December 29, 2006

VIA MESSENGER

Honorable Magalie Roman Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: ISO New England Inc. and NEPOOL Participants Committee, Amendments to Schedule 2 – Reactive Power Supply and Voltage Control of the ISO New England Inc. Open Access Transmission Tariff ; Docket No. ER07-___-000

Dear Secretary Salas:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] ISO New England Inc. (the "ISO") and New England Power Pool ("NEPOOL") Participants Committee[2] hereby jointly submit an original and six (6) copies of this transmittal letter and revised tariff sheets reflecting proposed amendments to Schedule 2 – Reactive Supply and Voltage Control from Generation Resource Service ("Schedule 2") of the ISO Open Access Transmission Tariff ("OATT"), including a Schedule 2 VAR Payment Implementation Rule to be added to the OATT (collectively, the "Schedule 2 Amendments").

The proposed Schedule 2 Amendments build upon the already existing rate design, as approved by the Commission since 1999,[3] to increase the ISO's access to reactive power resources and, thereby, enhance reliability in New England. The

[1] 16 U.S.C. § 824(d) (2005).

[2] Capitalized terms used but not defined in this filing have the meanings ascribed thereto in the ISO's Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 (the "Tariff"), the Second Restated New England Power Pool Agreement and the Participants Agreement. The OATT is Section II of the Tariff.

[3] *New England Power Pool*, 88 FERC ¶ 61,140 (1999).

Schedule 2 Amendments enhance reliability in New England by broadening the scope of eligibility for payment under Schedule 2 of the OATT to include qualified non-generator reactive power resources and by updating the rate paid for reactive power capability to reflect the current mix of generation in New England. These proposed amendments have the overwhelming support of the NEPOOL Participants, as reflected in a vote of almost 90% in support by the Participants Committee.

For the reasons described below, the ISO and NEPOOL submit that the Schedule 2 Amendments are just and reasonable. ISO and NEPOOL request that the Commission accept the Schedule 2 Amendments, without modification, to become effective on March 1, 2007, sixty (60) days after the date of this filing.

I. OVERVIEW OF FILING

Based on NEPOOL Participant interest, the ISO and NEPOOL initiated a review of the rules in New England governing the provision of reactive power and voltage support, including eligibility of resources, compensation and testing to recommend whether those rules should change and, if so, how they should change.[4] The proposed Schedule 2 Amendments, as described below, reflect the input from this review. For purposes of completeness, Section IV of this filing provides a brief history of the development of the existing rate schedule, as initially approved by the Commission in 1999, and as subsequently revised.

The proposed Schedule 2 Amendments are described in Section V of this filing. Specifically, Section V describes the proposed revisions to Schedule 2 to: (1) extend the current compensation for reactive power and voltage support to include non-generator dynamic reactive power resources; (2) clarify the eligibility criteria for all dynamic reactive power resources, including both generator and non-generator resources; (3) update the Capacity Cost ("CC") component of the rate design to account for changes in the cost-basis and mix of reactive power resources in New England since 1998; (4) expand the current testing program to include testing for leading capability; and (5) identify alternative means under the ISO OATT by which a non-generator dynamic reactive power resource can receive payment under the ISO OATT if it does not elect to recover its costs under Schedule 2. Additionally, Section V describes the required revisions to the operational and testing rules in order to accommodate the recommendations to expand the class of resources eligible for Schedule 2 payments to include non-generator dynamic resources, update the fixed CC charge for VAR capacity

[4] As further discussed in Section VI of this filing, in December 2004, the Transmission Committee established a VAR Working Group (the "VWG") to review the rules in New England governing the provision of reactive power and voltage support, including eligibility of resources, compensation and testing to recommend whether those rules should change and, if so, how they should change. The Transmission Committee is a Standing Committee under Section 8.2.1 of the Participants Agreement, which is an agreement between the ISO and NEPOOL that is part of the RTO arrangements for New England.

and modify the application of the CC Rate to recognize leading as well as lagging VAR capability. Section V also addresses the proposed phased-in implementation schedule for the Schedule 2 Amendments, which provides that commencing:

- March 1, 2007 – Cross Sound Cable will be accepted into the program as a Qualified Non-Generator Reactive Resource eligible for the CC Rate payment provided that it has satisfied all criteria specified in Section II.B, including a requirement that operating protocols for provision of reactive power voltage support from such equipment have been agreed to, in writing, between the ISO and the Cross Sound Cable operator.

- June 1, 2007 – The Base CC Rate will increase from $1.05/kVAR-year to $2.32/kVAR-year for the lagging capabilities of all dynamic reactive resources that have been accepted into the program. At this time, the ISO also will initiate the testing for the leading capabilities; that is, all Qualified Generator and Non-Generator Reactive Resource seeking to be compensated under Schedule 2 will be required to provide the appropriate data necessary to test for leading capability and the first set of these resources will perform leading capability tests during the 2007 leading capability test period.

- January 1, 2008 – The Adjusted Base CC Rate will be applied to reflect leading and lagging capability. Also, on this date, all other non-generator dynamic reactive resources that have demonstrated their compliance with the eligibility criteria established in Section II.B will be eligible to receive the CC payment under Schedule 2.

The proposed Amendments have been incorporated in Schedule 2 of the OATT in the following manner:

<u>Section I</u> – This Section has been added to Schedule 2 to provide definitions of the new terms used throughout the rate schedule.

<u>Section II</u> – This Section has been added to provide the specific criteria that "Qualified Generator Reactive Resources" and "Qualified Non-Generator Reactive Resources" must meet to be eligible for CC Rate payments under Schedule 2. Section II also includes a provision addressing the treatment of Non-Dynamic Reactive Resources for purposes of compensation.

<u>Section III</u> – This Section provides the formula applied to determine the payments to be made by Transmission Customers for VAR Service provided under Schedule 2. The provisions set forth in Section III are provided in Section I of the currently effective Schedule 2. The revisions reflected in this section clarify the provision of VAR Service, and add consistency in the terminology used.

Section IV – This Section has been added to define the cost allocation for VAR Service costs. Section IV does not change the existing cost allocation approach provided under the current rate schedule.

Section V – This Section sets forth the elements of the Schedule 2 rate design, as provided in Section II of the currently effective Schedule 2. As Section V reflects, while the existing Schedule 2 rate design remains unchanged, each element has been modified to recognize the addition of Qualified Non-Generator Reactive Resources. The provisions regarding the CC Rate have also been revised to provide for the update of the amount paid for the CC component, and to provide payment to resources based on their leading as well as their lagging capability.

Section VI – This Section has been added to provide alternative methods of payment for Qualified Non-Generator Reactive Resources that cannot recover their costs under Schedule 2.

Schedule 2 VAR Implementation Rule – The Implementation Rule has been added to describe the methodology for calculating and allocating dynamic reactive power capacity cost payments over a full range of leading and lagging capability.

II. COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. The ISO operates the New England bulk power system and administers New England's wholesale electricity markets pursuant to the Tariff and the Transmission Operating Agreements with the New England Transmission Owners. In its capacity as an RTO, the ISO has the responsibility to protect the short-term reliability of the New England Area and to operate the system according to reliability standards established by the Northeast Power Coordinating Council ("NPCC") and the North American Electric Reliability Council ("NERC").

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement. NEPOOL has grown to include over 300 members, and is the principal stakeholder organization of the New England RTO. The Participants include all of the electric utilities rendering or receiving services under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers, end users and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission in *ISO New England Inc. et al.*, 109 FERC ¶ 61,147 (2004), the Participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission.

All correspondence and communications in this proceeding should be addressed to the undersigned for the ISO as follows:

Raymond W. Hepper
Monica Gonzalez*
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
Tel: (413) 535-4178
Fax: (413) 535-4379
Email: mgonzalez@iso-ne.com

Howard H. Shafferman*
Daniel R. Simon
Ballard Spahr Andrews & Ingersoll, LLP
601 13th Street, NW
Suite 1000 South
Washington, DC 20005-3807
Tel: (202) 661-2200
Fax: (202) 661-2299
Email: hhs@ballardspahr.com

And to NEPOOL as follows:

David T. Doot
Eric K. Runge*
Day, Berry & Howard LLP
One International Place
Boston, MA 02110
Tel: (617) 345-4735
Fax: (617) 345-4745
Email: ekrunge@dbh.com

*Persons designated for service.

III. STANDARD OF REVIEW

The ISO submits the Schedule 2 Amendments pursuant to Section 205 of the FPA, which "gives a utility the right to file rates and terms for services rendered with its assets."[5] Under Section 205, the Commission "plays 'an essential passive and reactive' role"[6] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not "just and reasonable."[7] The Commission limits this inquiry "into whether the rates proposed by a utility are reasonable – and [this inquiring does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs."[8] The changes proposed herein "need not be the only reasonable

[5] *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002).

[6] *Id*. at 10 (*quoting City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir 1984).

[7] *Id*.

[8] *See ISO New England Inc.*, 114 FERC ¶ 61,315 at P 33 and n.35 (2005), *citing Pub. Serv. Co. of New Mexico v. FERC*, 832 F.2d 1201, 1211 (10th Cir. 1987) and *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984) ("*City of Bethany*"), *cert. denied*, 469 U.S. 917 (1984).

methodology, or even the most accurate."[9] As a result, even if an intervenor or the Commission develops an alternate proposal, the Commission must accept the ISO's Section 205 filing if it finds it is just and reasonable.[10]

IV. BACKGROUND

In order to maintain transmission voltages on the New England Transmission System within acceptable limits, generation facilities may be directed from time to time by the ISO, as the System Operator, to operate to produce or absorb reactive power. Schedule 2 of the OATT sets forth the rules that govern eligibility for compensation and payment for reactive power supply and voltage control service in New England. To the extent a generation facility is directed by the ISO to produce or absorb reactive power, that facility is compensated under Schedule 2 for its provision of reactive power and for the energy costs associated with the reactive power provided. A brief history of the development of Schedule 2 sets the framework for the Schedule 2 Amendments that are the subject of the instant filing.

On December 31, 1996, NEPOOL filed a comprehensive restructuring proposal, which included the Restated NEPOOL Agreement and the NEPOOL Open Access Transmission Tariff ("NEPOOL Tariff").[11] Schedule 2 to the NEPOOL Tariff provided a formula for quantifying and recovering the costs of reactive power supply and voltage control from generation resources. NEPOOL's initial filing of Schedule 2 included a number of changes to the *pro forma* Order No. 888 OATT. These changes were related to the rate design and payments for reactive power under Schedule 2. The justness and reasonableness of Schedule 2, among other issues, was set for hearing pursuant to a Commission Order issued on April 20, 1998.[12] The issues relating to Schedule 2, other than the calculation of a non-$0 CC component of the formula for compensation defined in Schedule 2, were resolved in a settlement agreement reached by the parties on April 5, 1999, and approved by the Commission on July 30, 1999.[13]

Pursuant to that settlement agreement, the costs for providing reactive power from generators in the NEPOOL Control Area are recovered exclusively through Schedule 2 of the NEPOOL Tariff and shared by transmission customers on a *pro rata* basis according

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[9] *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995).

[10] *Cf. Southern California Edison C o., et al.*, 73 FERC ¶ 61,219 at 61,608 n. 73 (1995) ("Having found the Plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protesters." (*citing City of Bethany*, 727 F.2d at 1136)).

[11] Prior to the February 1, 2005 implementation date for the New England RTO, NEPOOL had the filing rights for the NEPOOL OATT, which went into effect on March 1, 1997.

[12] *New England Power Pool,* 83 FERC ¶ 61,045 (1998).

[13] *New England Power Pool*, 88 FERC ¶ 61,140 (1999).

to their shares of regional network load and reserved capacity for Through or Out Service. As initially filed, Schedule 2 provided for reactive power compensation based on three cost components: (1) the Lost Opportunity Cost ("LOC") component, which compensates for the value of a generator's lost opportunity in the energy market in situations in which a generator that would otherwise be economically dispatched as directed by the ISO to reduce real power output to provide more reactive power; (2) the cost of energy consumed ("SCL") component, which compensates for the cost of energy consumed by a generator solely to provide reactive power support, such as the energy required to "motor" a hydroelectric generating unit; and (3) the CC component, which compensates for the fixed capital costs incurred by a generator associated with the installation and maintenance of the capability of providing reactive power. The charge for the CC component was originally set at $0 to reflect an agreement among the parties.

Subsequently, in 2001, NEPOOL further revised the compensation formula to include an additional component labeled "PC" and defined as "the portion of the amount paid to Market Participants for the hour for Energy produced by a generating unit that is considered under [Schedule 2] to be paid for VAR support."[14] The PC charges address the circumstances where a generator that was not economically dispatched is directed to come on line or increase power above its economic loading point to provide reactive power. This component compensates the generator for the difference between the locational marginal price ("LMP") and its offer price, if the LMP is lower than the offer price, for each hour the generator provides reactive power.[15] Also, in 2001, NEPOOL filed its Seventy-Third Agreement Amending the Restated NEPOOL Agreement ("Seventy-Third Agreement") amending the CC component that was originally set at $0 to allow for a non-$0 charge, which would compensate a "Qualified Generator" for maintaining a generator's capability to provide reactive power support.[16] In that filing, NEPOOL also described the calculations for each of the elements of the Schedule 2 rate design.

The existing rate design under Schedule 2 of the OATT consists of the same elements described in the Seventy-Third Amendment filing – the fixed CC component

[14] This revision to the Schedule 2 formula was directed by the Commission by order dated June 28, 2000, Docket Nos. EL00-62-000, *et al.*, *ISO New England Inc.*, 91 FERC ¶ 61,311 (2000) ("*CSM/MSS Order*"), and subsequently approved on June 13, 2001 in *ISO New England Inc.*, 95 FERC ¶ 61,384 (2001).

[15] On April 27, 2001, NEPOOL filed the Seventy-Second Agreement Amending the Restated NEPOOL Agreement ("Seventy-Second Agreement"), which proposed conforming changes in light of a order issued by the Commission on April 26, 2001, accepting market rule changes implementing three-part bidding and net commitment period compensation ("NCPC") in the NEPOOL Control Area. *New England Power Pool*, 95 FERC ¶ 61,123 (2001). The NCPC methodology approved by the Commission applied to the calculation of the PC charge component of Schedule 2. The Commission accepted the Seventy-Second Amendment in an unpublished letter order issued on June 1, 2001, in Docket No. ER01-1891-000.

[16] This Agreement was accepted by the Commission in an unpublished letter order issued on June 28, 2001, in Docket No. ER01-2161-000.

and the variable components of LOC, SCL and PC. As described in the Seventy-Third Amendment, Schedule 2 of the OATT compensates "Qualified Generators" for the equipment needed to provide VAR Service as directed by the ISO. Such compensation, however, is based on the lagging capability provided only by such "Qualified Generators," defined as "any generator that is in the Market System and provides measurable voltage support, as determined from time to time by the ISO to the New England Control Area." Non-generator dynamic reactive power sources are not eligible for compensation under Schedule 2. Moreover, the charge paid under the CC component reflects a negotiated rate based on the carrying costs associated with generator reactive power equipment owned by transmission owners in 1998 and has not been updated to account for changes in the cost-basis or mix of reactive resources now available and providing reactive support in New England.[17]

V. DESCRIPTION OF THE SCHEDULE 2 AMENDMENTS

The proposed Schedule 2 Amendments include the modifications to Schedule 2 of the OATT as approved by the Participants Committee. As further described below, the Schedule 2 Amendments: (1) expand eligibility for payment under Schedule 2 to non-generator dynamic reactive power resources; (2) make eligibility criteria clear for all dynamic reactive power resources; (3) update the CC rate from $1.05/kVAR-year (the current amount paid under the CC rate) to $2.32/kVAR-year to account for changes in the cost-basis or mix of reactive resources in New England since 1998; (4) use both leading and lagging VAR capability to determine the CC component payments; and (5) identify an alternative means under the OATT by which a non-generator dynamic reactive power resources can receive compensation if it does not elect to recover its costs under Schedule 2.

