:

- meet obligations under agreements that predate this Local Service Schedule;
- meet obligations of existing and pending Completed Application under this Local Service Schedule;
- maintain thermal, voltage and stability system performance within acceptable regional practices.

2. Guidelines and Principles followed by NSTAR: When performing the System Impact Study, NSTAR will apply the following, as amended and/or adopted from time to time.

- Good Utility Practice;
- Criteria, rules and reliability standards applicable to the New England Transmission System;
- NPCC criteria and guidelines; and
- NSTAR criteria and guidelines.

3. Transmission System Model Representation: The Transmission System model will be based on a library of load flow cases prepared by ISO for studies of the New England area. The models may include representations of other NPCC and neighboring systems. These load flow cases include individual system model representations provided by Transmission Owners and represent forecasted system conditions for up to ten (10) years into the future. This library of load flow cases is maintained and updated as appropriate by ISO, and is consistent with information filed under FERC Form 715. NSTAR will use system models that it deems appropriate for study of the Completed Application for service. Additional system models and operating conditions, including assumptions specific to a particular

analysis, may be developed for conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

4. System Conditions: Loading of all Transmission System elements shall be less than normal ratings for pre-contingency conditions and less than long-term emergency (LTE) ratings for post-contingency conditions. Post-contingency loading above LTE rating and less than short-term emergency (STE) rating may be allowed where demonstrated that loading can be reduced below the LTE rating within fifteen (15) minutes. Transmission System voltage shall be within the applicable design ratings of connected equipment for normal and emergency conditions. Normal and post-contingency voltages shall be in accordance with NSTAR and ISO standards.

5. Short Circuits: Transmission System short circuit currents shall be within the applicable equipment design ratings.

6. Study Analysis: System impact of the integration of new load will be evaluated to meet the requirements of design, identified in the guidelines and principles under Item 2 above, to provide sufficient transmission capability to maintain stability and to maintain thermal and voltage levels of lines and equipment within applicable limits. The same applies to the evaluation of Firm Point-To-Point Service when it has been determined that insufficient transfer capability is available and the Eligible Customer requests a System Impact Study be conducted.

7. Loss Evaluation: The impact of losses on the Transmission System will be taken into account in the System Impact Study to ensure Good Utility Practice in the design and operation of its system.

8. System Protection: Protection requirements will be evaluated by NSTAR in accordance with ISO, NPCC, and NSTAR criteria.

9. Approvals: NSTAR will conduct the System Impact Study to ensure compliance with its planning and design policies and practices. However, the actions to be taken by the Parties to implement the recommendations of the System Impact Study are subject to approval under the Tariff.

10. Study Scope and Reporting: The study will determine the impacts and identify changes required, if any, to NSTAR's existing Transmission System. NSTAR will provide the Eligible Customer with a written report of the physical interconnection alternative(s), required NSTAR system additions and/or modifications, if any, associated study grade cost estimates (+/- 25%) and the results of the analysis.

ATTACHMENT C

INDEX OF LOCAL POINT-TO-POINT SERVICE CUSTOMERS

Customer	Date of Service Agreement
AIG Trading Corporation	October 29, 1996
Altresco Pittsfield Light Plant	December 26, 1996
Aquila Power Company	February 26, 1997
Axia Energy, LP	June 20, 2001
Baltimore Gas & Electric Co.	January 14, 1997
Bangor Hydro-Electric Co.	October 1, 1996
Belmont Municipal Light Dept.	December 11, 1996
Central Vermont Public Service	January 3, 1997
Chicopee Municipal Light Dept.	October 2, 1996
CINERGY Capital and Trading, Inc.	January 1, 1998
CINERGY Operating Companies	December 1, 1997
Citizens Lehman Power Sales	November 6, 1996
Constellation Power Source, Inc.	July 11, 1997
Duke Energy Solutions, Inc.	March 19, 1999
DukeSolutions, Inc.	May 18, 1999
Edison Source	June 9, 1997
Electric Clearinghouse, Inc.	October 7, 1996
Entergy Nuclear Generation Company	April 10, 2003
Equitable Power Services Company	October 29, 1996
Green Mountain Power Corporation	January 10, 1997
HQ Energy Services (US) Inc.	February 8, 1999
LG&E Power Marketing, Inc.	October 8, 1996
Maine Public Service Company	September 30, 1996
Massachusetts Bay Transportation Authority	May 1, 1999
Massachusetts Municipal Wholesale Electric Co.	September 6, 1996
Merchant Energy Group of the Americas, Inc.	August 16, 1998
Mirant Canal, LLC	July 6, 1998

Mirant Americas Energy Marketing, LP	April 28, 2004
Montaup Electric Co.	October 15, 1996
Morgan Stanley Capital Group, Inc.	October 29, 1996
NEPOOL on Behalf of NEPOOL Participants	June 1, 1997
New England Power Company	December 30, 1996
New York State Gas & Electric Corp.	December 16, 1997
NorAm Energy Services	November 14, 1997
Northeast Energy Services, Inc.	June 17, 1997
NP Energy, Inc.	August 1, 1997
NRG Power Marketing, Inc.	January 1, 2001
NSTAR Electric Company	December 24, 1996
PECO Energy Power Team	January 3, 1997
Rainbow Energy Power Marketing	November 7, 1996
Reading Municipal Light Department	September 6, 1996
Sithe New England Holdings, LLC	January 3, 1998
Sonat Power Marketing, Inc.	November 14, 1997
Southern Energy Trading and Marketing, Inc.	March 10, 1997
Strategic Energy Ltd.	May 11, 1999
The Power Company of America	November 18, 1996
Town of Braintree Electric Light Dept.	September 6, 1996
Town of Hingham Municipal Light Plant	September 9, 1996
Town of Hull Municipal Light Plant	December 11, 1996
Trans Alta Energy Marketing	November 24, 1998
Trans Canada Power Corporation	January 27, 1997
Western Power Services, Inc.	December 24, 1996
Williams Energy Services Company	July 17, 1997
VTEC Energy, Inc.	March 24, 1998

ATTACHMENT D
ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirements for NSTAR ("the Company") will reflect the costs for its Transmission System, including costs attributable to those incurred by the Company in owning, leasing, maintaining and supporting the Transmission System net of revenues for transmission services provided under any other FERC accepted tariff or under any contract with other parties that provides reimbursement to the Company for transmission related services. Under no circumstances shall the Company's Local Network Service rates include costs that are charged through any other rate or tariff. The Transmission Revenue Requirements will be an annual calculation based on the estimated costs for its Transmission System during the Service Year.

The Company shall make an annual informational filing with the FERC on or before May 31 of each year which shall include a True-up of estimated costs and revenues, and actual costs and revenues for the preceding Service Year. Actual costs will be determined using data required to be reported annually in the FERC Form 1 and recorded on the Company's books in accordance with FERC's Uniform System of Accounts; unless the use of other data, such as subaccount balances, is specifically required by the provisions below, in which case an officer of the Company, shall certify that the development, accuracy and application of such other data is in accordance with the provisions of this Local Service Schedule. Such certification will be included with the annual informational filing along with adequate detail that supports the values contained within the True-up calculation. References to specific FERC Form 1 pages, line numbers and columns included in this Local Service Schedule are based on the 2006 Form 1 of the Company's predecessor entities. Subsequent FERC changes to Form 1 may be adopted to the extent they are consistent with the provisions and terms of this Local Service Schedule and not otherwise prohibited by FERC.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section II.1 of the OATT or the Local Service Schedule and as used herein have the following definitions:

A. ALLOCATION FACTORS

1. <u>Transmission Wages and Salaries Allocation Factor</u> shall equal the ratio of transmission-related direct wages and salaries including those of affiliated companies as reported in the Company's annual FERC Form 1, page 354, line 21, column (b) to the Company's total direct wages and salaries including those of the affiliated companies as reported in the Company's FERC Form 1, page 354, line 28, column (b), and excluding administrative and general wages and salaries as reported in the Company's FERC Form 1, page 354, line 27, column (b).

2. <u>Plant Allocation Factor</u> shall equal the ratio of the sum of Transmission Plant, excluding HQ leases, plus Transmission Related Intangible and General Plant to Total Plant in Service excluding HQ Leases.

B. TERMS

<u>Administrative and General Expense</u> shall equal the expenses as reported in the Company's FERC Form 1, page 323, line 197, column (b), excluding Property Insurance included in FERC Account No. 924, Regulatory Commission Expense included in FERC Account No. 928, and Advertising Expense included in FERC Account No. 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded). The amount of Postretirement Benefits Other Than Pensions ("PBOP") expense in FERC Account No. 926 shall be separately stated as a footnote to the Company's FERC Form 1, page 323, line 187, column (b): Current Year and column (c): Previous Year.

<u>Amortization of Gain on Reacquired Debt</u> shall equal the amortization amount recorded in FERC Account No. 429.1.

<u>Amortization of Loss on Reacquired Debt</u> shall equal the expenses as recorded in FERC Account No. 428.1.

<u>Amortization of Investment Tax Credits</u> shall equal the credits as recorded in FERC Account No. 411.4.

<u>Depreciation Expense for Transmission Plant</u> shall equal the transmission expenses as recorded in FERC

Account No. 403 as reported in the Company's annual FERC Form 1 page 336, line 7, column (f).

General Plant shall equal the gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation and Amortization Expense shall equal the general plant expenses as recorded in FERC Account Nos. 403 for depreciable items and 404 for items subject to amortization as reported in the Company's annual FERC Form 1, page 336, line 10, column (f).

General Plant Depreciation Reserve shall equal the general reserve balance as recorded in FERC Account No. 108 and reported in the Company's annual FERC Form 1, page 219, line 28, column (b).

General Plant Amortization Reserve shall equal the general reserve balance as recorded in FERC Account No. 111 and reported in the Company's annual FERC Form 1, page 200 in a footnote to line 14.

Hydro-Quebec DC Facilities (HQ Leases) shall equal the balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

Intangible Plant shall equal the gross plant balance as recorded in FERC Account No. 303 as reported in the Company's annual FERC Form 1, page 205, line 4, column (g). The only allowable Intangible Plant for inclusion in the Local Service Schedule are software, patent or rights costs.

Intangible Plant Amortization Expense shall equal amortization expenses as recorded in FERC Account Nos. 404-405 as reported in the Company's annual FERC Form 1, page 336, line 1, column (f). The only allowable Intangible Plant Amortization Expense for inclusion in the Local Service Schedule is the amortization of software, patent or rights costs.

Intangible Plant Amortization Reserve shall equal the amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion in the Local Service Schedule is that related to the amortization of software, patent or rights costs.

Merger-Related Costs shall equal NSTAR Electric's amortized merger-related costs as authorized by FERC or by state regulatory order.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in the FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the FAS 109 asset and any FAS 109 balance liability.

Payroll Taxes shall equal those payroll expenses as recorded in the FERC Account No. 408.1.

Plant Held for Future Use shall equal the balance in FERC Account No. 105 that relates to land and land rights which have been purchased for future transmission use, or transmission related projects that were included in this account before January 1, 2007.

Prepayments shall equal the prepayment balance as recorded in FERC Account No. 165, plus any prepayment specifically related to the Company's Pension plans related to electric company operations recorded in FERC Account No. 182.3, Other Regulatory Assets.

Property Insurance shall equal the expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and 190 for those balances that are directly related to transmission, excluding those directly related to distribution or other businesses.

Total Gain on Reacquired Debt shall equal the gain as recorded in FERC Account No. 257.

Total Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 189.

Total Municipal Tax Expense shall equal the municipal tax expenses as recorded in FERC Account No. 408.1 as reported in the Company's annual FERC Form 1, page 263, line 10, column (i).

Total Plant in Service shall equal the total gross plant balance as recorded in FERC Account Nos. 301-399 excluding HQ Leases recorded in those accounts.

Total Transmission Depreciation Reserve shall equal the transmission reserve balance as recorded in FERC Account No. 108 as reported in the Company's annual FERC Form 1, page 219, line 25, column (b), excluding HQ-related amounts recorded in that account.

Transmission Depreciation Expense shall be the annual depreciation expense for transmission accounts computed using the following rates, as approved by FERC in Docket No. ER03-1274:

Account	Description	Rate
352	Structures and Improvements	2.19%
353	Station Equipment	2.53%
354	Towers and Fixtures	2.03%
355	Poles and Fixtures	2.25%
356	Overhead Conductors and Devices	2.19%
357	Underground Conduit	2.06%
358	Underground Conductors and Devices	2.15%
359	Roads and Trails	1.63%

Transmission Merger-Related Costs shall equal NSTAR Electric's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal all transmission-related expenses as recorded in FERC Account Nos. 560-564 and 566-576.5, and shall exclude; (i) all HQ HVDC expenses recorded in those accounts, and (ii) expenses billed to the Company by ISO-NE for Scheduling and Dispatch Service.

Transmission Plant shall equal the balance as recorded in FERC Account Nos. 350-359.1, adjusted to exclude the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

Transmission Plant Materials and Supplies shall equal the balance as assigned to transmission, as recorded in FERC Account No. 154 as reported in the Company's annual FERC Form 1, page 227, lines 5 and 8, column (c).

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Gain/Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from Generators, minus (M) Transmission Rents Received from Electric Property, minus (N) Short-Term and Non-Firm Point-To-Point Service Revenues, minus (O) Regional Network Services (RNS) Revenues, minus (P) Through or Out Revenues, minus (Q) ISO-NE Scheduling and Dispatch Revenues.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) 50 percent of Transmission Related Construction Work In Progress (CWIP), less (e) Transmission Related Depreciation and Amortization Reserve, less (f) Transmission Related Accumulated Deferred Taxes, less, (g) AFUDC Regulatory Liability, plus (h) Transmission Related Gain/Loss on Reacquired Debt, plus (i) Other Regulatory Assets/Liabilities, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

(a) Transmission Plant will equal the balance of the investment in Transmission Plant. This value excludes the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

(b) Transmission Related Intangible and General Plant shall equal the sum of the balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the land and land rights portion of the balance of Transmission-related Plant Held for Future Use (FERC Account No. 105) plus the non-land Plant Held for Future Use related to projects that were included in Account No. 105 prior to January 1, 2007 to the extent such non-land plant has not been closed to Plant In Service; such balances to be provided in conformance with the FERC Uniform System of Accounts, Instruction E, Account No. 105 which requires that "…property included in this account shall be classified according to detail accounts (301-399)…and shall be maintained in such detail as though the property were in service."

(d) 50 Percent of Transmission Related Construction Work in Process (CWIP) shall equal the balance of Transmission related investment in FERC Account 107 multiplied by 50%, subject to any exclusions pursuant to the provisions of Section 4.1 of this Local Service Schedule.

(e) Transmission Related Depreciation and Amortization Reserve shall equal the balance of Total Transmission Depreciation Reserve as reported in the Company's annual FERC Form 1, page 219 line 25, column (b), plus the balance of Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve. Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve shall equal the product of (i) the sum of the Intangible Plant Amortization Reserve, General Plant Depreciation Reserve and General Plant Amortization Reserve and (ii) the Transmission Wages and Salaries Allocation Factor. The Total Transmission Depreciation Reserve balance excludes any amounts related to the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

(f) Transmission Related Accumulated Deferred Taxes shall equal the electric balance of Total Accumulated Deferred Income Taxes (for those balances that are directly related to transmission, plus the balances not directly related to other businesses), with the remaining accumulated deferred taxes not directly related to other businesses being allocated on the same basis used for the related rate base assets.

(g) AFUDC Regulatory Liability shall equal 50% of the capitalized AFUDC booked on transmission projects as recorded in FERC Account No. 254.

(h) Transmission Related Gain/Loss on Reacquired Debt shall equal the electric balance of Total Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

(i) Other Transmission Related Regulatory Assets/Liabilities shall equal the electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(j) Transmission Prepayments shall equal the electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

(k) Transmission Materials and Supplies shall equal the electric balance of Transmission Plant Materials and Supplies.

(l) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the Transmission Operation and Maintenance Expense included in Section II.G, Transmission Related Administrative and General Expenses included in Section II.H, and Transmission Support Expenses included in Section II.K.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital for Service Years ending before January 1, 2013 will be calculated based 70% upon the capital structure at the end of each year and 30% upon a pro-forma capital structure consisting of 50% debt, 0% preferred, and 50% common equity; thereafter the pro-forma capital structure will be the same as the actual capital structure, and will equal the sum of (i), (ii) and (iii) below. Notwithstanding the foregoing, for Service Years ending before January 1, 2013, NSTAR's Weighted Cost of Capital will be the lower of the blended rate as calculated herein or the actual rate.

(i) the long-term debt component, which equals the product of: the actual weighted average embedded cost to maturity of the long-term debt then outstanding; and the sum of (a) the ratio that long-term debt is to the total capital multiplied by 70%, plus (b) 50% pro-forma capital structure multiplied by 30%.

(ii) the preferred component shall be the product of: the embedded cost of preferred stock outstanding at the end of each year; and the sum of (a) the ratio that preferred stock is to the total capital multiplied by 70%, plus (b) 0% pro-forma capital structure multiplied by 30%.

(iii) the return on equity component shall be the product of: the allowed ROE of the common equity; and the sum of (a) the ratio that common equity is to the total capital multiplied by 70%, plus (b) 50% pro-forma capital structure multiplied by 30%. The allowed ROE shall be ~~10.57~~11.14%, plus any additional incentive ROE adders as may be applied to specific investment approved by the Commission pursuant to Order No. 679~~, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period~~. The allowed ROE shall be subject to revision at any time by unilateral filing by NSTAR under Section 205 of the FPA or by such Section 205 filing by NSTAR on a joint basis with other New England transmission owners. In either case, the revised ROE shall become effective no later than sixty days after the filing in accordance with the provisions of the FPA and also subject to any suspension or refund condition which the Commission may order pursuant to its authority under that Section. Any filing made by NSTAR to revise the ROE in compliance with a Commission order shall become effective as of the date specified in such order and shall raise no issue regarding this Local Service Schedule other than the compliance with the Commission order. The allowed ROE is also subject to revision pursuant to the authority of the Commission under Sections 205 and 206 of the FPA.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{1 - FT}$$

where FT is the Federal Income Tax Rate and A is the weighted return on equity component, including preferred, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D below, C is the equity AFUDC component of Transmission Depreciation and Amortization Expense, as defined in Section II.B below, and D is Transmission Investment Base, as determined in Section II.A.1 above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1 - ST}$$

where ST is the State Income Tax Rate, A is the weighted return on equity component, including preferred, determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D below, C is the equity AFUDC component of Transmission Depreciation and Amortization Expense, as defined in Section II.B below, D is the Transmission Investment Base, as determined in II.A.1 above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation and Amortization Expense shall equal the sum of (i) the Depreciation Expense for Transmission Plant and (ii) an allocation of Intangible Plant Amortization Expense and General Plant Depreciation Expense, which is calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation Expenses by the Transmission Wages and Salaries Allocation Factor; less the Amortization of AFUDC Regulatory Credit as recorded in FERC Account No. 407.4.

C. Transmission Related Amortization of Gain/Loss on Reacquired Debt shall equal the electric Amortization of Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal the total electric municipal tax expense reported in the Company's FERC Form 1, page 263, Local Real Estate and Personal Property Taxes, column (i), multiplied by the Plant Allocation Factor.

F. Transmission Related Payroll Tax Expense shall equal the total electric payroll tax expense reported in the Company's FERC Form 1, page 263, Service Company Allocations and Capitalization, column (i), multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal the Transmission Operation and Maintenance Expenses in Section I.B above.

H. Transmission Related Administrative and General Expenses shall equal the sum of the (1) Administrative and General Expense multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance included in FERC Account No. 924, line 156 multiplied by the Transmission Plant Allocation Factor, (3) expenses included in Account No. 928(excluding Merger-Related Costs included in Account No. 928), line 160 related to (i) transmission related FERC Assessments, plus (ii) any other Federal and State transmission related expenses or assessments, plus (iii) the cost of any independent audit requested by the Mass AG as the representative for NSTAR's retail customers and (4) Transmission Merger-Related Costs. The amount of PBOP expense shall be separately stated. NSTAR commits to adhere to: (i) the Commission's PBOP policy as expressed in the Commission's December 17, 1992, Statement of Policy in Docket No. PL93-1-000, as the Commission may amend that policy from time to time in the future; and (ii) the provisions of Financial Accounting Statement 106, Employers' Accounting for Postretirement Benefits Other Than Pensions.

I. Transmission Related Integrated Facilities Charges shall equal the transmission payments to

Affiliates for use of the integrated transmission facilities of those Affiliates included in FERC Account No. 565.

J. Transmission Support Revenues shall equal the revenue received for transmission support included or includable in FERC Account Nos. 454 and 456 but excluding any revenue received for use of the Company's entitlement in the Hydro-Quebec Facilities.

K. Transmission Support Expense shall equal the expense paid by the Company for transmission support included in FERC Account No. 565, but excluding expenses for the Hydro-Quebec DC Facilities.

L. Transmission-Related Expense from Generators shall equal the expenses from generators that are reflected in a filing made by the Company with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the Local Service Schedule and included or includable in FERC Account No. 565.

M. Transmission Rents Received from Electric Property shall equal any FERC Account Nos. 454 and 456 Rents from Electric Property, associated with Transmission Plant but not reflected as a credit in Transmission Support Revenues in Section II.J.

N. Short-Term and Non-Firm Point-to-Point Service Revenues shall equal the applicable wheeling revenues received for Local Point-To-Point Service provided under this Local Service Schedule, including the transmission component of the Company's Third-Party Sales, as recorded in FERC Account Nos. 447 and 456.1.

O. Regional Network Services (RNS) Revenues shall equal the Company's RNS revenues pursuant to the Tariff, as included or includable in FERC Account Nos. 454, 456 and 456.1 but excluding any incremental revenues associated with FERC-approved adders for RTO participation and new investment.

P. Through or Out Revenues shall equal the distribution of revenues received by the Company for Through or Out Service pursuant to the Tariff as included or includable in FERC Account Nos. 454 and 456.1.

Q. ISO-NE Scheduling and Dispatch Revenues shall be the amount of revenues received by the Company from ISO-NE for scheduling and dispatch services pursuant to the Tariff as included or includable in FERC Account Nos. 454, 456 and 456.1.

ATTACHMENT E

INDEX OF LOCAL NETWORK SERVICE CUSTOMERS

Customer	Date of Service Agreement
ANP Blackstone Energy Company	October 1, 2000
Entergy Nuclear Generation Company	September 1, 1999
New England Power Company	September 6, 1996
NSTAR Electric Company	December 24, 1996
Sithe New Boston LLC	September 1, 1998
Sithe Framingham LLC	September 1, 1998
Sithe Mystic LLC	September 1, 1998
Sithe Edgar LLC	September 1, 1998
Sithe West Medway LLC	September 1, 1998
Town of Braintree Municipal Light Dept.	March 1, 1997
Town of Concord Municipal Light Plant	June 21, 2002
Town of Hingham Municipal Light Plant	March 1, 1997
Town of Hull Municipal Light Plant	March 1, 1997
Town of Norwood Municipal Light Dept.	September 6, 1996
Town of Reading Municipal Light Plant	March 1, 1997
Town of Wellesley Municipal Light Plant	June 21, 2002

ATTACHMENT F

FORMULA RATE TEMPLATE

NSTAR Electric Company

Annual Local Network Service Revenue Requirement

Service Year Ended December 31, xxxx

This template does not change the other provisions of this Schedule 21. The template is not a substitute for Schedule 21 language. If an inconsistency between the Schedule 21 language and the template arises, the Schedule 21 language is controlling. The template is illustrative and the actual true-up filing as made from time to time may include format changes or reflect non-material changes required by the Uniform System of Accounts.

Sheet 1

	(a)	(b)	(c)	(d)
Line	**Description**	**Section**	**Amount**	**Reference**
1	**Investment Base**	II.A.1		
2	Transmission Plant	II.A.1.a	$ -	Sheet 3, Line 1, Col (f)
3	Transmission Related Intangible & General Plant	II.A.1.b	-	Sheet 3, Line 4, Col (f)
4	Transmission Plant Held for Future Use	II.A.1.c	-	Sheet 3, Line 5, Col (f)
5	Transmission Related Construction Work in Progress	II.A.1.d	-	Sheet 3, Line 6, Col (f)
6	Total Plant		-	Sum Lines 2 thru 5
7	Trans Related Depreciation and Amortization Reserve	II.A.1.e	-	Sheet 3, Line 12, Col (f)
8	Transmission Related Accumulated Deferred Taxes	II.A.1.f	-	Sheet 3, Line 20, Col (f)
9	AFUDC Regulatory Liability	II.A.1.g	-	Sheet 3, Line 21, Col (f)
10	Total Net Plant		-	Sum Lines 6 thru 9
11	Transmission Related Gain/Loss on Reacquired Debt	II.A.1.h	-	Sheet 3, Line 22, Col (f)
12	Other Trans Related Regulatory Assets/Liabilities	II.A.1.i	-	Sheet 3, Line 28, Col (f)
13	Transmission Prepayments	II.A.1.j	-	Sheet 3, Line 29, Col (f)
14	Transmission Materials & Supplies	II.A.1.k	-	Sheet 3, Line 30, Col (f)
15	Transmission Related Cash Working Capital	II.A.1.l	-	Sheet 3, Line 35, Col (f)
16	**Total Investment Base**		$ -	Sum Lines 10 thru 15
17	**Revenue Requirement**			
18	Investment Return and Income Taxes	II.A.2	$ -	Sheet 2, Line 39, Col (c)
19	Transmission Depreciation and Amortization Expense	II.B	-	Sheet 4, Line 7, Col (f)
20	Amortization of Gain/Loss on Reacquired Debt	II.C	-	Sheet 4, Line 8, Col (f)
21	Transmission Related Amort. of Investment Tax Credits	II.D	-	Sheet 4, Line 9, Col (f)
22	Transmission Related Municipal Tax Expense	II.E	-	Sheet 4, Line 10, Col (f)
23	Transmission Related Payroll Tax Expense	II.F	-	Sheet 4, Line 11, Col (f)
24	Transmission Operation & Maintenance Expense	II.G	-	Sheet 4, Line 30, Col (f)
25	Trans Related Administrative and General Expense	II.H	-	Sheet 4, Line 44, Col (f)
26	Transmission Related Integrated Facilities Charges	II.I	-	Sheet 5, Line 10, Col (e)
27	Transmission Support Revenues	II.J	-	Sheet 5, Line 15, Col (e)
28	Transmission Support Expense	II.K	-	Sheet 5, Line 20, Col (e)
29	Transmission Related Expense from Generators	II.L	-	Sheet 5, Line 23, Col (e)
30	Transmission Rents Received from Electric Property	II.M	-	Sheet 5, Line 28, Col (e)
31	Short-Term and Non-Firm P-T-P Service Revenues	II.N	-	Sheet 5, Line 31, Col (e)
32	Regional Network Services (RNS) Revenues	II.O	-	Sheet 5, Line 36, Col (e)
33	Through or Out Revenues	II.P	-	Sheet 5, Line 39, Col (e)
34	ISO-NE Scheduling and Dispatch Revenues	II.Q	-	Sheet 5, Line 43, Col (e)
35	**Total LNS Revenue Requirement**		$ -	Sum Lines 18 thru 34
36	Wholesale LNS Revenues Received:			
37	Item # 1		-	
38	Item #2		-	

39	Last Item	-	
40	Total Wholesale LNS Revenue	$ -	Sum Lines 37 thru 39
41	**Total Retail LNS Revenue Requirement**	**$ -**	Line 35 - Line 40
42	Average 12 CP		
43	Sum of Monthly Peaks (kw)	-	FF1: 400.17(b)
44	Average Peak	-	Line 43 / 12
45	Annual Rate per kw	$ -	Line 35 / Line 44
46	Monthly Rate per kw	$ -	Line 45 / 12
47	Daily Rate per kw	$ -	Line 45 / 365

NSTAR Electric Company
Investment Return and Income Taxes
Service Year Ended December 31, xxxx
Sheet 2

Line	(a) Description	(b) Tariff Section	(c) Balance	(d) Capitalization Ratio *	(e) Cost *	(f) Weighted Cost *	(g) Equity Cost	(h) Reference
1	**Weighted Cost of Capital**	II.A.2.a						
2	Long Term Debt	II.A.2.a.i	$ -		0.0000%	0.0000%		FF1: Page 112.24(c)
3	Preferred Stock	II.A.2.a.ii	-		0.0000%	0.0000%	0.0000%	FF1: Page 112.3(c)
4	Common Equity	II.A.2.a.iii	-		0.0000%	0.0000%	0.0000%	FF1: Page 112.16(c) - Line 3(c)
5	Total		$ -			0.0000%	0.0000%	Sum Lines 2 thru 4
6	**Investment Return**	II.A.2						
7	Total Investment Base		$ -					Sheet 1, Line 16, Col (c)
8	Weighted Cost of Capital		0.0000%					Line 5, Col (f)
9	Total Return on Investment		$ -					Line 7 * Line 8
10	**Federal Income Tax**	II.A.2.b						
11	A = Equity Cost		0.0000%					Line 5, Col (g)
12	B = Transmission Amortization of ITC		$ -					Sheet 1, Line 21, Col (c)
13	C = Equity AFUDC		-					FF1: Page 117.38
14	Total B + C		-					Line 12 + Line 13
15	D = Investment Base		-					Line 7
16	(B + C) / D		0.00%					Line 14 / Line 15
17	(A + [(C + B) / D]		0.00%					Line 11 + Line 16
18	FT = Federal Income Tax Rate		35.00%					Federal corporate tax rate
19	1 - FT		65.00%					1 - Line 18
20	Federal Tax Factor		0.00000%					Line 17 * Line 18 / Line 19
21	Total Federal Income Taxes		$ -					Line 15 * Line 20
22	**State Income Tax**	II.A.2.c						
23	A = Equity Cost		0.0000%					Line 5, Col (g)
24	B = Transmission Amortization of ITC		$ -					Sheet 1, Line 21, Col (c)
25	C = Equity AFUDC		-					
26	Total B + C		-					Line 24 + Line 25
27	D = Investment Base		-					Line 7
28	(B + C) / D		0.00%					Line 26 / Line 27
29	(A + [(C + B) / D]		0.00%					Line 23 + Line 28
30	ST = State Income Tax Rate		6.50%					Massachusetts corporate tax rate
31	1 - ST		93.50%					1 - Line 30
32	Federal Tax Factor		0.00000%					Line 23
33	State Tax Factor		0.00000%					(Line 29 + Line 32) * Line 30 / Line 31
34	Total State Income Taxes		$ -					Line 27 * Line 33
35	**Investment Return and Income Taxes**	II.A.2						

36	Return on Investment	$ -	Line 9
37	Federal Income Taxes	-	Line 21
38	State Income Taxes	-	Line 34
39	**Total Return and Income Taxes**	**$ -**	Sum Lines 36 thru 38

* Note that weighting and cost are determined on Sheet 7

NSTAR Electric Company

Investment Base

Service Year Ended December 31, xxxx

Sheet 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Tariff				**Allocations**	
						LNS	
Line	**Description**	**Section**	**Total**	**Allocator**	**Factor**	**Amount**	**Reference**
1	**Transmission Plant**	II.A.1.a	$ -	Direct	100.0000%	-	FF1: Page 207.58(g)
2	General Plant		-	W&S	0.0000%	-	FF1: Page 207.99(g)
3	Intangible Plant		-	W&S	0.0000%	-	FF1: Page 205.5(g)
4	**Total Intangible & General Plant**	II.A.1.b	-			-	Sum Lines 2 thru 3
5	**Transmission Plant Held for Future Use**	II.A.1.c	-	Direct	100.0000%	-	FF1: Page 214.10&.23(d)
6	**Transmission Related CWIP**	II.A.1.d	-	CWIP	50.0000%	-	FF1: Page 216(b) Trans only
7	**Transmission Related Dep & Amort Reserve**	II.A.1.e					
8	Transmission Accumulated Depreciation		-	Direct	100.0000%	-	FF1: Page 219.25(b)
9	General Plant Accumulated Depreciation		-	W&S	0.0000%	-	FF1: Page 219.28(b)
10	General Plant Accumulated Amortization		-	W&S	0.0000%	-	FF1: Page 200.21(c) Footnote
11	Intangible Plant Accumulated Amortization		-	W&S	0.0000%	-	FF1: Page 200.21(c) Footnote
12	Total Transmission Related Depreciation Reserve		-			-	Sum Lines 8 thru 11
13	**Transmission Accumulated Deferred Taxes**	II.A.1.f					
14	Accumulated Deferred Taxes (190)		-		0.0000%	-	Sheet 8, Line 5, col (d)
15	Accumulated Deferred Income Taxes (281)		-			-	FF1: Page 113.62(c)
16	Accumulated Deferred Taxes - Property (282)		-				FF1: Page 275.9(k)
17	Less Transition Property		-				FF1: Page 275.4(k)
18	Net Acc. Def. Income Taxes - Other Property (282)		-	Plant	0.0000%	-	Sum Lines 16 thru 17
19	Accumulated Deferred Income Taxes - Other (283)		-		0.0000%	-	Sheet 8, Line 10, col (d)
20	Total					-	Sum Lines 17 thru 19
21	**AFUDC Regulatory Liability**	II.A.1.g	-	Direct	100.00%	-	FF1: Page 278.6(f)
22	**Gain/Loss on Reacquired Debt**	II.A.1.h	-	Plant	0.0000%	-	FF1: Page 111.81(c)+113.61(c)
23	**Other Regulatory Assets**	II.A.1.i					
24	FAS 106 (182.3 & 254)		-	W&S	0.0000%	-	FF1: Page 232.1.39(f)+278.(f)
25	FAS 109 (182.3 & 254)		-				FF1: Page 232.1.29(f)
26	Less FAS 109 - Liability (182.3 & 254)		-				FF1: Page 278.2(f)

27	Net FAS 109 (182.3 & 254)		-	Plant	0.0000%	-	Sum Lines 25 thru 26
28	Total Other Regulatory Assets		-			-	Line 24 + line 27
29	**Prepayments**	II.A.1.j	-	W&S	0.0000%	-	FF1: Page 111.57(c)+ 232.2.8(f)
30	**Transmission Materials & Supplies**	II.A.1.k	-	Direct	100.0000%	-	FF1: Page 227.8(c)+227.5(c) Trans
31	**Cash Working Capital**	II.A.1.l					
32	Operation & Maintenance Expense		-	WC	12.50%	-	Sheet 1, Line 24, col (c)
33	Administrative & General Expense		-	WC	12.50%	-	Sheet 1, Line 25, col (c)
34	Transmission Support Expenses		-	WC	12.50%	-	Sheet 1, Line 28, col (c)
35	Total Cash Working Capital		-			-	Sum Lines 32 thru 33

36	**Description**	**Allocation Factor**	**Reference**
37	Direct Allocation (Direct)	100.0000%	
38	Wages & Salary (W&S)	0.0000%	Sheet 6, Line 6(c)
39	Plant Allocation (Plant)	0.0000%	Sheet 6, Line 14(c)
40	Construction Work in Progress Allocation (CWIP)	50.0000%	Sheet 6, Line 15(c)
41	Cash Working Capital (WC)	12.50%	Tariff Section II.A.1.l

NSTAR Electric Company
Transmission Expenses
Service Year Ended December 31, xxxx
Sheet 4