A. <u>Proposed Changes to Eligibility Requirements for Compensation</u>

1. Expanding Compensation Eligibility to Include Qualified Non-Generator Reactive Resources

Based on the fact that non-generator dynamic reactive power devices are capable of providing reactive power support to the New England Transmission System, the ISO and NEPOOL submit that eligibility for compensation under Schedule 2 should be broadened to include such resources that have dynamic reactive power capability, meet certain specific eligibility requirements, and are not being compensated for the capability elsewhere. Currently, only "Qualified Generators" are eligible for reactive power compensation under Schedule 2. The largest, current single example of a non-generator dynamic reactive power resource is the Cross-Sound Cable, but other facilities may well qualify.

[17] *See* Transmittal Letter of the Seventy-Third Agreement at 7 (describing the Base CC Rate values as "a series of negotiated rates based on a number of estimates of the carrying costs per kVAR to generators associated with the equipment to provide VAR support").

Specifically, the Schedule 2 Amendments incorporate a new term – "Qualified Non-Generator Reactive Resource" – defined in Section I (Definitions) as "any non-generator source of dynamic reactive power that meets the criteria specified in Section II of the revised Schedule 2." Additionally, proposed Section II.B sets forth the criteria that reflect necessary conditions, which include:

1. the entity owning or controlling the reactive power capability of the non-generator reactive power resource is a Market Participant;

2. the non-generator reactive power equipment provides measurable dynamic reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO;

3. the type of dynamic reactive power equipment is within a category of reactive power equipment that has been approved by the ISO, with advisory input from the Reliability Committee;

4. the dynamic reactive power equipment is subject to the operating authority of the ISO and all necessary operating protocols for provision of reactive power voltage support from such equipment have been agreed to, in writing, between the ISO and the non-generator reactive power resource;

5. such equipment is interconnected to the New England Transmission System and metered and dispatchable by the ISO or otherwise subject to operational control by the ISO, and has its automatic voltage regulator status and control mode (including power factor, reactive power output and voltage control) telemetered to the ISO and the applicable Local Control Center; provided that the non-generator reactive resource shall have until January 1, 2009 to have the necessary telemetering equipment installed and operating;

6. the non-generator reactive resource meets the reactive power testing requirements applicable to such non-generators, as determined from time-to-time by the ISO and specified in the ISO New England Operating Documents; and

7. the installation of such equipment shall have been approved in accordance with the requirements of Section I.3.9 of the Tariff or its predecessor provisions under the New England regional transmission arrangements.

Moreover, Qualified Non-Generator Reactive Resources will be eligible to receive the same fixed CC rate as generator resources. The application of the non-CC elements of the Schedule 2 rate design – lost opportunity cost, cost of consumed energy, and cost of energy produced – to Qualified Non-Generator Reactive Resources, however, will be determined on a case-by-case basis, and subject to filings being made pursuant to

Section 205 of the Federal Power Act, at the time the particular category of equipment is approved for compensation under Schedule 2.

Since Schedule 2 may not appropriately compensate (a) a non-operating, non-dispatchable generator that functions as a synchronous condenser and (b) an operating generator that utilizes a clutch device to operate as both a real power generator and a synchronous condenser, Section VI of Schedule 2 permits a separate schedule and filing for compensation of the first type of resource. Schedule 2 does not provide separate treatment for operating generators that utilize a clutch device to operate as both a real power generator and a synchronous condenser because of potential market rule and operational impacts. If alternative treatment is warranted, changes will be examined by the ISO and NEPOOL through the stakeholder process. Until the time that alternative treatment is determined and filed, operating generators that have the ability to utilize a clutch device to operate as both a real power generator and a synchronous condenser will receive Schedule 2 compensation based on its generator reactive capability only.

2. Clarification of Eligibility Criteria Applicable to All Dynamic Reactive Power Sources

Schedule 2 is amended to memorialize and clarify the criteria for new generator eligibility for CC Rate payments. Currently, Section II.1.1 of Schedule 2 defines a "Qualified Generator" as "any generator that is in the Market System and provides measurable voltage support, as determined from time to time by the ISO to the New England Control Area." As with Qualified Non-Generator Reactive Resources, the proposed amendments to Schedule 2 provide specific criteria that new generators must satisfy to be eligible for CC Rate payments under Schedule 2.

The Schedule 2 Amendments include a new Section II.A, which sets forth the criteria that new generators that elect to join the Schedule 2 program after June 1, 2007 (*i.e.*, "Qualified Generator Reactive Resources" also defined in Section I, Definitions) must meet in order to qualify for CC Rate payments under Schedule 2. The criteria are as follows:

1. the entity owning or controlling the reactive power capability of the generator reactive resource is a Market Participant;

2. the generator is: (a) interconnected to the New England Transmission System or (b) interconnected to the distribution system but participating in the New England Markets and (c) is metered and dispatchable by the ISO or otherwise subject to operational control by the ISO;

3. the generator provides measurable reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO, and has its automatic voltage regulator status and control mode (including

power factor, reactive power output and voltage control) telemetered to the ISO and the applicable Local Control Center; provided that the generator shall have until January 1, 2009 to have the necessary telemetering equipment installed and operating;

4. the generator meets the reactive power testing requirements applicable to generators, as determined from time-to-time by the ISO and specified in the ISO New England Operating Documents; and

5. the installation of the generator shall have been approved in accordance with the requirements of Section I.3.9 of the Tariff or its predecessor or successor provisions under the New England regional transmission arrangements.

These criteria apply to new or existing generators that are not in the program as of June 1, 2007 that elect to join the Schedule 2 program after June 1, 2007. Any generator that is receiving "VAR Payments"[18] under Schedule 2 on June 1, 2007 shall be deemed to be a Qualified Generator Reactive Resource as of that date, provided that it continues to meet the criteria specified in (1), (3) and (4), above and meets certain informational requirements of the ISO as specified in the Schedule 2 Amendments. As is currently the case, under the Schedule 2 Amendments any generator that is run by the ISO to provide reactive power support to the New England Transmission System will be paid its variable costs in accordance with the non-CC Rate components of Schedule 2.

B. Proposed Changes to Compensation for VAR Services

1. Elements of the Schedule 2 Rate Design

The existing rate design for reactive power compensation consists of four components – the capacity cost ("CC"), lost opportunity cost ("LOC"), cost of energy consumed ("SCL"), and cost of energy produced ("PC"). Under the proposed amendments, the existing elements of the Schedule 2 rate design remain intact. The proposed expansion of Schedule 2 eligibility to include non-generator dynamic resources does not require any changes to the components of the compensation formula as currently approved. However, each element has been expanded to apply to both generators and non-generator dynamic reactive power sources, as appropriate. Importantly, and as fully explained below, the existing rate design and the rate paid under the CC component (currently, $1.05/kVAR-year) are being modified and updated. Finally, as a matter of terminology, the acronyms for the cost of energy consumed and cost of energy produced have been modified, respectively, to "CEC" and "CEP" to avoid confusion regarding the meaning of these acronyms.

[18] The Schedule 2 Amendments provide a new definition of "VAR Payments" – "the payment made to Qualified Reactive Resources for VAR Service Capability under Section V.A of this Schedule 2" – in Section I, Definitions.

2. Proposed Revisions to the CC Component

a. Revisions to Update the Rate Paid Under the CC Component

With regard to the CC component, the VWG played an important role in updating the rate paid under this component to account for changes in the cost-basis or mix of reactive resources in the New England since 1998. As provided in Section II.1.4 of Schedule 2, the current CC Rate is $1.05/kVAR-year, which is based upon pre-1998 cost data, and further resulted from a negotiated settlement. The VWG considered a number of different means of updating the CC component, including developing unit-specific revenue requirements as well as using the so-called "AEP methodology"[19] applied to a proxy unit. Ultimately, the VWG recommended updating the CC Rate through a negotiated rate based on a weighted-average blend of the costs of older generators in New England and the costs of newer generators as reflected in the AEP methodology filings in PJM Interconnection, LLC ("PJM"). The VWG recommended that the ratio for the blend of those costs would be two-thirds to one-third, which would reflect the approximate ratio of megawatts of pre-market generation (roughly 20,000 MWs) and added post-market generation (roughly 10,000 MWs) currently existing in New England.[20]

In order to calculate the updated CC Rate using this blended approach, the VWG had to obtain data for pre- and post-market generation. The data used for the pre-market (*i.e.*, pre-1998) generation was already available as it was used to develop the current CC revenue requirement, as described in NEPOOL's Seventy-Third Agreement. The cost-based average revenue requirement of those generators was $1.38/kVAR-year. [21] Most of the new generation that has been added in New England is combined cycle gas-fired technology, and because it has been built under a market regime and not under a cost-of-service regime, cost data related to the generators was not easily accessible. A sub-group of the VWG, however, was able to gather data from AEP methodology filings made by generators in PJM since 2000.[22] Using data from this set of generators is reasonable,

[19] *See American Electric Power Service Corporation*, 88 FERC ¶ 61,141 (1999) (the initial case establishing the "AEP methodology"). The AEP methodology determines the cost of the generator, exciter and step-up transformer, allocates a portion to VAR capability and levelizes that cost over the life of the unit to get a VAR cost of service rate.

[20] The competitive bid-based markets commenced in New England in 1998. A substantial amount of new generation started to be built beginning in 1998.

[21] *See* Transmittal Letter of Seventy-Third Agreement at 7 (describing the agreed-upon value for the CC charge).

[22] The data compiled by the sub-group of the VWG is appended herein behind Attachment 3. While this data is based on generators in PJM, the use of this data as a proxy for the costs of newer generators is reasonable because the generators are a similar vintage and technology, and in most cases have the same manufacturer as the majority of the post-market generators in New England; and (2) the revenue requirement numbers had undergone scrutiny through the FERC approval process.

because: (1) the generators are a similar vintage and technology (*i.e.*, post-1998 combined cycle gas-fired generators), and in most cases have the same manufacturer as the majority of the post-market generators in New England; and (2) the revenue requirement numbers had undergone scrutiny through the FERC approval process. The rate calculated for the average revenue requirement for those generators is $4.20/kVAR-year. Using a blend of the pre- and post-market generation resulted in a blended revenue requirement of $2.32/kVAR-year or ((2 * $1.38) + $4.20) /3 = $2.32.

Assuming that the current qualified generator reactive resource mix stays constant and Cross Sound Cable receives CC payments in 2007, it is estimated that the impact of increasing the CC Rate from $1.05 kVAR-year to $2.32 kVAR-year will increase the total Schedule 2 fixed payments in the second half of 2007 from roughly $1.015 million/month (which equates to $12.2 million/year) to roughly $2.3 million/month (which equates $27.3 million/year).[23]

The Schedule 2 Amendments incorporate the blended rate of $2.32/kVAR-year in new Section V.4 of Schedule 2, which provides the cost components for Qualified Reactive Resource's Payments, previously provided in Section II of Schedule 2. This blended rate of $2.32/kVAR-year on a net lagging basis is reasonable when compared to the numbers from the pre-market generation in New England and the post-2000 combined cycle, gas-fired generators from PJM. Further, the use of this approach provides the same benefits of simplicity and avoidance of administrative burden or regulatory litigation as would the use of a proxy unit, while at the same time being grounded in reasonable cost data for the reactive power equipment.[24] In addition, new Section V.4 provides for the updated CC Rate to remain in effect for five years and to be revisited near the end of the five years to determine whether another adjustment to the rate is appropriate then in light of any changes to the mix of reactive resources in New England, especially, as new generators are added or older generators are retired.

One issue that surfaced during the development of the updated CC Rate was how payment of the CC Rate should be reconciled with payments to generators under the Forward Capacity Market ("FCM") when it is fully implemented at the end of the transition period (*i.e.*, 2010) such that there would not be any double payment. ISO and NEPOOL have agreed that any measures needed to ensure that there will not be such double payment will be addressed in the development of the final FCM rules rather than through new provisions in Schedule 2 of the OATT.

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[23] A spreadsheet containing the historical Schedule 2 VAR costs over a twelve-month period used to calculate the impact of increasing the CC Rate from $1.05/kVAR-year to $2.32/kVAR-year is included herein behind Attachment 4.

[24] *See* Transmittal Letter of Seventy-Third Agreement at 7 (describing the use of an agreed-upon proxy value – the Base VAR Rate – for defining the carrying costs associated with providing capability for VAR Support as administratively efficient and simple). As noted above, the Commission accepted the Seventy-Third Agreement in an unpublished letter order issued on June 28, 2001, in Docket No. ER01-2161-000.

b. Application of the CC Rate Over the Full Range of Leading and Lagging Capability

The Schedule 2 Amendments include proposed revisions to Schedule 2 to allow the application of the CC payment over the full range of a reactive power resource's leading and lagging capability. As described in more detail below and as reflected in new Section V.4 of Schedule 2, such revisions also will provide an incentive to reactive resources to test in both the leading and lagging mode. Currently under Schedule 2, generators are compensated for their VAR capability based on lagging capability only, which is physically determined by testing the lagging VAR capability of each generator. The proposed amendments are structured to ensure that the total of the leading and lagging payments equal the general CC component rate of $2.32/kVAR-year which, as further discussed below, is initially to be paid solely on a net lagging basis.

Establishing a CC payment that is based on both leading and lagging capability provides (a) reactive resources the incentive to perform VAR tests to prove their leading and lagging capability, and (b) the ISO and the Local Control Centers with actual operational-based VAR resource data that can be used to more accurately support the planning and real-time operation of the transmission system. Attaching the CC Rate compensation mechanism to the VAR testing requirement (and associated test results) provides a number of additional benefits that the VAR testing requirement by itself will not accomplish. Some of the primary benefits of attaching the CC Rate compensation mechanism to the VAR testing criteria are:

1. Such criteria provide additional incentive to the owners of the dynamic reactive resources to perform both the leading and lagging VAR tests. (Knowing that CC Rate compensation is based on the leading and lagging test results provides the financial incentive to the generator owner to test in both the lead and the lag to the best of the resource's abilities).

2. The testing recognizes the dynamic reactive resources' strengths or weaknesses related to its ability to produce and absorb VARs and then bases the compensation on the entire voltage control range. To the extent that a dynamic reactive resource can produce and absorb VARs the CC Rate will fairly compensate the resource for its actual leading and lagging capabilities.[25]

[25] For example, if a facility, based on its testing results, has the ability to produce many VARs (*e.g.*, 210 MVAR Lag), but cannot absorb many VARs (*e.g.*, 75 MVAR), the resource will be paid for 285 MVAR. If the testing requirement is maintained, but the tie to compensation is removed, the sum of the incentive that encourages the resource to prove to what extent it can really produce or absorb VARs is removed.

3. Applying the testing criteria results in payment for what the dynamic reactive resources can actually produce or absorb, rather than what the dynamic reactive resources might be able to perform as provided on paper.

4. As a result of testing, the ISO and the Local Control Centers have more accurate data to support planning and real-time operations.