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Tariff		Allocations			
Line	Description	Section	Total	Allocator	Factor	LNS Amount	Reference
1	**Transmission Depreciation Expense**	II.B					
2	Transmission Depreciation	II.B.i		Direct	100.00%	$ -	FF1: Page 336.7(f)
3	General Plant Depreciation and Amortization	II.B.ii		W&S	0.00%	-	FF1: Page 336.10(f)
4	Amortization of Transmission Related Intangible Plant			W&S	0.00%	-	FF1: Page 336.1(f)
5	Amortization of AFUDC Regulatory Credit		-			-	FF1: Page 278.6(d) (amort)
6	Net Amortization of Transmission Related Intangible Plant		-			-	Sum Lines 4 and 5
7	Total Transmission Depreciation Expense		$ -			$ -	Sum Lines 2, 3 and 6
8	**Amortization of Gain/Loss on Reacquired Debt**	II.C		Plant	0.00%	$ -	FF1: Page 117.64c
9	**Transmission Related Amortization of ITC**	II.D		Plant	0.00%	$ -	FF1: Page 114.19(c)
10	**Transmission Related Municipal Tax Expense**	II.E		Plant	0.00%	$ -	FF1: Page 263.5(i)
11	**Transmission Related Payroll Tax Expense**	II.F		W&S	0.00%	$ -	FF1: Page 263.8i
12	**Transmission Operation and Maintenance Expense**	II.G					
13	Operation Supervision & Engineering (560)			Direct	100.00%	$ -	FF1: Page 321.83(b)
14	Load Dispatching (561)		-	Internal Costs		-	FF1: Page 321.83(b)
15	Load Dispatch - Reliability (561.1)		-	Internal Costs		-	FF1: Page 321.85(b) footnote
16	Load Dispatch-Mon and Oper Trans System (561.2)		-	Internal Costs		-	FF1: Page 321.86(b) footnote
17	Load Dispatch-Trans Service and Scheduling (561.3)		-	Internal Costs		-	FF1: Page 321.87(b) footnote
18	Scheduling, System Control and Dispatch Services (561.4)		-	Internal Costs		-	FF1: Page 321.88(b) footnote

19	Reliability, Planning and Standards Development (561.5)		-	Internal Costs		-	FF1: Page 321.89(b)
20	Transmission Service Studies (561.6)		-	Internal Costs		-	FF1: Page 321.90(b)
21	Generation Interconnection Studies (561.7)		-	Internal Costs		-	FF1: Page 321.91(b)
22	Reliability, Planning and Standards Development (561.8)		-	Internal Costs		-	FF1: Page 321.92(b) footnote
23	Station Expenses (562)		-	Direct	100.00%	-	FF1: Page 321.93(b)
24	Overhead Lines Expenses (563)		-	Direct	100.00%	-	FF1: Page 321.94(b)
25	Underground Lines Expenses (564)		-	Direct	100.00%	-	FF1: Page 321.95(b)
26	Miscellaneous Transmission Expenses (566)		-	Direct	100.00%	-	FF1: Page 321.97(b)
27	Rents (567)		-	Direct	0.00%	-	Sheet 5, Line 7, col (d)
28	Transmission Maintenance (568 - 573)		-	Direct	100.00%	-	FF1: Ppage 321.111(b)
29	Regional Market Expense (575)		-	Internal Costs	0.00%	-	FF1: Ppage 322.131(b)
30	Total Transmission O&M Expense		$ -			$ -	Sum Lines 13 thru 28
31	**Transmission Related A&G Expenses**	II.H					
32	Administrative and General Expenses		$0				FF1: Page 323.197(b)
33	Property Insurance (924)		-				FF1: Page 323.185(b)
34	Employee Pension and Benefits (926)		-				FF1: Page 323.187(b)
35	Regulatory Commission Expense (928)		-				FF1: Page 323.189(b)
36	General Advertising Expense (930.1)		-				FF1: Page 323.191(b)
37	Merger Related Costs		-				FF1: Page 320 FN
38	Sub-Total		-	W&S	0.00%	-	Sum Lines 32 thru 37
39	Property Insurance (924)	II.H.2	-	Plant	0.00%	-	Line 33
40	Employee Pension and Benefits (926) - Note 1	II.H.1	-	W&S	0.00%	-	Line 34
41	Regulatory Commission Expense (928)	II.H.3	-	Footnote	0.00%	-	Line 59
42	General Advertising Expense (930.1)	II.H	-		0.00%	-	Line 36
43	Transmission Merger Related Costs		-	Direct	100.00%	-	FF1: Page 320 FN
44	Total Transmission Related A&G Expenses		$ -			$ -	Sum Lines 39 thru 43
45	Regulatory Commission Expense (928)	II.H.3					
46	DPU - General Assessment		$ -		0.00%	$ -	FF1: Page 350.1 (d)
47	DPU - Appropriation Account		-		0.00%	-	FF1: Page 350.2 (d)
48	DPU - AGO Assessment #1		-		0.00%	-	FF1: Page 350.3 (d)

49	DPU - AGO Assessment #2		-		0.00%	-	FF1: Page 350.4 (d)
50	DPU - Outage Reporting Assessment		-		0.00%	-	FF1: Page 350.5 (d)
51	DPU - Manhole Cover Assessment		-		0.00%	-	FF1: Page 350.6 (d)
52	DPU - Stray Voltage Assessment		-		0.00%	-	FF1: Page 350.7 (d)
53	MA Emergency Management Agency		-		0.00%	-	FF1: Page 350.8 (d)
54	FERC Assessment		-	Direct	100.00%	-	FF1: Page 350.9 (d)
55	FER LICAP Docket		-	Direct	100.00%	-	FF1: Page 350.10 (d)
56	FERC RMR Docket		-	Direct	100.00%	-	FF1: Page 350.11 (d)
57	FERC Docket ER07-549, Including cost of audit		-	Direct	100.00%	-	FF1: Page 350.12 (d)
58	DPU Regulatory Proceeding Costs 05-85		-		0.00%	-	FF1: Page 350.13 (d)
59	Total Regulatory Commission Expenses	II.H.3	-		0.00%	-	Sum Lines 46 thru 58

	Description	Allocation Factor	Reference
60	Direct Allocation (Direct)	100.0000%	
61	Wages & Salaries Allocation (W&S)	0.0000%	Sheet 6, Line 6(c)
62	Plant Allocation (Plant)	0.0000%	Sheet 6, Line 14(c)

63 **Note 1**

64 Included in the Employee Pension and Benefits Expenses are costs related to Post Retirement Benefits other than Pension (PBOP). PBOP costs are determined

65 by an independent actuary as required by FASB 106. The PBOP expense included in Account 926 for 20xx was $xx,xxx,xxx as compared to $xx,xxx,xxx in the prior year;

66 as shown

67 on the FF1, Page 323, footnote. Applying the labor allocator to the total PBOP expense results in $x,xxx,xxx of PBOP expense being recovered through the LNS Tariff

68 in 20xx as compared to $x,xxx,xxx in the prior year.

NSTAR Electric Company
Support Expense & Revenue Detail
Service Year Ended December 31, xxxx
Sheet 5

	(a)	(b)	(c)	(d)	(e)
Line	Description	Tariff Section	Amount	Includable Amount	Reference
1	Transmission Rents (Account 567)	II.G			
2	Hydro Quebec DC Phase I Support			-	FF1: Page 320.98 (b) Footnote
3	Hydro Quebec DC Phase II Support			-	FF1: Page 320.98 (b) Footnote
4	New England Power Support			-	FF1: Page 320.98 (b) Footnote
5	Hydro Quebec Phase II NEP AC, Chester SVC			-	FF1: Page 320.98 (b) Footnote
6	Transmission Line Rents		-	-	FF1: Page 320.98 (b) Footnote
7	Total Transmission Rents Received		-	-	Sum Lines 2 thru 6
8	Transmission Related Integrated Facilities Charges	II.I	-	-	
9	- none -		-	-	
10	Total Trans Related Integrated Facilities Charges		-	-	Sum Lines 9 thru 9
11	Transmission Support Revenues 456 & 456.1	II.J			
12	Item #1			$ -	FF1: Page 300.21(b) Footnote
13	Item # 2			-	FF1: Page 300.21(b) Footnote
14	Last Item		-	-	FF1: Page 300.22(b) Footnote
15	Total Short Term & Non-Firm PTP Revenues		$ -	$ -	Sum Lines 12 thru 14
16	Transmission Support Expense (565)	II.K			
17	Item #1			-	FF1 Q2: Page 332.2(h)
18	Item # 2			-	FF1 Q3: Page 332.2(h)
19	Last Item		-	-	FF1: Page 332.2(h)
20	Total Transmission Support Expense		-	-	Sum Lines 17 thru 19
21	Transmission Related Expense from Generators	II.L			N/A
22	- none -		-	-	
23	Total Trans Related Expense from Generators		-	-	Sum Lines 22 thru 22
24	Rents Received from Electric Property (454)	II.M			
25	Item #1			-	FF1: Page 300.19(b) Footnote
26	Item # 2			-	FF1: Page 300.19(b) Footnote
27	Last Item		-	-	FF1: Page 300.19(b) Footnote
28	Total Rents Received		-	-	Sum Lines 25 thru 27
29	Short-Term and Non-Firm Point-to-Point Rev	II.N	$ -	$ -	N/A
30	- none -		-	-	
31	Total ST and Non-Firm Point-to-Point Revenues		-	-	Sum Lines 30 thru 30
32	Regional Network Service Revenues (456):	II.O			
33	RNS Transmission Revenue		-	-	
34	RNS PTF Post 2003 investment 1 % Adder		-	-	RNS Revenue Requirement
35	RNS PTF RTO Participation 0.5% Adder		-	-	RNS Revenue Requirement

36	Total Regional Network Services Revenues		-	-	Sum Lines 33 thru 35
37	Through or Out Revenues	II.P	$ -	$ -	N/A
38	- none -		-	-	
39	Total Through or Out Revenue		-	-	Sum Lines 38 thru 38
40	ISO-NE Scheduling & Dispatch Revenue	II.Q			
41	Nepool Scheduling & Dispatch Revenue		-	-	
42	RTO Participation 0.5% Adder		-	-	Reguional Schedule 1 Revenue Requirement
43	Total ISO-NE Scheduling & Dispatch Revenue		-	-	Sum Lines 42 thru 42

NSTAR Electric Company

Allocation Factors

Service Year Ended December 31, xxxx

Sheet 6

	(a)	(b)	(c)	(d)
		Tariff		
Line	**Description**	**Section**	**Amount**	**Reference**
1	**Transmission Wages & Salaries Allocation Factor**	I.A.1		
2	Transmission Related Direct Wages & Salaries		$ -	FF1: Page 354.21(b)
3	Total Direct Wages & Salaries		-	FF1: Page 354.28(b)
4	Administrative & General Wages & Salaries		-	FF1: Page 354.27(b)
5	Net Total Direct Wages & Salaries		-	Line 3 less Line 4
6	Transmission Wages & Salaries Allocation Factor		**0.0000%**	Line 2 / Line 5
7	**Plant Allocation Factor**	I.A.2		
8	Transmission Plant Investment		$ -	FF1: Page 207.58(g)
9	HQ Leases		-	
10	Transmission Related General Plant		-	Sheet 3, Line 2, Col (f)
11	Transmission Related Intangible Plant		-	Sheet 3, Line 3, Col (f)
12	Total Transmission Plant Investment		-	Sum Lines 8 thru 11
13	Total Plant in Service		-	FF1: Page 207.104(g)
14	Plant Allocation Factor		**0.0000%**	Line 12 / Line 13

15	**Construction Work in Progress Allocation Factor**	II.A.1.d	**50.0000%**

NSTAR Electric Company

Cost of Long Term Debt

Service Year Ended December 31, xxxx

Sheet 7

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	FF1:256(a)	FF1:256(d)		FF1:256(e)	FF1:256(b)	FF1:256(h)		FF1:256(c)					
		Long Term Debt				Principal		Debt	Call				
			Term	Coupon	Original	Amount	Percent	Disc &	Premium on	Net	Cost to	Weighted	
Line	Series	Dated	(Years)	Rate	Issue	Outstanding	of Total	Exp	Debt	Proceeds	Maturity	Cost	Reference
							Col f / Col f Total			**Col f - Col h - Col i**	**Col d + ((Col h + Col i) / (Col e / Col d))**	Col h * Col g	
1	MIFA Bonds	2/8/94	20	5.75%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
2	4.875% Debentures	4/13/04	10	4.875%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
3	7.8% Debentures	5/10/95	15	7.80%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
4	4.875 Debentures	10/9/02	10	4.875%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
5	5.75% Debentures	3/13/06	30	5.750%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
6	5.625% Debentures	11/19/07	10	5.63%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
7	Total				$ -	$ -	0.00%	$ -	$ -	$ -		0.0000%	Sum Lines 1 Thru 6

Cost of Preferred Stock

	FF1:250(a)			FF1:250(a)		FF1:250(f)			
		Preferred Stock				Principal			
				Coupon	Original	Amount	Percent	Weighted	
	Series	Dated	Term	Rate	Issue	Outstanding	of Total	Cost	Reference
8	4.25%	6/13/1956	N/A	4.25%			0	0.0000%	FF1: Page 250 & 251
9	4.78%	7/10/1958	N/A	4.78%			0	0.0000%	FF1: Page 250 & 251
10	Total				$ -	$ -	0.00%	0.0000%	Sum Lines 8 Thru 9

Effective NSTAR ROI

Tariff Section II.A.2.a

	(a)	(b)	(c)	(d)	(e)	(f)
Line	**Description**	**Common**	**Preferred**	**LTD**	**Total**	**Reference**
11	Amount			$	-	Sheet 2, lines 2 thru 4
12	Cost	0.0000%	0.0000%	0.0000%		See Note
13	Actual Weighting	0.0000%	0.0000%	0.0000%	0.0000%	Line 11 / Total Line 11
14	Weighted Cost	0.0000%	0.0000%	0.0000%	0.0000%	Line 12 * Line 13
15	70% of Weighted Cost	0.0000%	0.0000%	0.0000%		Line 14 * 70%
16	Tariff Weighting	50.0000%	0.0000%	50.0000%	100.0000%	Tariff Section II.A.2.a
17	Weighted Cost	0.0000%	0.0000%	0.0000%	0.0000%	Line 12 * Line 16
18	30% of Weighted Cost	0.0000%	0.0000%	0.0000%		Line 17 * 30%
19	Blended Cost of Capital	0.0000%	0.0000%	0.0000%	0.0000%	Line 15 + Line 18

20	**Lower of Blended or Actual**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	Lower of line 14, col (e) or line 19, col (e) Tariff Section II.A.2.a
21	Note:					
22	The Regurn on Equity component is specified in Tariff Section II.A.2.a.iii					
23	The Cost of Preferred Stock is calculated on line 10					
24	The Cost of Long Term Debt is calculated on line 7					

NSTAR Electric Company

Annual Local Network Service Revenue Requirement

Service Year Ended December 31, xxxx

Sheet 8

Transmission Related ADIT - Tariff Section II.A.1.f

	(a)	(b)	(c)	(d)	(e)
Line	Description	Amount	Allocator	Rate Base	Notes
1	**Account 190**				
2	Item # 1		0.0000%	$ -	FF1: Page 234.2(c) Footnote
3	Item #2		0.0000%	-	FF1: Page 234.2(c) Footnote
4	Last Item	-	0.0000%	-	FF1: Page 234.2(c) Footnote
5	Total 190	$ -	0.0000%	$ -	Sum Lines 2 thru 4
6	**Account 283**				
7	Item # 1		0.0000%	-	FF1: Page 276.3(k) Footnote
8	Item #2		0.0000%	-	FF1: Page 276.3(k) Footnote
9	Last Item	-	0.0000%	-	FF1: Page 276.3(k) Footnote
10	Total 283	$ -	0.0000%	$ -	Sum Lines 7 thru 9
11	Wages & Salary Allocator	0.0000%			Sheet 6, Line 6, Col (d)
12	Plant Allocator	0.0000%			Sheet 6, Line 14, Col (d)

ATTACHMENT L

CREDITWORTHINESS POLICY

I. General Information:

This Attachment L details the specific requirements for the creditworthiness procedures of NSTAR. All customers taking (i) any service under Schedule 21-NSTAR or (ii) any FERC-regulated interconnection service from NSTAR must meet the terms of this Policy (where all the above, collectively, are referred to as "Services"). The creditworthiness of each customer must be established prior to receiving service from NSTAR. A customer will be evaluated at the time its application for service is provided to NSTAR. A credit review shall be conducted for each transmission customer not less than annually or upon reasonable request by the transmission customer. This Attachment L, when updated, will be done so in accordance with Section 10 of this Policy and as posted on NSTAR's OASIS.

All customers must comply with the terms of this Attachment L. Each customer should refer to NSTAR's web site at www.nstar.com, or NSTAR's OASIS site, for the NSTAR representative to whom to forward the information required by this Attachment L.

Upon receipt of a customer's information, NSTAR will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a customer, NSTAR will notify the customer of its Financial Assurance requirements. NSTAR will provide a written evaluation, upon request, to customers who are not required to provide Financial Assurance.

II. Financial Information:

Customers receiving transmission service or requesting interconnection service must submit, if available, the following:

- All current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch of the customer.
- Audited financial statements provided by a registered independent auditor for the two most recent years, or the period of its existence, if shorter, for the customer.

III. Creditworthiness Requirements:

A. The customer must meet at least one of the following quantitative criteria in order to receive unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges:

i) If rated, the customer must have either for itself or for its outstanding debt the following:

- Standard and Poor's or Fitch rating of at least a BBB, or
- Moody's rating of at least a Baa2.

ii) If un-rated or if rated below BBB/Baa2, as stated in a), the customer must meet all of the following:

- A Current Ratio of at least 1.0 times (current assets divided by all current liabilities);
- A Total Capitalization Ratio of less that 60% debt: total debt (including all short-term borrowing) divided by total shareholders' equity plus total debt;
- "Earnings before interest, taxes, depreciation and amortization" in most recent fiscal quarter divided by expense for interest" (EBITDA-to-Interest Expense Ratio) of at least 2.0 times; and
- Audited Financial Statement with an unqualified audit opinion.

iii) If the customer relies on the creditworthiness of a parent company, the customer's parent company must meet the criteria set out in (a) or (b) above, and must provide to NSTAR a written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from NSTAR.

iv) If the customer is a municipal that is a member of the Massachusetts Municipals Wholesale Electric Cooperative (MMWEC), MMWEC must meet the criteria set out in (a) or (b) above and provide to NSTAR a written guarantee that MMWEC will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from NSTAR.

B. If the customer does not qualify for unsecured credit under Section A, the customer will qualify for unsecured credit equivalent to two months of transmission service charges, or for interconnections, the credit equivalent of two months of the annual facilities charges and other ongoing charges, if one of the following qualitative factors is met:

- § The customer has, on a rolling basis, 12 consecutive months of payments to NSTAR with no missed, late or defaults in payment; or
- § The customer has an executed long-term contract for the sale of the full output (energy and capacity) of its generating unit and either has executed a corresponding service agreement under Schedule 21-NSTAR for the transmission of that output or the execution of such a service agreement is pending the customer's demonstration of creditworthiness pursuant to this Attachment L.

IV. Financial Assurance:

If the customer does not meet the applicable requirements for Creditworthiness set out in Section III above, then the customer must either:

- Pay in advance for service an amount equal to the lesser of the total charge for Transmission Service or the charge for three months of Transmission Service not less than 5 days in advance of the commencement of service; or

- Obtain Financial Assurance in the form of a: letter of credit, performance bond, or corporate guarantee equal to the equivalent of 3 months of Transmission Service charges prior to receiving service.

If the customer pays for service in advance, NSTAR will pay to the customer interest on the amounts not yet due to NSTAR , computed in accordance with the Commission's regulations at 18 CFR ? 35.191(a)(2)(iii).

V. Contesting Creditworthiness Determination:

The Transmission Customer may contest NSTAR's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate a

Transmission Customer's creditworthiness. NSTAR will review and respond to the request within 20 calendar days.

VI. Process for Changing Credit Requirements:

In the event that NSTAR plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, NSTAR shall submit such changes in a filing to the Commission under Section 205 of the Federal Power Act. NSTAR shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

A. General Notification Process

i) NSTAR shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

ii) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s).

iii) NSTAR shall consult with interested stakeholders upon request.

iv) Following Commission acceptance of such filing and upon the effective date, NSTAR shall revise Attachment L and an updated version of Schedule 21-NSTAR shall be posted the ISO-NE website.

B. Transmission Customer Responsibility

When there is a change in requirements pursuant to this Attachment L, it is the responsibility of the customers to forward updated financial information to NSTAR at the address noted on NSTAR's OASIS site and indicate whether the change affects their ability to meet the requirements of this Attachment L. In such cases where the customer's status has changed, the customer must take the necessary steps to comply with the revised requirements of the Attachment L by the effective date of the change.

VII. Posting Collateral Requirements:

A. Changes in Customer's Financial Condition

Each customer must inform NSTAR, in writing, within five (5) business days of any material change in its financial condition, and, if the customer qualifies under Section III.A(c), that of its parent company. A material change in financial condition may include, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

B. Change in Creditworthiness Status

- A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in Section IV above if one or more of the following conditions apply:
- The customer no longer meets the applicable criteria for Creditworthiness in Section III above;
- The customer exceeds the amount of unsecured credit extended by NSTAR, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or
- The customer has missed two or more payments for any of the services offered by NSTAR in the last 12 months.

In the event that NSTAR determines that there is a change in the credit level or collateral requirements, the customer may request a written explanation of the basis for this change. Such notification should be sent to the NSTAR contact indicated on the NSTAR OASIS site. NSTAR shall respond to such request within 20 days of receipt of such notification.

Unless otherwise noted above, when there is a change in a customer's Creditworthiness Status requiring the customer to provide Financial Assurance, the customer must provide such Financial Assurance within 20 business days from the date the customer either notifies NSTAR, as required in Section VI.B above, or receives notice from NSTAR.

VIII. Ongoing Financial Review:

Each customer is required to submit to NSTAR annually or when issued, as applicable:

- Current rating agency report;
- Audited financial statements from a registered independent auditor; and
- 10-Ks and 8-Ks, promptly upon their issuance.

IX. Suspension of Service:

NSTAR may immediately suspend service (with notification to Commission) to a customer, and may initiate proceedings with Commission to terminate service, if the customer does not meet the terms described in Sections III through VIII above at any time during the term of service or if the customer's payment obligations to NSTAR exceed the amount of unsecured or secured credit to which it is entitled under this Attachment L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

Eversource

SCHEDULE 21-ES

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Appendix A: Network Formula Requirements for Category A Costs

Appendix B: Network Formula Requirements for Category B Costs

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Attachment ES-E: Localized Costs Responsibility Agreement

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Attachment ES-H: Annual Transmission Revenue Requirements

Attachment ES-I: Annual Localized Transmission Revenue Requirement

Attachment ES-L: Creditworthiness Procedures

SCHEDULE 21-ES

LOCAL SERVICE SCHEDULE

This Local Service Schedule, designated Schedule 21-ES, governs the terms and conditions of service taken by Transmission Customers over the Transmission System of The Connecticut Light and Power Company, Public Service Company of New Hampshire and Western Massachusetts Electric Company (together, "Eversource"), but not over the Transmission System of their affiliate, NSTAR Electric Company, which provides service pursuant to Schedule 21-NSTAR.

I. COMMON SERVICE PROVISIONS

1 Definitions

Capitalized terms not defined herein shall have the meanings given them in the Tariff.

1.1 Annual Transmission Costs

The total annual cost of the Transmission System for purposes of Local Network Service shall be the amount specified in Attachments ES-H and ES-I, until amended by Eversource or modified by the Commission.

1.2 Annual True Up

The reconciliation to actual costs and actual loads of the estimated costs and loads costs used for billing purposes under Section 3.0 of this Local Service Schedule for any Service Year.

1.3 Category A Load Ratio Share

Ratio of a Transmission Customer's Category A Network Load to Eversource's total load computed in accordance with Sections 16.5 and 16.6 under Part III of this Local Service Schedule and calculated on a rolling twelve month basis. Also referred to as "Load Ratio Share".

1.4 Category B Load Ratio Share

Ratio of a Transmission Customer's Monthly Category B Load in the Designated State or Area for a Localized Facility to the Monthly Transmission System Category B Load for such Designated State or Area, calculated in accordance with Sections 16.5 and 16.6, and calculated on a rolling twelve month basis.

1.5 Designated Agent

See Tariff. Also, the Designated Agent of Eversource is Eversource Energy Service Company ("Eversource Service") which is a subsidiary of Eversource Energy.

1.6 Designated State or Area

The state or area to which the Commission allocates the costs of a Localized Facility identified in Section 16.3.

1.7 **Interest**

The amount computed in accordance with the Commission's regulations at 18 CFR §35.19a (a)(2)(iii). Interest on deposits and shall be calculated from the day the deposit check is credited to Eversource's account.

1.8 **Interruption**

A reduction in non-firm transmission service due to economic reasons pursuant to Schedule 21.

1.9 **Localized** Facility

Facility or costs that the New England System Operator determines should not be included in Attachment F of the ISO OATT.

1.10 **Network Load**

The load that a Network Customer designates for Local Network Service. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.11 **Network Operating Agreement**

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Part III of this Local Service Schedule.

1.12 **Network Upgrades**

Modifications or additions to transmission-related facilities that are integrated with and support Eversource's overall Transmission System for the general benefit of all users of such Transmission System.

1.13 **New England System Operator**

ISO New England Inc. ("ISO") or its successor entity.

1.14 **Party(ies)**

Eversource and the Transmission Customer receiving service under the Tariff.

1.15 **Short-Term Firm Point-To-Point Transmission Service**

Firm Point-To-Point Transmission Service with a term of less than one year.

1.16 Service Agreement

Service Agreement is a transmission service agreement for transmission service provided under this Local Service Schedule or Localized Costs Responsibility Agreement ("LCRA").

1.17 **Service Year**

The calendar year in which the Transmission Customer is receiving service under this Local Service Schedule.

1.18 **Eversource**

The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire, each an operating company of Eversource Energy, but excluding their affiliate NSTAR Electric Company, which provides Transmission Service pursuant to Schedule 21-NSTAR.

1.19 **Eversource's Monthly Transmission System Peak**

The maximum firm usage of the Eversource Transmission System in a calendar month (this does not include load of Eversource's customers exclusively connected to PTF).

1.20 **Eversource Transmission System**

The PTF and non-PTF facilities owned, controlled or operated by Eversource that are used to provide transmission service under this Local Service Schedule. This includes PTF facilities whose costs are not included in the regional rate.

1.21 **Transmission Service**

Point-To-Point Transmission Service provided under this Local Service Schedule on a firm and non-firm basis.

2. Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. Eversource is required to provide (or offer to arrange with the New England System Operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Service (i) Scheduling, System Control and Dispatch.

The Transmission Customer serving load within the Eversource Control Area shall also obtain the following ancillary services: (i) Reactive Supply and Voltage Control from Generation Sources, (ii) Regulation and Frequency Response, (iii) Energy Imbalance, (iv) Operating Reserve - Spinning, and (v) Operating Reserve - Supplemental.

The Transmission Customer serving load within the Eversource Control Area is required to acquire the appropriate Ancillary Services, whether from the New England System Operator, Eversource, another party, or by self-supply.

The Transmission Customer may not decline Eversource's or the New England System Operator's offer of appropriate Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from Eversource.

If Eversource is unable to provide Scheduling, System Control and Dispatch, Eversource can fulfill its obligation to provide this Ancillary Service by acting as the Transmission Customer's agent to secure this Ancillary Service from the New England System Operator. The Transmission Customer may elect to (i) have Eversource act as its agent to obtain Scheduling, System Control and Dispatch, (ii) secure Scheduling, System Control and Dispatch directly from the New England System Operator, or from a third party.

Eversource or New England System Operator shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedule that is attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by Eversource in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one’s wholesale merchant or an Affiliate’s use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Eversource system.

3. Billing and Payment

3.1 **Billing Procedure**

Within a reasonable time after the first day of each month, Eversource Service shall submit an invoice to the Transmission Customer for the charges for all services furnished or costs allocated under the Tariff during the preceding month.

The invoice shall be paid by the Transmission Customer within twenty five (25) days of the date of the invoice. All payments shall be made in immediately available funds payable to Eversource Service, or by wire transfer to a bank named by Eversource Service. Billing hereunder shall be based on cost estimates made by Eversource subject to Annual True-up when actual costs for the Service Year are known. Such Annual True-up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-up relates. The Annual True-up will include interest calculated in accordance with Section 35.19a of the Commission’s regulations. If the in service date of a forecasted capital addition changes, and the impact of such change on Eversource's annual revenue requirement is ten percent or more, Eversource Service will adjust current billing to the Transmission Customer as appropriate.

3.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by Eversource Service.

3.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to Eversource Service on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after Eversource Service notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, Eversource may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between Eversource and the Transmission Customer, Eversource will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then Eversource may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy. Neither Party shall have the right to challenge any monthly bill or to bring any court or administrative action of any kind questioning the propriety of any bill after a period of twenty four (24) months from the date the bill was due; provided, however, that in the case of a bill based on estimates, such twenty-four month period shall run from the due date of the final adjusted bill.

3.4 Transmission Customer Right to Audit

Eversource shall keep complete and accurate accounts and records with respect to its performance under this Local Service Schedule and shall maintain such data for a period of at least two (2) years after final billing for audit by a Transmission Customer. The Transmission Customer shall provide thirty (30) days' written notice to Eversource to request an audit of all such accounts and records relevant to service provided to the Transmission Customer for a specific time period. The Transmission Customer shall have the right, during normal business hours and at its own expense, to examine, inspect and make copies of all such accounts and records relevant to service provided to the Transmission Customer at such offices where such accounts and records are maintained, insofar as may be necessary for the purpose of ascertaining the reasonableness and accuracy of all relevant data, estimates or statements of charges submitted hereunder to the Transmission Customer. The records made available to a Transmission Customer for auditing purposes hereunder shall not include information pertaining to the loads of or charges to an individual customer other than the Transmission Customer; unless the Transmission Customer requests that the Commission order that such information be made available to the Transmission Customer and the Commission so orders. Nothing in this section shall be interpreted as limiting the Transmission Customer's access to system-wide load or charge data.

3.5 Regulatory Oversight of Formula Rate

Eversource will submit to the Connecticut Public Utilities Regulatory Authority, the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission ("State Commissions") the following information:

(a) A copy of the New England Power Pool's ("NEPOOL's") or any successor's annual informational filing at FERC supporting the total transmission revenue requirement for New England, which contains information submitted by Eversource supporting its total transmission revenue requirement;

(b) Eversource's total transmission revenue requirement as calculated in Attachments H & I under Schedule 21-ES;

(c) A copy of Eversource's applications under Restated NEPOOL Agreement Section 15.5, concerning the installation of or material changes to transmission facilities (or any successor approval process), and Section 18.4, concerning plans for additions, retirements, or changes in the capacity of transmission facilities (including descriptions of facilities and cost estimates);

(d) A copy of ISO New England's or any successor's Regional Transmission System Plan, which contains all identified improvements to the New England power system approved by the ISO New England or any successor's board;

(e) A copy of Eversource's filing to each New England state's siting council for those projects to be recovered through the RNS or LNS rates, such copy to be filed with the State Commissions when the estimated costs of the projects in question are proposed to be included in the RNS and LNS rates;

(f) At the same time that new estimated rates are implemented, the estimated cost for each capital addition (on a project-by-project basis) the cost of which is to be included in the estimated rates; and, for each such capital addition with an estimated cost of $20 million or greater, Eversource will provide the following to the extent available: (i) a breakdown of the projected cost into the following categories: labor (broken down into planning, engineering, construction, and other), outside services (broken down into planning, engineering, construction and other), materials (broken down into station equipment, towers and poles, overhead conductor, underground conduit and conductor, and other), land (broken down into fee ownership, easement, and other), and other (if applicable) and (ii) a non-binding estimate of the total project costs by calendar quarter;

(g) Within 60 days after the true-up is rendered for a year, the actual cost for each capital addition that was placed in service during that year; and, for each such capital addition with an actual or estimated cost of $20 million or greater, Eversource will provide the following to the extent available: (i) a breakdown of the actual cost into the following categories: labor (broken down into planning, engineering, construction, and other), outside services (broken down into planning, engineering, construction, and other), materials (broken down into station equipment, towers and poles, overhead conductor, underground conduit and conductor, and other), land (broken down into fee ownership, easement, and other), and other (if applicable) and (ii) the actual total project costs by calendar quarter.

4. Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of Eversource to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

5. Creditworthiness: See Attachment ES-L to this Schedule 21-ES.

6. Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

II. POINT-TO-POINT TRANSMISSION SERVICE

Scheduling of Point-To-Point Transmission Service:

The System Operator will dispatch all resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate external transactions. Resources within the New England Control Area using Firm Point-to-Point Transmission Service shall be dispatched based on economic merit in accordance with Market Rule 1 and will have no physical scheduling or dispatch rights. Transmission Customers will be charged for congestion costs and any other costs associated with such dispatch in accordance with Market Rule 1.

7. Nature of Firm Point-To-Point Transmission Service

7.1 Classification of Firm Transmission Service

The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule ES-2, as appropriate, for Long and Short-Term Firm Point-To-Point Transmission Service. In the event that either a Transmission Customer has not made a capacity reservation, or a Transmission Customer exceeds its firm capacity reservation at the Point of Receipt and Point of Delivery the Transmission Customer shall be billed and pay for its actual use of such excess capacity in addition to any Reserved Capacity pursuant to Schedule ES-2, including ancillary services provided pursuant to Schedule ES-1 hereto.

8. Nature of Non-Firm Point-To-Point Transmission Service

8.1 Classification of Non-Firm Point-To-Point Transmission Service

The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule ES-3, as appropriate, for non-firm Point-To-Point Transmission Service. In the event that either a Transmission Customer has not made a capacity reservation, or a Transmission Customer exceeds its non-firm capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer shall be billed and pay for its actual use of such excess capacity in addition to any Reserved Capacity pursuant to Schedule ES-3, including ancillary services provided pursuant to Schedule ES-1 hereto. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and/or energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule ES-3.

9. Service Availability

9.1 Real Power Losses

Real Power Losses are associated with all transmission service. Eversource is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as determined under Market Rule 1. The applicable Real Power Loss factors are as follows:

The amount of transmission losses incurred in transmitting power from the POR(s) to the POD(s) ("Loss Amount") shall be determined from time to time by the New England System Operator in accordance with ISO procedures applicable at the time of delivery. The Loss Amounts, when determined by the New England System Operator, shall be posted on Eversource’s Open Access Same-Time Information System ("OASIS"). In the event that the New England System Operator, for any reason, does not determine the entire Loss Amount, the losses not determined by the New England System Operator shall be based on average system losses as set forth below:

Cumulative Losses in Percent

POR/POD	Peak*	Off-Peak	24 Hr. Avg.
Bulk Transmission	1.98	2.42	2.21
Bulk Substation	2.46	2.92	2.70
Pri. Distribution	4.58	4.50	4.54

*Peak hours are defined as 0700-2300, Monday-Friday; Off-Peak hours are all other hours.

10. Procedures for Arranging Firm Point-To-Point Transmission Service

10.1 Deposit

A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either three month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month.

11. Additional Study Procedures For Firm Point-To-Point Transmission Service Requests:

11.1 Disbursement Methodology for Late Study Penalties

See Attachment ES-D to Schedule 21-ES.

12. Compensation for Transmission Service

The Transmission Customers taking Point-To-Point Transmission Service shall pay Eversource for any Direct Assignment Facilities, Ancillary Services and applicable study costs, along with the following:

12.1 Rates and Charges for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Services are provided in the Attachments appended to this Local Service Schedule: Firm Point-To-Point Transmission Services (Schedule ES-2); and Non-Firm Point-To-Point Transmission Services (Schedule ES-3).

12.2 Rates for Firm and Non-Firm Point-To-Point Transmission Services

Rates for Firm and Non-Firm Point to Point Transmission Services shall be determined as set forth in Attachments ES-2 and ES-3 of this Local Service Schedule on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 3 of this Local Service Schedule. Eversource shall use Part II of the Tariff to make its Third-Party Sales. Eversource shall account for such use at the applicable Tariff rates.