To properly implement VAR compensation for leading and lagging capability and tie the VAR compensation mechanism to the VAR testing requirement, there needs to be a conversion of the Base CC Rate, which is calculated based upon lagging values, into an Adjusted CC Rate that recognizes both leading and lagging VAR capability within the program, and maintains a revenue distribution consistent with what the resources would have been paid under the Base CC Rate times their lagging VAR capability. The conversion of the Base CC Rate to the Adjusted CC Rate maintains the Base CC Rate and its lagging capability determinants as the foundation of the Adjusted CC Rate calculation. The Adjusted CC Rate calculation then modifies the Base CC Rate into a blended rate that recognizes the leading and lagging MVARs of the dynamic reactive resources in the Schedule 2 program in a manner such that – if one were to take the composite resource that was reflected in the Base CC Rate calculation and compensate it based on either (a) the Base CC Rate times its lagging capability or (b) the Adjusted CC Rate times its lagging and leading capability – the resulting payment would be about the same. This calculation results in a comparable distribution of Adjusted CC Rate compensation to that which would have been paid under a straight Base CC Rate compensation mechanism, which is already in place under the current Schedule 2.

The conversion of the "Base CC Rate" -- $2.32/kVAR-year – into an Adjusted CC Rate, expressed in the form of $kVAR/year, representing the amount to be paid for leading and lagging capability, is set forth in Section V.4 of Schedule 2. As further described in the Schedule 2 VAR Implementation Rule, which, as indicated above, will be added to Schedule 2 of the OATT, [26] the CC rate conversion methodology that was developed to allow for the payment of both leading and lagging capability converts the Base CC Rate of $2.32/kVAR-year into a "blended lead/lag" rate (the Adjusted CC Rate) on an annual basis. The "blended lead/lag" rate recognizes the tested dynamic reactive resources capability as inputs, and applies an increase/decrease limiter during a three-year transition period to avoid drastic changes in annual rate caused by a rush of recognized MVARs into or out of the program.

As proposed in Section V.3, the Adjusted CC Rate will be calculated in accordance with the following formula: Adjusted CC Rate ($CCRate_{adjusted}$) shall equal:

[26] The Schedule 2 VAR Payment Implementation Rule describes the basis for each element of the Adjusted CC Rate formula and the methodology for the calculation. As proposed in Section V.5, the details of the Schedule 2 VAR Implementation Rule may be modified by the ISO without a further filing under the FPA provided that such modifications are consistent with the requirements of Schedule 2, and are supported by at least two-thirds of the voting percentage of the Transmission Committee members.

(the Base CC Rate ($CCRate_{base}$) * Current Total Aggregate lagging VARs) / (Current Total Aggregate Lagging VARs + Current Total Aggregate Leading VARs). The Total Aggregate Leading and Lagging VAR values reflect the untested and tested values of all dynamic reactive resources that are in the program at the beginning of each calendar year. During the first three years of the program, the dynamic reactive resources that are currently in the program will be required to have completed leading and lagging VAR tests. As dynamic reactive resources that are added to the program will have one calendar year to perform both leading and lagging VAR tests, by the end of the transition period in year three, almost every dynamic reactive resource will have performed both leading and lagging VAR tests. At that point the only dynamic reactive resources that would not have tested would be those resources that joined the VAR program in year three of the transition period.

There is a concern that the addition or removal of too many dynamic reactive resources into or out of the VAR program in any one year would cause a dramatic change in the Adjusted CC Rate calculation. In addition, if all dynamic reactive resources were to fail to test in one direction (*e.g.*, the leading direction) then the resulting Adjusted CC Rate would be based solely on lagging capability and result in a value of $2.32/kVAR-year. This would result in a number of things, particularly: (a) only compensating dynamic reactive resources for their one side of their VAR capability (in the example, lagging capability); (b) providing a disincentive of resources in the program to fully test their VAR capability in the other direction (in the example, in the leading direction); and (c) providing a disincentive to new dynamic reactive resources to join the program (in the example, new resources that have primarily leading VAR capability). To restrict this from occurring and to maintain payment incentives if there were to be a withdrawal of VAR capability primarily in one direction, increase and decrease limiters are applied to the Adjusted CC Rate calculation. These limiters mitigate the potential impact of major increases or decreases of VAR capability within the program during the three-year transition period and afterwards. The extent by which these limiters can impact the Adjusted CC Rate calculation is more restrictive during the transition period as compared to how they are applied afterwards.

c. Inclusion of Non-Generator Reactive Resources in the Measurement of the CC Rate Payment Cap

Currently, Section II.1.3 of Schedule 2 provides a megawatt-based CC Rate Payment Cap that is applied to the annual CC Rate at the beginning of the year on a prospective basis for that calendar year. The CC Rate Payment Cap formula does not need to be revised to accommodate the inclusion of non-generator reactive power sources, but the measured total capability of the system should be based on both generators and non-generator dynamic reactive power sources, and MVARs of the non-generator sources should be converted to MWs. The Schedule 2 Amendments include this change in proposed Section V.7 of Schedule 2. As that section provides, a "Qualified Non-Generator Reactive Resource's Seasonal Claimed Capability" shall be calculated by taking 2.5 times the maximum dynamic reactive power capability on a lagging basis demonstrated by the Qualified Non-Generator Reactive Resource during the testing of its VAR Service capability consistent with ISO New England Operating Procedures for measurement of such capability.

C. Proposed Revisions to Operational Procedures and Requirements

The appropriate operational and testing rules associated with reactive supply and voltage control will be amended to incorporate the other changes proposed herein. Currently, Schedule 2 provides for "Qualified Generators" to receive a "VAR Payment," which equals the "VAR Rate" multiplied by the Qualified Generator's "Qualified VARs." The Qualified VARs is a Generator's actual lagging VAR capability at its point of delivery to the New England Transmission System. The Qualified VARs for each Qualified Generator are determined through a testing process, the details of which are set forth in ISO New England Operating Procedures. Currently, this testing process only evaluates a Qualified Generator's lagging VAR capability. Accordingly, the "lagging only" VAR testing program will be replaced with an expanded test that includes generators and non-generator dynamic reactive resources and a leading VAR capability test.[27] This expanded reactive resource testing program will recognize the current lagging VAR testing mechanism requirements as well as the recently issued NERC standard requiring generators to prove their reactive control capability, which becomes effective on January 1, 2007.[28]

The operational and business procedures dealing with reactive supply and voltage control will be amended to ensure that a non-generator reactive resource operates its reactive power equipment with automatic voltage regulator ("AVR") or other similar equipment that ensures dynamic response to system voltage needs.[29] The Schedule 2 Amendments include metering requirements for AVR telemetering to the ISO and Local Control Center control rooms as one of the criteria that must be satisfied by January 1, 2009 for any reactive resource to be deemed (or continue to be deemed) a "Qualified Reactive Resource."

D. Proposed Implementation of Schedule 2 Amendments

In order to accommodate the functionalities reflected in the Schedule 2 Amendments, the software and business processes associated with VAR compensation under Schedule 2 will require extensive revisions. For instance, the implementation of the Schedule 2 Amendments will require: (1) recognition of newly included non-generator dynamic reactive power resources as registered assets within the ISO system;

[27] The applicable ISO New England Operating Procedures are referenced in Section V.10 of Schedule 2.

[28] NERC Standard MOD-025-1 "Verification of Generator Gross and Net Reactive Power Capability."

[29] The applicable ISO New England Operating Procedures are referenced in Section II of Schedule 2.

(2) revisions to the associated business processes within ISO Settlements and System Operations; (3) modification of the ISO-developed stand-alone software that supports the administration and billing of VAR Services under Schedule 2; (4) inclusion of AVR telemetered data within the ISO control room; and (5) development and administration of the expanded VAR testing program. These changes also will require the availability of new data and likely require revisions or replacement of the current ISO-developed stand-alone software supporting the administration, including dynamic reactive resource testing and billing, of VAR Services under Schedule 2. Such revisions will implicate many of the ISO departments, primarily impacting the Customer Service, System Operations, System Operation Support, Settlements, Audit and IT departments.

Because the ISO's IT, system and market development personnel are currently engaged in the implementation of other important, large-impact projects with fixed deadlines,[30] the ISO proposed, and the stakeholders agreed to, a phased-in approach for the implementation of the Schedule 2 Amendments. Under this transition schedule, upon the effective date of the changes to Schedule 2 (*i.e.*, March 1, 2007), Cross Sound Cable will become eligible to receive payment of the CC Rate under the currently effective rate of $1.05/kVAR-year provided that Cross Sound Cable has met all of the eligibility criteria specified in new Section II.B of Schedule 2 at that time. Commencing June 1, 2007, the ISO will apply the updated Base CC Rate ($2.32/kVAR-year) to payments for Qualified Reactive Resources' (including Cross Sound Cable) lagging capability, as is currently the case under Schedule 2. The ISO then will apply the Adjusted CC Rate to compensate resources for the full leading and lagging range of the VAR capability commencing January 1, 2008, which is the earliest date by which the ISO expects system changes to track leading VAR capability to be implemented. Other non-generator dynamic reactive resources will be eligible for VAR payments commencing January 1, 2008.

The Schedule 2 Amendments revise Schedule 2 to reflect the following phased-in implementation schedule:

- March 1, 2007 – Cross Sound Cable will be accepted into the program as a Qualified Non-Generator Reactive Resource eligible for the CC rate payment provided that it has satisfied all criteria specified in Section II.B, including a requirement that operating protocols for provision of reactive power voltage support from such equipment have been agreed to, in writing, between the ISO and the Cross Sound Cable operator.

[30] These include: (1) the completion of the market rules and supporting design for the Forward Capacity Market settlement both for the transition period by December, 2006, and the long-term market by February, 2007; (2) developing an implementation proposal for Long-Term Firm Transmission Rights in compliance with the Commission's Final Rule issued in Order No. 681 by January, 2007; and (3) the implementation of Appendix H of the Market Rule 1 implementation, Winter Readiness project, pricing of external nodes, combined cycle modeling and implementation of new Daylight Savings Time measures in system, which are scheduled for implementation over the next several months.

- June 1, 2007 – The Base CC Rate will increase from $1.05/kVAR-year to $2.32/kVAR-year for the lagging capabilities of all dynamic reactive resources that have been accepted into the program. At this time, the ISO will also initiate the formal testing for leading capabilities; that is, all generators seeking to be paid under Schedule 2 will be required to provide the appropriate data necessary to test for leading capability and the first set of generators will perform leading capability tests during the 2007 leading capability test period.

- January 1, 2008 – The Adjusted Base CC Rate will be modified to reflect leading and lagging capability. Also, on this date, all other non-generator dynamic reactive resources that have demonstrated their compliance with the eligibility criteria established in Section II.B will be eligible to receive the CC payment under Schedule 2.

VI. STAKEHOLDER PROCESS

A. Review of the Rules Governing Eligibility and Compensation for Reactive Power in New England

In December 2004, the Transmission Committee established the VWG to review the rules in New England governing the provision of reactive power and voltage support, including eligibility of resources, compensation and testing to recommend whether those rules should change and, if so, how they should change. Per the Transmission Committee's directive, the VWG conducted an in-depth review of: (1) the use of reactive power in New England; (2) what resources should be eligible for compensation; (3) how eligible resources are compensated now under the ISO OATT; (4) how, if at all, such compensation should change; (5) how reactive power costs should be allocated; and (6) the appropriate operational and testing rules associated with items 1-5 above.[31]

On April 25, 2006, the VWG presented to the Transmission Committee its recommendations with respect to each of the issues numbered above for potential modifications to Schedule 2 of the OATT. Following the VWG's presentation, the Transmission Committee requested that the VWG recommend potential modifications to Schedule 2 consistent with its recommendations. The Schedule 2 Amendments reflect the recommendations of the VWG, as discussed in Section IV above.

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[31] The VWG held monthly meetings from January 2005 to April 2006 to review and develop recommendations with respect to the rules governing eligibility for reactive power compensation in New England. These meetings were well-attended by representatives of the various sectors of NEPOOL Participants, representatives of the ISO, state regulatory staff, reactive power equipment developers and other interested persons.

B. NEPOOL Support for the Schedule 2 Amendments

The Schedule 2 Amendments reflect the overwhelming support of the NEPOOL Participants in New England. At its September 19, 2006 meeting, the Transmission Committee voted approximately 93% in favor, with no abstentions, to recommend Participants Committee support for the filing of the Schedule 2 Amendments. At that time, the Schedule 2 Amendments did not include an implementation schedule. At its October 13, 2006 meeting, the Participants Committee voted approximately 88% in support of filing the Schedule 2 Amendments, subject to further recommendation by the Transmission Committee on a specific implementation schedule for the amendments to Schedule 2 and further Participants Committee action on the recommendations. In response, the ISO worked with the Transmission Committee in developing an implementation schedule for the Schedule 2 Amendments. That implementation schedule, as reflected in the Schedule 2 Amendments, was unanimously supported by the Transmission Committee, and subsequently by the Participants Committee.

While the Schedule 2 Amendments reflect the overwhelming support of the Participants in New England, two areas of disagreement remain that warrant some discussion. The first area of disagreement is whether generators should be paid the CC Rate for VARs produced between a power factor range of 0.95 leading and 0.95 lagging. The vast majority of NEPOOL Participants expressed the view that they want to maintain the status quo under Schedule 2 and provide payment to generators for the VAR capability within this power factor range, recognizing that even if interconnected generators are required by way of their interconnection agreements to operate within this range to control voltage they should still be compensated for the reactive power they provide. The proponents of the change, however, proposed to recognize a generator's interconnection agreement requirements by applying a "deadband" in this power factor range for which generators would not be able to receive payment (the "CC Rate Deadband Proposal"), arguing that generators should not be paid for providing a service they have to provide as a requirement of interconnection to the system. Each of these proposals was considered by the Transmission Committee at its September 19, 2006 meeting. The existing CC Rate proposal contained in the Schedule 2 Amendments received approximately 85% support and the CC Rate Deadband Proposal received approximately 16% support.[32]

The second area of disagreement among the Participants involved the allocation of Schedule 2 costs to entities who utilize Schedule 2 services. Currently, reactive power payments under Schedule 2 are paid for by all regional transmission customers (*i.e.*, regional network load and reserved capacity for Through or Out Service). As briefly noted above, this method has been in effect since 1999, and is the same allocation used for non-generator dynamic reactive resources that are owned by the Participating

[32] The CC Rate Deadband Proposal was also presented at the October 13, 2006 Participants Committee meeting and failed to receive Participants Committee support as reflected by a show of hands vote.

Transmission Owners and recovered through regional transmission rates. In its review, the VWG considered two alternatives for the allocation of Schedule 2 costs: (1) to keep the current Commission-approved method of allocating Schedule 2 costs to all regional transmission customers; or (2) to change the cost allocation so that the CC component costs would be allocated under the current method to all transmission customers but the variable costs under Schedule 2 (*i.e.*, the lost opportunity cost, cost of energy produced and cost of energy consumed) would be allocated on a localized basis to transmission customers within the Reliability Region(s) where voltage support is required – the "Reliability Region Cost Allocation Proposal."[33] The latter alternative to localize some costs was considered by the Transmission Committee at the September 19 meeting, but only obtained support of 45% in a straw poll,[34] whereas the former alternative to maintain the status quo for cost allocation received supermajority support.[35]

VII. REQUESTED EFFECTIVE DATE

The ISO and NEPOOL request that the Commission accept the Schedule 2 Amendments as reflected in the appended tariff sheets to become effective March 1, 2007.

VIII. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates.[36] However, the changes included in the Schedule 2 Amendments are not traditional "rates" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the ISO requests waiver of Section 35.13 of the Commission's regulations. Notwithstanding its request for waiver, the ISO submits the following

[33] To put in context, the costs of the fixed component (i.e., the CC costs) over the last 12 calendar months total $12,183,512.83. The variable costs (i.e., the PC, LOC and SCL costs) over the last 12 calendar months total $23,255,938.71.

[34] The Reliability Region Cost Allocation Proposal was also presented to the Participants Committee at the October 13th meeting as a motion to amend the main motion on the substance of Schedule 2, but failed with approximately a 60% vote in favor (a two-thirds or better vote was required to pass the proposed amendment) and thus, is not included in the Schedule 2 Amendments filed herein.

[35] Although the current cost allocation method under Schedule 2 remains unchanged by the Schedule 2 Amendments submitted herein, the ISO intends to address this issue further in its currently established cost allocation working group. The ISO will initiate this effort following the conclusion of the ongoing review of the cost allocation for Local Second Contingency Protection Resources. Once this review is completed, the ISO will discuss the issue with the working group to evaluate the current and potential alternative methods, the underlying policies and implementation requirements, for allocating Schedule 2 costs and to determine whether any changes should be proposed to the current just and reasonable method for allocating such costs within New England.

[36] 18 C.F.R. § 35.13 (2005).

additional information in substantial compliance with relevant provisions of Section 35.13.

35.13(b)(1) - Materials included herewith are as follows:

- This transmittal letter;
- Attachment 1: Redlined Tariff sheets reflecting the changes proposed by this filing;[37]
- Attachment 2: Clean revised Tariff sheets reflecting the changes proposed by this filing;
- Attachment 3: A spreadsheet containing data from AEP methodology filings made by generators in PJM since 2000 used in the development of the updated CC Rate;
- Attachment 4: A spreadsheet containing the historical Schedule 2 VAR costs used to calculate the impact of increasing the CC Rate; and
- Attachment 5: List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been sent.

35.13(b)(2) - As set forth in Section VI above, the ISO and NEPOOL request that the proposed changes become effective March 1, 2007.

35.13(b)(3) - Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at http://www.iso-ne.com/regulatory/ferc/nepool/gov_prtcpnts_eserved.pdf. A paper copy of this transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, and to the New England Conference of Public Utility Commissioners, Inc. The names and addresses of these governors and regulatory agencies are shown in Attachment 3. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified on Attachment 3 to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

[37] Because the changes to Schedule 2 are so extensive, in some places the substance of existing portions of the schedule have shifted to different tariff sheets from where they previously appeared. To make it easier for the Commission to discern the substance of the changes, the redlines in Attachment 1 show the changes in substance rather than the changes to each individual tariff sheet.

35.13(b)(4) - A description of the materials submitted pursuant to this filing is contained in Section IV of this transmittal letter.

35.13(b)(5) - The reasons for this filing are discussed in Sections I and IV of this transmittal letter.

35.13(b)(6) - The ISO's approval of these changes is evidenced by this filing. These changes reflect the results of the Participant Processes required by the Participants Agreement and reflect the support of Participants Committee.

35.13(b)(7) – Neither the ISO nor NEPOOL has knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

IX. CONCLUSION

For the reasons stated above, the ISO and NEPOOL request that the Commission approve this filing, without modification, to be effective on March 1, 2007.

ISO NEW ENGLAND INC.

By: Monica Gonzalez / DRS

Raymond W. Hepper
Monica Gonzalez
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
Tel: (413) 535-4178
Fax: (413) 535-4379
Email: mgonzalez@iso-ne.com

NEW ENGLAND POWER POOL

By: Eric K. Runge / DRS

David T. Doot
Eric K. Runge
Day, Berry & Howard LLP
One International Place
Boston, MA 02110
Tel: (617) 345-4735
Fax: (617) 345-4745
Email: ekrunge@dbh.com

Attachments
cc: Entities Listed in Attachment 5

Attachment 1

SCHEDULE 2

REACTIVE SUPPLY AND VOLTAGE CONTROL FROM ~~GENERATION SOURCES~~QUALIFIED REACTIVE RESOURCES SERVICE

In order to maintain transmission voltages on the New England Transmission System (for voltage constraints that are reflected in the ISO's systems for operating the New England Transmission System or in the ISO~~'s operating procedures~~ New England Operating Procedures) within acceptable limits, ~~generation facilities~~Qualified Reactive Resources (as defined below) are operated to produce (or absorb) reactive power. ~~Thus, Reactive Supply and Voltage Control from Generation Sources Service~~Thus, VAR Service (as defined below) must be provided ~~for each transaction~~to support Regional Network Service and Through or Out Service on the New England Transmission System (~~for~~both of which services have a direct impact on voltage constraints that are reflected in the ISO's systems for operating the New England Transmission System or in the ISO~~'s operating procedures~~ New England Operating Procedures). The amount of ~~Reactive Supply and Voltage Control from Generation Sources~~VAR Service that must be supplied with respect to a Transmission Customer's ~~transaction~~Regional Network Service and Through or Out Service will be determined based on the degree of dynamic reactive power support necessary to maintain transmission voltages within limits that are ~~generally accepted in the region and~~ consistently adhered to ~~by~~in the operation of the New England Transmission ~~Owners~~System. Additional information regarding the processes used to collect data and calculate amounts due or payable under this Schedule 2 can be found in the Ancillary Service Schedule 2 Business Procedure posted on the ISO website. ~~Local level service may be provided~~

~~by the PTOs under Schedule 21 of~~Transmission Customers taking Local Service, MTF Service or OTF Service may also need to acquire voltage support services not otherwise provided under this Schedule 2 pursuant to Schedules 18, 20A, 20B or 21 to this OATT, as appropriate.

~~I. DETERMINING THE AMOUNT TO BE PAID FOR SERVICE UNDER THIS SCHEDULE~~

~~Reactive Supply and Voltage Control from Generation Sources Service is to be provided through the ISO and the Transmission Customer must purchase through the ISO service for voltage support capability provided by Qualified Generators and service when the ISO (or applicable Local Control Center dispatching center) determines, in the exercise of its discretion, that it is necessary to direct a generating unit to alter its operations in an hour in order to provide such service. The charge for such service shall be paid by each Transmission Customer which receives either Regional Network Service or Through or Out Service and shall be determined in accordance with the following formula:~~

$$\cancel{CH = (CC + LOC + SCL + PC)\left(\frac{HL_1 + RC_1}{HL + RC}\right)}$$

~~in which~~

~~CH = the amount to be paid by the Transmission Customer for the hour;~~

I. DEFINITIONS

Qualified Generator Reactive Resource(s): means any generator source of dynamic reactive power that meets the criteria specified in Section II of this Schedule 2.

Qualified Non-Generator Reactive Resource(s): means any non-generator source of dynamic reactive power that meets the criteria specified in Section II of this Schedule 2.

Qualified Reactive Resource(s): means any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource.

VAR Service: means the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power.

VAR Payment: means the payment made to Qualified Reactive Resources for VAR Service capability under Section V.A. of this Schedule 2.

VAR CC Rate: means the CC Rate paid to Qualified Reactive Resources for VAR Service capability under Section V.A. of this Schedule 2.

II. ELIGIBILITY FOR PAYMENT UNDER SCHEDULE 2

A. Qualified Generator Reactive Resources

Qualified Generator Reactive Resources shall be eligible for VAR Payments under this Schedule 2. In addition, any generator that is dispatched by ISO-NE for the purpose of providing voltage support to the New England Transmission System shall be eligible to recover its Lost Opportunity Costs ("LOC"), Cost of Energy Consumed ("CEC"), and Cost of Energy Produced ("CEP") pursuant to Sections V.B-D of this Schedule 2.

A generator shall be deemed a Qualified Generator Reactive Resource if it meets the following criteria:

1. the entity owning or controlling the reactive power capability of the generator reactive resource is a Market Participant;

2. the generator is: (a) interconnected to the New England Transmission System or (b) interconnected to the distribution system but participating in the New England Markets and (c) is metered and dispatchable by the ISO or otherwise subject to operational control by the ISO;

3. the generator provides measurable reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO, and has its automatic voltage regulator status and control mode (including power factor, reactive power output and voltage control) telemetered to the ISO and the applicable Local Control Center; provided that the generator shall have until January 1, 2009 to have the necessary telemetering equipment installed and operating;

4. the generator meets the reactive power testing requirements applicable to generators, as determined from time-to-time by the ISO and specified in the ISO New England Operating Documents; and

5. the installation of the generator shall have been approved in accordance with the requirements of Section I.3.9 of the Tariff or its predecessor or successor provisions under the New England regional transmission arrangements.

Any generator that has been receiving VAR Payments under Schedule 2 prior to June 1, 2007 shall be deemed to be a Qualified Generator Reactive Resource as of that date, provided that it continues to meet the criteria specified in Section II, A. (1), (3) and (4), above; provided that, commencing June 1, 2007, generators that are Qualified Generator

Reactive Resources as of June 1, 2007 but that do not submit an updated NX-12 form with leading VAR data prior to June 1, 2007 will not receive VAR Payments until the beginning of the year following the submittal of their updated NX-12 leading VAR data. Additionally, following June 1, 2007 each generator seeking to be newly designated as a Qualified Generator Reactive Resource shall submit information to the ISO regarding its capability to provide leading VAR Service prior to receiving any leading VAR Payments under Schedule 2. Such information shall be submitted in the form and within the timeframe prescribed in the Ancillary Service Schedule 2 Business Procedure and/or the Schedule 2 VAR Payment Implementation Rule.

B. Qualified Non-Generator Reactive Resources

Qualified Non-Generator Reactive Resources shall be eligible for VAR Payments under this Schedule 2 commencing on January 1, 2008, except for the Cross Sound Cable, which shall be eligible for VAR Payments commencing March 1, 2007, provided that Cross Sound Cable has satisfied all of the eligibility criteria specified below in this Section B. However, to the extent that cost recovery for the dynamic reactive power capability of a non-generator resource could occur under the PTF cost recovery mechanism, it shall occur only under such cost recovery mechanism and not under this Schedule 2.

A non-generator shall be deemed a Qualified Non-Generator Reactive Resource if it meets the following criteria:

1. the entity owning or controlling the reactive power capability of the non-generator reactive power resource is a Market Participant;

2. the non-generator reactive power equipment provides measurable dynamic reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO;

3. the type of dynamic reactive power equipment is within a category of equipment that has been approved by the ISO, with advisory input from the Reliability Committee;

4. the dynamic reactive power equipment is subject to the operating authority of the ISO and all necessary operating protocols for provision of reactive power voltage support from such equipment have been agreed to, in writing, between the ISO and the non-generator reactive power resource;

5. such equipment is interconnected to the New England Transmission System and metered and dispatchable by the ISO or otherwise subject to operational control by the ISO, and has its automatic voltage regulator status and

control mode (including power factor, reactive power output and voltage control) telemetered to the ISO and the applicable Local Control Center; provided that the non-generator shall have until January 1, 2009 to have the necessary telemetering equipment installed and operating;

6. the non-generator reactive resource meets the reactive power testing requirements applicable to such non-generators, as determined from time-to-time by the ISO and specified in the ISO New England Operating Documents; and

7. the installation of such equipment shall have been approved in accordance with the requirements of Section I.3.9 of the Tariff or its predecessor provisions under the New England regional transmission arrangements.

C. Non-Dynamic Reactive Resources

Nothing in this Schedule 2 is intended to preclude, or provide support for, the cost recovery under a separate schedule to the Tariff, filed with the Commission pursuant to the requirements of Sections 205 or 206 of the Federal Power Act, for non-generator, non-dynamic reactive resources that are interconnected to and provide VAR Service to the New England Transmission System but do not meet the criteria to be deemed either Qualified Non-Generator Reactive Resources or PTF.

III. DETERMINING THE AMOUNT TO BE PAID FOR SERVICE UNDER THIS SCHEDULE

~~Reactive Supply and Voltage Control from Generation Sources Service is to~~VAR Service under this Schedule 2 shall be provided through the ISO. ~~and the~~ Transmission Customers must purchase VAR Service through the ISO ~~service for voltage support capability provided by Qualified Generators and service when the ISO (or applicable Local Control Center dispatching center) determines, in the exercise of its discretion, that it is necessary to direct a generating unit to alter its operations in an hour in order to provide such service. The charge for such service shall be paid by each Transmission Customer which receives either Regional Network Service or Through or Out Service and~~for the support of transmission voltages on the New England Transmission System. The charge for VAR Service shall be determined in accordance with the following formula:

$$CH = (CC + LOC + \cancel{SCL + PC}\,CEC + CEP)\left(\frac{HL_1 + RC_1}{HL + RC}\right)$$

in which:

CH = the amount to be paid by the Transmission Customer for the hour;

CC = the capacity costs for the hour shall be the VAR Revenue Requirement determined as set forth herein divided by the number of hours in the month;

LOC = the lost opportunity costs for the hour to be paid ~~to Market Participants who provide VAR support~~for a dynamic reactive power resource that provides VAR Service to meet reliability criteria within one or more Reliability Regions;

CEP~~PC~~ = the cost of energy produced which is the portion of the amount paid ~~to Market Participants~~ for the hour for Energy produced by a ~~generating unit that is considered under this Schedule 2 to be paid for VAR support~~dynamic reactive power resource for VAR Service to meet reliability criteria within one or more Reliability Regions;

CEC~~SCL~~ = the cost of energy consumed which is the cost of energy used in the hour by ~~generating facilities, synchronous condensers or static controlled VAR regulators~~a dynamic reactive power resource in order to provide VAR ~~support to the transmission system~~Service to meet reliability crieria within one or more Reliability Regions;

HL_1 = the Regional Network Load of the Transmission Customer for the hour;

HL	=	the aggregate of the Regional Network Loads of all Transmission Customer for the hour;
RC_1	=	the Reserved Capacity for Through or Out Service of the Transmission Customers for the hour; and
RC	=	the aggregate Reserved Capacity for Through or Out Service of all Transmission Customers for the hour.

IV. ALLOCATION OF VAR SERVICE COSTS

The charge for VAR Service shall be paid by each Transmission Customer that receives either Regional Network Service or Through or Out Service.

V~~II~~. DETERMINING A ~~GENERATOR'S COMPENSATION FOR PROVIDING SERVICE~~QUALIFIED REACTIVE RESOURCE'S PAYMENT UNDER THIS SCHEDULE

The compensation to be paid to ~~generators~~resources providing ~~Schedule 2~~VAR ~~s~~Service shall be ~~based on the four components~~as set forth below.

~~1~~A. Capacity Cost (CC)

~~1.~~1. A Qualified ~~Generator~~Reactive Resource shall be eligible to receive ~~compensation for the capability to deliver VARs to the system (a "~~VAR Payment~~s")~~ under the Capacity Cost component of this Schedule 2

~~measurable voltage support, as determined from time to time by the ISO to the New England Control Area~~for the capability to provide VAR Service.~~as provided herein. A "Qualified Generator" is any generator that is in the Market System and provides~~

~~1.~~2. ~~The VAR~~ Payment for VAR Service associated with lagging capability is not intended to compensate a Qualified Generator ~~for losses associated with station use and energizing the generator leads and~~Reactive Resource for reactive power absorbed by the generator step-up transformer. Payment for VAR Service associated with leading capability is intended to compensate a Qualified Generator Reactive Resource for reactive power absorbed by the generator step-up transformer.

~~1.~~3. The "VAR CC Rate" will be established each year as of January 1 on a prospective basis for that calendar year and shall be the ~~Base VAR~~Adjusted CC Rate * Min (1, (1.2*Forecast Peak Adjusted Reference Load for the year/(SUM of all ~~(~~Qualified ~~Generator's~~Reactive Resources' Summer Seasonal Claimed Capability))).