III. LOCAL NETWORK SERVICE

13. Nature of Local Network Service

13.1 Real Power Losses

Real Power Losses are associated with all transmission service. Eversource is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as determined under Market Rule 1. The applicable Real Power Loss factors are as follows:

The amount of transmission losses incurred in transmitting power across the Eversource Transmission System to the Network Customer's Network Load shall be determined from time to time by the New England System Operator in accordance with ISO procedures applicable at the time of delivery. The Loss Amounts, when determined by the New England System Operator, shall be posted on the Open Access Same-Time Information System ("OASIS"). In the event that the New England System Operator, for any reason, does not determine the entire Loss Amount, the losses not determined by the New England System Operator shall be based on average system losses as set forth below:

Cumulative Losses in Percent

POR/POD	Peak*	Off-Peak	24 Hr. Avg.
Bulk Transmission	1.98	2.42	2.21
Bulk Substation	2.46	2.92	2.70
Pri. Distribution	4.58	4.50	4.54

*Peak hours are defined as 0700-2300, Monday-Friday; Off-Peak hours are all other hours.

14. Network Resources

14.1 Use of Interface Capacity by the Network Customer

There is no limitation upon a Network Customer's use of the Eversource Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of Eversource's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

15. Additional Study Procedures For Local Network Service Requests

15.1 Disbursement Methodology for Late Study Penalties

See Attachment ES-D to Schedule 21-ES

16. Rates and Charges

The Network Customer shall pay Eversource for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

16.1 Rates and Charges

Rates for Local Network Service shall be determined as set forth in Schedule ES-4 on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 3 of this Local Service Schedule.

16.2 Eligible Customers Taking Service Under the ISO Tariff

Any Eligible Customer taking Regional Network Service under the ISO Tariff in a Designated State or Area shall pay to Eversource Service the customer's Category B Load Ratio Share of the Formula Requirements as calculated in Schedule ES-4, Appendix B for such Designated State or Area. Eversource Service shall execute a LCRA under this Local Service Schedule, in the form set forth in Attachment ES-E, to recover such charges from such customer. Eversource Service shall not bill any such customer any such costs until (1) such LCRA has been executed with the

Eligible Customer, or (2) an unexecuted LCRA has been permitted to be made effective **by** the Commission.

16.3 Listing of Localized Facilities by Designated State or Area:

(a) Connecticut:
Bethel to Norwalk Project
Middletown to Norwalk Project
Glenbrook Cables Project
Greater Springfield Reliability Project (Connecticut portion)

(b) Massachusetts:
Greater Springfield Reliability Project (Massachusetts portion)

16.4 **Monthly Demand Charge**

The Network Customer shall pay monthly Demand Charges, which shall be determined by multiplying its Category A Load Ratio Share times one twelfth (1/12) of the Formula Requirements in Schedule ES-4, Appendix A, and by multiplying its Category B Load Ratio Share for the Designated State or Area times one twelfth (1/12) of the Formula Requirements in Schedule ES-4, Appendix B for the Localized Facilities that are in such Designated State or Area.

16.5 **Determination of Network Customer's Monthly Network Load**

The Network Customer's Monthly Category A Network Load is its hourly load (including its designated Network Load not physically interconnected with Eversource under Schedule 21) coincident with Eversource's Monthly Transmission System Peak.

The Network Customer's Monthly Category B Load for a Designated State **or** Area for a Localized Facility is its hourly load in such Designated State or Area coincident with the monthly transmission system peak load for such Designated State or Area.

For Localized Facilities for which the Designated State or Area is identified as "Connecticut" in Section 16.3(a) of this Schedule 21-ES, the customer's hourly load shall be all of the customer's

Regional Network Load in Connecticut, and the monthly transmission system peak load shall be all Regional Network Load in Connecticut.

For Localized Facilities for which the Designated State or Area is identified as "Massachusetts" in Section 16.3(b) of this Schedule 21-ES, the customer's hourly load shall be all of the customer's Regional Network Load in Massachusetts, and the monthly transmission system peak load shall be all Regional Network Load in Massachusetts; provided, that the customer's monthly load and the monthly transmission system peak load shall exclude the load of generators taking RNS for the delivery of offline station service.

16.6 **Determination of Eversource's Monthly Transmission System Load**

Eversource's Monthly Transmission System Category A Load is Eversource's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to this Local Service Schedule plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.[1]

Eversource's Monthly Transmission System Category B Load for the Designated State or Area for a **Localized** Facility is the monthly transmission system peak load for such Designated State or Area.[1]

For Localized Facilities for which the Designated State or Area is identified as "Connecticut" in Section 16.3(a) of this Schedule 21-ES, the monthly transmission system peak load shall be all Regional Network Load in Connecticut.

For Localized Facilities for which the Designated State or Area is identified as "Massachusetts" in Section 16.3(b) of this Schedule 21-ES, the monthly transmission system peak load shall be all Regional Network Load in Massachusetts; provided, that the monthly transmission system peak load shall exclude the load of generators taking RNS for the delivery of offline station service.

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[1] Excludes MWs associated with lump sum payment transactions identified in footnote 2.

17. Operating Arrangements

17.1 Operation under the Network Operating Agreement

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

17.2 Network Operating Agreement

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Eversource Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between Eversource and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Eversource Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with Eversource, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and NPCC requirements. Eversource shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment ES-G.

SCHEDULE ES-1

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by Eversource (if Eversource is the Control Area operator) or indirectly by Eversource making arrangements with the New England System Operator that performs this service for the Eversource Transmission System. The Transmission Customer must purchase this service from Eversource or the New England System Operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the New England System Operator performs this service for Eversource, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Eversource by that New England System Operator.

Each Point-To-Point Transmission Customer under this Local Service Schedule will be charged for Transmission Scheduling, System Control and Dispatch Services for the total Reserved Capacity specified in each reservation for Point-To-Point Transmission Service made under this Local Service Schedule at the rates set forth in Appendix A of this Schedule ES-1. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer **shall** pay for its actual use of such excess capacity in addition to any Reserved Capacity. The charge for such excess use of capacity shall be determined by multiplying the sum of the actual use in excess of its capacity reservation times the hourly non-firm rate posted on Eversource's OASIS including ancillary services provided pursuant to Schedule ES-1 hereto.

Each Network Customer under this Local Service Schedule will be charged a monthly Transmission Scheduling, System Control and Dispatch Service Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Formula Requirements specified in Appendix B of this Schedule ES-1.

Each Transmission Customer with generation within the New England Control Area shall be required also to provide for Scheduling, System Control and Dispatch Service for that generation. It is anticipated that the Transmission Customer will obtain these services from the ISO. Eversource will make available

Generation Scheduling, System Control and Dispatch Service at the rates set forth in Appendix C of this Schedule ES-1.

Each Transmission Customer with generation located outside of the New England Control Area shall be required to provide for Scheduling, System Control and Dispatching Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting for these services from the provider of these services within the Control Area where the generation is located.

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-1 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-1

Appendix A

POINT-TO-POINT TRANSMISSION RATE

Eversource's Formula Rate for Point-To-Point Transmission Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$\textit{Formula Rate}_i = (A_{i-1} - B_{i-1})\, C_{i-1} \text{ WHERE:}$$

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of Eversource for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule ES-1.

- B_{i-1} is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling and dispatch revenues shall be those recorded on the books of each of the companies comprising Eversource hereunder in FERC Account No. 456.1 pertaining to Transmission of Electricity for Others and such other applicable FERC accounts for the calendar year prior to the Service Year.

- C_{i-1} is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

SCHEDULE ES-1

Appendix A

Exhibit 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses revenue requirements for each of the companies comprising Eversource hereunder is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES

Eversource's System Control and Load Dispatching Expense, for the calendar year prior to the Service Year, as recorded in FERC Account 561.1-561.4 and the revenue requirement calculation for the CL&P Dispatch Center Plant as described in Appendix A, Exhibit 2.

SCHEDULE ES-1

APPENDIX A

EXHIBIT 2

CL&P DISPATCH CENTER REVENUE REQUIREMENT

This exhibit calculates the CL&P Dispatch Center Revenue Requirement. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section I. of the ISO-NE Transmission, Markets and Services Tariff and as used in this exhibit have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch Center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period January 1, 2008 through December 31, 2008, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the CONVEX Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The

Connecticut Light & Power Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Exhibit 2.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

The Dispatch Center Investment Base will be the year-end balances of: (a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P's capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

A x B x C

where:

A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TE / (1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE ES-1

Appendix B

NETWORK TRANSMISSION FORMULA REQUIREMENTS

Eversource's formula requirements for Network Transmission Scheduling, System Control and Dispatch Service is determined from the following formula.

Formula Requirements$_i$ = (A_{i-1} - B_{i-1})

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of Eversource for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix B of Schedule ES-1.

- B_{i-1} is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling, system control and dispatch revenues shall be those recorded on the books of each of the companies comprising Eversource hereunder in FERC Account No. 456.1 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

SCHEDULE ES-1

APPENDIX B

EXHIBIT 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses for each of the companies comprising Eversource hereunder is determined as follows:

A. <u>ANNUAL CONTROL CENTER EXPENSES</u>

Eversource's System Control and Load Dispatching Expense), for the calendar year prior to the Service Year as recorded in FERC Account 561.1-561.4 and the revenue requirement calculation for the CL&P Dispatch Center Plant as described in Appendix B, Exhibit 2.

SCHEDULE ES-1

APPENDIX B

EXHIBIT 2

CL&P DISPATCH CENTER REVENUE REQUIREMENT

This exhibit calculates the CL&P Dispatch Center Revenue Requirement. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section I. of the ISO-NE Transmission, Markets and Services Tariff and as used in this exhibit have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch Center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period January 1, 2008 through December 31, 2008, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the CONVEX Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The

Connecticut Light & Power Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Exhibit 2.

A. <u>Dispatch Center Return and Associated Income Taxes</u> shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

<u>The Dispatch Center Investment Base</u> will be the year-end balances of: (a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

<u>The Cost of Capital Rate</u> will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P's capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

A x B x C

where:

A = Dispatch Center Investment Base
B = Cost of equity capital (the sum of the preferred stock component and common equity component)
C = TE / (1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE ES-1

Appendix C

GENERATION RATES

Eversource’s Formula Rate for Generation Scheduling, System Control and Dispatch Service ("Formula Rate") shall be calculated using the Point-to-Point Formula Rate for Transmission Scheduling, System Control, and Dispatch Service in Appendix A of Schedule ES-1.

SCHEDULE ES-2

FIRM POINT-TO-POINT SERVICE

I. Each month, Eversource Service shall bill the Transmission Customer for Long-Term Firm and Short-Term Firm Transmission Service and the Transmission Customer shall be obligated to pay Eversource the charges as set forth in this Schedule ES-2, as applicable.

A. TRANSMISSION CHARGES

1. Determination of Transmission Charges

The Transmission Charges will provide for recovery of the costs of the transmission facilities ofEversource. The Category A Transmission Charges for each month will equal the sum of the Category A Charges for each monthly (or longer term), weekly or daily transaction during such month. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer **shall** pay for its actual use of such excess capacity in addition to the charges for each monthly, weekly or daily transactions during such month. The charge for such excess use of capacity shall be determined by multiplying the actual hourly use in excess of its capacity reservation times the applicable Category A on-peak or off-peak hourly non-firm rate posted on Eversource's OASIS pursuant to Schedule ES-3 including ancillary services provided pursuant to Schedule ES-1 hereto.

The Category A Charge for each monthly (or longer term) transactions will be the product of: (a) Eversource's Category A Formula Rate (expressed in $ per kilowatt-year), divided by twelve (12) months, and (b) the Reserved Capacity set forth for such monthly (or longer term) transaction (expressed in kilowatts).

The Category A Charge for each weekly transaction will be the product of: (a) Eversource's Weekly Category A Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-week), and (b) the Reserved Capacity set forth for such weekly transaction (expressed in kilowatts). Eversource's Weekly Category A Rate is Eversource's Category A Formula Rate for Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Category A Charge for each daily transaction will be the product of: (a) Eversource's Daily Category A Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth for such daily transaction (expressed in kilowatts). Eversource's Daily Category A Rate is Eversource's Weekly Category A Rate for Short-Term Firm Point-To-Point Transmission Service divided by five (5) days. The total of the Transmission Customer's charges for daily transactions, under an individual reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

2. Eversource's Formula Rates

Eversource's Formula Rates for Long-Term Firm and Short-Term Firm Point-To-Point Service shall be determined in accordance with the rate formulas specified in Appendix A of this Schedule ES-2.

3. Tax Rates and Taxes

Eversource's Formula Rates set forth in this schedule in effect during a Service Year shall be based on the local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, Eversource's Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

4. Provision re: Exchanges

With respect to Entitlement Transactions or Energy Transactions or other transactions that involve an exchange, each party to such transaction shall be treated as an individual Transmission Customer under this Local Service Schedule. Accordingly, a separate Schedule ES-2 or other applicable charge(s) will be calculated for, and a separate bill will be rendered to, each such individual Transmission Customer.

5. Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Eversource must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6. Resales

The rates and rules governing charges and discounts in Sections I.A.1 and 5 of this Schedule ES-2 stated above shall not apply to resales of transmission service, compensation for which shall be governed by Schedule 21.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to Eversource Service each month the following additional charges for Long-Term, and Short-Term Firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Long-Term Firm or Short Term Firm Point-To-Point Transmission Service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES CHARGE**

Eversource shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreements.

C. **OTHER**

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-2 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-2

Appendix A

CATEGORY A RATE

FIRM POINT-TO-POINT TRANSMISSION SERVICE

Eversource's Category A Formula Rate for Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.
Formula $\text{Rate}_i = (A_i - B_i + C_i - D_i) / E_i$

WHERE:

- i equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H,

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services, to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load (E),[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments (expressed in dollars) to the New England System Operator as recorded in FERC Account 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with the Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- E is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-2

[Reserved]

SCHEDULE ES-3

NON-FIRM POINT-TO-POINT SERVICE

I. Eversource shall bill the Transmission Customer for Non-Firm Point-To-Point Transmission Service, and the Transmission Customer shall be obligated to pay Eversource the charges as set forth in this Schedule ES-3 as applicable.

A. **TRANSMISSION CHARGES**

1. General

The Transmission Customer shall pay to Eversource Service each month the Category A Transmission Charges calculated for all of the Transmission Customer's monthly transactions, weekly transactions, daily transactions and hourly transactions, each as set forth below. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer shall pay for its actual use of such excess capacity in addition to the charges for each monthly, weekly, daily or hourly transactions during such month. The charge for such excess use of capacity shall be determined by multiplying the actual hourly use in excess of its capacity reservation times the applicable Category A on-peak or off-peak hourly non-firm rate posted on Eversource's OASIS pursuant to this Schedule ES-3 including ancillary services provided pursuant to Schedule ES-1 hereto.

With respect to any wholesale transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a Transmission Charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

The Category A Transmission Charge for each month applicable to a monthly transaction shall be determined as the product of: (a) the Category A rate posted on Eversource's Open Access Same-Time Information System ("OASIS") at the time the service is reserved, not to exceed Eversource's Annual Category A Rate for Non Firm Point-To-Point Transmission Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such month (expressed in kilowatts).

The Category A Transmission Charge for each month applicable to weekly transactions shall be the sum of the transmission charges determined for each weekly transaction during such month. The transmission charge for each weekly transaction shall be determined as the product of: (a) the Category A rate posted on Eversource's OASIS at the time the service is reserved, not to exceed Eversource's Weekly Category A Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-week), and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such week (expressed in kilowatts). Eversource's Weekly Category A Rate is Eversource's Annual Category A Rate for Non-Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Transmission Charge for each month applicable to daily transactions will be the sum of the transmission charges determined for each daily transaction. The transmission charge for each daily transaction shall be determined as the product of: (a) the rate posted on Eversource's OASIS at the time the service is reserved, not to exceed Eversource's Daily Category A Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such day (expressed in kilowatts). Eversource's Daily Category A On-Peak Rate is Eversource's Weekly Category A Rate for Non-Firm Point-To-Point Transmission Service divided by five (5) days. Eversource's Daily Category A Off-Peak Rate is Eversource's Weekly Category A Rate for Non-Firm Point-To-Point Transmission Service divided by seven (7) days. The total of the Transmission Customer's charges for daily transactions, under an individual Reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

The Transmission Charge for each month applicable to hourly transactions will be the sum of the transmission charges determined for each hourly transaction during such month. The transmission charge for each hour of an hourly Transaction shall be determined as the product of: (a) the rate posted on Eversource's OASIS at the time the service is reserved, not to exceed Eversource's Daily Category A Firm Point-To-Point Transmission Service Rate divided by sixteen (16) hours (expressed in $ per kilowatt-hour), and (b) the Reserved Capacity as set forth in the Transmission Customer's applicable Reservation for such hour (expressed in kilowatts). Eversource's Hourly Category A On-Peak Rate is equal to Eversource's Daily Category A Rate for Non-Firm Transmission Service divided by sixteen (16) hours. Eversource's Hourly Category A Off-Peak Rate is equal to Eversource's Daily Category A Rate for Non-Firm Transmission

Service divided by twenty-four (24) hours. The total of the Transmission Customer's charges for hourly transactions, under an individual Reservation, in a twenty-four (24) hour period shall not exceed the charges based on the Daily Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

2. Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Eversource must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

3. Resales

The rates and rules governing charges and discounts in Sections I.A.1 and 2 of this Schedule ES-3 stated above shall not apply to resales of transmission service, compensation for which shall be governed by Schedule 21.

4. Credit to the Transmission Charge

Whenever service provided hereunder is interrupted or curtailed by Eversource, the Local Control Center or the New England System Operator, the Transmission Charges to the Transmission Customer calculated pursuant to Section A, of this Schedule ES-3 shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service.

The credit to the Transmission Customer for each such hour of interruption or curtailment shall be calculated as the product of (i) the applicable equivalent hourly charge for hourly, daily, weekly, or monthly transactions, and (ii) the kilowatts of service interruption or curtailment during such hour.

5. Eversource's Annual Formula Rate for Non Firm Point-To-Point Transmission Service

Eversource's Annual Formula Rates for Non Firm Point-To-Point Transmission Service shall be expressed in $ per kilowatt-year and shall be determined in accordance with the rate formulas specified in Appendix A of this Schedule ES-3 ("Formula Rates").

6. Tax Rates and Taxes

The Formula Rates set forth in this Schedule ES-3 in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, the Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay Eversource Service each month the following additional charges for Non-firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Non-Firm Point-To-Point Transmission Service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES**

Eversource reserves its rights to make a Section 205 filing for recovery of its costs to administer this Local Service Schedule and the Service Agreements.

C. **OTHER**

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-3 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-3

Appendix A

CATEGORY A RATE

FOR NON-FIRM POINT-TO-POINT SERVICE

Eversource's Category A Formula Rate for Non-Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{Formula Rate}_i = (A_i - B_i + C_i - D_i) / E_i$$

WHERE:

- i equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H.

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load (E),[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments (expressed in dollars) to the New England System Operator as recorded in FERC Account 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with the Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- E is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-3[RESERVED]

SCHEDULE ES-4

CHARGE PROVISIONS FOR LOCAL NETWORK SERVICE

I. Network Customers will pay the following demand charges for Local Network Service.

A. **DEMAND CHARGE A**

1. Determination of Demand Charge:
The Demand Charge will be determined in accordance with Section ~~16.3~~16.4 of this Local Service Schedule.

2. Eversource's Annual Transmission Revenue Requirements:
The annual Transmission Revenue Requirements shall be determined in accordance with the formula specified in Appendix A of this Schedule ES-4 ("Formula Requirements").

B. **DEMAND CHARGE B**

1. Determination of Demand Charge
The Demand Charge will be determined in accordance with Section ~~16.3~~16.4 of this Local Service Schedule.

2. Eversource Annual Transmission Revenue Requirements:
The annual Transmission Revenue Requirements for each Localized Facility of a Designated State or Area shall be determined in accordance with the formula specified in Appendix B of this Schedule ES-4 ("Formula Requirements").

C. TAX RATES AND TAXES

The Formula Requirements set forth in this Schedule ES-4 in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, the Formula Requirements will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to Eversource Service each month the following additional charges for Local Network Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES CHARGE**

Eversource shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreements.

C. **OTHER**

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-4 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-4

Appendix A

NETWORK FORMULA REQUIREMENTS

FOR CATEGORY A COSTS

Eversource's formula requirements for Local Network Service is determined from the following formula.

$$\text{Formula Requirements}_i = A_i - B_i + C_i - D_i$$

WHERE:

- $_i$ equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H.

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load,[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments to (expressed in dollars) the New England System Operator as recorded in FERC Accounts 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

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2 Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-4

Appendix B

NETWORK FORMULA REQUIREMENTS

FOR CATEGORY B COSTS

Eversource's formula requirements for Local Network Service and for Eligible Customers taking Regional Network Service under this Tariff in a Designated State or Area of a Localized Facility, is determined from the following formula, and separately determined for each Designated State or Area of a Localized Facility.

$$\text{Formula Requirements}_i = D_i$$

WHERE:

- $_i$ equals the Service Year.

- D is the annual Localized Transmission Revenue Requirements (expressed in dollars) of the Localized Facilities of Eversource for a Designated State or Area of a Localized Facility, as described in Attachment ES-I.

ATTACHMENT ES-C

AVAILABLE TRANSFER CAPABILITY METHODOLOGY

TABLE OF CONTENTS

1. Introduction

ISO is the regional transmission organization ("RTO"), serving the New England Control Area. ISO is responsible for the development, oversight, and fair administration of New England's wholesale market, management of the bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is interconnected to three neighboring Balancing Authority Areas ("BAA"): New Brunswick System Operator Area ("NBSO Area"), New York Independent System Operator Area ("NYISO Area"), and Hydro-Quebec TransEnergie Area ("HQTE Area").

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Service Provider for Regional Network Service ("Regional Transmission Service") associated with Pool Transmission Facilities, the Participating Transmission Owners ("PTOs") provide local transmission service over Non-Pool Transmission Facilities within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Transmission Service provided under Schedule 21 pursuant to the Transmission Operating Agreement ("TOA"). Pursuant to CFR § 37.6(b)[1] of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. The ISO is not responsible for the calculation of these values.

Pursuant to the terms of the Transmission Operating Agreement executed between the companies comprising Eversource hereunder as Participating Transmission Owners ("PTOs") and ISO, Eversource is a Transmission Service Provider and calculates TTC and ATC for certain Local Facilities over which Point-to-Point transmission service is provided under Schedule 21-ES of the ISO Open Access Transmission Tariff ("ISO OATT").

[1] §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted (§37.6(b)(1)(i)).

Non-PTF facilities are primarily radial paths that provide transmission service directly to interconnected generators. It is possible, in the future that a particular path may interconnect more nameplate capacity generation than the path's TTC. However, for Eversource's Non-PTF modeled by the ISO or the Local Control Center ("LCC"), the ISO or the LCC will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path consistent with ISO's economic, security constrained dispatch methodology.

Eversource does not currently have any Posted Paths based on the above definition. However, if Eversource does have any Posted Path(s) in the future, Eversource will calculate TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to those functions performed or utilized by Eversource as the Transmission Provider of Schedule 21-ES Local Point-to Point transmission service over Non-PTF pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)
- Use of Rollover Rights (ROR) in the calculation of ETC

As explained in Section 2, TTC and ATC are required to be calculated only for certain non-PTF internal Posted Paths over which Local Point-to-Point transmission service is provided under Schedule 21-ES. TTC and ATC is not calculated by Eversource for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and Eversource does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission's pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the ISO Area, the New England Control Area, out of the New England Control Area, or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

This process for submitting External Transactions into the New England Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, Eversource owns Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those Local Facilities, the market participant may obtain a transmission service reservation from Eversource under Schedule 21-ES prior to delivery of energy into the New England Wholesale Market. This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. Eversource **Total Transfer Capability (TTC)**

The Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21-ES is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on Eversource's OASIS site.

Eversource will calculate and post TTC on its OASIS site for all non-PTF Posted Paths that are eligible for Point-to-Point transmission service reservations. The TTC on Eversource's non-PTF Local Facilities that are eligible for Local Point-to-Point transmission service reservations are relatively static values. Eversource thus calculate the TTC for Non-PTF Posted Paths that may require Local Point-to-Point Local Point-to-Point transmission reservations on its OASIS provider page according to NAESB Standards.

4. Capacity Benefit Market (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of Eversource's ATC calculation and because CBM for the New England Control Area is set to zero (0), Eversource utilizes a zero (0) CBM value.

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservations (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. Eversource does not have any external interfaces, and therefore TRM for Eversource's non-PTF facilities is zero.

6. Calculation of ATC for Eversource's Local Facilities - General Description:

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a transmission provider's ATC methodology. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. With this simplified version of ATC, there is no detailed algorithm to be described or posted. Thus, for those non-PTF facilities that serve as a path for Eversource's Schedule 21-ES Point-to-Point Transmission Customers, Eversource has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day.

However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Schedule 21-ES Firm ATC (ATC_F)

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-ES that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-ES transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

6.1.2 Calculation of ATC_F in the Schedule 21-ES Operating Horizon (OH)

For purposes of this Attachment C OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses, the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service under Schedule 21-ES is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-ES transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Because Firm Schedule 21-ES transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

6.2 Calculation of Schedule 21-ES Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-ES are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-ES transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-ES are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus $ETC_{F,}$ plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$)

6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

As stated above, Eversource's non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators. It is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

7. Posting of Schedule 21-ES ATC

7.1 Location of ATC Posting

ATC values are posted on Eversource's OASIS site.

7.2 Updates To ATC

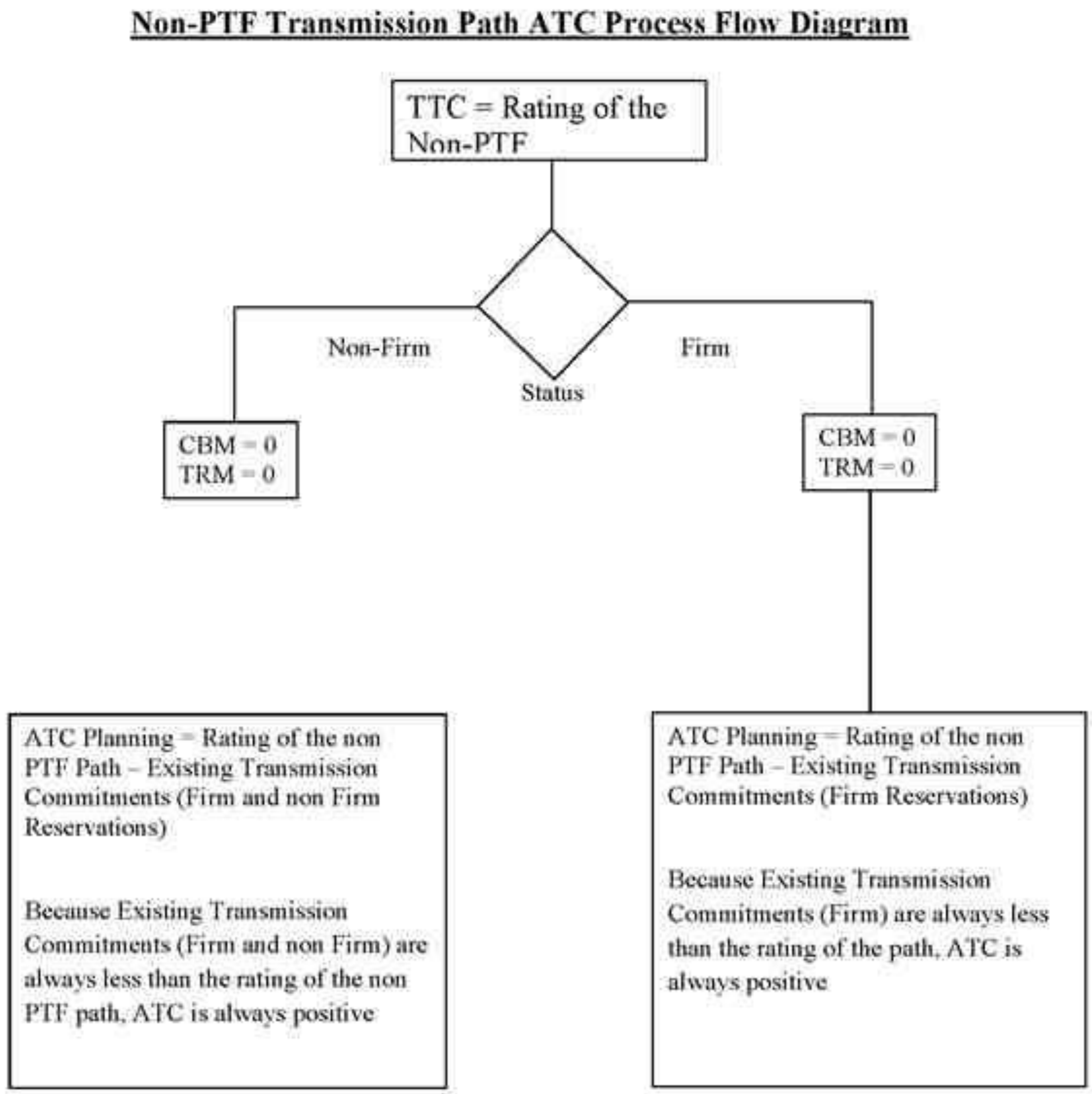
When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

7.3 Coordination of ATC Calculations

Schedule 21-ES non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms A link to the actual mathematical algorithm for the calculation of ATC for the Eversource non-PTF internal interfaces is located at https://www.eversource.com/Content/docs/default-source/Tranmission/attachment-6.pdf?sfvrsn=0.

8. Process Flow Diagram for ATC Calculation



ATTACHMENT ES-D

PENALTY DISBURSEMENT METHODOLOGY

Late Study Penalties: Penalties paid by the Transmission Provider pursuant to Schedule 21 are referred to as "Late Study Penalties," and therefore subject to distribution to all Transmission Customers that are not affiliated with the Transmission Provider. On the month following the end of each calendar quarter, each Transmission Customer that is not affiliated with the Transmission Provider shall receive, on the relevant monthly invoice, a credit for its share of the Late Study Penalties that were assessed during the applicable calendar quarter. The Transmission Customer's share of the Late Study Penalties (if any) will be determined as follows:

(a) For each quarter, the Transmission Provider will determine: (1) the sum of all Late Study Penalties assessed during the quarter measured in dollars (LSRq), and (2) the sum of all transmission revenue from Transmission Customers that are not affiliated with the Transmission Provider during that quarter, measured in dollars (LSTRq). Where:

LSRq =	Late Study Penalty Revenue in the quarter
LSTRq =	Transmission Revenue from Transmission Customers not affiliated with the Transmission Provider in the quarter

(b) For each quarter, each Transmission Customer that was not affiliated with the Transmission Provider will receive a credit equal to the product of (i) LSRq multiplied by (ii) a fraction derived from dividing the amount of transmission revenue from that Transmission Customer (TC1) during that quarter (measured in dollars), where TC1 is equal to one Transmission Customer, and a denominator equal to LSTRq.

(c) The Transmission Provider shall apply the credit for Late Study Penalties to service that the non-affiliated Transmission Customer takes from the Transmission Provider pursuant to this Schedule 21-ES. Any remaining credit will be refunded to the Transmission Customer.

ATTACHMENT ES-E

LOCALIZED COSTS RESPONSIBILITY **AGREEMENT**

This Localized Costs Responsibility Agreement ("LCRA" or "Agreement"), dated as of ______________________, is entered into by and between the Eversource Energy Service Company ("Eversource Service" or "COMPANY"), acting as agent for [The Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire], andthe "Transmission Customer".

The Transmission Customer is ____________________________________. The Transmission Customer has been determined to be an Eligible Customer taking Regional Network Service under the Tariff whose load **is located in the** Designated State or Area for a **Localized** Facility listed in **Section** 16.3 **of** Schedule 21-ES of the Tariff**.**

The Transmission Customer agrees to pay its portion of the cost of Localized Facilities in the Designated State or Area in which the Transmission Customer's load is located as provided in the Tariff and in accordance with Commission orders. Billing under this Agreement shall commence on the later of: (1) 0001 hours on ____________________, or (2) such other date as permitted by the Commission.

Charges under this Agreement shall terminate on the earlier of: (1) the date on which the costs of the Localized Facilities in the Designated State or Area in which the Transmission Customer's load is located are fully depreciated; or (2) the date upon which the Transmission Customer no longer takes Regional Network Service under the Tariff in the Designated State or Area in which the Transmission Customer's load is located; provided, that the Transmission Customer shall remain responsible for all final payment obligations. In the event that the Transmission Customer sells or assigns, or transfers its load to another entity ("New Transmission Customer"), the Transmission Customer must provide Eversource Service with at least ninety (90) calendar days advance written notice of the sale, assignment, or transfer.

The Transmission Customer shall remain liable for the performance of all obligations under this Agreement until a new LCRA has been executed between the New Transmission Customer and Eversource Service, or in the case of an unexecuted LCRA, such other date as it has been **permitted to** be made effective by the Commission. No sale or assignment shall **become effective** until the Parties have complied with all Applicable Laws and Regulations required for such sale, assignment, or transfer**.**

Other special provisions (if any)

____.

Any notice or request made to or by any Party regarding this greement shall be made in writing and shall be telecommunicated or delivered either in person, or by prepaid mail (return receipt requested) to the representative of the other Party as indicated below. Such representative and address for notices or requests may be changed from time to time by notice by one Party to the other.

COMPANY:

____

____

____

TRANSMISSION CUSTOMER:

____

____

____

Any exhibits to thisAgreement and the Tariff are incorporated herein and made a part hereof. ThisAgreement may be amended, from time to time, as provided for in Schedule 21-ES of the Tariff.

IN WITNESS WHEREOF, the Parties have caused thisAgreement to be executed by their respective authorized officials as of the date first above written.

EVERSOURCE ENERGY SERVICE COMPANY

By: ___________________________________

Its _______________________

TRANSMISSION CUSTOMER

By: ________________________________

Its ___________________________________

ATTACHMENT ES-G
NETWORK OPERATING AGREEMENT

This Network Operating Agreement is an appendix to Schedule 21-ES (this Local Service Schedule) of the OATT and operates as an implementing agreement for Local Network Service under this Local Service Schedule. This Network Operating Agreement is subject to and in accordance with Part III of this Local Service Schedule. All definitions and other terms and conditions of this Local Service Schedule are incorporated herein by reference.

1.0 Definitions:

1.1 Data Acquisition Equipment

Supervisory control and data acquisition ("SCADA"), remote terminal units ("RTUs") to obtain information from a Party's facilities, telephone equipment, leased telephone circuits, fiber optic circuits, and other communications equipment necessary to transmit data to remote locations, and any other equipment or service necessary to provide for the telemetry and control requirements of this Local Service Schedule.

1.2 Data Link

The direct communications link between the Transmission Customer's energy control center and Eversource's designated location(s) that will enable Eversource to receive real time telemetry and data from the Transmission Customer.

1.3 Metering Equipment

High accuracy, solid state kW, kVAR, kWh meters, metering cabinets, metering panels, conduits, cabling, high accuracy current transformers and high accuracy potential transformers, which directly or indirectly provide input to meters or transducers, metering recording devices, telephone circuits, signal or pulse dividers, transducers, pulse accumulators, metering sockets, test switch devices, enclosures, conduits, and any other metering, telemetering or communication equipment necessary to implement the provisions of this Local Service Schedule.

1.4 Protective Equipment

Protective relays, relaying panels, relaying cabinets, circuit breakers, conduits, cabling, current transformers, potential transformers, coupling capacitor voltage transformers, wave traps, transfer trip and fault recorders, which directly or indirectly provide input to relays, fiber optic communication equipment, power line carrier equipment and telephone circuits, and any other protective equipment necessary to implement the protection provision of this Local Service Schedule.

2.0 Term

The term shall be as provided in the Service Agreement consistent with this Local Service Schedule (including, but not limited to, application procedures, commencement of service, and effect of termination).

3.0 Point(s) Of Interconnection

Local Network Service will be provided by Eversource at the point(s) of interconnection specified in Appendix __, as amended from time to time. Each point of interconnection in this listing shall have a unique identifier, meter location, meter number, metered voltage, terms on meter compensation and designation of current or future year of in service.

4.0 Cogeneration And Small Power Production Facilities

If a Qualifying Facility is located or locates in the future on the System of the Transmission Customer, and the owner or operator of such Qualifying Facility sells the output of such Qualifying Facility to an entity other than the Transmission Customer, the delivery of such Qualifying Facility's power shall be subject to and contingent upon transmission arrangements being established with Eversource prior to commencement of delivery of any such power and energy.

5.0 Character Of Service

Network Transmission Service at the points of interconnection shall be in the form of single phase or balanced three-phase alternating current at a frequency of sixty (60) hertz. The Transmission Customer shall operate and maintain its electric system in a manner that avoids: (i) the generation of harmonic frequencies exceeding the limits established by the latest revision of IEEE-519; (ii) voltage flicker exceeding the limits established by the latest revision of IEEE-141; (iii) negative sequence currents; (iv) voltage or current fluctuations; (v) frequency variations; or (vi) voltage or power factor levels that could adversely affect Eversource’s electrical equipment or facilities or those of its customers, and in a manner that complies with all applicable NERC, NPCC, ISO and Eversource’s operating criteria, rules, regulations, procedures, guidelines and interconnection standards as amended from time to time.

6.0 Continuity Of Service

(a) Eversource and the Transmission Customer shall operate and maintain their respective network systems, in accordance with Good Utility Practice, and in a manner that will allow Eversource to safely and reliably operate the Eversource Transmission System in accordance with this Local Service Schedule, so that either Party shall not unduly burden the other Party; provided, however, that notwithstanding any other provision of this Local Service Schedule, Eversource shall retain the sole responsibility and authority for all operating decisions that could affect the integrity, reliability and security of the Eversource Transmission System.

(b) Eversource shall exercise reasonable care and Due Diligence to ensure Local Network Service hereunder in accordance with Good Utility Practice; provided, however, that Eversource shall not be responsible for any failure to ensure electric power service, nor for interruption, reversal or abnormal voltage of the service, if such failure, interruption, reversal or abnormal voltage is due to a Force Majeure.

7.0 Power Factor

(a) Where Local Network Service provided under this Local Service Schedule is for delivery of power to a load center of the Transmission Customer served from the Eversource Transmission System, the Transmission Customer shall maintain load power factor levels, during both on- and off- peak hours, appropriate to meet the operating requirements of Eversource, and shall follow the ISO standards and practices, as set forth in the Service Agreement.

(b) Where Local Network Service provided under this Local Service Schedule is for delivery of power from a generating facility connected to the Eversource Transmission System, the Transmission Customer shall deliver power at a lagging or leading power factor as set forth in the Service Agreement.

(c) Where Local Network Service provided under this Local Service Schedule is for delivery of power from outside the Eversource Transmission System, the obligation to maintain proper sending and receiving end voltages rests with the Transmission Customer, as set forth in the Service Agreement.

(d) In the event that the power factor levels and reactive supply requirements set forth in the Service Agreement are not maintained by the Transmission Customer, Eversource shall thereupon have the right to take the appropriate corrective action and to charge the Transmission Customer for the costs thereof.

Eversource shall have the right, at any time, unilaterally to make a Section 205 filing with the Commission for the recovery of any such costs.

8.0 Metering

(a) The Transmission Customer shall, at its expense, purchase all necessary metering equipment to accurately account for the electric power being transmitted under this Local Service Schedule. Eversource may require the installation of telemetering equipment for the purposes of billing, power factor measurements and to allow Eversource to maximize economic and reliable operation of its transmission system. Such metering equipment shall meet the specifications and accepted metering practices of Eversource and applicable criteria, rules, standards and operating procedures, or such successor rules and standards. At Eversource's option, communication metering equipment may be installed in order to transmit meter readings to Eversource's designated locations.

(b) Electric power being transmitted under this Local Service Schedule will be measured by meters at all points of interconnection and/or on generating facilities (Network and non-Network Resources) located on and outside the Transmission Customer's system as required by Eversource.

(c) The Transmission Customer shall purchase meters capable of time-differentiated (by hour) measurement of the instantaneous flow in kW and net active power flow in kWh and of reactive power flow. All meters shall compensate for applicable line and/or transformer losses in accordance with Good Utility Practice when measurement is made at any location other than the point of interconnection.

(d) Eversource reserves the right: (i) to determine metering equipment ownership; (ii) to determine the equipment installation at each point of interconnection; (iii) to require the Transmission Customer to install the equipment -- or -- install the equipment with the Transmission Customer supplying without cost to Eversource a suitable place for the installation of such equipment; (iv) to determine other equipment allowed in the metering circuit; (v) to determine metering accuracy requirements; (vi) to determine the responsibilities for operation, maintenance, testing and repair of metering equipment.

(e) Eversource shall have access to metering data, including telephone line access, which may reasonably be required to facilitate measurement and billing under this Local Service Schedule. Eversource may require the Transmission Customer provide, at its expense, a separate dedicated voice grade telephone circuit for Eversource and the Transmission Customer to remotely access each meter.

Metering equipment and data shall be accessible at all reasonable hours for purposes of inspection and reading.

(f) All metering equipment shall be tested in accordance with practices of Eversource, applicable criteria, rules, standards and operating procedures or upon the request by Eversource. If at any time metering equipment fails to register or is determined to be inaccurate, in accordance with Eversource's practices and applicable criteria, rules, standards and operating procedures, the Transmission Customer shall make the equipment accurate as soon thereafter as practicable, and the meter readings and rate computation for the period of such inaccuracy, insofar as can reasonably be ascertained, shall be adjusted; provided, however, that no adjustment to charges shall be required for any period exceeding two (2) months prior to the date of the test. Representatives of Eversource will be afforded opportunity to witness such tests.

9.0 Network Load

The Transmission Customer shall provide Eversource with the actual hourly Network Load for each calendar month by the seventh day of the following calendar month.

10.0 Data Transfer:

(a) The Transmission Customer shall provide timely, accurate real time information to Eversource in order to facilitate performance of its obligations under this Local Service Schedule.

(b) The selection of real time telemetry and data to be received by Eversource and the Transmission Customer shall be necessary for safety, reliability, security, economics, and/or monitoring of real-time conditions that affect the Eversource Transmission System. This telemetry shall include, but is not limited to, loads, line flows (MW and MVAR), voltages, generator output, and status of substation equipment at any of the Transmission Customer's transmission and generation facilities. To the extent that Eversource or the Transmission Customer requires data that are not available from existing equipment, the Transmission Customer shall, at its expense and at locations designated by Eversource or the Transmission Customer, install any metering equipment, data acquisition equipment, or other equipment and software necessary for the telemetry to be received by Eversource or the Transmission Customer. Eversource shall have the right to inspect equipment and software associated with the data transfer in order to assure conformance with Good Utility Practices.

11.0 Maintenance of Equipment

The Transmission Customer shall, on a regular basis in accordance with practices of Eversource, applicable criteria, rules, standards and operating procedures or at the request of Eversource, and at its expense, test, calibrate, verify and validate the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule. Eversource shall have the right to inspect such tests, calibrations, verifications and validations of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule. Upon Eversource's request, the Transmission Customer will provide Eversource a copy of the installation, test and calibration records of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software. Eversource shall, at the Transmission Customer's expense, have the right to monitor the factory acceptance test, the field acceptance test, and the installation of any metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule.

12.0 Notification

(a) The Transmission Customer shall notify and coordinate with Eversource prior to the commencement of any work or maintenance by the Transmission Customer, Network Member, or contractors or agents performing on behalf of either or both, which may directly or indirectly have an adverse effect on the Transmission Customer or Eversource's data link, or the reliability of the Eversource Transmission System. All notifications for scheduled outages of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software must meet the requirements of the ISO and Eversource.

13.0 Emergency System Operations

(a) The Transmission Customer, at its expense, shall be subject to all applicable emergency operation standards promulgated by NERC, NPCC, ISO and Eversource which may include but not limited to underfrequency relaying equipment, load shedding equipment and voltage reduction equipment.

(b) Eversource reserves the right to take whatever actions they deem necessary to preserve the integrity of the Eversource Transmission System during emergency operating conditions. If the Local Network Service at the points of interconnection is causing harmful physical effects to the Eversource

Transmission System facilities or to its customers (e.g., harmonics, undervoltage, overvoltage, flicker, voltage variations, etc.), Eversource shall promptly notify the Transmission Customer and if the Transmission Customer does not take the appropriate corrective actions immediately, Eversource shall have the right to interrupt Local Network Service under this Local Service Schedule in order to alleviate the situation and to suspend all or any portion of Local Network Service under this Local Service Schedule until appropriate corrective action is taken.

(c) In the event of any adverse condition or disturbance on the Eversource Transmission System or on any other system directly or indirectly interconnected with the Eversource Transmission System, Eversource may, as it deems necessary, take actions or inactions that, in Eversource's sole judgment, result in the automatic or manual interruption of Local Network Service in order to: (i) limit the extent or damage of the adverse condition or disturbance; (ii) prevent damage to generating or transmission facilities; (iii) expedite restoration of service; or (iv) preserve public safety.

14.0 Cost Responsibility

(a) The Transmission Customer shall be responsible for the costs incurred by the Transmission Customer and Eversource to implement the provisions of this Local Service Schedule including, but not limited to, engineering, administrative and general expenses, material and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, and relocation of equipment, or software.

(b) Additionally, the Transmission Customer shall be responsible for all costs incurred by the Transmission Customer and Eversource for on-going operation and maintenance of the metering, telecommunications and safety protection facilities and equipment required to implement the provisions of this Local Service Schedule. Such work shall include, but not limited to, normal and extraordinary engineering, administrative and general expenses, material, and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, or relocation of equipment required to accommodate service under this Local Service Schedule.

15.0 Default

The Transmission Customer's failure to implement the terms and conditions of this Network Operating Agreement will be deemed to be a default under this Local Service Schedule and will result in Eversource seeking, consistent with FERC rules and regulations, immediate termination of service under this Local Service Schedule.

16.0 Regulatory Filings

Nothing contained in this Local Service Schedule or any associated Service Agreement, including this Network Operating Agreement, shall be construed as affecting in any way the right of Eversource to unilaterally make application to the Commission for a change in any portion of this Network Operating Agreement under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

IN WITNESS WHEREOF, the Parties have caused this Network Operating Agreement to be executed by their respective authorized officials as of the date written.

Date: ________________________

Eversource Energy Service Company
by: _____________________________
its Vice President

Transmission Customer
by: _____________________________
its _____________________________

ATTACHMENT ES-H
ANNUAL TRANSMISSION REVENUE REQUIREMENTS

Attachment ES-H Methodology:

This formula sets forth the method that Eversource will use to determine its annual Total Transmission Revenue Requirements. The Transmission Revenue Requirements reflect Eversource's total cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to transmission customers under this Local Service Schedule. The Transmission Revenue Requirements will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31 of the following year. The calculation will be based on the previous calendar year's FERC Form 1 data, with an estimate of Eversource's current year average plant additions, Construction Work in Progress (CWIP), and the Allowance for Funds Used During Construction (AFUDC) regulatory liability account. Plant additions will be multiplied by a fixed charge carrying cost, and CWIP and the AFUDC regulatory liability account will be multiplied by the Cost of Capital. The revenue requirements will be updated thereafter each June 1 based on actual costs from the Service Year. The true-up information will be based on actual data, in lieu of allocated data if specifically identified in the FERC Form 1. For a capital addition whose cost exceeds $20 million, Eversource will make rate base adjustments to estimates and in the true-up process to represent the estimated and actual in-service dates for the capital addition. Specifically, Eversource will adjust for transmission plant, CWIP, AFUDC regulatory liability, accumulated depreciation and accumulated deferred taxes.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Eversource's Transmission-related direct wages and salaries, including those of affiliated companies, to Eversource's total direct wages and salaries, including those of affiliated companies, excluding administrative and general wages and salaries.

2. Plant Allocation Factor shall equal the ratio of the sum of total investment in Transmission Plant and Transmission Related General Plant to Total Plant in Service.

B. Terms

Administrative and General Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on Eversource's transmission projects as recorded in FERC Account 254 consistent with Commission orders.

Amortization of Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal Eversource's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal Eversource's transmission expense as recorded in FERC Account No. 403.

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's gross plant balance for the Dispatch Center as recorded in FERC Account Nos. 350-359 and 389-399.

Dispatch Center Depreciation Expense shall equal the Dispatch Center depreciation expense as recorded in FERC Account No. 403.

Dispatch Center Amortization of Investment Tax Credits shall equal the Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of Eversource's Dispatch Center deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource's Dispatch Center deferred tax balance as recorded in FERC Account No. 190.

Dispatch Center Municipal Tax Expense shall equal the Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

General Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 389-399, less the Dispatch Center general plant.

General Plant Depreciation Expense shall equal Eversource's general plant expenses as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal Eversource's general plant reserve balance as recorded in FERC Account No. 108 less the portion of such reserve for the Dispatch Center.

Merger-Related Costs shall equal Eversource's amortized merger-related costs as authorized by FERC or by state regulatory order.

Other Regulatory Assets/Liabilities – FAS 106 shall equal the net of Eversource's FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in Eversource's FERC Account No. 254.

Other Regulatory Assets/Liabilities – FAS 109 shall equal the net of Eversource's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Eversource's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in Eversource's FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal Eversource's balance in FERC Account No. 105.

Prepayments shall equal Eversource's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Eversource's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of Eversource's deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 408.1, 409.1.

Total Plant in Service shall equal Eversource's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal Eversource's Transmission reserve balance as recorded in FERC Account 108 less the portion of such reserve for the Dispatch Center.

Transmission Merger-Related Costs shall equal Eversource's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562-564 and 566-576.5 and shall exclude all HQ HVDC expenses booked to accounts 560 through 576.5 and expenses already included in Transmission Support Expense, as described in Section I below, that are included in FERC Account Nos. 560-576.5.

Transmission Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 350-359, less Dispatch Center transmission plant.

Transmission Plant Materials and Supplies shall equal Eversource's balance as assigned to transmission, as recorded in FERC Account 154.

Transmission Related Construction Work in Progress shall equal Eversource's investment in Transmission-related projects as recorded in FERC Account 107 consistent with commission orders.

II. Calculation of Transmission Revenue Requirements

The Transmission Revenue Requirement shall equal the sum of Eversource's (A) Return and Associated Income Taxes, (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expense (I) Transmission Support Expense, and(J) Transmission Related Taxes and Fees Charge.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be the average balances of (a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) Transmission Related Construction Work in Progress, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Other Regulatory Assets/Liabilities, less (i) AFUDC Regulatory Liability, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

(a) Transmission Plant will equal the balance of Eversource's investment in Transmission Plant.

(b) Transmission Related General Plant shall equal Eversource's balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the balance of Transmission Plant Held for Future Use.

(d) Transmission Related Construction Work in Progress shall equal the portion of Eversource's investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.

(e) Transmission Related Depreciation Reserve shall equal the balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related General Plant

Depreciation Reserve. Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor.

(f) Transmission Accumulated Deferred Taxes shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes multiplied by the Plant Allocation Factor, less the transmission and general plant components of Dispatch Center Accumulated Deferred Income Taxes.

(g) Transmission Related Loss on Reacquired Debt shall equal Eversource's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

(h) Other Regulatory Assets/Liabilities shall equal Eversource's electric balance of any deferred rate recovery of FAS 106 expense multiplied by the Transmission Wages and Salaries Allocation Factor, plus Eversource's electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(i) AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on Eversource's transmission projects as recorded in FERC Account 254 consistent with Commission orders.

(j) Transmission Prepayments shall equal Eversource's electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

(k) Transmission Materials and Supplies shall equal Eversource's electric balance of Transmission Plant Materials and Supplies.

(l) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense and Transmission Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Eversource's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of:

(i) the long term debt component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's long-term debt then outstanding and the ratio that long-term debt is to Eversource's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's preferred stock then outstanding and the ratio that preferred stock is to Eversource's total capital.

(iii) the return on equity component, shall equal the product of Eversource's return on equity ("ROE") of ~~10.57~~11.14% and the ratio that common equity is to Eversource's total capital.

(b) Federal Income Tax shall equal

[(A+[(C+B)/D]x (FT)] divided by (1-FT)

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., and D is Transmission Investment Base, as Determined in II.A.1., above.

(c) State Income Tax shall equal

[A+[(C+B)/D] + Federal Income Tax)x(ST)] divided by (1-ST)

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., D is the

Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Transmission Plant, plus an allocation of General Plant Deprecation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor, less the amortization of AFUDC Regulatory Credit as recorded in Account 407.4, less the transmission plant and general plant components of Dispatch Center Depreciation Expense.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal Eversource's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal Eversource's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor less the transmission plant and general plant components of Dispatch Center Amortization of Investment Tax Credits.

E. Transmission Related Municipal Tax Expense shall equal Eversource's electric Total Municipal Tax Expense multiplied by the Plant Allocation Factor, less the transmission plant and general plant components of Dispatch Center Municipal Tax Expense.

F. Transmission Related Payroll Tax Expense shall equal Eversource's electric Payroll Tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal Transmission Operation and Maintenance Expenses.

H. Transmission Related Administrative and General Expenses shall equal the sum of (1) Eversource's Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by the Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments in Account 928 plus specific transmission related expenses included in Account 930.1, plus Transmission Merger-Related Costs and, (4) specific transmission related public education expenses included in Account 426.54.

I. Transmission Support Expense shall equal the expense paid by Eversource for transmission support.

J. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Local Service Schedule that is not specifically identified under any other section of this Local Service Schedule.

ATTACHMENT ES-I
ANNUAL LOCALIZED TRANSMISSION REVENUE REQUIREMENT

Attachment ES-I Methodology

This formula sets forth the method that Eversource will use to determine its annual total revenue requirements for each Localized Facility ("Localized Transmission Revenue Requirement"). Subsequent references in this formula to "Localized Facility" and "Localized Transmission Revenue Requirement" refer to the Localized Facility and Localized Facility Revenue Requirement for each individual Localized Transmission Project. Each Localized Facility is identified in Section 16.3.

The Localized Transmission Revenue Requirement will be calculated for an initial term for a Localized Facility commencing on the date of the New England System Operator's Schedule 12C cost allocation determination for the Localized Facility and ending on the May 31st following the date approved by the Commission for including the costs of the Localized Facilities in this Attachment ES-I ("Initial Term"), and continuing thereafter for successive 12 month periods commencing each June 1st ("Rate Year"). The Localized Transmission Revenue Requirement for the Initial Term for a Localized Facility will be calculated based on the estimated cost of the Localized Facilities for such period, and will be charged to customers in equal monthly installments beginning on the date permitted by the Commission, and continuing through the end of the Initial Term. The Localized Transmission Revenue Requirement for the Initial Term for a Localized Facility will be trued up for the appropriate calendar year by June 30th of the succeeding year(s) based on actual costs for the Initial Term.

The Localized Transmission Revenue Requirement for a Localized Transmission Project for a Rate Year commencing after the Initial Term (and for succeeding Rate Years) will be an annual calculation based on the previous calendar year's Localized Transmission Revenue Requirements, plus the forecasted revenue requirements of Localized Facilities to be placed in service in the upcoming Rate Year. Each June 30th, the Localized Transmission Revenue Requirement in effect during the portion of the Rate Year that occurred in the previous calendar year will be trued-up based on actual costs from such previous calendar year.

The true-up information will be based on actual data, in lieu of allocated data if specifically identified in the FERC Form 1, or based on allocated data if such specific information is not identified. For a capital addition whose cost exceeds $20 million, Eversource will make rate base adjustments to estimates and in the true-up process to represent the estimated and actual in-service dates for the capital addition. Specifically, Eversource will adjust for transmission plant, accumulated depreciation and accumulated deferred taxes.

The Localized Transmission Revenue Requirement for Eversource that is based on data for calendar year 2004 or later shall include a Localized Incremental Return and Associated Income Taxes on Eversource's Localized PTF transmission plant investments placed in-service on or after January 1, 2004 (such investments referred to herein as "Localized Post-2003 PTF Investment"). The Localized Incremental Return and Associated Income Taxes for Localized Post-2003 Investment shall incorporate an incentive ROE adder of 100 basis points for plant investments placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157 et al. for any projects included in the Regional System Plan ("RSP"), and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments. ~~The total ROE for any project, including any authorized ROE incentives for Post-2003 PTF Investment and any other incentive ROE approved by FERC under Order No. 679 shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period.~~ The data used in determining Eversource's Localized Incremental Return and Associated Taxes for Localized Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in Eversource accounting records.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. Localized Transmission Allocation Factor shall equal the ratio of Localized Transmission Plant in Service to total investment in Transmission Plant.

2. Total Localized Plant Allocation Factor shall equal the ratio of Localized Transmission Plant in Service to Total Plant in Service.

3. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Eversource's Transmission-related direct wages and salaries, including those of affiliated companies, to Eversource's total direct wages and salaries, including those of affiliated companies, and excluding administrative and general wages and salaries.

B. Terms

Administrative and General Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

Amortization of Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal Eversource's expenses as recorded in FERC Account No. 411.4.

Depreciation Expense for Localized Transmission Plant shall equal Eversource's Localized Facilities expenses as recorded in FERC Account No. 403.

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's gross plant balance for the Dispatch Center as recorded in FERC Account Nos. 350-359 and 389-399.

General Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 389-399 less Dispatch Center general plant.

General Plant Depreciation Expense shall equal Eversource's general plant expenses as recorded in FERC Account No. 403 less the portion of such expense for the Dispatch Center.

General Plant Depreciation Reserve shall equal Eversource's general plant reserve balance as recorded in FERC Account No. 108 less the portion of such reserve for the Dispatch Center.

Merger-Related Costs shall equal Eversource's amortized merger-related costs as authorized by FERC or by state regulatory order.

Payroll Taxes shall equal those payroll expenses as recorded in Eversource's FERC Account Nos. 408.1 and 409.1.

Prepayments shall equal Eversource's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Eversource's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of Eversource's deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 408.1, 409.1.

Transmission Merger-Related Costs shall equal Eversource's amortized merger-related transmission costs as authorized by FERC.

Localized Transmission Plant in Service shall equal Eversource's Localized Facilities gross plant balance as recorded in FERC Account Nos. 350-359.

Localized Transmission Plant Held for Future Use shall equal Eversource's Localized Facilities balance as recorded in FERC Account 105.

Localized Transmission Depreciation Reserve shall equal Eversource's Localized Facilities reserve balance as recorded in FERC Account 108.

Transmission Operation and Maintenance Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562-564 and 566-576.5 and shall exclude all HQ HVDC expenses booked to accounts 560 through 576.5 and expenses already included in Transmission Support Expense, as described in Section I below, which are included in FERC Account Nos. 560-576.5.

Transmission Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal Eversource's balance as assigned to transmission, as recorded in FERC Account 154.

Total Plant in Service shall equal Eversource's total gross plant balance as recorded in FERC Account Nos. 301-399.

II. Calculation of Localized Transmission Revenue Requirements

The Localized Transmission Revenue Requirements shall equal the sum of Eversource's (A) Localized Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment), (B) Localized Transmission Depreciation Expense, (C) Localized Transmission Related Amortization of Loss on Reacquired Debt, (D) Localized Transmission Related Amortization of Investment Tax Credits, (E) Localized Transmission Related Municipal Tax Expense, (F) Localized Transmission Related Payroll Tax Expense, (G) Localized Transmission Operation and

Maintenance Expense, (H) Localized Transmission Related Administrative and General Expense , (I) Localized Transmission Support Expense, and (J) Localized Transmission Related Taxes and Fees Charge. The Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment for Eversource shall be calculated using the investment base components specifically identified in Section A.1 of the formula below.

A. Localized Return and Associated Income Taxes shall equal the product of the Localized Transmission Investment Base and the Cost of Capital Rate. To calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Plant will only include Sections II.A.1.(a), (c), and (d), in the manner indicated.

1. Localized Transmission Investment Base

The Localized Transmission Investment Base will be the average balances of (a) Localized Transmission Plant, plus (b) Localized Transmission Plant Held for Future Use less (c) Localized Transmission Related Depreciation Reserve, less (d) Localized Transmission Related Accumulated Deferred Taxes, plus (e) Localized Transmission Related Loss of Reacquired Debt, plus (f) Localized Transmission Prepayments, plus (g) Localized Transmission Materials and Supplies, plus (h) Localized Transmission Related Cash Working Capital.

(a) Localized Transmission Plant will equal the balance of (1) Eversource's investment in Localized Transmission Plant plus, (2) Eversource's balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the Localized Transmission Allocation Factor. In order to calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Post-2003 PTF Transmission Plant shall be separately identified.

(b) Localized Transmission Plant Held for Future Use shall equal Eversource's balance of Localized Transmission Plant Held for Future Use.

(c) Localized Transmission Related Depreciation Reserve shall equal the balance of Localized Transmission Depreciation Reserve plus the balance of Localized Transmission Related General Plant Depreciation Reserve. Localized Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor, further multiplied by the Localized

Transmission Allocation Factor. In order to calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Related Depreciation Reserve associated with Localized Post-2003 PTF Investment shall equal Eversource's balance of Localized Transmission Depreciation Reserve.

(d) Localized Transmission Related Accumulated Deferred Taxes shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Total Localized Plant Allocation Factor. To calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Related Accumulated Deferred Taxes associated with Localized Post-2003 PTF Investment shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes multiplied by the Total Localized Plant Allocation Factor.

(e) Localized Related Loss on Reacquired Debt shall equal Eversource's electric balance of Total Loss on Reacquired Debt multiplied by the Total Localized Plant Allocation Factor.

(f) Localized Transmission Prepayments shall equal Eversource's electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor.

(g) Localized Transmission Materials and Supplies shall equal Eversource's electric balance of Transmission Plant Materials and Supplies multiplied by the Localized Transmission Allocation Factor.

(h) Localized Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of (i) Localized Transmission Operation and Maintenance Expense, plus (ii) Localized Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Eversource's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the average capital structure and will equal the sum of:

(i) the long term debt component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's long-term debt then outstanding and the ratio that long-term debt is to Eversource's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's preferred stock then outstanding and the ratio that preferred stock is to Eversource's total capital.

(iii) the return on equity component shall equal the product of Eversource's return on equity ("ROE") of ~~11.07~~11.64% and the ratio that common equity is to Eversource's total capital. In order to calculate the Localized Incremental Return and Associated Taxes for Post-2003 PTF Investment, the Localized Incremental Return on Equity shall be the product of (1) Eversource's incremental return on equity of 1% for transmission plant investments associated with projects included in the RSP and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157 et al., and (2) any ROE incentive adder approved by the FERC under Order No. 679 for other transmission plant investments~~, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period~~; and (3) the ratio of that common equity to total capital.[1]

(b) Federal Income Tax shall equal

[(A+[(C+B)/D]) x (FT)] divided by (1-FT)

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Localized Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Localized Transmission Depreciation Expense, as defined in Section II.B., and D is Localized Transmission Investment Base, as Determined in II.A.1., above.

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1 FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679.

(c) State Income Tax Shall equal:

[(A+[(C+B)/D] + Federal Income Tax) x (ST)] divided by (1-ST)

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the

Localized Transmission Related Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Localized Transmission Depreciation Expense, as defined in Section II.B., D is the Localized Transmission Investment Base, as determined in II.A.1. above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Localized Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Localized Transmission Plant, plus an allocation of General Plant Deprecation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor.

C. Localized Transmission Related Amortization of Loss on Reacquired Debt shall equal Eversource's electric Amortization of Loss on Reacquired Debt multiplied by the Total Localized Plant Allocation Factor.

D. Localized Transmission Related Amortization of Investment Tax Credits shall equal Eversource's electric Amortization of Investment Tax Credits multiplied by the Total Localized Plant Allocation Factor.

E. Localized Transmission Related Municipal Tax Expense shall equal Eversource's Total Municipal Tax Expense multiplied by the Total Localized Plant Allocation Factor.

F. Localized Transmission Related Payroll Tax Expense shall equal Eversource's electric Payroll Taxes expense, multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Localized Transmission Allocation Factor.

G. Localized Transmission Operation and Maintenance Expense shall equal Eversource’s Transmission Operation and Maintenance Expense multiplied by the Localized Transmission Allocation Factor.

H. Localized Transmission Related Administrative and General Expense shall equal the sum of (1) Eversource’s Administrative and General Expense multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor, (2) Property Insurance multiplied by the Total Localized Plant Allocation Factor, (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by the Total Localized Plant Allocation Factor, (4) Federal and State transmission related expenses or assessments in Account 928 multiplied by the Localized Transmission Allocation Factor, (5) specific transmission related expenses included in Account No. 930.1, multiplied by the Localized Transmission Allocation Factor, plus Transmission Merger-Related Costs multiplied by the Localized Transmission Allocation Factor and (6) specific Localized Facility related public education expenses included in Account 426.54.

I. Transmission Support Expense shall equal the expense paid by Eversource for transmission support for Localized Facilities.

J. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on transmission service provided under this Local Service Schedule that is not specifically identified under any other section of this Local Service Schedule, multiplied by the Localized Transmission Allocation Factor.

SCHEDULE 21-ES

ATTACHMENT ES-L

Creditworthiness Procedures

1. **General Information**

All customers taking any service under Schedule 21-ES, the Local Service Schedule ("LSS"), and the associated schedules of The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire ("Eversource") must meet the terms of this Attachment ES-L.

2. **Establishing Creditworthiness**

a) Each customer's creditworthiness must be established before receiving transmission services from Eversource. A customer will be evaluated at the time that its application for transmission service is provided to Eversource based on the creditworthiness information required under this Attachment ES-L. Eversource shall conduct a credit review of each Transmission Customer not less than annually or upon reasonable request by the Transmission Customer.

b) Eversource will review the customer's creditworthiness information for completeness and will notify the customer if additional information is required.

c) Upon completion of a creditworthiness evaluation of a customer, Eversource will forward a written evaluation to the customer if they determine that Financial Assurance must be provided.

3. Financial Information

Customers requesting transmission service must submit if available the following:

a) All current rating agency reports of the customer from Standard and Poor's ("S&P"), Moody's Investors Service ("Moody's"), and/or Fitch Ratings ("Fitch").

b) A Management Discussion and Analysis ("MD&A") along with audited financial statements provided by an independent registered public accounting firm or a registered independent auditor for the three (3) most recent fiscal years, or the period of the customer's existence, if shorter than three (3) years.

4. Creditworthiness – Qualification for Unsecured Credit

a) A customer may receive unsecured credit from Eversource equivalent to three (3) months of the transmission charges. The customer must meet at least one of the following criteria:

(i) If rated, the customer's lowest rating from the three rating agencies on its senior unsecured long-term debt; or if the customer does not have such a rating, then one rating level below the rating then assigned to the customer's corporate credit rating, as follows:

1. a Standard and Poor's or Fitch rating of at least BBB, or

2. a Moody's rating of least Baa2.

(ii) If un-rated or if rated below BBB/Baa2, as described in 4(a)(i) above, the customer must meet all of the following creditworthiness criteria for the three (3) most recent fiscal years:

1. A Capitalization Ratio (Debt divided by the sum of shareholders' equity and Debt) of no more than 60 percent Debt, where "Debt" is defined as the sum of all long-term and short-term debt, preferred securities and capital leases. Each of which is recorded in accordance with generally accepted accounting principles;

2. Earnings before interest, taxes, depreciation and amortization ("EBITDA") in the most recent fiscal quarter divided by interest expense (ratio of EBITDA-to-interest expense of at least three (3) times); and

3. Audited Financial Statements with an unqualified auditor opinion.

b) If the customer relies on the creditworthiness of a parent company, the parent company must satisfy the ratings criteria in Section 4(a) above, and must provide to Eversource a written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from Eversource.

c) If the customer or the customer's parent company do not qualify for unsecured credit under Sections 4(a) or (b) above, the customer can still qualify for unsecured credit equivalent to three (3) months of transmission service charges, if:

(i) the customer has, on a rolling basis, 12 consecutive months of payments to Eversource with no missed, late or defaults in payment; or

(ii) the customer has an executed long-term contract for the sale of the full output (energy and capacity) of its generating unit and either has executed a corresponding service transmission service agreement under Schedule 21-ES for the transmission of that output or the execution of such agreement is pending the customer's demonstration of creditworthiness.

5. Financial Assurance

If the customer does not meet the applicable requirements for unsecured credit set out in Section 4 then the customer must either:

a) pay in advance an amount equal to the lesser of the total charge for transmission service not less than five (5) days in advance of the commencement of service, in which case Eversource will pay to the customer interest on the amounts not yet due to Eversource, computed in accordance with 18 C.F.R. §35.19(a)(2)(iii) of the Commission's Regulations; or

b) obtain Financial Assurance in the form of a letter of credit or a parent guarantee equal to the equivalent of three (3) months of transmission service charges prior to receiving service.

(i) The letter of credit must be one or more irrevocable, transferable standby letters of credit issued by a United States commercial bank or a United States branch of a foreign bank provided that such customer is not an affiliate of such bank. The issuing bank must have a credit rating of at least A2 from Moody's or an A rating from S&P or Fitch, or an equivalent credit rating by another nationally recognized rating service reasonably acceptable to Eversource, provided that such bank shall have assets totaling not less than ten billion dollars ($10,000,000,000). All costs of the letter of credit shall be borne by the applicant for such letter of credit. In the event of an inconsistency in the ratings by Moody's, S&P, or Fitch, a "split rating", the lowest credit rating shall apply.

(ii) If the credit rating of a bank or other financial institution issuing a letter of credit to a customer falls below the levels specified in Section 5(b)(i) above, the customer shall have three (3) business days to obtain a suitable letter of credit from another bank or other financial institution that meets the specified levels unless Eversource agrees in writing to extend such period.

6. Notifications

Each customer must inform Eversource in writing within three (3) business days of any material change in its or its letter of credit issuer's financial condition, and if the customer qualifies under Section 4(b), that of its parent company. A material change in financial condition may include, without limitation, the following:

a) change in ownership by way of a merger, acquisition, or substantial sale of assets;
b) downgrade by a recognized major financial rating agency;
c) placement on credit watch with negative implications by a major financial rating agency;
d) a bankruptcy filing by the customer or parent;
e) any action requiring the filing of a SEC Form 8-K;
f) declaration of or acknowledgement of insolvency;
g) report of a significant quarterly loss or decline in earnings;
h) resignation of key officer(s); or
i) issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

7. Ongoing Financial Review

Each customer is required to submit to Eversource annually or when issued, as applicable:

a) current rating agency reports;
b) audited financial statements from an independent registered public accounting firm or a registered independent auditor; and
c) SEC Forms 10-K and 8-K, promptly upon their filing.

8. Change in Creditworthiness Status

A customer who has been extended unsecured credit pursuant to Section 4, must comply with the terms of Financial Assurance in Section 5, if one or more of the following conditions apply:

a) the customer no longer meets the applicable criteria for unsecured credit in Section 4;

b) the customer exceeds the amount of unsecured credit extended by Eversource, in which case Financial Assurance equal to the amount of exceeded unsecured credit must be provided within five (5) business days; or

c) the customer has missed two or more payments for any of the transmission services provided by Eversource in the last twelve (12) months.