~~1.~~4. ~~The "Base VAR Rate" shall be $0.90/kVAR-yr in 2001; $0.95/kVAR-yr in 2002; $1.00/kVAR-yr in 2003 and $1.05/kVAR-yr in 2004 and thereafter.~~The "Base CC Rate" shall be $1.05/kVAR-yr before June 1, 2007 and shall be $2.32/kVAR-yr commencing June 1, 2007 and shall not be changed pursuant to Section 205 of the Federal Power Act until January 1, 2012. An examination of the Base CC Rate shall be completed no later than July 1, 2011; such examination shall determine whether the Base CC

Rate is still appropriate or whether it should be changed commencing

January 1, 2012.

5. Commencing January 1, 2008, the Adjusted CC Rate shall be a single rate applied over the full range of leading and lagging capability of a Qualified Reactive Resource and shall be determined as described below. Until then, the Adjusted CC Rate shall be applicable only for lagging capability and shall equal the Base CC Rate. Commencing January 1, 2008, on an annual basis, the Base CC Rate shall be converted into an Adjusted CC Rate, expressed in the form of $/kVAR-yr, representing the amount to be paid for leading and lagging capability. From that time forward, the Adjusted CC Rate shall be calculated in accordance with the following formula: Adjusted CC Rate ($CCRate_{adjusted}$) shall equal: (the Base CC Rate ($CCRate_{base}$) * Current Total Aggregate lagging VARs) / (Current Total Aggregate Lagging VARs + Current Total Aggregate Leading VARs). The basis of each such formula element and methodology for calculation is set forth in the Schedule 2 VAR Payment Implementation Rule. The details of the Schedule 2 VAR Payment Implementation Rule may be modified by the ISO without a filing under the Federal Power Act, provided that: (i) the modifications are consistent with the requirements of this Schedule 2; and (ii) the modifications receive the support of at least two-thirds of the voting percentage of the Transmission Committee members.

~~1.5~~6. The "Forecast Peak Adjustment Reference Load" shall be the value published in the then-most recently published Forecast Report of Capacity, Energy, Loads and Transmission (the "CELT ~~r~~Report") at the time the VAR CC Rate is established for a year.

7. "Seasonal Claimed Capability" for Qualified Reactive Resources shall be determined as follows:

a.~~1.6.~~ A "Qualified Generator Reactive Resource's Seasonal Claimed Capability" shall be the Seasonal Claimed Capability of each Qualified Generator applicable for the season in which the ISO Forecast Peak Adjusted Load is forecast to occur. The Seasonal Claimed Capability (SCC) represents the Summer (SCC-S) and Winter (SCC-W) Claimed Capability of a generating unit (or ISO approved combination of units in accordance with ISO New England Operating Procedures). Claimed Capability Ratings are the maximum dependable load carrying ability, in megawatts to three decimal places, of such unit or units, excluding capacity required for station use. SCC-S and SCC-W are the MW values of the Resource that will be used as billing determinants under this Tariff.

b. A “Qualified Non-Generator Reactive Resource’s Seasonal Claimed Capability” shall be 2.5 times the maximum dynamic reactive power capability on a lagging basis demonstrated by the Qualified Non-Generator Reactive Resource during the testing of its VAR Service capability consistent with ISO Procedures for measurement of such capability.

~~1.~~7. The “VAR Revenue Requirement” shall be the sum over a month of all Qualified Reactive Resources’ VAR Payments~~SUM (Qualified Generator’s VAR Payment)~~.

~~1.~~8. A Qualified ~~Generator~~Reactive Resource’s VAR Payment shall equal ~~the~~ (1/12) * (VAR CC Rate*Qualified VARs).

~~1.8.1. The VAR Rate is determined pursuant to paragraph 1.3 above.~~

~~1.8.2~~9. Qualified ~~Generators~~Reactive Resources will be paid their VAR Rate under this Section for each month of a calendar year starting with the month in which ~~this Section becomes effective~~the resource is approved as a Qualified Reactive Resource.

~~1.9. “Qualified VARs” shall be:~~

~~1.9.1. Qualified VARs of an untested unit shall be equal to the Lagging VAR capability at Seasonal Claimed Capability for the season of forecasted peak as indicated on the Qualified Generator’s NX-12D form that is then in effect adjusted for losses to station service and energizing the generator leads and generator step-up transformer.~~

10. “Qualified VARs” shall be determined as follows:

(a)~~1.9.2.~~ ~~As soon as practicable, but in no event longer than two years from the effective date of this Section,~~In accordance with the ISO New England Operating Procedures, the Qualified VARs of a Qualified ~~Generator~~Reactive Resource initially shall be determined ~~at its point of delivery to the system,~~through an actual testing in accordance with the then-applicable ~~Operating Procedures~~VAR testing procedures set forth in the ISO New England Operating Procedures. At least every five (5) years after that initial test, an ongoing test of the ~~VAR~~ capability of a Qualified ~~Generator across its full operating range shall be conducted~~Reactive Resource to supply VAR Service in both leading and lagging capability shall be conducted. Prior to January 1, 2008, the Qualified VARs of a Qualified Reactive Resource shall equal the lagging VAR capability of the resource as determined pursuant to this section. On and after January 1, 2008, the Qualified VARs of a Qualified Reactive Resource shall equal the sum total of the absolute values of the leading and lagging VAR capability of the resource determined pursuant to this section.

(b) Prior to January 1, 2008:

- the Qualified VARs of an untested Qualified Generator Reactive Resource shall be equal to the lagging VAR capability at the Summer Seasonal Claimed Capability as indicated on the Qualified Generator Reactive Resource's

NX-12D form that is then in effect adjusted (downward for lagging capability) for reactive power absorbed by the generator step-up transformer.

- The Qualified VARs of an untested Qualified Non Generator Reactive Resource shall be equal to the lagging VAR capability at the corresponding Summer Seasonal Claimed Capability or an equivalent point as indicated on the Qualified Non-Generator Reactive Resource's NX-12D form that is then in effect adjusted for reactive power absorbed by its step-up transformer.

(c) On and after January 1, 2008:

- the Qualified VARs of an untested Qualified Generator Reactive Resource shall be equal to the sum of the absolute values of the lagging VAR capability at the Summer Seasonal Claimed Capability and the leading VAR capability at the EcoMin point as indicated on the Qualified Generator Reactive Resource's NX-12D form that is then in effect adjusted (downward for lagging capability and upward for leading capability) for reactive power absorbed by the generator step-up transformer.

- The Qualified VARs of an untested Qualified Non-Generator Reactive Resource shall be equal to the sum of the absolute values of the lagging VAR capability at the corresponding Summer Seasonal Claimed Capability or an equivalent point and the leading VAR capability at the corresponding EcoMin point or an equivalent point as indicated on the Qualified Non-Generator Reactive Resource's NX-12D form that is then in effect adjusted for reactive power absorbed by its step-up transformer.

~~2~~B. Lost Opportunity Cost (LOC)

~~2.~~1. ~~The Lost Opportunity Cost for hydro, pumped storage and thermal generating units~~ The LOC for generators that are dispatched down by, or at the request of, the ISO, or a ~~PTO's~~ Local Control Center~~, or PTO dispatch center~~ for the purpose of providing ~~reactive supply and voltage control~~VAR Service will be calculated pursuant to Market Rule 1.

2. Commencing January 1, 2008, Qualified Non-Generator Reactive Resources shall be eligible for payment of the LOC for Qualified Non-Generator Reactive Resources that are dispatched down (pursuant to the authority established within written operating protocols developed under Section II.B.4) at the request of the ISO or a Local Control Center for the purpose of providing VAR Service. The LOC of such Qualified Non-Generator Reactive Resources will be calculated pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

C~~3~~. Cost of Energy Consumed (CEC~~SCL~~)

~~3.~~1. ~~Motoring Hydro or Pumped Storage Generating Units.~~ The CEC~~SCL~~ associated with hydro and pumped storage generating units that are motoring at the request of the ISO~~,~~ or a ~~PTO's~~ Local Control Center~~, or PTO dispatch center~~ for the purpose of providing ~~reactive supply and voltage control~~VAR Service will equal the cost of energy to motor and will be calculated in each hour as follows: CEC~~SCL~~ = (MWhUnit * (~~ECP or~~ LMP or ~~A~~actual energy cost), where the MWh Unit are calculated pursuant to the Ancillary Service Schedule 2 Business Procedure. The ~~A~~actual energy cost applies only if motoring energy is purchased through a bilateral contract.

~~3.~~2. ~~Synchronous Condensers and Static Controlled VAR Regulators (SC/SCV). The SCL~~For the Chester SCV, the CEC will be set to zero ($0), and the cost of energy to supply reactive supply and voltage control from the Chester SCV will be treated as losses on the New England Transmission System.~~ This treatment will be revisited by the ISO on an as-needed basis (*e.g.*, upon the addition of a new SC or SCV within the New England Control Area).~~

3. Commencing January 1, 2008, Qualified Non-Generator Reactive Resources shall be eligible for payment of the CEC incurred by

Qualified Non-Generator Reactive Resources for the purpose of providing VAR Service (pursuant to the authority established within written operating protocols developed under Section II.B.4). The CEC of such Qualified Non-Generator Reactive Resources shall be measured pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

4. Cost of Energy Produced (CEP~~PC~~)

4.~~.~~1. ~~Thermal Generating Units.~~ The CEP~~PC~~ associated with thermal generating units that are brought on-line by the ISO~~,~~ or a ~~PTO's~~ Local Control Center~~, or PTO dispatch center~~ for the purpose of providing ~~reactive supply and voltage control~~VAR Service shall equal the portion of the total uplift to be paid that resource for a day that is attributed to the hour(s) during which the resource is run to provide ~~this service~~VAR Service in accordance with Market Rule 1 and the ISO ~~System Rules~~New England Operating Documents.

4.~~.~~2. ~~Hydro and Pumped Storage Generating Units. The PC~~The CEP associated with hydro or pumped storage generating units that are producing real power and that have also been brought on-line by the ISO~~,~~ or a ~~PTO's~~ Local Control Center~~, or PTO dispatch center~~ to provide ~~reactive supply and voltage control~~ VAR Service shall equal the portion of the total uplift to be paid that resource for a day that is attributed to the hour(s) during which the resource is run to provide ~~this service~~VAR Service in accordance with Market Rule 1 and the ISO ~~System Rules~~New England Operating Documents.

3. Commencing January 1, 2008, Qualified Non-Generator Reactive Resources shall be eligible for payment of the CEP incurred by

Qualified Non-Generator Reactive Resources for the purpose of providing VAR Service (pursuant to the authority established within written operating protocols developed under Section II.B.4). The CEP of such Qualified Non-Generator Reactive Resources shall be measured pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

VI. ALTERNATIVE PAYMENT FOR VAR SERVICE

Where a non-generator source of VAR Service (i) responds to identified needs for dynamic reactive power on the New England Transmission System, as identified in the Regional System Plan, and (ii) is confirmed by the ISO as a dynamic reactive power resource that will meet the identified need, and (iii) such non-generator source of VAR Service meets the criteria to be a Qualified Non-Generator Reactive Resource but cannot recover its costs of providing dynamic reactive power under Schedule 2, such non-generator may submit a separate schedule to the ISO OATT to be filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act for a rate to be paid to allow such resource to recover its costs related to providing VAR Service. In such case, it shall not be considered a Qualified Non-Generator Reactive Resource under this Schedule 2 and its provision of VAR Service and payment shall be governed solely by such separate schedule filed with the Commission.

SCHEDULE 2 VAR PAYMENT IMPLEMENTATION RULE

This rule describes the steps to be taken to calculate the VAR CC Rate on or after January 1, 2008 in accordance with Section V.A. of Schedule 2. Applicable to that time forward on an annual basis, the Base CC Rate shall be converted into a VAR CC Rate, expressed in the form of $/kVAR-yr, representing the amount to be paid for leading and lagging capability.

The following calculations shall be done in December of each year to calculate the VAR CC Rate for the next year of VAR Payments for leading and lagging reactive power capability in the following year. As described below, the VAR CC Rate shall be updated on an annual basis utilizing the most current leading and lagging test results, and it is expected to take three years to test all of the Qualified Reactive Resources in leading mode.

1. Calculate the "Current Total Aggregate Lagging VARs", which shall equal the "Current Net Aggregate Tested Lagging VARs" plus the "Current Net Aggregate Non-Tested Lagging VARs";

   Where:

   a. the Current Net Aggregate Tested Lagging VARs shall equal the total of Net Lagging kVARs for all Schedule 2 Qualified Reactive Resources that have completed a successful lagging VAR test, as reflected in the most current monthly *VAR Status Report* that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html); this value will reflect the lagging kVARs of Schedule 2 Qualified Reactive Resources as taken from its lagging VAR test results adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross lagging VARs test results adjusted down for losses); and

b. the Current Net Aggregate Non-Tested lagging VARs shall equal the total of net lagging kVARs for all Schedule 2 Qualified Reactive Resources that have not yet completed a successful lagging VAR test, as reflected in the most current monthly *VAR Status Report* that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html); this value will reflect the lagging kVARs of Schedule 2 Qualified Reactive Resources as taken from its NX-12D (and NX-9B, where needed to calculate generator step-up transformer losses) data at EcoMin adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross lagging VARs NX-12D data at SCC adjusted down for losses).

c. Increase and decrease limiters shall be applied to potential increases or decreases in the Current Total Aggregate Lagging VARs as follows:

i. Current Total Aggregate Lagging VARs Limiters for Year 1 (2008) and Year 3 (2010):

- The Current Total Aggregate Lagging VARs value shall not be limited for Year 1 and Year 3.

ii. Current Total Aggregate Lagging VARs Limiters for Year 2 (2009):

- Current Total Aggregate Lagging VARs Increase Limiter for Year 2: the calculated Current Total Aggregate Lagging VARs will be limited to no greater than 110% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for the prior year (Year 1); and

- Current Total Aggregate Lagging VARs Decrease Limiter for Year 2: the calculated Current Total Aggregate Lagging VARs will be limited to no less than 90% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for the prior year (Year 1).

iii. Current Total Aggregate Lagging VARs Limiters for Year 4 (2011) and beyond:

- Current Total Aggregate Lagging VARs Increase Limiter for Year 4 and beyond: the calculated Current Total Aggregate Lagging VARs will be limited to no greater than 130% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for Year 3; and

- Current Total Aggregate Lagging VARs Decrease Limiter for Year 4 and beyond**:** the calculated Current Total Aggregate Lagging VARs will be limited to no less than 70% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for Year 3.