9. Procedures for Changes in Credit Levels and Collateral Requirements

a) Eversource shall issue notice to a customer of any changes to the approved credit levels and/or collateral requirements within five (5) business days after (1) receiving notification of any material changes in financial condition under Section 6 above; (2) receiving the information required for the customer's ongoing financial review listed in Section 7 above; or (3) the occurrence of any of the events leading to a change in creditworthiness requirements listed in Section 8 above.

b) A customer may submit a written request that Eversource provide an explanation of the reasons for the changes in credit levels and/or collateral requirements within five (5) business days after receiving notification of the changes. Eversource will provide a written response within five (5) business days after receiving such a request.

10. Contesting Creditworthiness Determinations

A customer may contest Eversource's determination of its creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. The request should provide information supporting the basis for a re-evaluation of the customer's creditworthiness. Eversource will review the request and respond within 20 calendar days of receipt.

11. Process for Changing Credit Requirements

a) In the event Eversource plans to revise the Schedule 21-ES requirements for credit levels or collateral requirements described in this Attachment ES-L, they will make a filing under Section 205 of the Federal Power Act.

b) Eversource shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

c) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised changes(s) to this Attachment ES-L.

d) Eversource shall consult with interested stakeholders upon request.

e) Following Commission acceptance of such filing and upon the effective date, Eversource shall revise its Attachment ES-L an updated version of Schedule 21-ES shall be posed to the ISO-NE web site.

f) When Eversource changes its credit requirements for service under Schedule 21-ES, the customer is responsible for forwarding updated financial information to Eversource. The customer must indicate whether the change affects its ability to meet the requirements of Attachment ES-L. In cases where the customer's credit status has changed, the customer must take the necessary steps to comply with the revised credit requirements of Attachment ES-L by the effective date of the change.

12. Suspension of Service

Eversource may immediately suspend service (with notification to the Commission) to a customer, and may initiate proceedings with the Commission to terminate service, if the customer does not meet the terms described in Sections 4 through 8 at any time during the term of service or if the customer's payment obligations to Eversource exceed the amount of unsecured or secured credit to which it is entitled under this Attachment ES-L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

SCHEDULE 21 - UES

UNITIL ENERGY SYSTEMS, INC.

LOCAL SERVICE SCHEDULE

SCHEDULE 21-UES

Unitil Energy Systems, Inc. Local Service Schedule

I. COMMON SERVICE PROVISIONS

Unitil Energy Systems, Inc. ("UES") is a participant in the New England Control Area and has agreed to provide transmission and ancillary services over PTF pursuant to the Tariff. The services provided under this Schedule 21-UES apply only to Non-PTF, except in the case of service to Network Customers that have all or part of their Network Load directly connected to the PTF in the Local Network. These Network Customers shall pay for Local Network Service pursuant to Attachment H to this Schedule 21-UES. Provisions of this Schedule 21-UES shall have priority over any conflicting provisions in the Tariff.

1 Definitions

1.0 Annual Transmission Costs: The total annual cost of the Local Network for purposes of Local Network Service shall be the amount specified in Attachment H until amended by UES or modified by the Commission.

1.1 Curtailment: A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

1.2 Load Ratio Share: Ratio of a Transmission Customer's Network Load to UES's total load computed in accordance with Sections II.10 and II.10(a) of this Schedule under Sections Supplementing Schedule 21 of the OATT and calculated on a rolling twelve month basis.

1.3.1 Local Network: The transmission facilities owned, controlled, or operated by UES that are used to provide transmission service under Schedule 21 of the OATT.

1.4 Local Network Service (LNS): The transmission service provided under Schedule 21 of the OATT and this Schedule.

1.5 Network Load: The load that a Network Customer designates for Local Network

Service under Schedule 21 of the OATT. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Schedule 21 of the OATT for any Local Point-To-Point Service that may be necessary for such non-designated load.

1.6 Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support the UES's overall Local Network for the general benefit of all users of such Local Network.

1.7 Parties: UES and the Transmission Customer receiving service under this Schedule and the OATT.

SECTIONS SUPPLEMENTING THE BODY OF THE TARIFF

Preamble

The following provisions supplement the provisions of the Tariff. Provisions of this Schedule 21-UES shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-UES correspond to or are consecutive to the section numbers in the body of the Tariff that are affected by the additional provisions herein.

Sections Supplementing Section I: General Terms and Conditions

1.7 Creditworthiness: For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, UES may require reasonable credit review procedures in accordance with Attachment L of Schedule 21-UES.

Sections Supplementing Section II of the Tariff: Open Access Transmission Tariff (OATT)

II.A. COMMON SERVICE PROVISIONS

II.4 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. UES is required to provide (or offer to arrange with the ISO as discussed below), and the Transmission Customer is required to purchase, Local Scheduling, System Control and Dispatch Service. The following Ancillary Services are available pursuant to Section II.4 of the Tariff only to the Transmission Customer serving load within the New England Control Area (i) Reactive Supply and Voltage Control Service, (iii) Regulation and Frequency Response, (iii) Energy Imbalance, (iv) Ten-Minute Spinning Reserve Service, (v) Ten-Minute Non-Spinning Reserve Service and (vi) Thirty-Minute Operating Reserve Service.

II.8 Billing and Invoicing; Accounting

8.2 Invoicing: Within a reasonable time after the first day of each month, UES shall submit an invoice to the Transmission Customer for the charges for all services furnished under the OATT during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to UES, or by wire transfer to a bank named by the UES.

8.4 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to UES on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after UES notifies the Transmission

Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, UES may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between UES and the Transmission Customer, UES will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending

resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then UES may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

II.10.2 Stranded Cost Recovery

UES may seek to recover stranded costs from the Transmission Customer pursuant to this OATT in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, UES must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

SECTIONS SUPPLEMENTING SCHEDULE 21 OF THE OATT

I. Local Point-to-Point Service Over the Local Network Owned by UES

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-UES shall govern Local Point-To-Point transactions using the Local Network owned by UES. Provisions of this Schedule 21-UES shall have priority over any conflicting provisions in the Tariff. The section numbers of this Schedule 21-UES correspond to or are consecutive to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

To the extent not otherwise covered in the OATT, the then-current ISO New England Operating Documents, or the TOA, or the rules adopted thereunder, whenever UES implements least-cost redispatch procedures in response to a transmission constraint, UES and the Transmission Customer(s) taking Local Point-To-Point Service will each bear a proportionate share of the total redispatch cost.

3 Service Availability

b) Determination of Available Transfer Capability (ATC): A description of UES's specific methodology for assessing ATC is contained in Attachment C of this Schedule. In the event sufficient transfer capability may not exist to accommodate a service request, UES will respond by performing a System Impact Study.

g) Real Power Losses: Real power losses are associated with all transmission service. UES is not obligated to provide real power losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by UES. The applicable real power loss factors tabulated below will be applied to metered loads and Reserved Capacity amounts to account for losses on UES's system. The applicable real power loss factors are as follows:

Firm Local Point-to-Point Service = 0.53% at 34.5 kV subtransmission.
Non-firm Local Point-to-Point Service = 0.53% at 34.5 kV subtransmission

6) Procedures for Arranging Non-Firm Local Point-To-Point Service

f) Determination of Available Transfer Capability: Following receipt of a tendered schedule UES will make a determination on a non-discriminatory basis of ATC pursuant to Attachment C of this Schedule. Such determination shall be made as soon as reasonably practicable after receipt (during UES's normal business hours of 8:00 a.m. to 4:30 p.m., Monday to Friday), but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.

11 Sale or Assignment of Local Point-to-Point Service

c) Information on Assignment or Transfer of Service: UES currently has waiver from the obligations of FERC Order No. 889 to maintain an OASIS. In the future, upon implementation of any UES OASIS site, resellers may use UES's OASIS site to post transmission capacity available for resale.

II. Local Network Service using Non-PTF Owned by UES

Preamble

In addition to the provisions set forth in Schedule 21 of the OATT, the provisions of this Schedule 21-UES shall govern Local Network Service using Non-PTF owned by UES. Provisions of this Schedule 21-UES shall have priority over any conflicting provision in the Tariff. The section numbers of this Schedule 21-UES correspond to the sections of Schedule 21 of the OATT that are affected by the additional provisions herein.

Local Network Service allows the Network Customer to integrate, economically dispatch, and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which UES utilizes its Non-PTF to serve its Native Load Customers. Local Network Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Schedule 21 of the OATT.

2) Availability of Local Network Service

f) Real Power Losses: The Network Customer is responsible for replacing losses associated with all transmission service as calculated by UES. The applicable real power loss factors tabulated below will be applied to metered loads and Reserved Capacity amounts to account for losses on UES's system. The applicable real power loss factors are as follows:
Local Network Service = 0.53% at 34.5 kV subtransmission.

8) Load Shedding and Curtailments

a) Procedures: Prior to the Service Commencement Date, UES and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to Section II.20 of the Tariff, with the objective of responding to contingencies on the Local Network. The Parties will implement such programs during any period when the ISO, the Local Control Center or UES determines that a system contingency exists and such procedures are necessary to alleviate such contingency. UES will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

b) Transmission Constraints: During any period when UES determines that a transmission constraint exists on the Local Network, and such constraint may impair the reliability of UES's system, UES will take whatever actions, consistent with then-current ISO New England Operating Documents or the TOA, and the rules adopted thereunder, and with Good Utility Practice, that are reasonably necessary to maintain the reliability of UES's system. To the extent ISO determines that the reliability of the ISO New England transmission system can be maintained by redispatching resources, UES will initiate procedures pursuant to the OATT, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder to redispatch all Network Resources and UES's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between UES's use of the Local Network on behalf of its Native Load Customers and any Network Customer's use of the Local Network to serve its designated Network Load.

c) Cost Responsibility for Relieving Transmission Constraints: To the extent not otherwise covered in the OATT, the then-current ISO New England Operating Documents, or the TOA, or the rules adopted thereunder, whenever UES implements least-cost redispatch procedures in response to a transmission constraint, UES and the Network Customer(s) will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

d) **Curtailments of Scheduled Deliveries**: If a transmission constraint on UES's Local Network cannot be relieved through the implementation of least-cost redispatch procedures and UES determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with Section II.22 of the Tariff.

e) **Allocation of Curtailments**: The ISO, the Local Control Center or UES shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by UES and Network Customers in proportion to their respective Load Ratio Shares. Neither the ISO, the Local Control Center nor UES shall direct the Network Customer to Curtail schedules to an extent greater than either would Curtail UES's schedules under similar circumstances.

f) **Load Shedding**: To the extent that a system contingency exists on UES's Local Network and the ISO, the Local Control Center or UES determines that it is necessary for UES and the Network Customers to shed load, the Parties shall shed load in accordance with previously established procedures in accordance with Section II.22 of the Tariff, the then-current ISO New England Operating Documents, or the TOA, and the rules adopted thereunder.

g) **System Reliability**: Notwithstanding any other provisions of this Schedule, UES reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on the part of UES for the purpose of making necessary adjustments to, changes in, or repairs on UES's lines, substations, and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the event of any adverse conditions or disturbances on UES's Local Network or on any other system(s) directly or indirectly interconnected with UES's Local Network, UES, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. UES will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to UES's use of its Local

Network on behalf of its Native Load Customers. UES shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

9) Rates and Charges

In addition to the above sections that correspond to sections in Schedule 21 of the OATT, the following additional provision shall apply to Local Network Service over UES's Local Network.

a) Monthly Demand Charge: The Network Customer shall pay a Monthly Demand Charge which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of UES's Annual Transmission Revenue Requirement as specified in Attachment H to this Schedule 21-UES.

10) Determination of Network Customer's Local Monthly Network Load: The Network Customer's local monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with UES under Section II.5(c) of Schedule 21 of the OATT) coincident with UES's Monthly Local Network Peak. Monthly revenue requirements not otherwise paid for through charges to Eligible Customers for Local Point-to-Point Service will be allocated among UES's Network Customers receiving service under the tariff on the basis of their loads during the hour in the month in which the total connected load to the local network is at its maximum, without any adjustment for credits for generation.

In addition to the above sections that correspond to sections in Schedule 21 of the OATT, the following three provisions shall apply to Local Network Service over UES's local network.

10a) Determination of UES's Monthly Local Network Load: UES's monthly Local Network Load is UES's Monthly Local Network Peak minus the coincident peak usage of all firm Local Point-To-Point Service customers pursuant to Schedule 21 of the OATT plus the Reserved Capacity of all firm Local Point-To-Point Service customers.

10b) Recovery of PTF Transmission Revenue Requirements: The portion of UES's annual transmission revenue requirements with respect to PTF which is not recovered through the distribution of revenues from Regional Network Service or Local Point-to-Point Service shall be recovered from Eligible Customers taking Regional Network Service or Local Point-to-Point Service pursuant to Section II.13 of the Tariff.

SCHEDULE 1

Local Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into UES's Local Network Control Area. Local Scheduling, System Control and Dispatch Service is to be provided directly by UES and the ISO. The Transmission Customer must purchase this service from UES. The charges for UES's Local Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent that the ISO performs this service for UES, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to UES by the ISO.

Each firm Local Point-To-Point Service Customer under this Tariff will be charged for Local Scheduling, System Control and Dispatch Services for the total Reserved Capacity specified in each reservation for firm Local Point-To-Point Service made under the Tariff at the rates set forth in Appendix A of this Schedule 1.

Each Network Customer under this Tariff will be charged a monthly Local Scheduling, System Control and Dispatch Service Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Formula Requirements specified in Appendix B of this Schedule 1.
Each Transmission Customer with generation within the ISO's Control Area shall be required also to provide for Scheduling, System Control and Dispatch Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting with the ISO for these services on an unbundled basis. UES will make available Generation Scheduling, System Control and Dispatch Service at the rates set forth in Appendix C of this Schedule 1.

Each Transmission Customer with generation located outside of the ISO Control Area shall be required to provide for Scheduling, System Control and Dispatching Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting for these services from the provider of these services within the Control Area where the generation is located. UES shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule 1 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE 1

Appendix A

Determination Of UES's Local Network Point-To-Point Formula Rate
For Local Scheduling, System Control and Dispatch Service

UES's Formula Rate for Point-To-Point Local Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{FORMULA RATE}_i = \frac{A_{i-1} - B_{i-1}}{C_{i-1}}$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of UES for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule 1.

- B_{i-1} is the actual local scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual local scheduling and dispatch revenues shall be those recorded on the books of UES in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

- C_{i-1} is the single annual coincident peak transmission and distribution load (expressed in kilowatts) of UES for the calendar year prior to the Service Year, as reported in FERC Form No. 1.

Schedule 1

Appendix A

Exhibit 1

Determination Of Annual Control Center Expenses

The rate formula for determination of the annual control center expenses revenue requirements for UES is determined as follows:

A. <u>ANNUAL CONTROL CENTER EXPENSES</u> = Sum of UES's (Account 556 System Control and Load Dispatching Expense) + (Account 557 Other Expense) X .50* for the calendar year prior to the Service Year.

*This factor reflects allocation to the transmission function of a portion (50 percent) of the costs recorded in Accounts 556 and 557 associated with dispatching transmission and generating facilities. This 50 percent allocation of control center costs is based on two functions performed by the control center (i) control of generation and (ii) control of transmission.

SCHEDULE 1

Appendix B

Determination Of UES's
Network Formula Requirements
For Local Scheduling, System Control
And Dispatch Service

UES's formula requirements for Network Local Scheduling, System Control and Dispatch Service is determined from the following formula.

Formula Requirements_i = $A_{i-1} - B_{i-1}$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of UES for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to Appendix A of Schedule 1.

- B_{i-1} is the actual local scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual local scheduling, system control and dispatch revenues shall be those recorded on the books of UES in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

SCHEDULE 1

Appendix C

Determination Of
UES's Formula Rate
For Generation Scheduling, System Control And Dispatch Service

UES's Formula Rate for Generation Scheduling, System Control and Dispatch Service ("Formula Rate") shall be calculated using the Formula Rate for Point-to-Point Local Scheduling, System Control and Dispatch Service in Appendix A of Schedule 21 - UES.

SCHEDULE 7

Long-Term Firm Local and Short-Term Firm Local Point-to-Point Service

The Transmission Customer shall compensate UES each month for firm Reserved Capacity at the sum of the applicable charges set forth below:

1) **Yearly delivery**: one-twelfth of the demand charge of $ N/A /KW of firm Reserved Capacity per year.

2) **Monthly delivery**: $ N/A /KW of firm Reserved Capacity per month.

3) **Weekly delivery**: $ N/A /KW of firm Reserved Capacity per week.

4) **Daily delivery**: $ N/A /KW of firm Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of firm Reserved Capacity in any day during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by UES must be announced to all Eligible Customers solely by posting on Unitil.com, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on Unitil.com, and (3) once a discount is negotiated, details must be immediately posted on Unitil.com. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, UES must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on UES's Local Network.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section I.11 (a) of Schedule 21 of the OATT.

SCHEDULE 8

Non-Firm Local Point-To-Point Service*

The Transmission Customer shall compensate UES for non-firm Local Point-To-Point Service up to the sum of the applicable charges set forth below:

1) **Monthly delivery**: $ N/A /KW of Reserved Capacity per month.

2) **Weekly delivery**: $ N/A /KW of Reserved Capacity per week.

3) **Daily delivery**: $ N/A /KW of Reserved Capacity per day.
The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) **Hourly delivery**: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $ N/A /MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by UES must be announced to all Eligible Customers solely by posting on Unitil.com, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on Unitil.com, and (3) once a discount is negotiated, details must be immediately posted on Unitil.com. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, UES must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on UES's Local Network.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section I.11 (a) of

Schedule 21 of the OATT.

* Rates reflect a 25% discount off the firm Point-To-Point rates

SCHEDULE 9

DISTRIBUTION ADDER UNDER TARIFF

In the case where distribution facilities of UES are employed in providing service under Schedule 21 of the OATT, the Transmission Customer shall compensate UES for the use of such facilities. In addition to the charges contained in this Tariff, the compensation for such distribution facilities will be determined on a case-by-case basis.

All such charges shall be subject to appropriate regulatory approval.

ATTACHMENT C

Methodology To Assess Available Transfer Capability

1. Introduction

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, but does not include the transmission system in northern Maine (i.e., Aroostook and parts of Penobscot and Washington Counties) that is radially connected to New Brunswick and administered by the Northern Maine Independent System Administrator. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERS Standards: MOD-001 – Available Transmission System Capability ("MOD-001"). MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Service Provider for regional transmission service ("Regional Transmission Service") associated with Pool Transmission Facilities, the Participating Transmission Owners ("PTOs") provide local transmission service over Non-Pool Transmission Facilities within the RTOP footprint and are responsible for calculating TTC and ATC associated with Local Transmission Service provided under Schedule 21 pursuant to the Transmission Operating Agreement ("TOA"). Pursuant to CFR § 37.6(b)[13] of the FERC Regulations, Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. The ISO is not responsible for the calculation of these values.

Posted Path is defined as any control area to control area interconnection; any path for which service is

13 Section §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted 13 2 Path as set out in this section.

denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.[14]

UES does not currently have any Posted Paths based on the above definition. However, to the extent that UES does in the future have a Posted Path, UES will calculate TTC using the NERC Standard MOD-029 – Rated System Path Methodology ("MOD-029") as outlined below.

1.1 Scope of Document

The scope of this document is limited to those functions performed by UES as the Transmission Service Provider of Schedule 21-UES Point-to Point transmission service over Local Facilities pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT:

- Methodology for calculating Total Transfer Capability (TTC)
- Methodology for calculating Available Transfer Capability (ATC)
- Existing Transmission Commitment (ETC)
- Use of Transmission Reliability Margin (TRM)
- Use of Capacity Benefit Margin (CBM)
- Use of Rollover Rights (ROR) in the calculation of ETC

TTC and ATC are required to be calculated only for certain non-PTF internal Posted Paths over which Point-to-Point transmission service is provided under Schedule 21-UES. TTC and ATC is not calculated by UES for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and UES does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Section § 37.6(b)(1)(i).

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the New England Control Area, out of the New England Control Area or through the New England Control Area. The New England Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS or Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, UES owns Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those Local Facilities, the market participant may obtain a transmission service reservation from UES under Schedule 21-UES prior to delivery of energy into the Real-Time Energy Market.[15] This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. Schedule 21-UES Total Transfer Capability (TTC)

The TTC on UES' non-PTF Local Facilities that require Point-to-Point transmission service reservations

15 See n - 2, 3 and 6, supra.

are relatively static values and are calculated using the NERC Standard MOD-029 – Rated System Path Methodology. TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. UES calculates TTC according to this definition applying the process as described below.

3.1 Guidelines and Principles

When estimating TTC, UES will apply the following, as amended and/or adopted from time to time

- Good Utility Practice
- NERC criteria and guidelines
- ISO New England criteria, rules and reliability standards
- Northeast Power Coordinating Council (NPCC) criteria and guidelines
- Unitil Energy Systems, Inc. guides

3.2 Transmission System Model Representation

UES will estimate TTC using transmission system load flow models developed for UES' system. The models may include representations of other neighboring systems. UES will use system models that it deems appropriate for study of the request for firm transmission service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

3.3 Contingency Analysis

UES will perform, if necessary, power flow and transient stability analysis to ensure that the interface's physical limits will not be violated for credible system contingencies per NERC, NPCC and ISO reliability criteria. TTC, based on contingency analysis, is the incremental transfer capability of the transmission system following the loss of the most critical element while maintaining thermal, and stability performance of the system within acceptable regional practices and consistent with guidelines of Item 3.1 of this Attachment.

3.4 Posting TTCs

When necessary, UES will estimate TTC as outlined above and post on its website.

4. Capacity Benefit Margin (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of ATC calculation, CBM for the New England Control Area is set to zero (0).

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed firm transmission reservations (PTP_F) plus any rollover rights for firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed non-firm transmission reservations (PTP_{NF}). There are no allowances necessary for non-firm Network Integration Transmission Service ($NITS_{NF}$), non-firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. UES, under Schedule 21, does not have any external interfaces, and therefore, TRM for UES' non-PTF facilities is zero.

6. Calculation of ATC for UES' Local Facilities

General Description

This section defines the ATC calculations performed by UES for its non-PTF internal interfaces. Consistent with the NERC definition, the equation for Available Transfer Capability is: ATC = (TTC – CBM – TRM – Existing Transmission Commitments + Postbacks + counterflows). As discussed above, the CBM and TRM for the PTF interfaces for which UES calculates ATC are zero (0). As consistent with the ISO calculation, the equations for firm and non-firm Available Transfer Capability are:

Firm ATC = (TTC – CBM – TRM – firm ETC)
Non-firm ATC = (TTC – CBM – TRM – firm and non-firm ETC).[16]

As discussed above, the TRM and CBM for UES's non-PTF paths are zero. The purpose of the Existing Transmission Commitments ("ETC") component of the ATC equation is for FG&E to reduce the amount of ATC by the amount of existing firm transmission commitments that are not otherwise included in CBM or TRM. There is no requirement to purchase transmission service in advance of flowing energy in Real-Time, and there is no MW amount set aside by FG&E on any interface. One such example is point-to-point service commitments. Point-to-point service commitments sharing common transmission paths would be combined through system modeling to calculate the net existing transmission capacity (ETC) impact. This ETC value is then used in the ATC calculation shown above. Therefore there are no Existing Transmission Commitments to be applied in the ATC equation. For this reason, ETC equals zero (0) for the purposes of ATC calculation. Because Postbacks and counterflows are related to ETC and ETC is zero (0), both Postbacks and counterflows also are equal to zero (0).

As described in Section 2, under Schedule 21-UES, UES requires the purchase of transmission service in advance of delivery of energy to the New England Wholesale Market over certain non-PTF paths, and those existing transmission commitments would be applied to the ATC equation for the specific posted path. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Entities submit their bids and offers to move energy into, out of and through the Energy Market through External Transactions. As Real-Time approaches, the ISO determines which of the submitted External

16 Existing Transmission Commitments ("ETC")

Transactions will be scheduled in the coming hour in accordance with the rules set forth in the ISO New England Operating Documents. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of External Transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF facilities that serve as a path for the UES' Schedule 21-UES Point-to-Point Transmission Customers, UES would post the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it would be posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Schedule 21-UES Firm ATC (ATC_F)

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C, PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-UES that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-UES transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

6.1.2 Calculation of ATC_F in the Schedule 21-UES Operating Horizon (OH)

For purposes of this Attachment C, OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily firm Transmission Service under Schedule 21-UES is the only firm service offered in the Operating Horizon (OH). $\text{Postbacks}_{\mathbf{F}}$ and $\text{counterflows}_{\mathbf{F}}$ of Schedule 21-UES transmission reservations are not considered in the $ATC_{\mathbf{F}}$ calculation. Therefore, $ATC_{\mathbf{F}}$ in the OH is equal to the TTC minus $ETC_{\mathbf{F}}$.

6.1.3 Because firm Schedule 21-UES transmission service is not offered in the Scheduling Horizon (SH): $ATC_{\mathbf{F}}$ in the SH is zero.

6.2 Calculation of Schedule 21-UES Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

$ATC_{\mathbf{NF}}$ is the capability for non-firm transmission reservations that remain after allowing for $ETC_{\mathbf{F}}$, $ETC_{\mathbf{NF}}$, scheduled CBM ($CBM_{\mathbf{S}}$), unreleased TRM ($TRM_{\mathbf{U}}$), non-firm Postbacks (Postbacks_{NF}) and non-firm counterflows ($\text{counterflows}_{\mathbf{NF}}$).

As discussed above, the TRM and CBM for Schedule 21-UES are zero. Non-firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. $TRM_{\mathbf{U}}$, $\text{Postbacks}_{\mathbf{NF}}$ and $\text{counterflows}_{\mathbf{NF}}$ of Schedule 21-UES transmission reservations are not considered in this calculation. Therefore, $ATC_{\mathbf{NF}}$ in the PH is equal to the TTC minus $ETC_{\mathbf{F}}$ and $ETC_{\mathbf{NF}}$.

6.2.2 Calculation of ATC_{NF} in the OH

$ATC_{\mathbf{NF}}$ available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-UES are zero. $TRM_{\mathbf{U}}$, counterflows and $ETC_{\mathbf{NF}}$ are not considered in this calculation. Therefore, $ATC_{\mathbf{NF}}$ in the OH is equal to the TTC minus $ETC_{\mathbf{F}}$, plus postbacks of $PTP_{\mathbf{F}}$ in OH as $PTP_{\mathbf{NF}}$ ($\text{Postbacks}_{\mathbf{NF}}$).

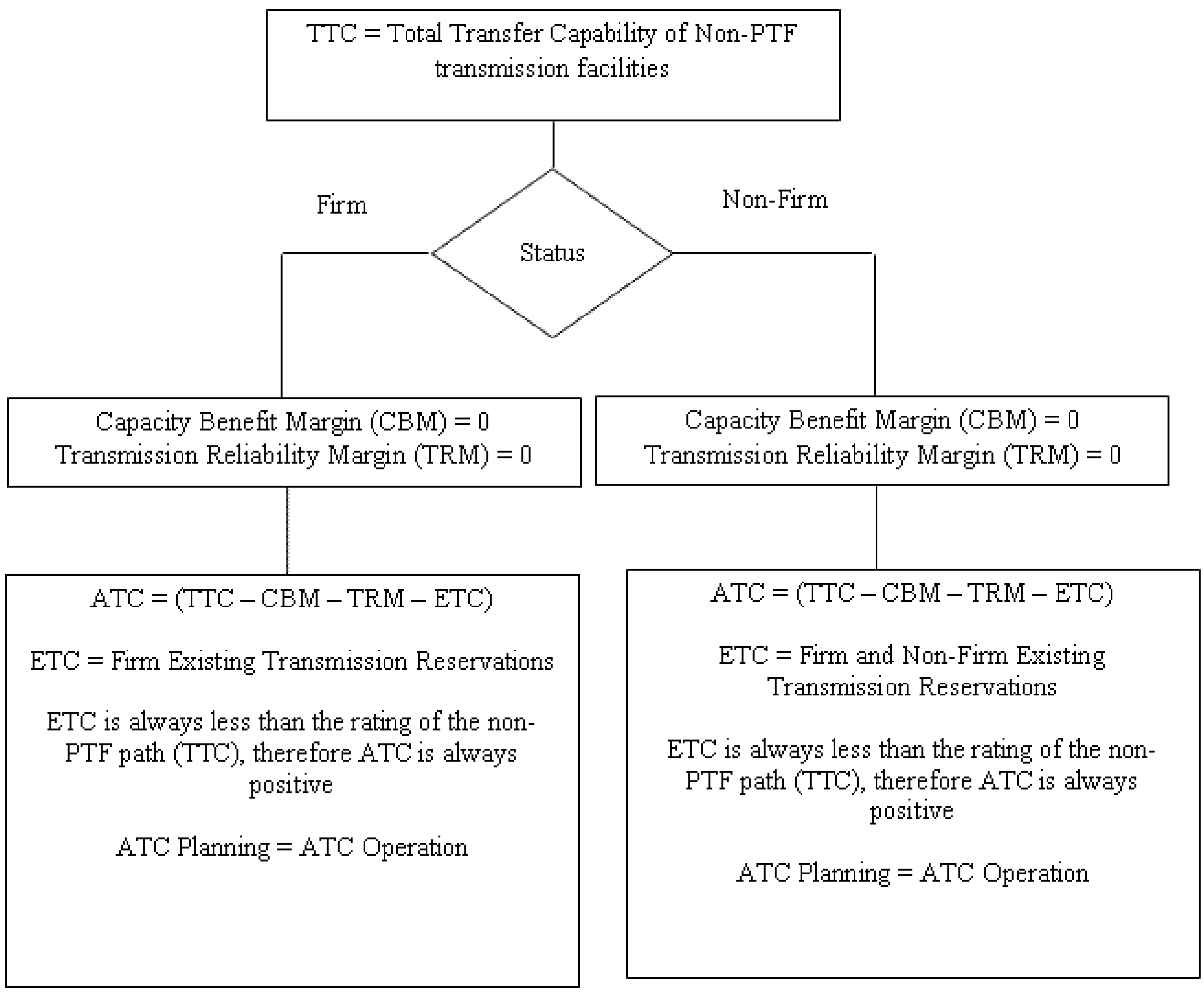
6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

As stated above, UES' non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators. It is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

ATC Process Flow Diagram for Non-PTF Interfaces

The process flow diagram illustrates the steps through which ATC is calculated both on an operating and planning horizon.



7. Posting of Schedule 21-UES ATC

7.1 Location of ATC Posting.

When necessary, UES will estimate ATC values for these internal paths as outlined above and post on its website, http://www.unitil.net/nepool/nh/pdf/atc_cbm_ttc_trm_ues.pdf.

7.2 Updates To ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

7.3 Coordination of ATC Calculations

Schedule 21-UES non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms

A link to the actual mathematical algorithm for the calculation of ATC for UES' non-PTF internal interfaces is located at http://www.unitil.com/sites/default/files/pdfs/ues_atc_algorithms_3_11.pdf .

ATTACHMENT D

Methodology for Completing a System Impact Study

UES will perform System Impact Studies for the purpose of determining the feasibility of integrating Network Load and Network Resources into UES's Local Network under Schedule 21 of the OATT, or for the purpose of determining the feasibility of providing Local Point-To-Point Service under this Tariff. All System Impact Studies will be completed using the same method employed by UES to integrate into UES's Local Network (i) generation resources owned or acquired to serve its Native Load Customers, and (ii) its Native Load Customers' load. Specifically, System Impact Studies will be performed by applying the applicable criteria, rules, standards and operating procedures. In addition to applying the aforementioned applicable criteria, rules, standards and operating procedures , to determine the feasibility of providing service to Network Load and/or Local Point-To-Point Service, System Impact Studies will also be performed by applying Unitil Service Corp.'s "Electric System Planning Guide."

ATTACHMENT E

Index Of Local Point-To-Point Service Customers

Customer	Date of Service Agreement

ATTACHMENT H

Annual Transmission Revenue Requirement

For Local Network Service

1. The Annual Transmission Revenue Requirement for purposes of the Local Network Service shall be $ N/A.

2. The amount in (1) shall be effective until amended by UES or modified by the Commission.

3. If UES receives a distribution pursuant to Section II.13 of the Tariff from ISO out of revenues paid for Through or Out Service or for In Service (as defined in the OATT), the amounts received shall reduce its local network service revenue requirements.

4. Any rate developed hereunder shall employ a cost of equity of 11.14~~10.57~~%.

ATTACHMENT I

Index Of Local Network Service Customers

Customer	Date of Service Agreement
Unitil Energy Systems, Inc.	December 1, 2002

Attachment L

Creditworthiness Policy

1. Introduction

This guide establishes creditworthiness standards for transmission service and/or interconnection service customers ("Customers") entering into new or amended service agreements with Unitil Energy Systems, Inc. ("UES") under the ISO New England Open Access Transmission Tariff ("ISO-NE OATT").[17] In accordance with the Federal Energy Regulatory Commission's Policy Statement on Credit-Related Issues for Electric OATT Transmission Providers, Independent System Operators and Regional Transmission Organizations ("Policy Statement"), this Creditworthiness Policy is intended to make UES's credit-related practices more transparent and comprehensive. The following describes UES credit review procedures and the types of security that are acceptable to UES to protect against the risk of non-payment.

2. Creditworthiness

UES will evaluate the creditworthiness of Customers entering into new or amended transmission or interconnection service agreements with UES in order to assess a Customer's credit risk relative to the exposure of "Total Outstanding Obligation" as defined in Section 2.1 below, created by the transaction or transactions that UES has with the Customer. For purposes of determining the ability of a Customer to meet its obligations, UES may require the Customer to submit financial information for the credit review, including credit ratings, credit reports and audited financial statements for the last five years, including audited quarterly reports for the prior two years, if available. Further, the Customer will be expected to provide calculations of the following: Current Total Capitalization Ratio, Including Short-Term Debt; Tangible Net Worth for a period within sixty days of a Customer's request; Earnings Before Interest, Taxes, Depreciation and Amortization for twelve of the last fifteen consecutive months; and additional calculations and other information deemed necessary for the evaluation credit. In completing its evaluation, UES may consider other factors including but not limited to past billing history or the characteristics of service being requested.

2.1 Total Outstanding Obligation

The Customer's Total Outstanding Obligation to UES will be the sum total of the following components:

17 *See* ISO New England Inc., ISO New England Inc. Transmission, Markets and Services Tariff, Section II. This policy is applicable to transmission or interconnection service agreements established from time-to-time under Schedules 21 - UES of the ISO-NE OATT and to individually negotiated agreements for similar transmission or interconnection services .

2.1.1 If the Customer is making payments to UES for ongoing expenses (including, but not limited to, O&M expenses related to interconnections or other monthly charges such as monthly transmission charges under Schedule 21 – UES) the Customer will be required to provide security pursuant to Section 2.2 below, for four months' worth of the Customer's average payment obligation for such charges.

2.1.2 In accordance with the provisions of the ISO-NE OATT, a Customer will pay a Contribution in Aid of Construction ("CIAC") or transfer ownership of facilities to UES for transmission or interconnection facilities that are to be constructed on behalf of a Customer at the Customer's sole expense. If UES determines in good faith that the receipt of CIAC payments or property from the Customer are non-taxable, UES will require a form of security from the customer pursuant to Section 2.2 below for the amount of the potential tax liability to UES that would occur if such facilities were deemed taxable.

2.1.3 In accordance with the provisions of Schedule 21 – UES to the ISO-NE OATT, a Customer will pay a formula rate over time for return of and on the cost of capital incurred by UES on behalf of a Customer at the Customer's sole expense. The Customer will also be required to provide security pursuant to Section 2.2 below, for the unamortized balance of plant in service reserved for the sole use of the Customer.

2.2 Creditworthiness Requirements

A Customer will be considered creditworthy upon satisfying at least one of the following conditions or a combination of those conditions at the time that the customer enters into a transmission or interconnection service agreement and for so long as the Customer maintains satisfaction of at least one of these conditions for any outstanding obligations thereunder:

2.2.1 The Customer maintains a minimum credit rating from Standard & Poor's Long-term Issuer Credit Rating of BBB- or better or Moody's Investors Service Long-term Issuer Credit Rating of Baa3 or better so long as the Customer's Total Outstanding Obligation plus any other unsecured obligations with UES does not exceed the Credit Limits discussed in Section 4 below. When UES reviews a Customer's rating from two or more rating agencies and a split rating is present, the lower debt rating will apply. In the event that the Customer has no rating from either Standard & Poor's or Moody's Investors Service, a rating from Fitch may also be used with

acceptable ratings equivalent to those from either Standard and Poor's or Moody's Investors Service. If unrated, the Customer's financial statements will be reviewed to determine an equivalent rating based on the Customer's unsecured credit limits and/or financial statements.

If, at any time, the Customer's rating falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify UES within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to UES, as described in this Section 2.2.

2.2.2 The Customer provides and maintains in effect during the term of and until full and final payment and performance of the service agreement an unconditional and irrevocable standby letter of credit for the Total Outstanding Obligation in the form and substance and issued by a bank reasonably acceptable to UES. A draft, acceptable form letter of credit is attached. Any such bank must satisfy the creditworthiness criteria described in 2.2.1 above.

If, at any time, the bank's rating falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify UES within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to UES, as described in this Section 2.2.

2.2.3 If the Customer's parent or an affiliate company satisfies the creditworthiness criteria described in 2.2.1 above and, subject to the Credit Limits stated in Section 4 below, such company submits to UES and maintains in effect a letter of guaranty reasonably acceptable to UES as to amount, form and substance for the term of and until full and final payment and performance of the service agreement.

If, at any time, the credit rating of the Customer's parent or affiliate providing the guaranty falls below investment grade (BBB- from Standard and Poor's and/or Baa3 from Moody's or equivalent ratings from Fitch), the Customer will be required to (i) notify UES within 10 days and, (ii) within 30 days, provide another form of security reasonably acceptable to UES, as described in this Section 2.

2.2.4 The Customer makes an advance payment to UES in immediately available funds for the Total Outstanding Obligation.

3. Customer Costs Requiring Prepayment

In accordance with the provisions of the ISO-NE OATT, a Customer will pay a Contribution in Aid of Construction ("CIAC") for transmission or interconnection facilities to be constructed by UES on behalf of a Customer at the Customer's sole expense. The Customer will have the option to (i) prepay the CIAC in immediately available funds to UES, or (ii) make periodic CIAC progress payments, as defined in the Customer's service agreement, to prepay in increments capital costs scheduled to be incurred by UES. If UES determines in good faith that such payments or property transfers made by the Customer should be reported as income subject to taxation, the Customer shall also prepay all costs associated with the cost consequences of the current tax liability imposed on UES by those facilities (the "Tax Gross- up").

4. Determination of Credit Limits

UES reserves the right to limit the total amount of unsecured credit extended to a Customer under 2.2.1 and 2.2.3 above such that the sum of all unsecured credit that such Customer has with UES, including the Total Outstanding Obligation, shall not exceed the Credit Limits defined below. Such limitations are based on an assessment of the Customer's or its Guarantor's credit rating and the net worth of the Customer's or its Guarantor's assets.

Standard and Poor's (or Equivalent) Rating	Unsecured Credit Limit as Percent of Customer's or Guarantor's Tangible Net Worth
A and above	1.00%
A-	0.50%
BBB+	0.30%
BBB	0.20%
BBB-	0.10%

Once UES has evaluated or reevaluated and determined the maximum Credit limits for each Customer, it will inform the prospective Customer of the amount of such credit limits. A customer may request in writing a reevaluation of the maximum Credit limits, within 14 days from the date that they were informed by UES of such limits. Justification for such a reevaluation should be contained in the request. All requests for reevaluation must be submitted directly to the UES Contract Administrator.

From time to time, principally due to unknown factors such as changing market, economic, banking or other financial conditions, but not solely limited to these factors, UES may find it necessary to modify or amend its creditworthiness policies and guidelines after a 15 day notice period and require that present and future Transmission Customers fulfill any additional conditions contained in the modified Creditworthiness Guide. Transmission Customers will have 30 days after the notice period to cure any deficiency.

FORM LETTER OF CREDIT

___________________________________ Bank

____

(address)

IRREVOCABLE STANDBY LETTER OF CREDIT

DATE: _____________________

AMOUNT U.S. $_______________

____

FOR INTERNAL IDENTIFICATION PURPOSES ONLY

Our Number:

Beneficiary:	Applicant:
__________________________	_________________________
__________________________	_________________________
__________________________	_________________________
__________________________	_________________________

Attn: At the request of:

Ref:____

LADIES AND GENTLEMEN:

WE HEREBY ESTABLISH THIS IRREVOCABLE, AND UNCONDITIONAL, EXCEPT AS STATED HEREIN, LETTER OF CREDIT NUMBER _____________ (LETTER OF CREDIT), BY ORDER OF, FOR THE ACCOUNT OF, AND ON BEHALF OF [CUSTOMER NAME] (ACCOUNT PARTY) IN FAVOR OF UNITIL ENERGY SYSTEMS, INC. (BENEFICIARY) FOR DRAWINGS, IN ONE OF MORE DRAFTS, UP TO AN AGGREGATE AMOUNT NOT EXCEEDING U.S. $_______________ EFFECTIVE IMMEDIATELY. THE TERM 'BENEFICIARY' INCLUDES ANY SUCCESSOR OF THE NAMED BENEFICIARY.

THIS LETTER OF CREDIT CANNOT BE AMENDED, MODIFIED OR REVOKED WITHOUT THE PRIOR WRITTEN CONSENT OF BOTH THE BANK AND THE BENEFICIARY. THE BENEFICIARY SHALL NOT BE DEEMED TO HAVE WAIVED ANY RIGHTS UNDER THIS LETTER OF CREDIT, UNLESS AN OFFICER OF THE BENEFICIARY SHALL HAVE SIGNED A WRITTEN WAIVER EXPRESSLY REFERENCING THE RIGHT TO BE WAIVED. NO SUCH WAIVER SHALL BE EFFECTIVE AS TO ANY TRANSACTION THAT OCCURS SUBSEQUENT TO THE DATE OF THE WAIVER, NOT AS TO ANY CONTINUANCE OF A BREACH AFTER THE WAIVER.

WE HEREBY UNDERTAKE TO PROMPTLY HONOR YOUR DRAFT(S) DRAWN ON US, INDICATING OUR LETTER OF CREDIT NUMBER __________ IS ISSUED, PRESENTABLE AND PAYABLE AND WE GUARANTY TO THE DRAWERS, ENDORSERS, AND BONA FIDE HOLDERS OF THIS LETTER OF CREDIT, THAT DRAFTS UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT WILL BE HONORED. THIS LETTER OF CREDIT MAY NOT BE TRANSFERRED OR ASSIGNED BY US.

SUBJECT TO THE EXPRESS TERMS AND CONDITIONS HEREIN, FUNDS UNDER THIS LETTER OF CREDIT ARE AVAILABLE TO YOU BY PRESENTATION AT OUR OFFICES LOCATED AT [_______________] OF BENEFICIARY'S DRAWING CERTIFICATE ISSUED SUBSTANTIALLY IN THE FORM OF ANNEX 1 ATTACHED HERETO AND WHICH FORMS AN INTEGRAL PART HEREOF, DULY COMPLETED AND PURPORTEDLY BEARING THE ORIGINAL SIGNATURE OF AN OFFICER OF THE BENEFICIARY. PRRESENTATION OF ANY DRAWING CERTIFICATE UNDER THIS LETTER OF CREDIT MAY BE MADE IN PERSON TO US OR MAY BE SENT TO US BY TELEX TO [_________________] OR BY FACSIMILE

TRANSMISSION TO FACSIMILE TELEPHONE NUMBER [_______________].

ALL COMMISSIONS AND CHARGES WILL BE BORNE BY THE ACCOUNT PARTY. IF DOCUMENTS, IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT, ARE RECEIVED BEFORE 10:00 AM (EASTERN TIME) ON A BUSINESS DAY, PAYMENT WILL BE EFFECTED ON OR BEFORE 5:00 PM (EASTERN TIME) ON THE NEXT BUSINESS DAY. IF DOCUMENTS, IN COMPLIANCE WITH THE TERMS OF THIS LETTER OF CREDIT ARE RECEIVED AFTER 10:00 AM ON A BUSINESS DAY, PAYMENT WILL BE EFFECTED ON OR BEFORE 5:00 PM ON THE SECOND BUSINESS DAY FOLLOWING SUCH DATE OF RECEIPT.

EXCEPT AS EXPRESSLY STATED HEREIN, THIS UNDERTAKING IS NOT SUBJECT TO ANY AGREEMENT, CONDITION OR QUALIFICATION. THIS LETTER OF CREDIT DOES NOT INCORPORATE, AND SHALL NOT BE DEEMED MODIFIED OR AMENDED BY REFERENCE TO ANY DOCUMENT, INSTRUMENT OR AGREEMENT (A) THAT IS REFERRED TO HEREIN (EXCEPT FOR THE UNIFORM CUSTOMS, AS DEFINED BELOW), OR (B) IN WHICH THIS LETTER OF CREDIT IS REFERRED TO OR TO WHICH THIS LETTER OF CREDIT RELATES.

OUR OBLIGATION UNDER THIS LETTER OF CREDIT SHALL BE OUR INDIVIDUAL OBLIGATION AND IS IN NO WAY CONTINGENT UPON THE REIMBURSEMENT WITH RESPECT THERETO, OR UPON OUR ABILITY TO PERFECT ANY LIEN, SECURITY INTEREST OR ANY OTHER REIMBURSEMENT.

THIS LETTER OF CREDIT EXPIRES WITH OUR CLOSE OF BUSINESS ON [364 days from effective date]; HOWEVER, IT IS A CONDITION OF THIS LETTER OF CREDIT THAT IT SHALL BE DEEMED AUTOMATICALLY EXTENDED WITHOUT AMENDMENT FOR 364 DAYS FROM THE PRESENT OR ANY FUTURE EXPIRATION DATE HEREOF, UNLESS AT LEAST SIXTY (60) DAYS BEFORE ANY SUCH EXPIRATION DATE WE NOTIFY YOU BY REGISTERED MAIL ADDRESSED TO: [address of beneficiary, ATTN: ______________], THAT WE ELECT NOT TO RENEW THIS LETTER FOR SUCH ADDITIONAL PERIOD.

THIS LETTER OF CREDIT IS SUBJECT TO THE UNIFORM CUSTOMS AND PRACTICE FOR DOCUMENTARY CREDITS (1993 REVISION) INTERNATIONAL CHAMBER OF COMMERCE, PUBLICATION NO. 500. IF THIS LETTER OF CREDIT EXPIRES DURING THE INTERRUPTION OF BUSINESS AS DESCRIBED IN ARTICLE 17 THEREOF WE HEREBY SPECIFICALLY AGREE

TO EFFECT PAYMENT IF THE LETTER OF CREDIT IS DRAWN AGAINST WITHIN 30 DAYS AFTER THE RESUMPTION OF BUSINESS.

ANNEX 1 TO [BANKNAME]
IRREVOCABLE LETTER OF CREDIT NO. _____________

[INSERT DATE]
[BANK NAME]
[ATTENTION]
[BANK ADDRESS 1]
[BANK ADDRESS 2]

LADIES AND GENTLEMEN:

THE UNDERSIGNED _________________________________, A DULY ELECTED AND ACTING OFFICER OF UNITIL ENERGY SYSTEMS, INC. (THE "BENEFICIARY"), HEREBY CERTIFIES TO [INSERT BANK NAME] (THE "BANK"), WITH REFERENCE TO IRREVOCABLE LETTER OF CREDIT NO. _________ DATED ________________, ISSUED BY THE BANK IN FAVOR OF THE BENEFICIARY (THE "LETTER OF CREDIT"), AS FOLLOWS AS OF THE DATE THEREOF:

1. THE BENEFICIARY IS A PARTY TO THAT CERTAIN [INTERCONNECTION AGREEMENT], EFFECTIVE _______________, BETWEEN THE BENEFICIARY AND [CUSTOMER NAME] (THE "AGREEMENT").

2. BENEFICIARY IS MAKING A DRAWING UNDER THE LETTER OF CREDIT IN THE AMOUNT OF $___________ BECAUSE [CHECK APPLICABLE PROVISION]:

[____] (A) THERE CURRENTLY EXIST ONE OR MORE UNPAID AMOUNTS WHICH [CUSTOMER NAME] IS OBLIGATED TO PAY PURSUANT TO THE TERMS OF THE AGREEMENT.

[____] (B) THE BENEFICIARY HAS RECEIVED NOTICE FROM THE BANK OF ITS INTENTION NOT TO RENEW THE LETTER OF CREDIT BEYOND THE CURRENT EXPIRATION DATE AND [CUSTOMER NAME] HAS FAILED, PRIOR TO THE CLOSE OF BUSINESS ON ________________ [INSERT DATE WHICH IS NOT MORE THAN THIRTY (30) DAYS BEFORE THE PRESENT EXPIRATION DATE], TO DELIVER TO BENEFICIARY A REPLACEMENT LETTER OF CREDIT SATISFYING THE REQUIREMENTS OF THE AGREEMENT.

3. BASED UPON THE FOREGOING, THE BENEFICIARY HEREBY MAKES DEMAND UNDER THE LETTER OF CREDIT FOR PAYMENT OF U.S. DOLLARS __________________ AND _____/100THS (U.S. $_______________).

4. FUNDS PAID PURSUANT TO THE PROVISIONS OF THE LETTER OF CREDIT SHALL BE WIRE TRANSFERRED TO THE BENEFICIARY IN ACCORDANCE WITH THE FOLLOWING INSTRUCTIONS:

____

____

____

UNLESS OTHERWISE PROVIDED HEREIN, CAPITALIZED TERMS WHICH ARE USED AND NOT DEFINED HEREIN SHALL HAVE THE MEANING GIVEN EACH SUCH TERM IN THE LETTER OF CREDIT.

IN WITNESS WHEREOF, THIS CERTIFICATE HAS BEEN DULY EXECUTED AND DELIVERED ON BEHALF OF THE BENEFICIARY BY ITS DULY ELECTED AND ACTING OFFICER AS OF THIS _____ DAY OF ___________, _____.

BENEFICIARY: UNITIL ENERGY SYSTEMS, INC.

____

NAME:

____

TITLE:

SCHEDULE 21-VTransco

Local Service Schedule

Vermont Transco LLC

In accordance with paragraphs 126-130 of Commission Order No. 676-E, the NAESB Version 002 Standards listed below apply to the provision of transmission service pursuant to this Schedule 21-VTransco for service provided hereunder by Vermont Transco LLC:

Gas/Electric Coordination (WEQ-011, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009), Standards 011.12 and 011.13.

I. COMMON SERVICE PROVISIONS

This Local Service Schedule, designated Schedule 21-VTransco, governs the terms and conditions of service taken by Transmission Customers over VTransco's Transmission System who are not otherwise served under transmission service contracts with VTransco that are still in effect. In the event of a conflict between the provisions of this Schedule 21-VTransco and the other provisions of the Tariff, the provisions of this Schedule 21-VTransco shall control.

1 Definitions

Whenever used in this Schedule 21-VTransco, in either the singular or the plural, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Schedule 21-VTransco but not defined in this Section 1 shall have the meaning specified elsewhere in the Tariff, or if not defined therein, such terms shall have the meanings customarily attributed to such terms by the electric utility industry in New England.

1.1 Actual Transmission Costs: The total actual cost of VTransco's Transmission System for purposes of Local Network Service shall be the amount determined each month pursuant to the formula specified in Attachment D until amended by VTransco or modified by the Commission.

1.2 Firm Local Point-To-Point Transmission Service: Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery on VTransco's Transmission System pursuant to this Schedule 21.

1.3 Interruption: A reduction in non-firm transmission service due to economic reasons pursuant to the terms of this Schedule 21.

1.4 Load Ratio Share: Ratio of a Transmission Customer's Local Network Load to VTransco's total load computed in accordance with this Schedule 21-VTransco and calculated on a rolling twelve-month basis.

1.5 Local Network Customer: An entity receiving Local Network Service pursuant to the terms of this Schedule 21.

1.6 Local Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under this Schedule 21.

1.7 Local Point-To-Point Transmission Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under this Schedule 21.

1.8 Local Reserved Capacity: The maximum amount of capacity and energy that VTransco agrees to transmit for the Transmission Customer over VTransco's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under this Schedule 21. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.9 Non-Firm Local Point-To-Point Transmission Service: Point-To-Point Transmission Service on VTransco's Transmission System under this Schedule 21 that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption. Non-Firm Local Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.10 Parties: VTransco and the Transmission Customer receiving service under this Schedule 21-VTransco.

1.11 Receiving Party: The entity receiving the capacity and energy transmitted by VTransco to Point(s) of Delivery under this Schedule 21.

1.12 Service Commencement Date: The date that VTransco begins to provide service pursuant to the terms of an executed Service Agreement, or the date that VTransco begins to provide service in accordance with this Schedule 21.

1.13 Short-Term Firm Local Point-To-Point Transmission Service: Firm Local Point-To-Point Transmission Service under this Schedule 21-VTransco with a term of less than one year.

1.14 VTransco: Vermont Transmission Company, LLC.

1.15 VTransco's Monthly Transmission System Peak: The maximum firm usage of VTransco's Transmission System in a calendar month.

1.16 VTransco's Transmission System: The Non-PTF facilities owned, controlled or operated by VTransco that are used to provide transmission service under this Schedule 21.

2 [RESERVED]

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. VTransco offers to arrange with the ISO, and the Transmission Customer is required to purchase or otherwise obtain, the following Ancillary Services: (i) Scheduling, System Control and Dispatch. VTransco does not offer or provide any other ancillary services.

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1 of this Schedule 21-VTransco.

4 Billing and Payment

4.1 Billing Procedure: Within a reasonable time after the first day of each month, VTransco shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Schedule 21-VTransco during the preceding month.

The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to VTransco, or by wire transfer to a bank named by VTransco.

4.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by VTransco.

4.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to VTransco on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after VTransco notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, VTransco may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between VTransco and the Transmission Customer, VTransco will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then VTransco may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5 Accounting for VTransco's Use of the Tariff

VTransco shall record the following amounts, as outlined below.

5.1 Transmission Revenues: Include in a separate operating revenue account or sub-account the revenues it receives from Local Point-to-Point Transmission Service when making Third-Party Sales.

5.2 Study Costs and Revenues: Include in a separate transmission operating expense account or sub-account, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies that VTransco conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales, and include in a separate operating revenue account or sub-account the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under this Schedule 21.

6 Regulatory Filings

Nothing contained in the Tariff or any exhibit, appendix, schedule, attachment or Service Agreement related thereto shall be construed as affecting in any way the right of VTransco unilaterally to file with the Commission, or make application to the Commission for changes in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation with respect to this Schedule 21-VTransco under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder, or any other applicable statutes or regulations. Nothing contained in the Tariff or any exhibit, appendix, schedule, attachment or Service Agreement related hereto shall be construed as affecting in any way the ability of VTransco or any Transmission Customer receiving service under the Tariff to exercise any right under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

7 Force Majeure and Indemnification

7.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither VTransco nor the Transmission Customer will be considered in default as to any obligation under this Schedule 21 if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Schedule 21 is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Schedule 21.

7.2 Indemnification: The Transmission Customer shall at all times indemnify, defend, and save VTransco harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from VTransco's performance of its obligations under this Schedule 21 on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by VTransco.

8 Creditworthiness

VTransco's Creditworthiness Policy is provided in Attachment L of this Schedule 21-VTransco.

9 Dispute Resolution Procedures

9.1 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer and VTransco involving service under this Schedule 21 (excluding disputes arising from filings or rate changes or other changes to this Schedule 21-VTransco, or to any Service Agreement entered into under this Schedule 21-VTransco, which disputes shall be presented directly to the Commission forresolution) shall be referred to a designated senior representative of VTransco and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days (or such other period as the Parties may agree upon), such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below if the Parties in dispute agree to the use of such procedures.

9.2 External Arbitration Procedures: Any arbitration initiated under this Schedule 21-VTransco shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration Panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or ISO rules.

9.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Schedule 21 and any Service Agreement relevant to the dispute entered into under this Schedule 21 and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

9.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(A) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(B) one half the cost of the single arbitrator jointly chosen by the Parties.

9.5 Rights Under The Federal Power Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

10 Real Power Losses

Real Power Losses are associated with all transmission service. VTransco is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service provided over VTransco's Transmission System under this Schedule 21 as calculated by VTransco. The applicable Real Power Loss factor is 3.9 percent of the amount of energy to be transmitted.

11 Stranded Cost Recovery

VTransco may seek to recover stranded costs from the Transmission Customer pursuant to this Schedule 21 in accordance with the terms, conditions and procedures set forth in FERC Order Nos. 888 and 888-A. However, VTransco must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

II. LOCAL POINT-TO-POINT TRANSMISSION SERVICE

Preamble

VTransco will provide Firm and Non-Firm Local Point-To-Point Transmission Service over VTransco's Transmission System pursuant to the applicable terms and conditions of this Schedule 21. Local Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

12 Classification of Firm Transmission Service

The Transmission Customer will be billed for its Local Reserved Capacity under the terms of Schedule 7 of this Schedule 21-VTransco. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in this Schedule 21-VTransco. VTransco shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by VTransco) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery.

13. Classification of Non-Firm Point-To-Point Transmission Service

The Transmission Customer will be billed for Non-Firm Local Point-To-Point Transmission Service pursuant to Schedule 8 of this Schedule 21-VTransco. VTransco shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third Party Sales by VTransco) exceeds its non-firm local capacity reservation. Non-Firm Local Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application.

14 Response to a Completed Application

Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, VTransco shall make a determination of available transfer capability consistent with Attachment A of this Schedule 21-VTransco. VTransco shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application. Responses by VTransco must be made as soon as practicable to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

15 Limitations on Assignment or Transfer of Service

If an Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, VTransco will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of VTransco's Transmission System or the generating or distribution facilities of other Vermont utilities.

16 Metering and Power Factor Correction at Receipt and Delivery Points(s)

16.1 Transmission Customer Obligations: Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under this Schedule 21 and to communicate the information to VTransco. Such equipment shall remain the property of the Transmission Customer.

16.2 Power Factor: Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as VTransco. The power factor requirements are specified in the Service Agreement where applicable.

17 Compensation for Transmission Service

Rates for Firm and Non-Firm Local Point-To-Point Transmission Service are provided in the Schedules appended to this Schedule 21-VTransco: Long-Term Firm and Shirt-Term Firm Local Point-To-Point Transmission Service (Schedule 7); and Non-Firm Local Point-To-Point Transmission Service (Schedule 8). VTransco shall use this Schedule 21 to make its Third-Party Sales. VTransco shall account for such use at the applicable rates described herein.

III. LOCAL NETWORK SERVICE

18 Secondary Service

The Local Network Customer may use VTransco's Transmission System to deliver energy to its Local Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Deliveries from resources other than Network Resources will have a higher priority than any Non Firm Local Point-To-Point Transmission Service under this Schedule 21-VTransco.

19 Network Resources

19.1 Transmission Arrangements for Network Resources Not Physically Interconnected With VTransco: The Local Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with VTransco's Transmission System. VTransco will undertake reasonable efforts to assist the Local Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

19.2 Limitation on Designation of Network Resources: The Local Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Local Network

Customer may establish that execution of a contract is contingent upon the availability of transmission service under this Schedule 21.

19.3 Use of Interface Capacity by the Network Customer: With the exception of any of interfaces with other transmission systems that are designated as constrained interfaces under VTransco's FERC Rate Schedule No. 1, as supplemented, there is no limitation upon a Local Network Customer's use of VTransco's Transmission System at any particular interface to integrate the Local Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, a Local Network Customer's use of VTransco's total interface capacity with other transmission systems may not exceed the Local Network Customer's Load.

19.4 Network Customer Owned Transmission Facilities: The Local Network Customer that owns existing transmission facilities that are integrated with VTransco's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Local Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of VTransco to serve its power and transmission customers. For facilities constructed by the Local Network Customer subsequent to the Service Commencement Date, the Local Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with VTransco. Calculation of the credit shall be addressed in either the Local Network Customer's Service Agreement or any other agreement between the Parties.

20 Local Network Load Not Physically Interconnected with VTransco

This section applies to both the initial designation and the subsequent addition of new Local Network Load not physically interconnected with VTransco. To the extent that the Local Network Customer desires to obtain transmission service for a load not connected to VTransco's Transmission System, the Local Network Customer shall have the option of (1) electing to include the entire load as Local Network Load for all purposes under this Schedule 21 and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Transmission Service under this Schedule 21. To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

21 Load Shedding and Curtailment

21.1 Procedures: Prior to the Service Commencement Date, VTransco and the Local Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Local Network Operating Agreement with the objective of responding to contingencies on VTransco's Transmission System. The Parties will implement such programs during any period when the ISO or VTransco determines that a system contingency exists and such procedures are necessary to alleviate such contingency. If not otherwise notified by the ISO, VTransco will notify all affected Local Network Customers in a timely manner of any scheduled Curtailment.

21.2 Transmission Constraints: During any period when VTransco determines that a transmission constraint exists on VTransco's Transmission System, or that the ISO determines that a transmission constraint exists on the New England Transmission System, and such constraint may impair the reliability of VTransco's Transmission System, VTransco will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of VTransco's Transmission System. To the extent VTransco determines that the reliability of VTransco's Transmission System can be maintained by redispatching resources, VTransco will work with the ISO to initiate procedures pursuant to the Local Network Operating Agreement to redispatch all Network Resources and VTransco's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between VTransco's use of VTransco's Transmission System on behalf of its Native Load Customers and any Network Customer's use of VTransco's Transmission System to serve its designated Local Network Load.

21.3 Cost Responsibility for Relieving Transmission Constraints: Whenever VTransco implements least-cost redispatch procedures in response to a transmission constraint, VTransco and Local Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

21.4 Curtailments of Scheduled Deliveries: If a transmission constraint on VTransco's Transmission System or the New England Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and VTransco determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Local Network Operating Agreement.

21.5 Allocation of Curtailments: Working with the ISO, VTransco shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by VTransco and Local Network Customer in proportion to their respective Load Ratio Shares. VTransco shall not direct the Local Network Customer to Curtail schedules to an extent greater than VTransco would Curtail its own schedules under similar circumstances.

21.6 Load Shedding: To the extent that a system contingency exists on VTransco's Transmission System or the New England Transmission System and VTransco or the ISO determines that it is necessary for VTransco and the Local Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Local Network Operating Agreement.

21.7 System Reliability: Notwithstanding any other provisions of the Tariff, VTransco reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Local Network Service without liability on VTransco's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Local Network Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on VTransco's Transmission System or on any other system(s) directly or indirectly interconnected with VTransco's Transmission System, VTransco, consistent with Good Utility Practice, also may Curtail Local Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. VTransco will give the Local Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to VTransco's use of VTransco's Transmission System on behalf of its Native Load Customers. VTransco shall specify the rate treatment and all related terms and conditions applicable in the event that the Local Network Customer fails to respond to established Load Shedding and Curtailment procedures.

22 Rates and Charges

The Local Network Customer shall pay VTransco for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, as otherwise described in this Schedule 21 and consistent with Commission policy, and also the following:

22.1 Monthly Demand Charge: The Local Network Customer shall pay a monthly Demand Charge, which shall be determined each month by multiplying its Load Ratio Share for that month times

VTransco's Transmission Revenue Requirement for that month as specified in Attachment D of this Schedule 21-VTransco.

22.2 Determination of Network Customer's Monthly Local Network Load: VTransco's monthly Local Network Load is its hourly load (including its designated Local Network Load not physically interconnected) coincident with VTransco's Monthly Transmission System Peak.

22.3 Determination of VTransco's Monthly Transmission System Load: VTransco's monthly transmission system load is VTransco's Monthly Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Transmission Service customers pursuant to this Schedule 21-VTransco plus the Local Reserved Capacity of all Firm Local Point-To-Point Transmission Service customers.

22.4 Redispatch Charge: The Local Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Local Network Customer and VTransco. To the extent that VTransco incurs an obligation to the Local Network Customer for redispatch costs, such amounts shall be credited against the Local Network Customer's bill for the applicable month.

23 Operating Arrangements

23.1 Operation under The Network Operating Agreement: The Local Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Local Network Operating Agreement.

23.2 Network Operating Agreement: The terms and conditions under which the Local Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of this Schedule 21 shall be specified in the Local Network Operating Agreement. The Local Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Local Network Customer within VTransco's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between VTransco and the Local Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside VTransco's Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of this Schedule 21, including scheduling protocols. The Local Network Operating Agreement will recognize that the Local Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with VTransco for Ancillary Service No. 1 , and with the ISO for Ancillary Service Nos. 2 through 7, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and NPCC requirements. VTransco shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Local Network Operating Agreement is included in Attachment C.

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided by VTransco making arrangements with the ISO to perform this service for VTransco's Transmission System. The Transmission Customer must purchase this service from VTransco. To the extent the ISO performs this service for VTransco; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to VTransco by the ISO. The Load Dispatching Revenue Requirement, as defined in this Schedule 1, will reflect VTransco's costs for its Load Dispatching. No subtransmission or distribution costs may be included in the Load Dispatching Revenue Requirement. The Load Dispatching Revenue Requirement will be a monthly calculation based on actual costs for the month subject to corrective adjustments after rendition. The calculation is set forth below:

The Load Dispatching Revenue Requirement shall equal the sum of Vermont Electric's (A) Load Dispatching Cost, plus or minus (B) Billing Adjustment.

A. Load Dispatching Cost shall equal VTransco's total load dispatching expense as recorded in FERC Account No. 561.

B. Billing Adjustment shall equal the difference in the actual cost of Load Dispatching for the two months.

SCHEDULE 2

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SCHEDULE 7

Long-Term Firm and Short-Term Firm

Local Point-To-Point Transmission Service

The Transmission Customer shall compensate VTransco each month for Local Reserved Capacity at the sum of the applicable charges set forth below:

1) **Yearly delivery charge:** the same charge as for monthly delivery per MW of Local Reserved Capacity per month.

2) **Monthly delivery charge:** the revenue requirement for that month divided by the coincident peak demand for that month per MW of Local Reserved Capacity per month.

3) **Weekly delivery charge:** the charge for monthly delivery multiplied by twelve (12) and divided by fifty-two (52) per MW of Local Reserved Capacity per week.

4) **Daily delivery charge:** the charge for weekly delivery divided by five (5) per MW of Local Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in megawatts of Local Reserved Capacity in any day during such week.

5) **Discounts:** Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by VTransco must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate' use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, VTransco must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on VTransco's Transmission System.

6) **Resales:** The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

SCHEDULE 8

Non-Firm Local Point-To-Point Transmission Service

The Transmission Customer shall compensate VTransco for Non-Firm Local Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

1) **Monthly delivery charge:** the revenue requirement for that month divided by the coincident peak demand for that month per MW of Local Reserved Capacity per month.

2) **Weekly delivery charge:** the charge for monthly delivery multiplied by twelve (12) and divided by fifty-two (52) per MW of Local Reserved Capacity per week.

3) **Daily delivery charge:** the charge for weekly delivery divided by five (5) per MW of Local Reserved Capacity per day. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in megawatts of Reserved Capacity in any day during such week.

4) **Hourly delivery charge:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the charge for daily delivery divided by sixteen (16) per MWH. The total demand charge in any day, pursuant to a reservation for hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in megawatts of Local Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for hourly delivery, shall not exceed the rate specified in section (2) above times the highest amount in megawatts of Local Reserved Capacity in any hour during such week.

5) **Discounts:** Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by VTransco must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, VTransco must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on VTransco's Transmission System.

6) **Resales:** The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

ATTACHMENT A

Available Transfer Capability Methodology

<u>Introduction and Background</u>:

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types.

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

Pursuant to CFR § 37.6(b)[18] of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path.

Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted.

VTransco does not currently have a Posted Paths based on the above definition. However to extent that VTransco does in the future have a Posted Path VTransco will calculate TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

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18 §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

Basic information on ATC and TTC may be found on VT Transco's website at:
http://www.vermonttransco.com/ATCTTC/Pages/default.aspx .

Capacity Benefit Margin (CBM):

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of ATC calculation, As long as this market design is in place in New England, the CBM is set to zero (0). VTransco provides local transmission service over its non-PTF facilities that are connected to ISO-NE and the Vermont distribution utilities. VTransco does not reserve CBM for these paths, and the CBM is presently set to zero.

Existing Transmission Commitments, Firm (ETC_F):

The ETC_F are those confirmed Firm transmission reservation (PTP_F.) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF}):

The (ETC_{NF}**)** are those confirmed Non-Firm transmission reservations (PTP_{NF}) There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

Transmission Reliability Margin (TRM):

The Transmission Reliability Margin (TRM) is the portion of the TTC that cannot be used for the reservation of firm transmission service because of uncertainties in system operation conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. Since VTRANSCO provides transmission service over its non-PTF facilities that are connected only to the internal New England system, VTRANSCO does not reserve TRM for these paths, and the TRM is presently set to zero.

<u>Calculation of ATC for VTransco's Local Facilities – General Description:</u>

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology defines the required items to be identified when describing a transmission provider's ATC methodology.

As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of net energy transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF facilities that serve as a path for the VTransco Schedule 21-Vermont Transco Point-to-Point Transmission Customers, VTransco has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

<u>Calculation of ATC_F in the Planning Horizon (PH):</u>

For purposes of this Attachment A PH is any period before the Operating Horizon. Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service over Schedule 21-Vermont Transco that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and counterflows$_{\mathbf{F}}$ of Schedule 21-Vermont Transco transmission reservations are not considered in the ATC calculation. Therefore, ATC$_{\mathbf{F}}$ in the PH is equal to the TTC minus ETC$_{\mathbf{F}}$

Calculation of ATC$_{\mathbf{F}}$ in the Schedule 21-Vermont Transco Operating Horizon (OH):

For purposes of this Attachment A OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. At that time progresses the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC$_{\mathbf{F}}$ is the capability for Firm transmission reservations that remain after allowing for ETC$_{\mathbf{F}}$, CBM, TRM, Postbacks$_F$ and counterflows$_{\mathbf{F}}$**.**

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service over Schedule 21-Vermont Transco is the only firm service offered in the Operating Horizon (OH). Postbacks$_F$ and counterflows$_F$ of Schedule 21-Vermont Transco transmission reservations are not considered in the ATC$_F$ calculation. Therefore, ATC$_F$ in the OH is equal to the TTC minus ETC$_F$.

Because Firm Schedule 21-Vermont Transco transmission service is not offered in the Scheduling Horizon (SH): ATC$_{\mathbf{F}}$ in the SH is zero.

Calculation of ATC$_{\mathbf{NF}}$ in the PH:

ATC$_{NF}$ is the capability for Non-Firm transmission reservations that remain after allowing for ETC$_F$, ETC$_{NF}$, scheduled CBM (CBM$_S$), unreleased TRM (TRM$_U$), Non-Firm Postbacks (Postbacks$_{NF}$) and Non-Firm counterflows (counterflows$_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-Vermont Transco are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM$_U$, Postbacks$_{NF}$ and counterflows$_{NF}$ of Schedule 21-Vermont Transco transmission reservations are not considered in this calculation. Therefore, ATC$_{NF}$ in the PH is equal to the TTC minus ETC$_F$ and ETC$_{NF}$.