2. Calculate the Current Total Aggregate Leading VARs which shall equal the Current Net Aggregate Tested Leading VARs plus the Current Net Aggregate Non-Tested Leading VARs;

Where:

a. the Current Net Aggregate Tested Leading VARs shall equal the total of Net Leading kVARs for all Schedule 2 Qualified Reactive Resources that have completed a successful Leading VAR Test, as reflected in the most current monthly *VAR Status Report* that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html); this value will reflect the Leading kVARs of Schedule 2 Qualified Reactive Resources as taken from its leading VAR test results adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross leading VARs test results adjusted up for losses);

b. the Current Net Aggregate Non-Tested Leading VARs: shall equal the total of Net Leading kVARs for all Schedule 2 Qualified Reactive Resources that have not yet completed a successful Leading VAR Test, as reflected in the most current monthly *VAR Status Report* that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html). This value will reflect the Leading kVARs of Schedule 2 Qualified Reactive Resources as taken from its NX-12D (and NX-9B, where needed to calculate generator step-up transformer losses) data at EcoMin adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross leading VARs NX-12D data at EcoMin adjusted up for losses).

c. Current Total Aggregate Leading VARs Limiters

i. Current Total Aggregate Leading VARs Limiters for Year 1 and Year 4:

- The Current Total Aggregate Leading VARs value shall not be limited for Year 1 (2008) and Year 3 (2010) .

ii. Current Total Aggregate Leading VARs Limiters for Year 2 (2009) :

- Current Total Aggregate Leading VARs Increase Limiter for Year 2: the calculated Current Total Aggregate Leading VARs will be limited to no greater than 110% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for the prior year (Year 1); and

- Current Total Aggregate Leading VARs Decrease Limiter for Year 2: the calculated Current Total Aggregate Leading VARs will be limited to no less than 90% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for the prior year (Year 1).

iii. Current Total Aggregate Leading VARs Limiters for Year 4 and beyond:

- Current Total Aggregate Leading VARs Increase Limiter for Year 4 (2011) and beyond: the calculated Current Total Aggregate Leading VARs will be limited to no greater than 130% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for Year 3; and

- Current Total Aggregate Leading VARs Decrease Limiter for Year 4 and beyond: the calculated Current Total Aggregate Leading VARs will be limited to no less than 70% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for Year 3.

3. Calculate the Adjusted CC Rate ($CCRate_{adjusted}$): shall equal (the Base CC $Rate_{e}$ * Current Total Aggregate Lagging VARs) / (Current Total Aggregate Lagging VARs + Current Total Aggregate Leading VARs) where the Base CC Rate shall equal $2.32/kVAR-yr unless changed as provided for under Schedule 2.

4. VAR CC Rate ("VARCCRate"): shall equal (the Adjusted CC Rate) * (the lesser of 1 or (1.2 * "Forecast Peak Adjusted Reference Load" for the year / the sum of the "Qualified Reactive Resources' Seasonal Claimed Capability"));

Where:

a. the "Forecast Peak Adjusted Reference Load" for the year shall equal the amount specified as "Adjusted Reference Load" for the applicable year in *Section I.1 - Summaries – Summer* from the most current *Forecast Report of Capability, Energy, Loads and Transmission (CELT Report) (*http://www.iso-ne.com/trans/celt/report/index.html*)*;

b. The sum of the "Qualified Reactive Resources' Seasonal Claimed Capability" shall equal the Qualified Generator Reactive Resources' Seasonal Claimed Capability plus the Qualified Non-Generator Reactive Resources' Adjusted Seasonal Claimed Capability;

Where:

i. the Qualified Generator Reactive Resources' Seasonal Claimed Capability: shall equal the total of the *"Summer Seasonal Claimed Capability"* column of all Qualified Generator VAR Resources from the most current *VAR Status Report* (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html); and

ii. the Qualified Non-Generator Reactive Resources' Adjusted Seasonal Claimed Capability shall equal 2.50 times the total of the *"Summer Seasonal Claimed Capability"* column of all Qualified non-Generator VAR Resources from the most current *VAR Status Report* (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html).

5. Monthly VAR Payment for a Qualified Reactive Resource in a particular month shall equal the (VARCCRate / 12 * (its Monthly Net Lagging VARs for that month + its Monthly Net Leading VARs for that month)), as reflected in the applicable monthly *VAR Status Report* that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html).

a. Monthly Net Lagging VARs: Qualified Reactive Resource's Monthly Net Lagging VARs value shall equal its VAR value based on (a) its most recent successful Lagging VAR test or (b) if it has not yet completed such a test, its VAR value at SCC based on its submitted and ISO accepted NX-12D and NX-9B data. The Qualified VAR Resource's Monthly Net Lagging VARs value shall be reflected in the applicable monthly *VAR Status Report* that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html).

b. Monthly Net Leading VARs: a Qualified Reactive Resource's Monthly Net Leading VARs value shall equal its VAR value based on (a) its most recent successful Leading VAR test or (b) if it has not yet completed such a test, its VAR value at EcoMin based on its submitted and ISO accepted NX-12D and NX-9B data. The Qualified Reactive Resource's Monthly Net Leading VARs value shall be reflected in the applicable monthly *VAR Status Report* that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html).

Attachment 2

SCHEDULE 2

REACTIVE SUPPLY AND VOLTAGE CONTROL FROM QUALIFIED REACTIVE RESOURCES SERVICE

In order to maintain transmission voltages on the New England Transmission System (for voltage constraints that are reflected in the ISO's systems for operating the New England Transmission System or in the ISO New England Operating Procedures) within acceptable limits, Qualified Reactive Resources (as defined below) are operated to produce (or absorb) reactive power. Thus, VAR Service (as defined below) must be provided to support Regional Network Service and Through or Out Service on the New England Transmission System (both of which services have a direct impact on voltage constraints that are reflected in the ISO's systems for operating the New England Transmission System or in the ISO New England Operating Procedures). The amount of VAR Service that must be supplied with respect to a Transmission Customer's Regional Network Service and Through or Out Service will be determined based on the degree of dynamic reactive power support necessary to maintain transmission voltages within limits that are consistently adhered to in the operation of the New England Transmission System. Additional information regarding the processes used to collect data and calculate amounts due or payable under this Schedule 2 can be found in the Ancillary Service Schedule 2 Business Procedure posted on the ISO website. Transmission Customers taking Local Service, MTF Service or OTF Service may also need to acquire voltage support services not otherwise provided under this Schedule 2 pursuant to Schedules 18, 20A, 20B or 21 to this OATT, as appropriate.

I. DEFINITIONS

Qualified Generator Reactive Resource(s): means any generator source of dynamic reactive power that meets the criteria specified in Section II of this Schedule 2.

Qualified Non-Generator Reactive Resource(s): means any non-generator source of dynamic reactive power that meets the criteria specified in Section II of this Schedule 2.

Qualified Reactive Resource(s): means any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource.

VAR Service: means the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power.

VAR Payment: means the payment made to Qualified Reactive Resources for VAR Service capability under Section V.A. of this Schedule 2.

VAR CC Rate: means the CC Rate paid to Qualified Reactive Resources for VAR Service capability under Section V.A. of this Schedule 2.

II. ELIGIBILITY FOR PAYMENT UNDER SCHEDULE 2

A. Qualified Generator Reactive Resources

Qualified Generator Reactive Resources shall be eligible for VAR Payments under this Schedule 2. In addition, any generator that is dispatched by ISO-NE for the purpose of providing voltage support to the New England Transmission System shall be eligible to recover its Lost Opportunity Costs ("LOC"), Cost of Energy Consumed ("CEC"), and Cost of Energy Produced ("CEP") pursuant to Sections V.B-D of this Schedule 2.

A generator shall be deemed a Qualified Generator Reactive Resource if it meets the following criteria:

1. the entity owning or controlling the reactive power capability of the generator reactive resource is a Market Participant;

2. the generator is: (a) interconnected to the New England Transmission System or (b) interconnected to the distribution system but participating in the New England Markets and (c) is metered and dispatchable by the ISO or otherwise subject to operational control by the ISO;

3. the generator provides measurable reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO, and has its automatic voltage regulator status and control mode (including power factor, reactive power output and voltage control) telemetered to the ISO and the applicable Local Control Center; provided that the generator shall have until January 1, 2009 to have the necessary telemetering equipment installed and operating;

4. the generator meets the reactive power testing requirements applicable to generators, as determined from time-to-time by the ISO and specified in the ISO New England Operating Documents; and

5. the installation of the generator shall have been approved in accordance with the requirements of Section I.3.9 of the Tariff or its predecessor or successor provisions under the New England regional transmission arrangements.

Any generator that has been receiving VAR Payments under Schedule 2 prior to June 1, 2007 shall be deemed to be a Qualified Generator Reactive Resource as of that date, provided that it continues to meet the criteria specified in Section II, A. (1), (3) and (4), above; provided that, commencing June 1, 2007, generators that are Qualified Generator

Reactive Resources as of June 1, 2007 but that do not submit an updated NX-12 form with leading VAR data prior to June 1, 2007 will not receive VAR Payments until the beginning of the year following the submittal of their updated NX-12 leading VAR data. Additionally, following June 1, 2007 each generator seeking to be newly designated as a Qualified Generator Reactive Resource shall submit information to the ISO regarding its capability to provide leading VAR Service prior to receiving any leading VAR Payments under Schedule 2. Such information shall be submitted in the form and within the timeframe prescribed in the Ancillary Service Schedule 2 Business Procedure and/or the Schedule 2 VAR Payment Implementation Rule.

B. <u>Qualified Non-Generator Reactive Resources</u>

Qualified Non-Generator Reactive Resources shall be eligible for VAR Payments under this Schedule 2 commencing on January 1, 2008, except for the Cross Sound Cable, which shall be eligible for VAR Payments commencing March 1, 2007, provided that Cross Sound Cable has satisfied all of the eligibility criteria specified below in this Section B. However, to the extent that cost recovery for the dynamic reactive power capability of a non-generator resource could occur under the PTF cost recovery mechanism, it shall occur only under such cost recovery mechanism and not under this Schedule 2.

A non-generator shall be deemed a Qualified Non-Generator Reactive Resource if it meets the following criteria:

1. the entity owning or controlling the reactive power capability of the non-generator reactive power resource is a Market Participant;

2. the non-generator reactive power equipment provides measurable dynamic reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO;

3. the type of dynamic reactive power equipment is within a category of equipment that has been approved by the ISO, with advisory input from the Reliability Committee;

4. the dynamic reactive power equipment is subject to the operating authority of the ISO and all necessary operating protocols for provision of reactive power voltage support from such equipment have been agreed to, in writing, between the ISO and the non-generator reactive power resource;

5. such equipment is interconnected to the New England Transmission System and metered and dispatchable by the ISO or otherwise subject to operational control by the ISO, and has its automatic voltage regulator status and

control mode (including power factor, reactive power output and voltage control) telemetered to the ISO and the applicable Local Control Center; provided that the non-generator shall have until January 1, 2009 to have the necessary telemetering equipment installed and operating;

6. the non-generator reactive resource meets the reactive power testing requirements applicable to such non-generators, as determined from time-to-time by the ISO and specified in the ISO New England Operating Documents; and

7. the installation of such equipment shall have been approved in accordance with the requirements of Section I.3.9 of the Tariff or its predecessor provisions under the New England regional transmission arrangements.

C. Non-Dynamic Reactive Resources

Nothing in this Schedule 2 is intended to preclude, or provide support for, the cost recovery under a separate schedule to the Tariff, filed with the Commission pursuant to the requirements of Sections 205 or 206 of the Federal Power Act, for non-generator, non-dynamic reactive resources that are interconnected to and provide VAR Service to the New England Transmission System but do not meet the criteria to be deemed either Qualified Non-Generator Reactive Resources or PTF.

III. DETERMINING THE AMOUNT TO BE PAID FOR SERVICE UNDER THIS SCHEDULE

VAR Service under this Schedule 2 shall be provided through the ISO. Transmission Customers must purchase VAR Service through the ISO for the support of transmission voltages on the New England Transmission System. The charge for VAR Service shall be determined in accordance with the following formula:

$$CH = (CC + LOC + CEC + CEP)\left(\frac{HL_1 + RC_1}{HL + RC}\right)$$

in which:

CH = the amount to be paid by the Transmission Customer for the hour;

CC = the capacity costs for the hour shall be the VAR Revenue Requirement determined as set forth herein divided by the number of hours in the month;

LOC = the lost opportunity costs for the hour to be paid for a dynamic reactive power resource that provides VAR Service to meet reliability criteria within one or more Reliability Regions;

CEP = the cost of energy produced which is the portion of the amount paid for the hour for Energy produced by a dynamic reactive power resource for VAR Service to meet reliability criteria within one or more Reliability Regions;

CEC = the cost of energy consumed which is the cost of energy used in the hour by a dynamic reactive power resource in order to provide VAR Service to meet reliability crieria within one or more Reliability Regions;

HL_1 = the Regional Network Load of the Transmission Customer for the hour;

HL = the aggregate of the Regional Network Loads of all Transmission Customer for the hour;

RC_1 = the Reserved Capacity for Through or Out Service of the Transmission Customers for the hour; and

RC = the aggregate Reserved Capacity for Through or Out Service of all Transmission Customers for the hour.

IV. ALLOCATION OF VAR SERVICE COSTS

The charge for VAR Service shall be paid by each Transmission Customer that receives either Regional Network Service or Through or Out Service.

V. DETERMINING A QUALIFIED REACTIVE RESOURCE'S PAYMENT UNDER THIS SCHEDULE

The compensation to be paid to resources providing VAR Service shall be as set forth below.

A. Capacity Cost (CC)

1. A Qualified Reactive Resource shall be eligible to receive VAR Payments under the Capacity Cost component of this Schedule 2 for the capability to provide VAR Service.

2. Payment for VAR Service associated with lagging capability is not intended to compensate a Qualified Generator Reactive Resource for reactive power absorbed by the generator step-up transformer. Payment for VAR Service associated with leading capability is intended to compensate a Qualified Generator Reactive Resource for reactive power absorbed by the generator step-up transformer.

3. The "VAR CC Rate" will be established each year as of January 1 on a prospective basis for that calendar year and shall be the Adjusted CC Rate * Min (1, (1.2*Forecast Peak Adjusted Reference Load for the year/(SUM of all Qualified Reactive Resources' Summer Seasonal Claimed Capability))).

4. The "Base CC Rate" shall be $1.05/kVAR-yr before June 1, 2007 and shall be $2.32/kVAR-yr commencing June 1, 2007 and shall not be changed pursuant to Section 205 of the Federal Power Act until January 1, 2012. An examination of the Base CC Rate shall be completed no later than July 1, 2011; such examination shall determine whether the Base CC Rate is still appropriate or whether it should be changed commencing January 1, 2012.

5. Commencing January 1, 2008, the Adjusted CC Rate shall be a single rate applied over the full range of leading and lagging capability of a Qualified Reactive Resource and shall be determined as described below. Until then, the Adjusted CC Rate shall be applicable only for lagging capability and shall equal the Base CC Rate. Commencing January 1, 2008, on an annual basis, the Base CC Rate shall be converted into an Adjusted CC Rate, expressed in the form of $/kVAR-yr, representing the amount to be paid for leading and lagging capability. From that time forward, the Adjusted CC Rate shall be calculated in accordance with the following formula: Adjusted CC Rate ($CCRate_{adjusted}$) shall equal: (the Base CC Rate ($CCRate_{base}$) * Current Total Aggregate lagging VARs) / (Current Total Aggregate Lagging VARs + Current Total Aggregate Leading VARs). The basis of each such formula element and methodology for calculation is set forth in the Schedule 2 VAR Payment Implementation Rule. The details of the Schedule 2 VAR Payment Implementation Rule may be modified by the ISO without a filing under the Federal Power Act, provided that: (i) the modifications are consistent with the requirements of this Schedule 2; and (ii) the modifications receive the support of at least two-thirds of the voting percentage of the Transmission Committee members.

6. The “Forecast Peak Adjustment Reference Load” shall be the value published in the then-most recently published Forecast Report of Capacity, Energy, Loads and Transmission (the “CELT Report”) at the time the VAR CC Rate is established for a year.

7. “Seasonal Claimed Capability” for Qualified Reactive Resources shall be determined as follows:

   a. A “Qualified Generator Reactive Resource’s Seasonal Claimed Capability” shall be the Seasonal Claimed Capability of each Qualified Generator applicable for the season in which the ISO Forecast Peak Adjusted Load is forecast to occur. The Seasonal Claimed Capability (SCC) represents the Summer (SCC-S) and Winter (SCC-W) Claimed Capability of a generating unit (or ISO approved combination of units in accordance with ISO New England Operating Procedures). Claimed Capability Ratings are the maximum dependable load carrying ability, in megawatts to three decimal places, of such unit or units, excluding capacity required for station use. SCC-S and SCC-W are the MW values of the Resource that will be used as billing determinants under this Tariff.

b. A "Qualified Non-Generator Reactive Resource's Seasonal Claimed Capability" shall be 2.5 times the maximum dynamic reactive power capability on a lagging basis demonstrated by the Qualified Non-Generator Reactive Resource during the testing of its VAR Service capability consistent with ISO Procedures for measurement of such capability.

7. The "VAR Revenue Requirement" shall be the sum over a month of all Qualified Reactive Resources' VAR Payments.

8. A Qualified Reactive Resource's VAR Payment shall equal (1/12) * (VAR CC Rate*Qualified VARs).

9. Qualified Reactive Resources will be paid their VAR Rate under this Section for each month of a calendar year starting with the month in which the resource is approved as a Qualified Reactive Resource.

10. "Qualified VARs" shall be determined as follows:

(a) In accordance with the ISO New England Operating Procedures, the Qualified VARs of a Qualified Reactive Resource initially shall be determined through an actual testing in accordance with the then-applicable VAR testing procedures set forth in the ISO New England Operating Procedures. At least every five (5) years after that initial test, an ongoing test of the capability of a Qualified Reactive Resource to supply VAR Service in both leading and lagging capability shall be conducted. Prior to January 1, 2008, the Qualified VARs of a Qualified Reactive Resource shall equal the lagging VAR capability of the resource as determined pursuant to this section. On and after January 1, 2008, the Qualified VARs of a Qualified Reactive Resource shall equal the sum total of the absolute values of the leading and lagging VAR capability of the resource determined pursuant to this section.

(b) Prior to January 1, 2008:

- the Qualified VARs of an untested Qualified Generator Reactive Resource shall be equal to the lagging VAR capability at the Summer Seasonal Claimed Capability as indicated on the Qualified Generator Reactive Resource's

NX-12D form that is then in effect adjusted (downward for lagging capability) for reactive power absorbed by the generator step-up transformer.

- The Qualified VARs of an untested Qualified Non Generator Reactive Resource shall be equal to the lagging VAR capability at the corresponding Summer Seasonal Claimed Capability or an equivalent point as indicated on the Qualified Non-Generator Reactive Resource's NX-12D form that is then in effect adjusted for reactive power absorbed by its step-up transformer.

(c) On and after January 1, 2008:

- the Qualified VARs of an untested Qualified Generator Reactive Resource shall be equal to the sum of the absolute values of the lagging VAR capability at the Summer Seasonal Claimed Capability and the leading VAR capability at the EcoMin point as indicated on the Qualified Generator Reactive Resource's NX-12D form that is then in effect adjusted (downward for lagging capability and upward for leading capability) for reactive power absorbed by the generator step-up transformer.

- The Qualified VARs of an untested Qualified Non-Generator Reactive Resource shall be equal to the sum of the absolute values of the lagging VAR capability at the corresponding Summer Seasonal Claimed Capability or an equivalent point and the leading VAR capability at the corresponding EcoMin point or an equivalent point as indicated on the Qualified Non-Generator Reactive Resource's NX-12D form that is then in effect adjusted for reactive power absorbed by its step-up transformer.

B. Lost Opportunity Cost (LOC)

1. The LOC for generators that are dispatched down by, or at the request of, the ISO, or a Local Control Center for the purpose of providing VAR Service will be calculated pursuant to Market Rule 1.

2. Commencing January 1, 2008, Qualified Non-Generator Reactive Resources shall be eligible for payment of the LOC for Qualified Non-Generator Reactive Resources that are dispatched down (pursuant to the authority established within written operating protocols developed under Section II.B.4) at the request of the ISO or a Local Control Center for the purpose of providing VAR Service. The LOC of such Qualified Non-Generator Reactive Resources will be calculated pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

C. Cost of Energy Consumed (CEC)

1. The CEC associated with hydro and pumped storage generating units that are motoring at the request of the ISO or a Local Control Center for the purpose of providing VAR Service will equal the cost of energy to motor and will be calculated in each hour as follows: CEC = (MWhUnit * (LMP or actual energy cost), where the MWh Unit are calculated pursuant to the Ancillary Service Schedule 2 Business Procedure. The actual energy cost applies only if motoring energy is purchased through a bilateral contract.

2. For the Chester SCV, the CEC will be set to zero ($0), and the cost of energy to supply reactive supply and voltage control from the Chester SCV will be treated as losses on the New England Transmission System.

3. Commencing January 1, 2008, Qualified Non-Generator Reactive Resources shall be eligible for payment of the CEC incurred by Qualified Non-Generator Reactive Resources for the purpose of providing VAR Service (pursuant to the authority established within written operating protocols developed under Section II.B.4). The CEC of such Qualified Non-Generator Reactive Resources shall be measured pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

4. Cost of Energy Produced (CEP)

1. The CEP associated with thermal generating units that are brought on-line by the ISO or a Local Control Center for the purpose of providing VAR Service shall equal the portion of the total uplift to be paid that resource for a day that is attributed to the hour(s) during which the resource is run to provide VAR Service in accordance with Market Rule 1 and the ISO New England Operating Documents.

2. The CEP associated with hydro or pumped storage generating units that are producing real power and that have also been brought on-line by the ISO or a Local Control Center to provide VAR Service shall equal the portion of the total uplift to be paid that resource for a day that is attributed to the hour(s) during which the resource is run to provide VAR Service in accordance with Market Rule 1 and the ISO New England Operating Documents.

3. Commencing January 1, 2008, Qualified Non-Generator Reactive Resources shall be eligible for payment of the CEP incurred by Qualified Non-Generator Reactive Resources for the purpose of providing VAR Service (pursuant to the authority established within

written operating protocols developed under Section II.B.4). The CEP of such Qualified Non-Generator Reactive Resources shall be measured pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

VI. ALTERNATIVE PAYMENT FOR VAR SERVICE

Where a non-generator source of VAR Service (i) responds to identified needs for dynamic reactive power on the New England Transmission System, as identified in the Regional System Plan, and (ii) is confirmed by the ISO as a dynamic reactive power resource that will meet the identified need, and (iii) such non-generator source of VAR Service meets the criteria to be a Qualified Non-Generator Reactive Resource but cannot recover its costs of providing dynamic reactive power under Schedule 2, such non-generator may submit a separate schedule to the ISO OATT to be filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act for a rate to be paid to allow such resource to recover its costs related to providing VAR Service. In such case, it shall not be considered a Qualified Non-Generator Reactive Resource under this Schedule 2 and its provision of VAR Service and payment shall be governed solely by such separate schedule filed with the Commission.

SCHEDULE 2 VAR PAYMENT IMPLEMENTATION RULE

This rule describes the steps to be taken to calculate the VAR CC Rate on or after January 1, 2008 in accordance with Section V.A. of Schedule 2. Applicable to that time forward on an annual basis, the Base CC Rate shall be converted into a VAR CC Rate, expressed in the form of $/kVAR-yr, representing the amount to be paid for leading and lagging capability.

The following calculations shall be done in December of each year to calculate the VAR CC Rate for the next year of VAR Payments for leading and lagging reactive power capability in the following year. As described below, the VAR CC Rate shall be updated on an annual basis utilizing the most current leading and lagging test results, and it is expected to take three years to test all of the Qualified Reactive Resources in leading mode.

1. Calculate the “Current Total Aggregate Lagging VARs”, which shall equal the “Current Net Aggregate Tested Lagging VARs” plus the “Current Net Aggregate Non-Tested Lagging VARs”;

   Where:

   a. the Current Net Aggregate Tested Lagging VARs shall equal the total of Net Lagging kVARs for all Schedule 2 Qualified Reactive Resources that have completed a successful lagging VAR test, as reflected in the most current monthly *VAR Status Report* that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html); this value will reflect the lagging kVARs of Schedule 2 Qualified Reactive Resources as taken from its lagging VAR test results adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross lagging VARs test results adjusted down for losses); and

b. the Current Net Aggregate Non-Tested lagging VARs shall equal the total of net lagging kVARs for all Schedule 2 Qualified Reactive Resources that have not yet completed a successful lagging VAR test, as reflected in the most current monthly *VAR Status Report* that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html); this value will reflect the lagging kVARs of Schedule 2 Qualified Reactive Resources as taken from its NX-12D (and NX-9B, where needed to calculate generator step-up transformer losses) data at EcoMin adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross lagging VARs NX-12D data at SCC adjusted down for losses).

c. Increase and decrease limiters shall be applied to potential increases or decreases in the Current Total Aggregate Lagging VARs as follows:

i. Current Total Aggregate Lagging VARs Limiters for Year 1 (2008) and Year 3 (2010):

- The Current Total Aggregate Lagging VARs value shall not be limited for Year 1 and Year 3.

ii. Current Total Aggregate Lagging VARs Limiters for Year 2 (2009):

- Current Total Aggregate Lagging VARs Increase Limiter for Year 2: the calculated Current Total Aggregate Lagging VARs will be limited to no greater than 110% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for the prior year (Year 1); and
- Current Total Aggregate Lagging VARs Decrease Limiter for Year 2: the calculated Current Total Aggregate Lagging VARs will be limited to no less than 90% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for the prior year (Year 1).

iii. Current Total Aggregate Lagging VARs Limiters for Year 4 (2011) and beyond:

- Current Total Aggregate Lagging VARs Increase Limiter for Year 4 and beyond: the calculated Current Total Aggregate Lagging VARs will be limited to no greater than 130% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for Year 3; and

- Current Total Aggregate Lagging VARs Decrease Limiter for Year 4 and beyond**:** the calculated Current Total Aggregate Lagging VARs will be limited to no less than 70% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for Year 3.

2. Calculate the Current Total Aggregate Leading VARs which shall equal the Current Net Aggregate Tested Leading VARs plus the Current Net Aggregate Non-Tested Leading VARs;

Where:

a. the Current Net Aggregate Tested Leading VARs shall equal the total of Net Leading kVARs for all Schedule 2 Qualified Reactive Resources that have completed a successful Leading VAR Test, as reflected in the most current monthly *VAR Status Report* that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html); this value will reflect the Leading kVARs of Schedule 2 Qualified Reactive Resources as taken from its leading VAR test results adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross leading VARs test results adjusted up for losses);

b. the Current Net Aggregate Non-Tested Leading VARs: shall equal the total of Net Leading kVARs for all Schedule 2 Qualified Reactive Resources that have not yet completed a successful Leading VAR Test, as reflected in the most current monthly *VAR Status Report* that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html). This value will reflect the Leading kVARs of Schedule 2 Qualified Reactive Resources as taken from its NX-12D (and NX-9B, where needed to calculate generator step-up transformer losses) data at EcoMin adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross leading VARs NX-12D data at EcoMin adjusted up for losses).

c. Current Total Aggregate Leading VARs Limiters

i. Current Total Aggregate Leading VARs Limiters for Year 1 and Year 4:

- The Current Total Aggregate Leading VARs value shall not be limited for Year 1 (2008) and Year 3 (2010) .

ii. Current Total Aggregate Leading VARs Limiters for Year 2 (2009) :

- Current Total Aggregate Leading VARs Increase Limiter for Year 2: the calculated Current Total Aggregate Leading VARs will be limited to no greater than 110% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for the prior year (Year 1); and

- Current Total Aggregate Leading VARs Decrease Limiter for Year 2: the calculated Current Total Aggregate Leading VARs will be limited to no less than 90% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for the prior year (Year 1).

iii. Current Total Aggregate Leading VARs Limiters for Year 4 and beyond:

- Current Total Aggregate Leading VARs Increase Limiter for Year 4 (2011) and beyond: the calculated Current Total Aggregate Leading VARs will be limited to no greater than 130% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for Year 3; and

- Current Total Aggregate Leading VARs Decrease Limiter for Year 4 and beyond: the calculated Current Total Aggregate Leading VARs will be limited to no less than 70% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for Year 3.

3. Calculate the Adjusted CC Rate ($CCRate_{adjusted}$): shall equal (the Base CC $Rate_e$ * Current Total Aggregate Lagging VARs) / (Current Total Aggregate Lagging VARs + Current Total Aggregate Leading VARs) where the Base CC Rate shall equal $2.32/kVAR-yr unless changed as provided for under Schedule 2.

4. VAR CC Rate (“VARCCRate”): shall equal (the Adjusted CC Rate) * (the lesser of 1 or (1.2 * “Forecast Peak Adjusted Reference Load” for the year / the sum of the “Qualified Reactive Resources’ Seasonal Claimed Capability”));

Where:

a. the "Forecast Peak Adjusted Reference Load" for the year shall equal the amount specified as "Adjusted Reference Load" for the applicable year in *Section I.1 - Summaries – Summer* from the most current *Forecast Report of Capability, Energy, Loads and Transmission (CELT Report)* *(*http://www.iso-ne.com/trans/celt/report/index.html*)*;

b. The sum of the "Qualified Reactive Resources' Seasonal Claimed Capability" shall equal the Qualified Generator Reactive Resources' Seasonal Claimed Capability plus the Qualified Non-Generator Reactive Resources' Adjusted Seasonal Claimed Capability;

Where:

i. the Qualified Generator Reactive Resources' Seasonal Claimed Capability: shall equal the total of the *"Summer Seasonal Claimed Capability"* column of all Qualified Generator VAR Resources from the most current *VAR Status Report* (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html); and

ii. the Qualified Non-Generator Reactive Resources' Adjusted Seasonal Claimed Capability shall equal 2.50 times the total of the *"Summer Seasonal Claimed Capability"* column of all Qualified non-Generator VAR Resources from the most current *VAR Status Report* (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html).

5. Monthly VAR Payment for a Qualified Reactive Resource in a particular month shall equal the (VARCCRate / 12 * (its Monthly Net Lagging VARs for that month + its Monthly Net Leading VARs for that month)), as reflected in the applicable monthly *VAR Status Report* that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html).

a. Monthly Net Lagging VARs: Qualified Reactive Resource's Monthly Net Lagging VARs value shall equal its VAR value based on (a) its most recent successful Lagging VAR test or (b) if it has not yet completed such a test, its VAR value at SCC based on its submitted and ISO accepted NX-12D and NX-9B data. The Qualified VAR Resource's Monthly Net Lagging VARs value shall be reflected in the applicable monthly *VAR Status Report* that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html).

b. Monthly Net Leading VARs: a Qualified Reactive Resource's Monthly Net Leading VARs value shall equal its VAR value based on (a) its most recent successful Leading VAR test or (b) if it has not yet completed such a test, its VAR value at EcoMin based on its submitted and ISO accepted NX-12D and NX-9B data. The Qualified Reactive Resource's Monthly Net Leading VARs value shall be reflected in the applicable monthly *VAR Status Report* that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html).