Calculation of ATC$_{\mathbf{NF}}$ in the OH:

ATC$_{NF}$ available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-Vermont Transco are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus $ETC_{F,}$ plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$)

Negative ATC:

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

For those non-PTF Vermont Transco facilities that are primarily radial paths that provide transmission service to directly interconnected generators it is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

Posting of ATC Related Information - ATC Values:

As described above, the ATC values for VTransco's non-PTF utilized for internal Point-to-Point transmission service are always positive, and are thus set at 9999. The ATC values for these internal posted paths are posted in accordance with NAESB standards on VTransco's provider page of the ISO-NE OASIS website Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

Updates To ATC:

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

Coordination of ATC Calculations:

Schedule 21-Vermont Transco non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

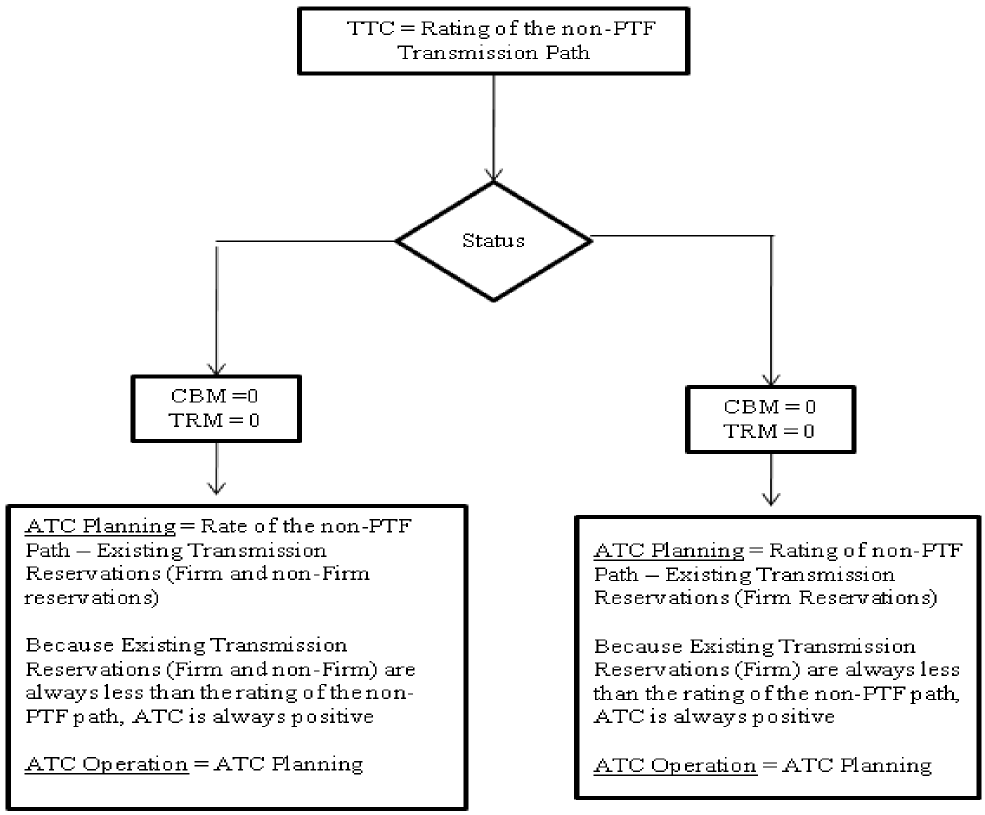
Mathematical Algorithms:

A link to the actual mathematical algorithm for the calculation of ATC for VTransco's non-PTF internal interfaces is located on VTransco's website at

http://www.vermonttransco.com/ATCTTC/Pages/default.aspx

Non-PTF Transmission Path ATC Process Flow Diagram

The process flow diagram illustrates the steps through which ATC is calculated both on an operating and planning horizon.



ATTACHMENT B

Methodology for Completing a System Impact Study

VTransco (or its designated agent) or the ISO may require System Impact Studies for the purpose of determining the feasibility of providing Long Term Firm Local Point-To-Point Transmission Service, integrating Network Resources or integrating Local Network Load for Transmission Customers (or Local Network Customers) under Schedule 21 of the Tariff. All System Impact Studies performed by VTransco will be completed using the same method employed by VTransco to provide firm transmission service to Purchasers under VTransco's FERC Rate Schedule No. 1, as supplemented. Specifically, System Impact Studies will be performed by applying NPCC Criteria and the "Reliability Standards of the New England Power Pool" while assuring that those loads fully dependent on VTransco's Transmission System that are receiving firm transmission service can be served reliably in accordance with VTransco's applicable reliability standards. The criteria, standards and guidelines referenced above are included as part of VTransco's annual FERC Form 715 filing.

ATTACHMENT C

Local Network Operating Agreement

This Local Network Operating Agreement is made this _____day of ____________, 20__, by and between Vermont Transco LLC. ("VTransco"), and ____________________________ ("Local Network Customer").

WHEREAS, VTransco has determined that the Local Network Customer has made a valid request for Local Network Service in accordance with Schedule 21 of the Tariff; and

WHEREAS, the Local Network Customer has represented that it is an Eligible Customer qualified to take service under the Tariff,

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, the Parties hereto agree as follows:

1. General Terms and Conditions

This Local Network Operating Agreement is an implementing agreement for Local Network Service under VTransco's Tariff and is subject to the Tariff, as the Tariff is in effect at the time this Agreement is executed or as the Tariff thereafter may be amended. The Tariff as it currently exists or is hereafter amended is incorporated herein by reference. In the case of any conflict between this Local Network Operating Agreement and the Tariff, the Local Network Operating Agreement shall control.

VTransco agrees to provide transmission service to the Local Network Customer's equipment or facilities, subject to the Local Network Customer operating its facilities in accordance with applicable criteria, rules, standards, procedures, or guidelines of VTransco, its Affiliates, the ISO, and the Northeast Power Coordinating Council ("NPCC"), as they may be adopted and/or amended from time to time. In addition to those requirements, service to the Local Network Customer's equipment or facilities is provided subject to the following specified terms and conditions.

a. Electrical Supply: The electrical supply to the Point(s) of Delivery shall be in the form of three-phase sixty hertz alternating current at a voltage class determined by mutual agreement of the parties.

b. Coordination of Operations: VTransco shall consult with the Local Network Customer regarding timing of scheduled maintenance of VTransco's Transmission System. In the event of a curtailment of service or the implementation of load shedding procedures, VTransco shall use due diligence to resume delivery of electric power as quickly as possible.

2. Reporting Obligations

a. The Local Network Customer shall be responsible for providing all information required by the ISO and NPCC and by VTransco's dispatching functions. The Local Network Customer shall respond promptly and completely to VTransco's requests for information, including but not limited to data necessary for operations, maintenance, regulatory requirements and analysis. In particular, that information may include:

i. For Local Network Loads: 10-year annual peak load forecast; load power factor performance; load shedding capability; under frequency load shedding capability; disturbance/interruption reports; protection system setting conformance; system testing and maintenance conformance; planned changes to protection systems; metering testing and maintenance conformance; planned changes in transformation capability; conformance to harmonic and voltage fluctuation limits; dead station tripping conformance; and voltage reduction capability conformance.

ii. For Network Resources and interconnected generators: 10 year forecast of generation capacity retirements and additions; generator reactive capability verification; generator under frequency relaying conformance; protection system testing and maintenance conformance; planned changes to protection system; and planned changes to generation parameters.

b. The Local Network Customer shall supply accurate and reliable information to VTransco regarding metered values for MW, MVAR, volt, amp, frequency, breaker status indication, and all other information deemed necessary by VTransco for safe and reliable operation. Information shall be gathered for electronic communication using one or more of the following: supervisory control and data acquisition ("SCADA"), remote terminal unit ("RTU") equipment, and remote access pulse recorders ("RAPR"). All equipment used for metering, SCADA, RTU, RAPR, and communications must be approved by VTransco.

3. Operational Obligations

The Local Network Customer shall request permission from VTransco prior to opening and/or closing circuit breakers in accordance with applicable switching and operating procedures. The Local Network Customer shall carry out all switching orders from VTransco, VTransco's Designated Agent, or the ISO in a timely manner.

a. The Local Network Customer shall balance the load at the Point(s) of Delivery such that the differences in the individual phase currents are acceptable to VTransco.

b. The Local Network Customer's equipment shall conform with harmonic distortion and voltage fluctuation standards of VTransco.

c. The Local Network Customer's equipment must comply with all environmental requirements to the extent they impact the operation of VTransco's system.

d. The Local Network Customer shall operate all of its equipment and facilities connected to VTransco's system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, and requirements of VTransco, the ISO, NPCC, the National Electric Safety Code and the National Electric Code.

e. The Local Network Customer is responsible for supplying voltage regulation equipment on its subtransmission and distribution facilities.

4. <u>Notice of Transmission Service Interruptions</u>

If at any time, in the reasonable exercise of VTransco's judgment, operation of the Local Network Customer's equipment adversely affects the quality of service or interferes with the safe and reliable operation of the system, VTransco may discontinue transmission service until the condition has been corrected. Unless VTransco perceives that an emergency exists or the risk of an emergency is imminent, VTransco shall give the Local Network Customer reasonable notice of its intention to discontinue transmission service and, where practical, allow suitable time for the Local Network Customer to remove the interfering condition. VTransco's judgment with regard to the discontinuance of service under this paragraph shall be made in accordance with Good Utility Practice. In the case of such discontinuance, VTransco shall immediately confer with the Local Network Customer regarding the conditions causing such discontinuance and its recommendation concerning timely correction thereof.

5. <u>Access and Control</u>

Properly accredited representatives of VTransco shall at all reasonable times have access to the Local Network Customer's facilities to make reasonable inspections and obtain information required in connection with Schedule 21 of the Tariff. Such representatives shall make themselves known to the Local Network Customer's personnel, state the object of their visit, and conduct themselves in a manner that shall not interfere with the construction or operation of the Local Network Customer's facilities. VTransco shall have control such that it may open or close the circuit breaker or disconnect and place safety grounds at the Point(s) of Delivery, or at the station, if the Point(s) of Delivery is remote from the station.

6. Point(s) of Delivery

Local Network Service shall be provided by VTransco to the Point(s) of Delivery as specified by the Local Network Customer in accordance with the Tariff.

7. Maintenance of Equipment

a. Unless otherwise agreed, VTransco shall own all metering equipment.

b. The Local Network Customer shall maintain all of its equipment and facilities connected to VTransco's system in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations and requirements of VTransco, the ISO and NPCC.

c. VTransco may request that the Local Network Customer test, calibrate, verify or validate the data link, metering, data acquisition, transmission, protective, or other equipment or software owned by the Local Network Customer, consistent with the Local Network Customer's routine obligation to maintain its equipment and facilities or for the purposes of investigating potential problems on the Local Network Customer's facilities. The Local Network Customer shall be responsible for the cost to test, calibrate, verify or validate the equipment or software.

d. The Transmissions Provider shall have the right to inspect the tests, calibrations, verifications and validations of the Local Network Customer's data link, metering, data acquisition, transmission, protective, or other equipment or other software connected to VTransco's system.

e. The Local Network Customer, at VTransco's request, shall supply VTransco with a copy of the installation, test, and calibration records of the data link, metering, data acquisition, transmission, protective or other equipment or software owned by the Local Network Customer and connected to VTransco's system.

f. VTransco shall have the right, at the Local Network Customer's expense, to monitor the factory acceptance test, the field acceptance test, and the installation of any metering, data acquisition, transmission, protective or other equipment or software owned by the Local Network Customer and connected to VTransco's system.

8. Emergency System Operations

a. The Local Network Customer's equipment and facilities, etc. shall be subject to all applicable emergency operation standards required of and by VTransco to operate in an interconnected transmission network.

b. VTransco reserves the right to take whatever actions or inactions it deems necessary during emergency operating conditions to: (i) preserve the integrity of VTransco's Transmission System, (ii) limit or prevent damage, (iii) expedite restoration of service, or (iv) preserve public safety.

9. Cost Responsibility

The Local Network Customer shall be responsible for all costs incurred by VTransco relative to the Local Network Customer's facilities. Appropriate costs may be allocated to more than one Local Network Customer, in a manner within the reasonable discretion of VTransco.

10. Additional Operational Obligations of Local Network Customer

a. Voltage or Reactive Control Requirements:

i. Unless directed otherwise by VTransco, the Local Network Customer shall ensure that all generating facilities designated as Network Resources are operated with an automatic voltage regulator(s). The Local Network Customer shall ensure that the voltage regulator(s) control voltage at the Point(s) of Receipt consistent with the range of voltage scheduled by VTransco, VTransco's agent or the ISO.

ii. At the discretion of VTransco, VTransco's Designated Agent or the ISO, the Local Network Customer may be directed to deactivate the automatic voltage regulator and to supply reactive power in accordance with a schedule which shall be provided by VTransco , VTransco's Designated Agent or the ISO, and in such event the Local Network Customer shall act in accordance with such direction.

iii. If the Local Network Customer does not have sufficient installed capacity in generating facilities designated as Network Resources to enable the Local Network Customer to operate such facilities consistent with recommendations of VTransco, or if Network Resources fail to operate at such capacity, VTransco or VTransco's Designated Agent may install, at the Local Network Customer's expense, reactive compensation equipment necessary to ensure the proper voltage or reactive supply at the Point(s) of Receipt.

b. <u>Station Service:</u> When generating facilities designated as Network Resources are producing electricity, the Local Network Customer shall supply its own station service power. If and when the Local Network Customer's generation facility is not producing electricity, the Local Network Customer shall obtain station service capacity and energy from the franchise utility providing service or other source.

c. <u>Protection Requirements:</u> Protection requirements are as defined elsewhere in this Tariff and applicable NPCC documents as may be adopted or amended from time to time.

d. <u>Operational Obligations:</u>

i. The ISO may require that generation facilities designated as Network Resources be equipped for Automatic Generation Control ("AGC"). The Local Network Customer shall be responsible for all costs associated with installing and maintaining an AGC system on applicable Network Resources.

ii. VTransco retains the right to require reduced generation at times when system conditions present transmission restrictions or otherwise adversely affect VTransco's other customers. VTransco shall use due diligence to resolve the problems to allow the generator to return to the operating level prior to VTransco's notice to reduce generation.

iii. All operations (including start-up, shutdown and determination of hourly generation) shall be coordinated with the ISO, VTransco or VTransco's Designated Agent.

e. Coordination of Operations:

i. The Local Network Customer shall furnish VTransco with generator annual maintenance schedules for all Network Resources and shall advise VTransco if a Network Resource is capable of participation in system restoration and/or if it has black start capability.

ii. VTransco reserves the right to specify turbine and/or generator control (e.g., droop) settings as determined by the System Impact or Facilities Study or subsequent studies. The Local Network Customer agrees to comply with such specifications by VTransco at the Local Network Customer's expense.

iii. If the generator is not dispatchable by the ISO, the Local Network Customer shall notify VTransco at least 48 hours in advance of its intent to take its resource temporarily off-line and its intent to resume generation. In circumstances such as forced outages, the Local Network Customer shall notify VTransco as promptly as possible of the Network Resource's temporary interruption of generation and/or transmission.

f. Power Factor Requirement: The Local Network Customer agrees to maintain an overall Load Power Factor and reactive power supply within predefined sub-areas as measured at the Point(s) of Delivery within ranges specified by VTransco or ISO criteria, rules and standards which identify the power factor levels that must be maintained throughout the applicable sub-area for each anticipated level of total ISO load. The Local Network Customer agrees to maintain Load Power Factor and reactive power requirements within the range specified by VTransco or the ISO, as appropriate for the sub-area based on total ISO load during that hour. The ISO may revise the power factor limits required from time to time. If the Local Network Customer lacks the capability to maintain the Load Power Factor within the ranges specified, VTransco may install, at the Local Network Customer's expense, reactive compensation equipment necessary to ensure proper load power factor at the Point(s) of Delivery.

g. Protection Requirement: The Local Network Customer's relay and protection systems must comply with all applicable VTransco, ISO and NPCC criteria, rules, procedures, guidelines, standards or requirements as may be adopted or amended from time to time.

h. Operational Obligation: The Local Network Customer shall be responsible for operating and maintaining security of its electric system in a manner that avoids adverse impact to VTransco's or other's interconnected systems and complies with all applicable VTransco , ISO and NPCC operating criteria, rules, procedures, guidelines and interconnection standards as may be amended or adopted from time to time. These actions include, but are not limited to: Voltage Reduction Load Shedding; Under Frequency Load Shedding, Block Load Shedding; Dead Station Tripping; Transferring Load Between Point(s) of Delivery; Implementing Voluntary Load Reductions Including Interruptible Customers; Starting Stand-by Generation; Permitting VTransco Controlled Service Restoration Following Supply Delivery Contingencies on VTransco Facilities.

11. Failure to perform

If the Local Network Customer fails to carry out its obligations under this Agreement, the matter shall be subject to the dispute resolution procedures of the Tariff.

The Parties whose authorizing signatures appear below warrant that they shall abide by the foregoing terms and conditions.

VERMONT TRANSCO LLC

By:

Title:

Dated:____________________

(Name of Local Network Customer)

By:

Title:

Dated:__________________

ATTACHMENT D

Transmission Revenue Requirement

For Local Network Integration Transmission Service

VTransco owns and operates transmission facilities which are used to provide transmission service only. VTransco does not own or operate any generation or distribution facilities. VTransco only incurs transmission-related costs. Accordingly, there is no need to allocate a transmission-related portion of what otherwise would be considered a general expense. For the same reason, there is no need to refer to specific costs in the formula as "transmission-related."

The Transmission Revenue Requirement calculated below reflects all costs that VTransco incurs in connection with VTransco's Transmission System. Generation and distribution costs are not included in the Transmission Revenue Requirement. The Transmission Revenue Requirement for a particular month will be based on the most recent monthly data available at that time (which typically will be data from two months earlier). To the extent the charges for a particular month result in an over-recovery or under-recovery of VTransco's actual costs, an adjustment will be made to VTransco's Transmission Revenue Requirement as soon as possible (typically two months later when the specific data regarding the over- or under-recovery becomes available).

The calculation is set forth below:

The Transmission Revenue Requirement shall equal the sum of VTransco's: (A) Return and Income Taxes, (B) Depreciation Expense, (C) Amortization of Loss on Reacquired Debt, (D) Municipal Tax Expense, (E) Payroll Tax Expense, (F) Operation and Maintenance Expense, (G) Administrative and General Expense, minus (H) Support Revenue, plus (I) Support Expense, minus (J) Short-Term Transmission Service and (K) Rents received from Electric property and (L) Revenue received from the ISO, plus or minus (M) Billing Adjustment.

Definitions

A. Return and Income Taxes shall equal the sum of VTransco's Rate of Return, Cost of Capital, and Income Taxes.

1. Rate of Return shall equal on an annual basis: ~~10.57~~11.14 percent of the par value of VTransco's outstanding Class A membership units, all as shown by VTransco's books as of the beginning of such month. The above rates shall not change from month to month, but may be modified in a proceeding initiated pursuant to the Federal Power Act.

2. Cost of Capital shall equal all fixed charges, including interest and amortization of debt discount and expense and premium on debt as recorded in FERC Account Nos. 419,427,428,431,432.

3. Income Taxes shall equal VTransco's income taxes including taxes on or measured by income as recorded in FERC Account Nos. 409-411.

B. Depreciation Expense shall equal VTransco's Depreciation Expense for Transmission Plant and General Plant as recorded in FERC Account Nos. 403 and 404.

C. Amortization of Loss on Reacquired Debt shall equal VTransco's Amortization of the balance on Loss on Reacquired Debt as recorded in FERC Account No. 428.1.

D. Municipal Tax Expense shall equal VTransco's total municipal tax expense as recorded in FERC Account No. 408.1.

E. Payroll Tax Expense shall equal VTransco's total electric payroll tax expense as recorded in FERC Account No. 408.1.

F. Operation and Maintenance Expense shall equal VTransco's expenses as recorded in FERC Account Nos. 560, 562-564 and 566-573 and shall exclude any Transmission Support Expense recorded in FERC Account No. 567.

G. Administrative and General Expense shall equal VTransco's expenses as recorded in FERC Account Nos. 920-935.

H. Transmission Support Revenues shall equal VTransco's revenue received for Transmission Support.

I. Transmission Support Expenses shall equal VTransco's expenses as recorded in FERC Account No. 567.

J. Short-Term Transmission Service shall equal any revenues received from transmission customers as payment for short-term point-to-point transmission service taken pursuant to Schedule 7 of this Schedule 21-VTransco.

K. Rents received from Electric property shall equal VTransco's rents received for the use by others of land, buildings, and other property devoted to electric operations as recorded in FERC Account No. 454.

L. Revenue Received from the ISO shall equal revenue received under the terms of the Tariff minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission.

M. Billing Adjustment shall equal the difference in the actual cost of transmission for the two month previous minus the Revenue Received for two months previous. In the event that the FERC accounts listed above are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts

Appendix A

PTF and non PTF Depreciation and General Plant Amortization Rates

Account	Description	Depreciation Rates (%) Effective July 1, 2017
Transmission Plant		
352.00	Structures and Improvements	2.35
353.00	Station Equipment	2.57
354.00	Towers and Fixtures	3.77
355.00	Poles and Fixtures	2.48
356.00	Overhead Conductors and Devices	1.71
357.00	Underground Conduit	2.51
357.00	Underground Conductors and Devices	2.67
359.00	Roads and Trails	1.27
General Plant		
390.00	Structures and Improvements	2.84
392.00	Transportation Equipment	5.79
397.00	Communication Equipment	4.69
General Plant Amortization		
391.00	Office Furniture and Equip (Pre 2013 Assets)	13.19
391.00	Office Furniture and Equip (Post 2012 Assets)	12.50
391.10	Computer Equipment (Pre 2013 Assets)	17.08
391.10	Computer Equipment (Post 2012 Assets)	20.00
391.20	Software (Pre 2013 Assets)	4.06
391.20	Software (2013-2015 Assets)	6.42
391.20	Software (Post 2015 Assets)	6.67
393.00	Stores Equipment (Pre 2013 Assets)	3.07
393.00	Stores Esquipment (Post 2012 Assets)	2.86
394.00	Tools, Shops and Garage Equipment	2.48

	(Pre 2013 Assets)	
394.00	Tools, Shops and Garage Equipment (Post 2012 Assets)	2.78
395.00	Laboratory Equipment (Pre 2013 Assets)	4.00
395.00	Laborabory Equipment (Post 2012 Assets)	4.00
398.00	Miscellaneous Equipment (Pre 2013)	30.11
398.00	Miscellaneous Equipment (Post 2012)	9.09

ATTACHMENT L

Creditworthiness Procedures

I. Overview

This provision is applicable to any Transmission Customer taking transmission or interconnection service (referred to as "Service" or "Services") under ISO New England Inc., ISO New England Inc. Transmission, Markets and Services Tariff, Section II—Open Access Transmission Tariff Schedule 21-VTransco (the "Tariff"). The creditworthiness of each Transmission Customer must be established before receiving Service from VTransco. A credit review shall be conducted for each Transmission Customer not less than annually or upon reasonable request by the Transmission Customer. VTransco shall make this credit review in accordance with procedures based on specific quantitative and qualitative criteria to determine the level of secured and unsecured credit required from the Transmission Customer. A summary of VTransco's Creditworthiness Requirements are described in this Attachment L, and posted on its website at http://www.velco.com/Files/about%20velco/Creditworthiness.pdf.

Upon receipt of a customer's information, VTransco will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a customer under this Policy, VTransco will forward a written evaluation if the customer is required to provide Financial Assurance.

II. Financial Information:

A) Transmission Customers requesting Service may be required to submit, if available, the following information:

1) All current credit rating reports from commercially accepted credit rating agencies including Standard and Poor's, Moody's Investors Service, and Fitch Ratings, and

2) Audited financial statements by a registered independent auditor for the two most recent years, or the period of its existence, if shorter than two years.

III. Quantitative and Qualitative Standards for Creditworthiness Determination:

A) Transmission Customers, rated and un-rated, will be required to meet specific quantitative creditworthiness requirements, as detailed below:

1) To qualify for unsecured credit, the Transmission Customer must meet at least one of the following criteria:

(i) the Transmission Customer must not be in default of any payment obligation under the Tariff; and

(ii) if rated, the Transmission Customer must meet one of the following criteria:

(a) the Transmission Customer has been in business at least one year and has a senior secured credit rating of at least Baa1 (Moody's) or BBB+ (Standard & Poors); or

(b) The Transmission Customer's parent company meets the criteria set out in (a) above, and the parent company provides a written guarantee that the parent company will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of Service.

(iii) if unrated or if rated below the BBB+/Baa1, as stated in (ii), the Transmission Customer must meet all of the following for the last 4 quarters, or the last 2 years if quarterly information is not available:

(a) A Current Ratio of at least 2.0 times (current assets divided by all current liabilities);

(b) A Total Capitalization Ratio of less than 55% debt, defined as total debt (including all capitalized leases and all short-term borrowings) divided by the sum of total shareholders' equity plus total debt;

(c) EBITDA-to-Fixed Charge Ratio of at least 3.0 times, defined as earnings before interest, taxes, depreciation and amortization divided by fixed charges (interest on debt as defined in Total Capitalization Ratio above plus preferred dividends on any outstanding preferred equity); and

(d) Unqualified audit opinions in audited financial statements provided; or

(e) The Transmission Customer's parent company meets the criteria set out in (a) through (d) above, and the parent company provides a written guarantee that the parent company will be unconditionally responsible for all financial obligations associated with the Transmission Customer's receipt of Service.

B) Qualitative Standards for Creditworthiness Determination:

In conjunction with the quantitative standards above, VTransco will consider qualitative standards when determining creditworthiness, such as:

1) Years in business: a company in business fewer than five years will be considered a greater risk.

2) Management's experience in the industry: a management team with an average of less than five year's experience will be considered a greater risk.

3) Market risk: consideration of pricing exposure, credit exposures, and operational exposures.

4) Litigation Risk: a pending legal action with potential monetary damages approaching 3% of gross revenues will be considered as significantly increasing company risk.

5) Regulatory Environment (State and Local): a company subject to significant exposure to regulatory decisions, such as key planning decisions, shall be considered as having increased risk.

6) Prior payment history with other Transmission Providers or other vendors: a company with an excellent payment history of greater than or equal to five years shall be considered a lesser risk.

IV. Financial Assurance:

A) If the Transmission Customer does not meet the Creditworthiness Requirements, then VT Transco may require the Transmission Customer to provide additional Financial Assurance by complying with one of the following:

1) for Service for one month or less, the Transmission Customer shall pay to VTransco or place in an escrow account that is accessible to VTransco the total charge for Service by the later of five business days prior to the commencement of Service or the time when it makes the request for Service; or

2) for Service of greater than one month, the Transmission Customer shall pay to VTransco or place in an escrow account that is accessible to VTransco the charge for each month's Service not less than five business days prior to the beginning of the month. For Network Integration Transmission Service Customers, the advance payment for each month shall be based on a reasonable estimate by VTransco of the charge for that month.

3) not less than five days prior to the commencement of Service, the Transmission Customer shall provide an unconditional and irrevocable Letter of Credit (as defined below) from a financial institution reasonably acceptable to VTransco or an alternative form of security proposed by the Transmission Customer and acceptable to VTransco and consistent with commercial practices established by the Uniform Commercial Code that is equal to the lesser of the total charge for Service or the charge for 90 days of service.

(i) "Letter of Credit" means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank provided that such Transmission Customer is not an affiliate of such bank, and provided that such bank has an issuer and/or corporate credit rating of at least A2 from Moody's or A from Standard and Poor's or Fitch Ratings. In the event of different ratings from the rating agencies, the lowest rating shall apply.

(ii) Costs of a Letter of Credit shall be borne by the customer.

(iii) If the credit rating of the bank issuing the Letter of Credit falls below the specified rating, the customer shall notify VTransco in writing within five business days of such event and shall have two business days following written notice to provide other appropriate Financial Assurance.

V. Credit Levels:

A) Transmission Customers meeting the Creditworthiness Requirements in Section III will be extended unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges.

B) Transmission Customers not meeting the Creditworthiness Requirements above in Sections III and IV may not receive unsecured credit from VTransco.

VI. Ongoing Financial Review:

Each Transmission Customer is required to submit to VTransco annually or when issued, as applicable:

A) Current rating agency report;

B) Audited financial statements from a registered independent auditor; and

C) 10-Ks and 8-Ks, promptly on their issuance.

VII. Contesting Creditworthiness Determination:

The Transmission Customer may contest VTransco's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. VTransco will review and respond to the request within 20 calendar days.

VIII. Procedures for Changes in Credit Levels and Collateral Requirements:

VTransco shall issue reasonable advance notice of changes to the credit levels and/or collateral requirements. A Transmission Customer may request that VTransco provide an explanation of the reasons for the change by contacting VTransco at:

Chief Financial Officer
366 Pinnacle Ridge Rd.
Rutland, VT 05701

The specific procedures for changes in credit levels and collateral requirements are as follows:

A) General Notification process

1) VTransco shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

2) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Policy.

3) VTransco shall consult with interested stakeholders upon request.

4) Following Commission acceptance of such filing and upon the effective date, VTransco shall revise its Attachment L Creditworthiness Policy and an updated version of Schedule 21-VTransco shall be posted the ISO-NE website.

B) Transmission Customer Responsibility

When there is a change in requirements, it is the responsibility of the Customer to forward updated financial information to VTransco and indicate whether the change affects the customer's ability to meet the requirements of the Creditworthiness Policy. In such cases where the customer's status has changed, the Customer must take the steps necessary to comply with the revised requirements of the Creditworthiness Policy by the effective date of the change.

C) Notification for Active Customers

1) "Active Customers" are defined as any current Transmission Customer that has reserved Service within the last 3 months.

2) All Active Customers will be notified via either e-mail or U.S. mail that the above posting has been made and must follow the steps outlined in the procedure.

IX. Posting Requirements

A) Changes in Customer's Financial Condition

Each customer must inform VTransco, in writing, within five (5) business days of any material change in its financial condition or the financial condition of a parent providing a guarantee. A material change in financial condition may include, but is not limited to, the following:

1) Change in ownership by way of a merger, acquisition, or substantial sale of assets;

2) A downgrade of long- or short-term debt rating by a major rating agency;

3) Being placed on a credit watch with negative implications by a major rating agency;

4) A bankruptcy filing;

5) A declaration of or acknowledgement of insolvency;

6) A report of a significant quarterly loss or decline in earnings;

7) The resignation of key officer(s);

8) The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results

B) Change in Creditworthiness Status:

A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in item IV if one or more of the following conditions apply:

1) The customer no longer meets the applicable criteria for Creditworthiness in item III;

2) The customer exceeds the amount of unsecured credit extended by VTransco, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or

3) The customer has missed two or more payments for any of the Services offered by VTransco in the last 12 months.

X. Suspension of Service:

VTransco may suspend service under this Schedule 21-VTransco to a Transmission Customer under the following circumstances;

A) If a Transmission Customer that qualifies for service as a result of providing a Letter of Credit or alternative form of security does not pay its bill within 20 days of receipt of the invoice as required by this Schedule 21-VTransco, and it has not complied with the billing dispute provisions of this Schedule 21-VTransco, VTransco may suspend service 30 days after notice to the Transmission Customer and the Commission that service will be suspended unless the Transmission Customer makes payment.

B) If a Transmission Customer that qualifies for service as a result of committing to prepay for service to or place the payment in an escrow account pursuant to Section IV A 1 or Section IV A 2 fails to prepay for service or place the amount in escrow as provided in such section, VTransco may suspend service immediately upon notice to the Transmission Customer and the Commission.

C) If a Transmission Customer to whom the provisions of Sections III through XI applies fails to meet any applicable requirements, VTransco may suspend service immediately upon notice to the Transmission Customer and the Commission. The suspension of service shall continue only for as long as the circumstances that entitle VTransco to suspend service continue. A Transmission Customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

ATTACHMENT F
ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF, including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of PTOs that are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF pursuant to Section II.49 of the Tariff, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO's costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12:

I. The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expense, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT and (O) Transmission Rents Received from Electric Property.

The details for implementation of Attachment F, as well as the definitions of the terms used in the Attachment F formula, shall be established in accordance with the Attachment F Implementation Rule contained in this OATT.

ATTACHMENT F
IMPLEMENTATION RULE

This rule sets forth details with respect to the determination each year of the Transmission Revenue Requirements for each PTO. Such Transmission Revenue Requirements shall reflect the PTO's costs for Pool Transmission Facilities ("PTF") and the Highgate Transmission Facilities ("HTF"), including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of PTOs which are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO's costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12. The HTF Transmission Revenue Requirements shall be subject to the limitations of inclusion of such costs as set forth in Appendix B to this Attachment. The owners of the HTF, or their designated agent, will submit the annual HTF Transmission Revenue Requirements calculation based on the previous calendar year's cost data from their FERC Form 1 or equivalent information from their official books and records, as appropriate.

The Post-96 Transmission Revenue Requirement for each PTO that is based on data for calendar year 2004 or later shall include an Incremental Return and Associated Income Taxes on the PTO's PTF transmission plant investments included in the Regional System Plan and placed in-service on or after January 1,2004 (such investments referred to herein as "Post-2003 PTF Investment"). The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment shall incorporate an incentive ROE adder of 100 basis points for plant investment placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157, et al. for any projects included in the RSP, and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments (however; the 125 basis point ROE incentive adder granted to NEEWS under Order No. 679 in Docket No. ER08-

1548 and the 50 basis point ROE incentive adder for RTO participation shall not apply to the costs related to the Central Connecticut Reliability Project, consistent with FERC's order) and for MPRP CWIP and NEEWS CWIP. ~~The total ROE for any project, including any authorized ROE incentives for Post-2003 PTF Investment and any other incentive ROE approved by FERC under Order No. 679 shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period.~~ The data used in determining each PTO's Incremental Return and Associated Taxes for Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in the PTO's accounting records.

The Post-1996 Pool PTF Rate, as calculated pursuant to Schedule 9, shall include for each PTO a Forecasted Transmission Revenue Requirement calculated in accordance with Appendix C to this Attachment F Implementation Rule. Additionally, the Pre-1997 and Post-1996 Pool PTF Rates shall include an Annual True-up calculated in accordance with Appendix C to this Attachment F Implementation Rule.

The PTOs shall make an annual informational filing on or before July 31 of each year showing the Pool PTF Rate in effect for the period beginning June 1 of that year through May 31 of the subsequent year.Further, the informational filing with respect to the determination of the Pool PTF Rate will include a breakdown by PTO of the amount of the change in PTF and HTF investment during the prior year and the PTF and HTF retirements or additions causing such change to beginning and end-of-year PTF balances and HTF balances (although beginning-of-year PTF balances and HTF balances are not used in the formula itself), and any additions to PTF and HTF, retirements of PTF and HTF, and reclassifications of PTF and HTF during the year for each PTO. If there are any corrections made to the information reflected in the informational filing after it has been submitted, the PTOs will file corrections to the informational filing. At least forty-five days before the informational filing is made with the Commission, the PTOs shall make available to Transmission Customers and any other interested parties a draft of the proposed filing for review and comment prior to the filing by posting such draft on the ISO website. The filing of the information filing does not re-open the formula rate set forth below for review, but rather is contestable only with respect to the accuracy of the information contained in the informational filing.

The ISO shall have the discretion to conduct audits of such charges, with advisory Stakeholder input on the scope of audit, including on any agreed-upon procedures to be used by the auditor. In this provision, the term "agreed-upon procedures" shall have the meaning afforded to it by the American Institute of Certified Public Accountants.

I. DEFINITIONS

Capitalized terms not otherwise defined in the Tariff and as used in this rule have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct wages and salaries including those of affiliated Companies to the PTO's total direct wages and salaries including those of the Affiliates' Companies and excluding administrative and general wages and salaries.