Attachment 3

Zone	Generator	Annual Reactive Power Service Revenue Requirement	Monthly Reactive Power Service Revenue Requirement	Ferc Docket	Fuel/Turbine	Claimed Real Power Capability (MW)	Net MVAR @ 0.9pf	Effective Net Voltage Support Rate ($/MVAR-yr)	Online Year	Fixed Capability Component	Heating Losses Component	Fixed Capability Component in $/MVAR-yr
AE	Atlantic City Electric Company	$ 3,712,750	$ 309,396									
	Conectiv Energy Supply, Inc.	$ 1,140,535	$ 95,045									
	TXU Pedricktown Cogeneration Company	$ 263,515	$ 21,960									
APS	Allegheny Energy Supply Company, LLC	$ 11,704,576	$ 975,381									
	Armstrong Energy Limited Partnership	$ 1,435,113	$ 119,593	ER03-229	Gas Peaker	600	291	$ 4,939				
	Pleasants Energy, LLC	$ 722,906	$ 60,242	ER03-451	Gas Peaker	300	145	$ 4,975				
	Duke Energy Fayette, LLC	$ 2,312,572	$ 192,714	ER03-794-002	Gas Peaker	620	300	$ 7,701				
	Monongahela Power Company	$ 3,193,690	$ 266,141									
	Allegheny Energy Supply Company, LLC	$ 1,354,022	$ 112,835									
	Monongahela Power Company	$ 403,763	$ 33,647									
BGE	Constellation Power Source, Inc.	$ 8,344,846	$ 695,404									
	ISG Sparrows Point, Inc.	$ 319,464	$ 26,622	ER03-852	Gas Peaker	152	74	$ 4,340				
DPL	Conectiv Energy Supply, Inc.	$ 3,756,981	$ 313,082									
	NRG Power Marketing, Inc.	$ 1,957,059	$ 163,088									
	Commonwealth Chesapeake Company	$ 1,270,890	$ 105,908	ER02-2520	Gas Peaker	342	166	$ 7,673				
JCPL	Jersey Central Power & Light Company	$ 3,009,853	$ 250,821									
	Calpine Energy Services, LP (Parlin)	$ 693,132	$ 57,761	ER04-889	Gas CC	114	55	$ 12,554	1991			
	Ocean Peaking Power, L.L.C.	$ 952,555	$ 79,380	ER05-289	Gas Peaker	330	160	$ 5,960				
	FPL Energy Power Marketing, Inc. NJEA	$ 515,329	$ 42,944	ER05-845	Gas Cogen	300	145	$ 3,547				
METED	Metropolitan Edison Company	$ 2,038,623	$ 169,885									
	Reliant Energy Hunterstown, LLC	$ 2,027,683	$ 168,974	ER03-1164-000	Gas CC	830	402	$ 5,044	2003	$ 1,749,489	$ 278,193	$ 4,352
	Calpine Energy Services, (Ontelaunee)	$ 1,176,052	$ 98,004	ER03-624-000	Gas CC	573	278	$ 4,238	2002	$ 1,105,962	$ 70,089	$ 3,985
PENELEC	Pennsylvania Electric Company	$ 2,061,826	$ 171,819									
	First Energy Solutions Corp.	$ 47,432	$ 3,953									
	Allegheny Electric Cooperative Inc.	$ 21,416	$ 1,785									
	Handsome Lake Energy, LLC	$ 370,304	$ 30,859	ER03-269-000	Gas Peaker	250	121	$ 3,058				
	Reliant Energy Seward, LLC	$ 1,142,356	$ 95,196	ER04-1164	Coal	521	252	$ 4,527				
PECO	Exelon Generation Company, LLC	$ 8,695,200	$ 724,600									
	FPL Energy Power Marketing, Inc.	$ 393,182	$ 32,765									
	Liberty Electric Power, LLC	$ 2,222,473	$ 185,206	ER03-1209-000	Gas CC	521	252	$ 8,808	2002	$ 2,042,120	$ 180,352	$ 8,093
	Fairless Energy, LLC	$ 3,146,914	$ 262,243	ER04-797	Gas CC	1,268	614	$ 5,124	2004	$ 1,250,696	$ 104,216	$ 2,037
	FPL Energy Power Marketing, Inc.	$ 1,500,000	$ 125,000	ER05-316-000	Gas CC	750	363	$ 4,129	2005			
	CED Rock Springs, LLC	$ 766,570	$ 63,881	ER05-288	Gas Peaker	355	172	$ 4,459				
	Old Dominion Electric Cooperative	$ 654,639	$ 54,553	ER05-682	Gas Peaker	317	154	$ 4,264				
PPL	PPL EnergyPlus, LLC	$ 9,040,000	$ 753,333									
	Allegheny Electric Cooperative, Inc.	$ 898,115	$ 74,843									
	Sunbury Generation, L.L.C.	$ 450,000	$ 37,500	ER02-2362	Coal	389	188	$ 2,389				
	WPS Westwood Generation, LLC	$ 103,950	$ 8,663	ER02-2361	Coal	30	15	$ 7,154				
	Safe Harbor Water Power Corporation	$ 2,149,747	$ 179,146	ER03-423	Hydro	400	194	$ 11,097				
	Conectiv Bethlehem, LLC	$ 2,699,389	$ 224,949	ER04-231-002	Gas CC	885	429	$ 6,298	2003	$ 1,783,970	$ 310,282	$ 4,162
	Lower Mount Bethel Energy, LLC	$ 1,086,303	$ 90,525	ER04-1142	Gas CC	600	291	$ 3,738	2004	$ 849,298	$ 237,005	$ 2,923
PEPCO	Mirant Potomac River, LLC	$ 4,733,477	$ 394,456									
	Potomac Power Resources, Inc.	$ 721,723	$ 60,144									
PSEG	PSEG Energy Resources & Trade, LLC	$ 8,587,290	$ 715,608									
	Calpine Energy Services, LP (Newark)	$ 478,818	$ 39,901	ER04-978	Gas CC	56	27	$ 17,654	1991			
	Newmarket Power Company, LLC	$ 1,778,283	$ 148,190	ER05-1058	Gas Peaker	149	72	$ 8,784				
	(Bayonne, Camden & Newark)			ER05-1059	Gas Peaker	146	71	$ 8,784				
				ER05-1060	Gas Peaker	123	60	$ 8,784				
ComEd	Exelon Generation	$ 10,227,259	$ 852,272									
	Midwest Generation, LLC	$ 2,295,784	$ 191,315	ER04-190	Coal	9,287	4,290	$ 535				
	University Park Energy, LLC	$ 543,304	$ 45,275	ER04-765	Gas Peaker	300	145	$ 3,739				
	Duke Energy Lee, LLC	$ 1,500,000	$ 125,000	ER04-641	Gas Peaker	640	310	$ 4,839				
	PPL University Park, LLC	$ 1,504,414	$ 125,368	ER04-911	Gas Peaker	540	262	$ 5,752				
	Reliant Energy Aurora, LP	$ 1,490,000	$ 124,167	ER04-1066	Gas Peaker	873	423	$ 3,524				
AEP	AEP East Operating Cos.	$ 26,091,131	$ 2,174,261									
	Big Sandy Peaker Plant, LLC	$ 525,904	$ 43,825	ER04-1103	Gas Peaker	300	145	$ 3,620				
	Wolf Hills Energy, LLC	$ 442,023	$ 36,835	ER04-1102	Gas Peaker	250	121	$ 3,651				
	Rolling Hills Generating, L.L.C.	$ 1,100,000	$ 91,667	ER04-1098	Gas Peaker	800	387	$ 2,839				
	Riverside Generating Company, L.L.C.	$ 1,702,765	$ 141,897	ER05-328	Gas Peaker	820	397	$ 4,288				
	Buckeye Power, Inc.	$ 1,215,129	$ 101,261	EL05-20	Coal	1,066	516	$ 2,354				
	Duke Energy Hanging Rock, LLC	$ 3,429,356	$ 285,780	ER05-567	Gas CC	1,240	601	$ 5,710	2003	$ 3,328,957	$ 100,398	$ 5,543
	Duke Energy Washington LLC	$ 1,569,806	$ 130,817	ER05-623	Gas CC	620	300	$ 5,228	2002	$ 1,519,992	$ 49,813	$ 5,062
	Indiana Municipal Power Agency	$ 489,001	$ 40,750	ER05-971	Gas Peaker	251	122	$ 4,023				
	Twelvepole Creek LLC	$ 1,457,832	$ 121,486	ER04-1166	Gas Peaker	458	222	$ 6,572				
Dayton	The Dayton Power and Light Company	$ 6,692,774	$ 557,731									
Dominion	Virginia Electric and Power Company	$ 22,222,702	$ 1,851,892									
	Tenaska Virginia Partners, L.P.	$ 1,385,697	$ 115,475	ER04-680	Gas CC	885	429	$ 3,233	2004	$ 1,179,258	$ 206,439	$ 2,751
	FPL Energy Power Marketing, (Doswell)	$ 1,341,384	$ 111,782	ER05-1119	Gas CC	600	291	$ 4,616	2000	$ 1,269,111	$ 72,272	$ 4,367
	FPL Energy Power Marketing, (Doswell)	$ 268,440	$ 22,370	ER05-1119	Gas CT	170	82	$ 3,260	2000			
PJM	**TOTAL**	**$ 197,800,726**	**$ 16,483,394**									
MISO Filings												
IP/MIOS	Dynegy Mid West Generation Inc	$ 7,584,800	$ 632,067	ER05-270	Coal	4,042	1,958	$ 3,874				
ATSI/MISO	Calpine Fox Energy Center	$ 1,352,081	$ 112,673	ER05-1361-000	Gas CC	600	291	$ 4,653	2005	$ 1,352,081	$ -	$ 4,653
FE/MISO	Troy Energy, LLC	$ 1,498,920	$ 124,910	ER03-1396-000	Gas Peaker	620	300	$ 4,992				
ATSI/MISO	Calpine Riverside Energy Center	$ 1,205,900	$ 100,492	ER04-1055	Gas CC	603	292	$ 4,129	2004	$ 1,074,616	$ 131,284	$ 3,680
ATSI/MISO	Calpine Rockgen	$ 622,400	$ 51,867	ER04-1059	Gas Peaker	475	230	$ 2,705				
MISO	Duke Vermillion	$ 1,100,000	$ 91,667	ER05-123	Gas Peaker	640	310	$ 3,549				
AMRN/MISO	Holland Energy	$ 1,065,200	$ 88,767	ER04-1075	Gas CC	650	315	$ 3,384	2002	$ 1,029,527	$ 35,673	$ 3,270
FE/MISO	Orion Power Midwest	$ 2,056,255	$ 171,355	ER04-717	Coal	1,310	634	$ 3,241				
IN/MISO	IMPA Georgetown	$ 166,176	$ 13,848	EL05-134	Gas Peaker	170	82	$ 2,018				
CMS/MISO	MI Power Livingston & Kalamazoo	$ 415,000	$ 34,583	ER05-341	Gas Peaker	200	97	$ 4,284				
KY/MISO	Renaissance Power	$ 881,000	$ 73,417	ER04-992	Gas Peaker	680	329	$ 2,675				
	COMBINED CYCLE AVERAGES							**$ 4,966**				**$ 4,221**

Attachment 4

Schedule 2 Costs from 05/05 through 10/06

- Corrected after Settlements review

(18 months)

	Variable	**Fixed**
May-05	15,903,321.65	1,034,788.43
Jun-05	6,040,456.72	1,048,417.05
Jul-05	2,925,783.61	1,044,618.74
Aug-05	1,159,770.96	1,029,508.10
Sep-05	3,600,306.98	1,016,535.31
Oct-05	1,931,910.18	1,016,535.31
Nov-05	3,000,807.17	1,016,535.31
Dec-05	1,076,721.74	1,016,535.31
Jan-06	2,712,756.80	1,016,535.31
Feb-06	1,814,888.20	1,016,535.31
Mar-06	1,363,754.76	1,024,426.83
Apr-06	2,365,682.30	1,024,426.83
May-06	1,165,467.37	1,024,426.83
Jun-06	1,307,725.62	1,024,426.83
Jul-06	3,202,213.31	1,022,112.37
Aug-06	3,418,803.33	1,022,112.37
Sep-06	1,144,950.40	1,022,112.37
Oct-06	682,167.71	953,327.15
18 mo Total	54,817,488.81	18,373,915.76
Mo Avg	3,045,416.05	1,020,773.10

(12 months)

	Variable	**Fixed**
Nov-05	3,000,807.17	1,016,535.31
Dec-05	1,076,721.74	1,016,535.31
Jan-06	2,712,756.80	1,016,535.31
Feb-06	1,814,888.20	1,016,535.31
Mar-06	1,363,754.76	1,024,426.83
Apr-06	2,365,682.30	1,024,426.83
May-06	1,165,467.37	1,024,426.83
Jun-06	1,307,725.62	1,024,426.83
Jul-06	3,202,213.31	1,022,112.37
Aug-06	3,418,803.33	1,022,112.37
Sep-06	1,144,950.40	1,022,112.37
Oct-06	682,167.71	953,327.15
12 mo Total	**23,255,938.71**	**12,183,512.82**
Mo Avg	**1,937,994.89**	**1,015,292.74**

Denotes numbers used in Schedule 2 Filing

	2nd half of 2007 calc			
	Fixed			CSC
Fixed=X*2.32	2,260,558.97	1	CSC=75*2.32	14,500
/1.05+CSC	2,260,558.97	2	*1000/12	14,500
	2,260,558.97	3		14,500
	2,260,558.97	4		14,500
	2,277,995.47	5		14,500
	2,277,995.47	6		14,500
	2,277,995.47	7		14,500
	2,277,995.47	8		14,500
	2,272,881.62	9		14,500
	2,272,881.62	10		14,500
	2,272,881.62	11		14,500
estimated	*2,274,500.00*	12		14,500
12 mo Total	**27,247,362.62**		12 mo Total	174,000
Mo Avg	**2,270,613.55**			

Attachment 5

New England Governors
and Utility Regulatory
and Related Agencies

December 28, 2006

Connecticut

The Honorable M. Jodi Rell
State Capitol
210 Capitol Ave.
Hartford, CT 06106

Connecticut Department of Public Utility Control
10 Franklin Square
New Britain, CT 06051-2605

Maine

The Honorable John E. Baldacci
One State House Station
Rm. 236
Augusta, ME 04333-0001

Maine Public Utilities Commission
State House, Station 18
242 State Street
Augusta, ME 04333-0018

Massachusetts

The Honorable Mitt Romney
Office of the Governor
Rm. 360 State House
Boston, MA 02133

Massachusetts Department of Telecommunications and Energy
One South Station
Boston, MA 02110

New Hampshire

The Honorable John H. Lynch
State House
25 Capitol Street
Concord, NH 03301

New Hampshire Public Utilities Commission
21 South Fruit Street
Suite 10
Concord, NH 03301-2429

Rhode Island

The Honorable Donald L. Carcieri
State House Room 115
Providence, RI 02903

Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

Vermont

The Honorable James H. Douglas
109 State Street, Pavilion
Montpelier, VT 05609

Vermont Public Service Board
112 State Street, Drawer 20
Montpelier, VT 05620-2701

New England Governors
and Utility Regulatory
<u>and Related Agencies</u> **<u>December 28, 2006</u>**

Anne C. George, President
New England Conference of
Public Utilities Commissioners, Inc.
c/o Connecticut Department of Public
Utility Control
10 Franklin Square
New Britain, CT 06051-2605

William M. Nugent
Executive Director
New England Conference of
Public Utilities Commissioners, Inc.
500 U.S. Route 1, Suite 21C
Yarmouth, ME 04096

Harvey L. Reiter, Esq.
Counsel for New England Conference
of Public Utilities Commissioners, Inc.
c/o Stinson Morrison Hecker LLP
1150 18th Street, NW, Suite 800
Washington, DC 20036-3816

Power Planning Committee
New England Governors' Conference, Inc.
76 Summer Street, 2nd Floor
Boston, MA 02110-1226