2. PTF/HTF Transmission Plant Allocation Factor shall equal the ratio of PTF/HTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF (Phase I/II HVDC-TF Leases).

3. Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, and Transmission Related Intangible and General Plant to Total Plant in service excluding Phase I/II HVDC-TF Leases.

B. TERMS

Administrative and General Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

Amortization of Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the PTO's credits as recorded in FERC Account No. 411.4.

<u>Depreciation Expense for Transmission Plant</u> shall equal the PTO's transmission expenses as recorded in FERC Account No. 403.

<u>General Plant</u> shall equal the PTO's gross plant balance as recorded in FERC Account Nos. 389-399.

<u>General Plant Depreciation and Amortization Expense</u> shall equal the PTO's general expenses as recorded in FERC Account No. 403 and NSTAR Electric's FERC Account No. 404 for items subject to amortization.

<u>General Plant Amortization Reserve</u> shall equal NSTAR Electric's general reserve balance as recorded in FERC Account No. 111.

<u>HTF Transmission Plant</u> shall equal the PTO's balance of investment in the Highgate Transmission Facilities as recorded in FERC Account Nos. 350-359.

<u>Intangible Plant</u> shall equal NSTAR Electric's gross plant balance as recorded in FERC Account No. 303. The only allowable Intangible Plant for inclusion are software, patent or rights costs.

<u>Intangible Plant Amortization Expense</u> shall equal NSTAR Electric's amortization expenses as recorded in FERC Account Nos. 404-405. The only allowable Intangible Plant Amortization Expense for inclusion is the amortization of software, patent or rights costs.

<u>Intangible Plant Amortization Reserve</u> shall equal NSTAR Electric's amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion is that related to the amortization of software, patent or rights costs.

<u>Maine Power Reliability Program Construction Work In Progress</u> ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107 for costs determined to be Pool- Supported PTF in accordance with Schedule 12 of this OATT.

Merger-Related Costs shall equal NSTAR Electric Company's ("NSTAR Electric"), CL&P's, Public Service Company of New Hampshire's ("PSNH") and WMECO's amortized merger-related costs as authorized by FERC or by state regulatory order.

New England East-West Solution Construction Work in Progress ("NEEWS CWIP") shall equal the NEEWS CWIP balances of The Connecticut Light and Power Company ("CL&P") and Western Massachusetts Electric Company ("WMECO") and New England Power Company ("NEP") as recorded in FERC Account No. 107 for costs determined to be Pool-Supported PTF in accordance with Schedule 12 of this OATT.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the PTO's FAS 106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the PTO's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the PTO's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in the PTO's FERC Account Nos. 408.1.

Phase I/II HVDC-TF Leases shall equal the PTO's balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

Plant Held for Future Use shall equal the PTO's balance in FERC Account No.105.

Prepayments shall equal the PTO's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the PTO's expenses as recorded in FERC Account No. 924.

PTF Transmission Plant shall equal the PTO's transmission plant as defined in the Section II.49 of the OATT and determined in accordance with Appendix A of this Rule, which is entitled "Rules for Determining Investment To be Included in PTF."

PTF/HTF Transmission Plant Investment shall equal the PTO's (a) PTF Transmission Plant plus (b) HTF Transmission Plant.

Total Accumulated Deferred Income Taxes shall equal the net of the PTO's deferred tax balance as recorded in FERC Account Nos. 281-283 and the PTO's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal the PTO's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal the PTO's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal the PTO's transmission reserve balance as recorded in FERC Account 108.

Transmission Merger-Related Costs shall equal NSTAR Electric's, CL&P's, PSNH's and WMECO's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564 and 566-573, and shall exclude all Phase I/II HVDC-TF expenses booked to accounts 560 through 573 and expenses already included in Transmission Support Expense, as described in Section K which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal the PTO's Gross Plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal the PTO's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP), (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Re lated Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT, (O) Transmission Rents Received from Electric Property and (P) Transmission Revenues from MEPCO Grandfathered Transmission Service Agreements. The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment for each PTO shall be calculated using the investment base components specifically identified in Section A. 1 of the formula below.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, Transmission Investment Base will only include Sections II.A. 1 .(a), (d), (e), (k), and (1) in the manner indicated.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of(a) PTF/HTF Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation and Amortization Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Transmission Related Loss on Re.acquired Debt, plus (g) Other Regulatory Assets/Liabilities, plus (h) Transmission Prepayments, plus (i) Transmission Materials and Supplies, plus (j) Transmission Related Cash Working Capital, plus (k) MPRP CWIP, plus (l) NEEWS CWIP.

(a) PTF Transmission Plant will equal the balance of the PTO's PTF Investment in (a) Transmission Plant plus (b) HTF Transmission Plant. This value excludes (i) the PTO's Phase I/II HVDC-TF Leases, (ii) the portion of any facilities, the cost of which is directly assigned under Schedule 11 to the OATT, to the Transmission Customer or a Generator Owner or Interconnection Requester, (iii) the Pre-1997 PTF gross plant investment associated with leased facilities occupied by the Phase II section of the Phase I/II HVDC-TF. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Post2003 PTF Transmission Plant shall be separately identified.

(b) Transmission Related Intangible and General Plant shall equal the sum of the PTO’s balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor and the PTF/HTF Transmission Plant Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the PTO’s balance of Transmission-related Plant Held for Future Use multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(d) Transmission Related Depreciation and Amortization Reserve shall equal the PTO’s balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve. Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve shall equal the product of the sum of Intangible Plant Amortization Reserve, General Plant Depreciation Reserve and General Plant Amortization Reserve, and the Transmission Wages and Salaries Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Depreciation Reserve associated with Post-2003 PTF Investment shall equal the PTO’s balance of Total Transmission Depreciation Reserve multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF Leases.

(e) Transmission Related Accumulated Deferred Taxes shall equal the PTO's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Related Accumulated Deferred Income Taxes associated with Post-2003 PTF Investment shall equal the PTO's balance of total property-related accumulated deferred income taxes as recorded in FERC accounts 281 and 282, multiplied by the ratio of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, to Total Plant in Service excluding Phase I/II HVDC-TF Leases, further multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases.

(f) Transmission Related Loss on Reacquired Debt shall equal the PTO's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(g) Other Regulatory Assets/Liabilities shall equal the PTO's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the PTO's electric balance of FAS 109 multiplied by the Plant Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(h) Transmission Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(i) Transmission Materials and Supplies shall equal the PTO's electric balance of Transmission Plant Materials and Supplies, multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the PTO's Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph J of the formula.

(k) MPRP CWIP shall equal CMP's balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and in accordance with CMP's Accounting Procedures for MPRP CWIP. In order to calculate the Incremental Return and Associated Income Taxes for MPRP CWIP, MPRP CWIP shall be separately identified.

(l) NEEWS CWIP shall equal CL&P, WMECO and NEP’s balances as recorded in FERC Account No. 107 for the NEEWS as authorized by Commission order and in accordance with the companies’ respective Accounting Procedures for NEEWS CWIP. In order to calculate the Incremental Return and Associated Income Taxes for NEEWS CWIP, NEEWS CWIP shall be separately identified.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the PTO's Weighted Cost of Capital, plus (b) Federal Income Tax plus (e) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, shall only reflect item (iii) below and shall apply in the manner indicated below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.

(iii) the return on equity component, shall be the product of the allowed ROE of the PTO's common equity and the ratio that common equity is to the PTO's total capital. For pre-

1997 and post-1996 assets, the ROE is ~~11.07~~11.64%. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental return on equity shall be the product of: (1) the PTO's incremental return on equity of 1.0% for plant investments associated with projects included in the RSP and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157, et al.; (2) any ROE incentive approved by the FERC under Order No. 679 for other plant investments (however; the 125 basis point ROE incentive adder granted to NEEWS under Order No. 679 in Docket No. ER08-1548 and the 50 basis point ROE incentive adder for RTO participation shall not apply to the costs related to the Central Connecticut Reliability Project, consistent with FERC's order) and MPRP CWIP and NEEWS CWIP, ~~provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period,~~ and (3) the ratio that common equity is to the PTO's total capital) [19]

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{I\text{-}FT}$$

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections ll.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section ll.B., and D is Transmission Investment Base, as determined in Section II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 - FT)}$$

[19] FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679.

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section ll.D.below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B.. D is the Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A’ is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation and Amortization Expense shall equal the PTF/HTF Transmission Plant Allocation Factor, multiplied by the sum of (i) the PTO’s Depreciation Expense for Transmission Plant, plus (ii) an allocation of Intangible Plant Amortization Expense and (iii) General Plant Depreciation and Amortization Expense calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation and Amortization Expense by the Transmission Wages and Salaries Allocation Factor.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal the PTO's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal the PTO's total electric municipal tax expense multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

F. Transmission Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal the PTO's Transmission Operation and Maintenance Expenses multiplied by the PTF/HTF Transmission Plant Allocation Factor.

H. Transmission Related Administrative and General Expenses shall equal the sum of the PTO's (1) Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, and (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments, plus specific transmission related expenses included in Account 930.1 plus Transmission Merger-Related Costs. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

I. Transmission Related Integrated Facilities Charges shall equal the PTO's transmission payments to Affiliates for use of the PTF and HTF integrated transmission facilities of those Affiliates.

J. Transmission Support Revenues shall equal the PTO's revenue received for PTF and HTF transmission support but excluding the support payments to PTOs or their designee pursuant to Schedule 11 and excluding the support payments to PTOs or their designee pursuant to Schedule

12 Part 1(a) and Part B.2, and excluding support payments, if any, made to PTOs or their respective designee pursuant to Part II.C of this OATT.

K. Transmission Support Expense shall equal the expense paid by (1) PTOs, (2) Transmission Customers or (3) Related Persons pursuant to Section II.49 of the Tariff for PTF and HTF transmission support other than expenses for payments made for congestion rights or for transmission facilities or facility upgrades placed in service on or after January 1, 1997, where the support obligation is required to be borne by particular PTOs or other entities in accordance with the OATT. Transmission Support Expenses by any entity other than a PTO, included in this provision, shall be capped at that entity's annual payment for Regional Network Service or its Point To Point Service for each individual Point To Point transaction from the resource with which the support payment is associated.

L. Transmission-Related Expense from Generators shall equal the expenses from generators that both (1) the PTO Administrative Committee determines should be included as transmission expense as a result of the impact of such generators on reducing transmission costs that would otherwise be required to be paid by Transmission Customers and (2) are reflected in a filing made by the PTOs with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the OATT.

M. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Section which is not specifically identified under any other section of this rule.

N. Revenues for Short-Term service under the OATT shall be revenues distributed to each PTO for short term service provided under the OATT, received after March 1, 1999. These revenues will be credited pro-rata between pre-1997 and post-1996 PTF revenue requirements in proportion to pre-1997 and post-1996 PTF Transmission Plant.

O. Transmission Rents Received from Electric Property shall equal any Account 454 Rents from electric property, associated with PTF and HTF Transmission Plant as defined in Section II.A.1.(a) above but not reflected as a credit in Transmission Support Revenues in paragraph K of this Attachment.

P. <u>Transmission Revenues from MGTSAs</u> shall equal any MGTSA revenues recorded in Account 456.

APPENDIX A TO ATTACHMENT F
IMPLEMENTATION RULE RULES FOR DETERMINING
INVESTMENT TO BE INCLUDED IN PTF

Section A – Transmission Lines*

Section B – Terminal Facilities*

Section C – Right of Way*

Effective June 1, 1998

*The following provision shall apply to Sections A, B and C below:

Of those transmission facilities that are upgrades, modifications or additions to the New England Transmission System on and after January 1, 2004, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section II.49 of this OATT shall be classified as PTF. Those transmission facilities that were PTF on December 31, 2003, and any upgrades to such facilities that meet the definition of PTF specified in this OATT, shall remain classified as PTF for all purposes under the Transmission, Markets and Services Tariff.

Section A: Rules for Determining Transmission Line Investment to be Included in PTF

Pool Transmission Facilities (PTF) are the transmission facilities owned by PTO rated 69 kV or above required to allow energy from significant power sources to move freely on the New England transmission network, and include:

1. All transmission lines and associated facilities owned by the PTOs rated 69 kV and above, except:

    a. those which are required to serve local load only, thereby contributing little or no parallel capability to the transmission network,

    b. generator leads, which are defined as the radial transmission from a generator bus to the nearest point on the transmission network,

c. lines that are normally operated open.

d. those that are classified as MTF.

2. Terminal facilities (including substation facilities such as transformers, circuit breakers, and associated equipment) required to interconnect the lines which constitute PTF (see Section B).

3. If a PTO with significant generation in its system (initially 25 MW) is connected to the New England Transmission System and none of the transmission facilities owned by the PTO qualify to be included in PTF as defined in “1” and “2” above, then such PTO’s connection to PTF will constitute PTF if both of the following requirements are met for this connection:

   a. The connection is rated 69 kV or above.

   b. The connection is the principal transmission link between the PTO and the remainder of the ISO PTF network.

The PTF facilities covered by this provision shall consist of a single line from the point of connection on the transmission network to the first bus within the PTO’s system.

4. R/W and land required for the installation of PTF facilities listed in “1”, “2”, or “3” (see Section C).

The following examples indicate the intent of the above definitions:

a. Radial tap lines to local load are excluded.

b. Lines which loop, from two geographically separate points on the transmission network, the supply to the load bus from the transmission network are included.

c. Lines which loop, from two geographically separate points on the transmission network, the connections between a generator bus, and the transmission network are included.

d. Radial connection or connections from a generating station to a single substation or switching station on the transmission network are excluded unless the requirements of paragraph 3 above are met.

e. The cost of a PTF line will include only those costs associated with that line. When other facilities require rebuilding or undergrounding to permit the construction of a PTF facility, the investment costs in the relocated or undergrounded facility will not be included.

f. Where multiple circuit structures support a mixture of PTF and Non-PTF circuits, the total cost of the multiple circuit structures will be allocated between the circuits in accordance with the ratio of costs of comparable individual structures.

The PTOs shall review at least annually the status of transmission lines and related facilities and determine whether such facilities constitute PTF and shall prepare and keep current a schedule or catalog of PTF facilities.

All new facilities being installed should be properly classified at the time the facilities are approved under Section I.3.9 of the Transmission, Markets and Services Tariff.

Transmission facilities owned or supported by a Related Person of a PTO which are rated 69 kV or above and are required to allow Energy from significant power sources to move freely on the New England Transmission System shall also constitute PTF provided (i) such Related Person files with the ISO its consent to such treatment; and (ii) the ISO determines in consultation with the PTO Administrative Committee determines that treatment of the facility as PTF will facilitate accomplishment of the ISO's objectives. If such facilities constitute PTF pursuant to this paragraph, they shall be treated as "owned" or "supported," as applicable, by a PTO for purposes of the OATT and the other provisions of the TOA, including the ability to include the cost associated with such PTF and any Transmission Support Expenses for support of PTF made by its Related Person in that PTO's Annual Transmission Revenue Requirements pursuant to Attachment F of the OATT.

Section B: Rules for Determining Terminal Investment to be Included in PTF

Terminal Investment is investment associated with the terminal facilities of electrical lines, including substation facilities such as transformers, circuit breakers, disconnects and airbreaks, bus conductor, related protection equipment and other related facilities (see paragraph 7).

1. The investment in terminal facilities shall be included where these facilities are identifiable and serve directly for terminating and/or switching PTF lines.

2. In cases where a line terminal is used in conjunction with both PTF and Non-PTF lines and/or facilities, it will be considered a PTF facility providing the terminal facility is at 69 kV or above and carries any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation. PTF equipment is any element of the transmission system in those parallel paths. Any equipment not in these parallel paths is Non-PTF.

3. Where line terminals are installed solely for Non-PTF facilities, and do not carry any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation, such terminal cost shall not be included in PTF.

4. A two-winding transformer which connects PTF facilities at both terminals along with any switcher which can be identified as pertaining solely to the transformer, will be included in their entirety as PTF.

5. An autotransformer or three winding transformer which connects PTF facilities at two (2) or more terminals, along with any switchgear which can be identified as pertaining solely to the PTF-connected terminals of the transformer, will be included in their entirety as PTF. An autotransformer or three winding transformer which is connected to PTF at only one terminal will not be PTF.

6. When a transformer supplies only Non-PTF facilities, the entire transformer installation, including the high side disconnect switch or circuit breaker and associated structures or tap lines shall be excluded from PTF except for the portion of line terminal facilities covered by paragraph 2.

7. Other facilities – the investment in that portion of a multi-use substation or switching station which is identifiable as serving a PTF function shall be included in PTF, while the investment in

such facilities which are identifiable as serving a Non-PTF function shall be excluded. The investment in land, structures, ground mats, fences, ducts, lighting, etc., can often be identified and thus allocated. The investment in other facilities in the substation or switching station, excluding transformers, which are not identifiable as serving either a PTF or a Non-PTF function and general overheads shall be allocated to PTF on the basis of the ratio of the investment in those facilities identified as PTF to the sum of the investments in the facilities which are identified as serving PTF and Non-PTF functions; the equipment cost of power transformers shall not be included in this calculation for determining the division of investment, since this would produce a distorted balance.

8. Alternate method of allocating the cost of terminal facilities – In those cases where the major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and Non-PTF according to the number of terminals serving PTF and Non-PTF facilities.

9. In cases where microwave facilities are used in whole or part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by the microwave facilities except where these facilities are otherwise supported under the Microwave Sharing Agreement dated June 1, 1970 among some of the New England utilities.

10. Generator unit transformers and generator circuit breakers shall be excluded from PTF, unless otherwise included by paragraphs 1 or 5.

11. In cases where remote control (Supervisory Control) and telemetering facilities are used in whole or in part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by these facilities.

12. The PTO Administrative Committee may designate appropriate facilities as PTF.

Section C: Rules for Determining PTF R/W Costs

1. If a R/W has only PTF lines and no Non-PTF lines are expected to be added, the entire cost of the R/W is to be included as PTF.

2. If the R/W has only PTF lines but includes additional unused R/W which was purchased for future use by Non-PTF lines, the cost of the additional R/W is not to be included as PTF.

3. If the R/W contains both PTF and Non-PTF lines, the R/W cost to be assigned to PTF is to be determined as follows:

   a. Where new or additional R/W is required to permit the construction of PTF line(s) and the added R/W is adequate to contain the new PTF, the cost of the new R/W is to be assigned to the PTF line(s), (even if the PTF line is located on the old R/W).

   b. Where an existing R/W is used (without additional R/W), the amount allocated to PTF will be determined in accordance with paragraph 4.

   c. Where a R/W is widened, but the new facilities, either PTF or Non-PTF, require partial use of the existing R/W, the incremental cost of the new R/W will be assigned to the new facilities. The width of the original R/W will be added to the width of the new R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W will be allocated to the new facilities in proportion to the width of the old R/W assigned to the new facilities. Thus, the R/W for the new facilities will be the additional R/W plus a share of the old R/W.

4. In allocating R/W between PTF and Non-PTF lines, each shall bear a share of the R/W in accordance with the following formulae.

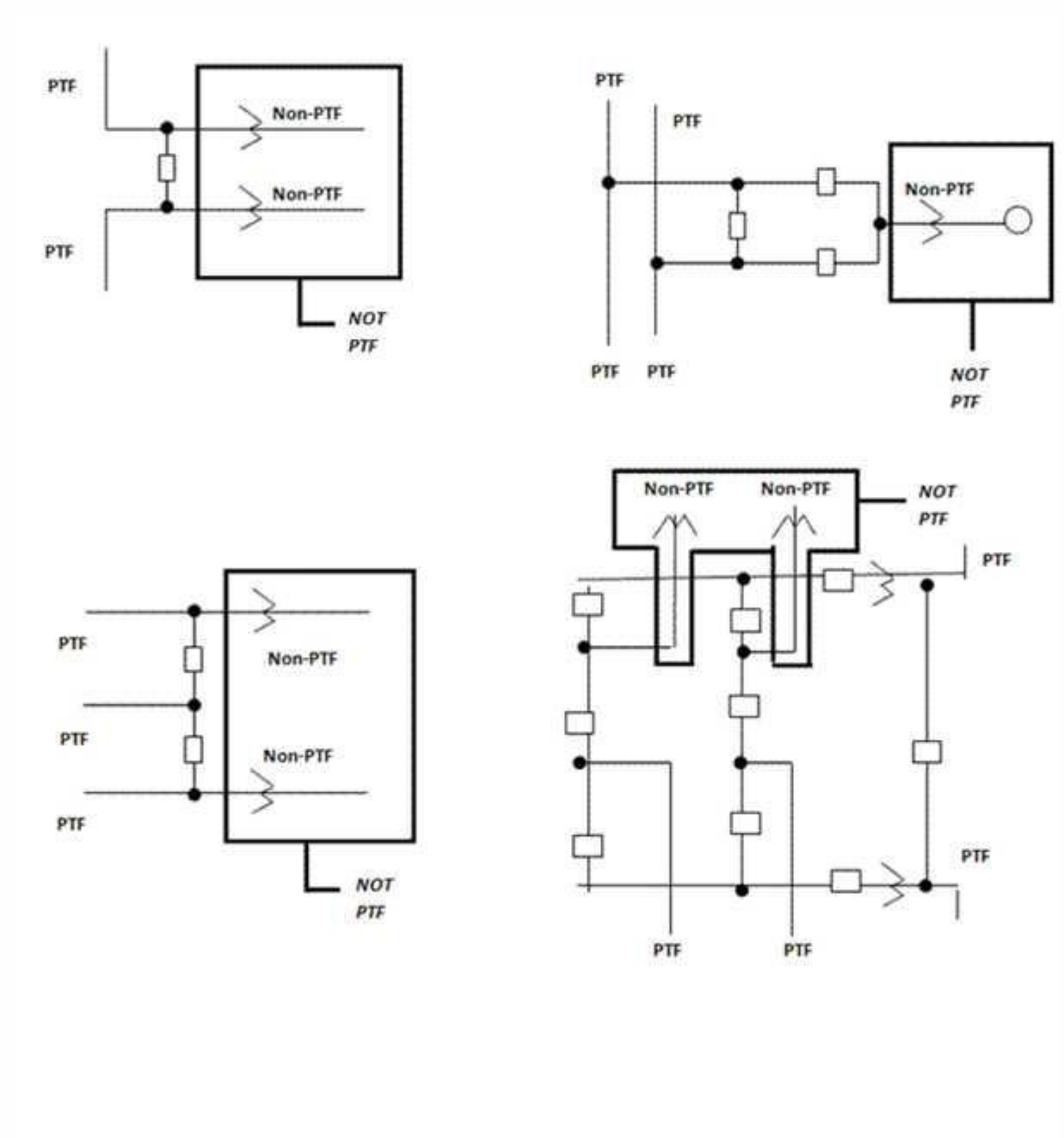
   a. Determine the R/W width required for each facility if constructed independently using appropriate type structures.

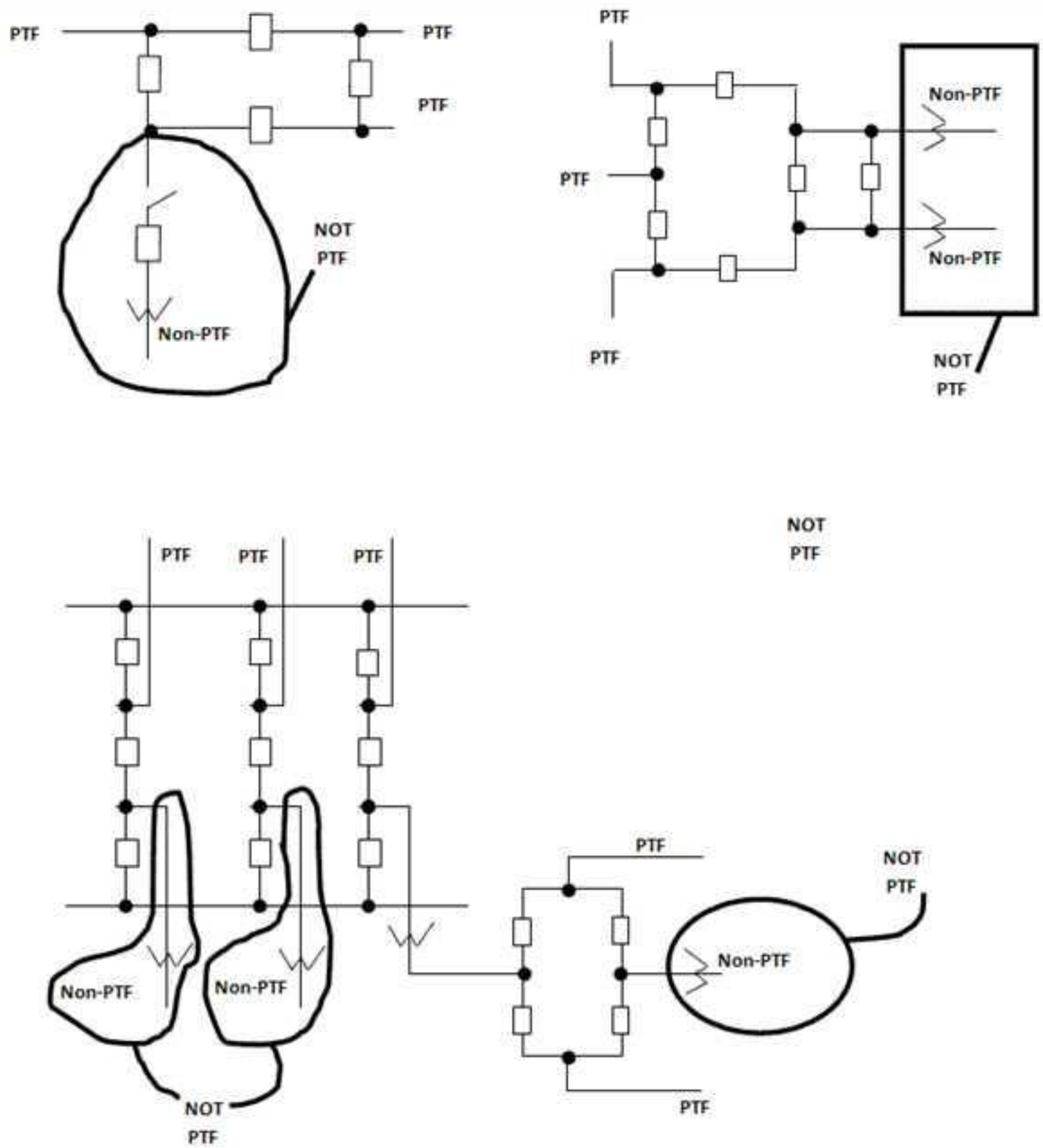
   b. Allocate the actual R/W width to each facility in the proportion its independent R/W requirement would be to the sum of the independent R/W requirements.

5. R/W and land held for future PTF facilities may be included in PTF facilities only if specifically approved by the PTO Administrative Committee included under paragraph 1.

ATTACHMENT 1 TO APPENDIX A TO ATTACHMENT F IMPLEMENTATION RULE

Examples of the Methods for Distinguishing PTF from Non-PTF Terminal Facilities in a Number of Typical Substation Configurations

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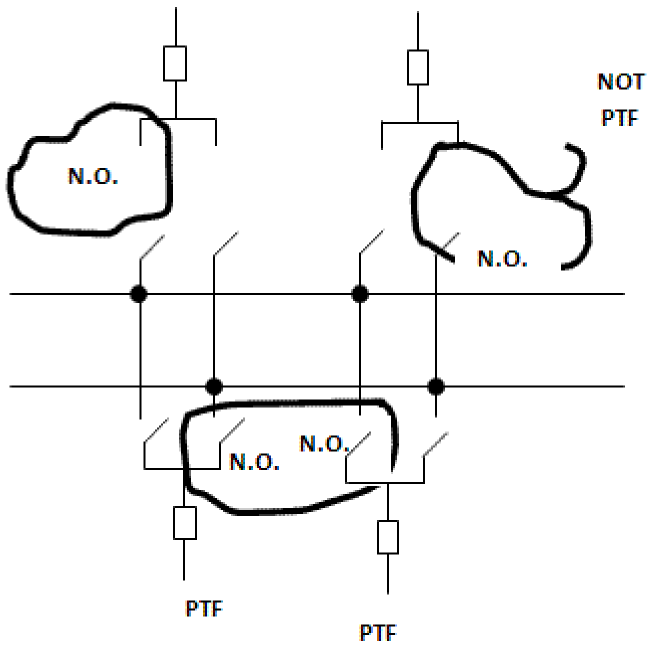
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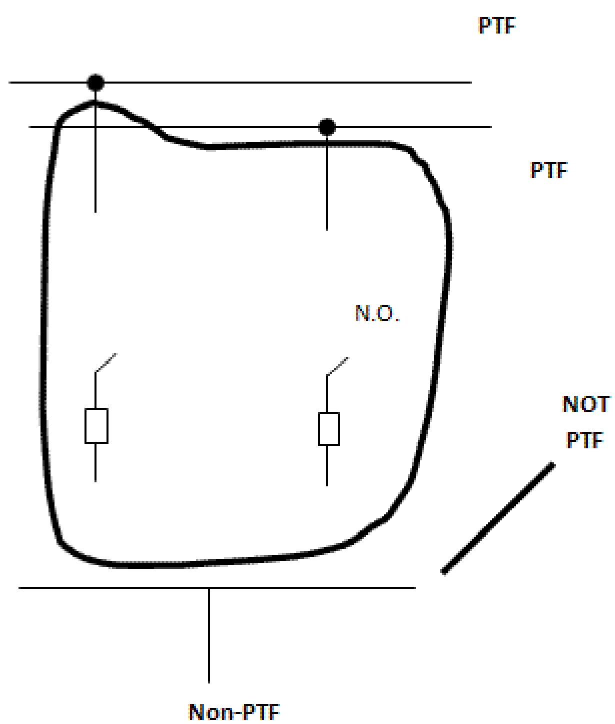
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APPENDIX B TO ATTACHMENT F IMPLEMENTATION RULE
HTF TRANSITION SCHEDULE

The inclusion of HTF Annual Transmission Revenue Requirements in Attachment F (and the calculation of the Pool PTF Rate) to this OATT will be limited by the provisions of this schedule.

VELCO, as a PTO and acting as agent for the HTF owners, may include the HTF Annual Transmission revenue Requirements (i.e., HTF Transmission Plant) within the Attachment F calculations. Additionally, the total HTF Annual Transmission Revenue Requirements included shall be limited to the following:

Year 1: A maximum of $1.2M in Year 1. For the sole purpose of this Schedule, "Year 1" shall be defined as the first full year after the Operations Date:

Year 2: A maximum of $2.0M in Year 2. For the sole purpose of this Schedule, "Year 2" shall be defined as the second full year after the Operations Date;

Year 3: A maximum of $2.8M in Year 3. For the sole purpose of this Schedule, "Year 3" shall be defined as the third full year after the Operations Date;

Year 4: A maximum of $3.5M in Year 4. For the sole purpose of this Schedule, "Year 4" shall be defined as the fourth full year after the Operations Date;

and

Year 5 and thereafter: All HTF Annual Transmission Revenue Requirements shall be included in Attachment F.

ATTACHMENT F IMPLEMENTATION RULE
APPENDIX C

I. DEFINITIONS

(i) Adjusted Carrying Charge Factor (ACCF): shall equal the sum of the Carrying Charge Factor and the quotient of (i) the Cost of Capital Rate multiplied by the PTOs' Transmission Related Accumulated Deferred Taxes associated with Post-1996 PTF Transmission Plant for the most recently concluded calendar year, and (ii) Post-1996 PTF Transmission Plant for the most recently concluded calendar year, as shown:

> ACCF = CCF + [(COC * Transmission Related Accumulated Deferred Taxes associated with Post-1996 PTF Transmission Plant) ÷ Post-1996 PTF Transmission Plant]

(ii) Annual True-up – Pre-1997 (ATU): shall be the difference between the actual Pre-1997 Annual Transmission Revenue Requirements and the as-billed Pre-1997 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Pre-1997 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO's relevant Pre-1997 PTF cost data for the most recently concluded calendar year. The as-billed Pre-1997 Annual Transmission Revenue Requirements shall be those Pre-1997 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year.

(iii) Annual True-up – Post-1996 (ATU'): shall be the difference between the actual Post-1996 Annual Transmission Revenue Requirements and the as-billed Post-1996 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Post-1996 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO's relevant Post-1996 PTF cost data for the most recently concluded calendar year.The as-billed Post-1996 Annual Transmission Revenue Requirements shall be those Post-1996 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year and which included the sum of the Post-1996 Transmission Revenue Requirements for the year prior to the most recently concluded calendar year plus the Forecasted Transmission Revenue Requirements for the most recently concluded calendar year.

(iv) Carrying Charge Factor (CCF): shall reflect the most recent calendar year data used in determining Post-1996 Annual Transmission Revenue Requirements and shall equal the sum of Attachment F Sections II.A, excluding MPRP CWIP and NEEWS CWIP, through II.H divided by Attachment F Section II.A.1.a.

(v) Cost of Capital Rate (COC): shall be determined in accordance with Attachment F Section II.A.2.

(vi) Forecast Period: The calendar year immediately following the calendar year for which the most recent FERC Form 1 data is available.

(vii) Forecasted ADIT (FADIT): shall equal the PTOs' projected change in Accumulated Deferred Income Taxes from the most recently concluded calendar year related to accelerated depreciation and associated with PTF Transmission Plant for the Forecast Period calculated in accordance with Treasury regulation Section 1.167(l)-1(h)(6).

(viii) Forecasted CL&P NEEWS CWIP (FCCWIP): shall equal CL&P's estimated incremental change in NEEWS CWIP for the Forecast Period.

(ix) Forecasted MPRP CWIP (FCWIP): shall equal CMP's estimated incremental change in MPRP CWIP for the Forecast Period.

(x) Forecasted NEP NEEWS CWIP (FNCWIP): shall equal NEP's estimated incremental change in NEEWS CWIP for the Forecast Period.

(xi) Forecasted Transmission Plant Additions (FTPA): shall equal an estimate of the PTO's Post-1996 PTF plant additions for the Forecast Period.

(xii) Forecasted Transmission Revenue Requirement (FTRR): shall equal FTPA multiplied by the ACCF, minus FADIT multiplied by the COC, plus FCWIP multiplied by the MCOC, plus FCCWIP multiplied by CCOC, plus FWCWIP multiplied by WCOC, plus FNCWIP multiplied by NCOC, as shown:

FTRR = (FTPA * ACCF) - (FADIT * COC) + (FCWIP * MCOC) + (FCCWIP * CCOC) + (FWCWIP * WCOC) + (FNCWIP * NCOC)

(xiii) Forecasted WMECO NEEWS CWIP (FWCWIP): shall equal WMECO's estimated incremental change in NEEWS CWIP for the Forecast Period.

(xiv) MPRP Cost of Capital Rate (MCOC): shall be determined in accordance with Attachment F Section II.A.2.

(xv) NEEWS CL&P Cost of Capital Rate (CCOC): shall be determined in accordance with Attachment F Section II.A.2.

(xvi) NEEWS WMECO Cost of Capital Rate (WCOC): shall be determined in accordance with Attachment F Section II.A.2.

(xvii) NEEWS NEP Cost of Capital Rate (NCOC): shall be determined in accordance with Attachment F Section II.A.2.

II. INTEREST ON ANNUAL TRUE-UPS

Interest on the Annual True-up amounts (i.e., interest applicable to any over or under collection) shall be calculated in accordance with the methodology specified in the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii).

III. INFORMATIONAL FILINGS

The PTOs' annual informational filing shall include supporting documentation for their estimated capital additions to be placed in service during the current calendar year as well as supporting documentation pertaining to any annual true-up and interest calculations.