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February 1, 2007

VIA ELECTRONIC FILING

The Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
Room 1A-East, First Floor
888 First Street, N.E.
Washington, D.C. 20426

Re: ISO New England Inc. and New England Power Pool Participants Committee, Docket No. ER07-365-000

Dear Ms. Salas:

Attached for electronic filing in the above-referenced docket is the *Motion for Leave to Answer and Answer of ISO New England Inc.* A copy of the foregoing has been served upon all parties included in the Commission's service list.

If you have any questions or concerns regarding this filing, please feel free to contact me. Thank you for your assistance in this matter.

Respectfully submitted,

/s/ Sherry A. Quirk
Sherry A. Quirk, Esq.
Travis R. Smith, Esq.

Counsel for ISO New England Inc.

Attachment
cc: Official Service List

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	**)**	**Docket No. ER07-365-000**
and	**)**	
New England Power Pool	**)**	
Participants Committee	**)**	

MOTION FOR LEAVE TO ANSWER AND ANSWER OF ISO NEW ENGLAND INC.

Pursuant to Rules 212, 213, and 101(e) of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission" or "FERC"),[1] ISO New England Inc. (the "ISO") hereby submits its *Motion for Leave to Answer and Answer* to various pleadings filed in the above-captioned proceeding in response to the ISO's and the New England Power Pool ("NEPOOL") Participants Committee's December 22, 2006 filing (the "ICR Filing"), wherein the ISO and NEPOOL proposed to revise Market Rule 1 to formalize the processes and methodologies used to determine the Installed Capacity Requirements ("ICR"),[2] Local Sourcing Requirements and the Maximum Capacity Limit for the New England Control Area (collectively the "ICR Rules").

[1] *See* 18 C.F.R. §§ 385.212, 385.213, 385.101(e) (2006).

[2] Capitalized terms used but not otherwise defined in this *Answer* 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.

I.
BACKGROUND

Pursuant to the Commission-approved Settlement Agreement filed in Docket No. ER03-563-000, *et al.* establishing a Forward Capacity Market ("FCM") in New England, the ISO was required to submit the subject ICR Filing by the fourth quarter of 2006 for Commission action, as appropriate, no later than the second quarter of 2007. This schedule was intended to allow the filing of ICR values (calculated pursuant to the process detailed in the ICR Filing) for use in the first Forward Capacity Auction, which, under the terms of the FCM Settlement Agreement, will take place in early 2008. Because the FCM, unlike the previous Installed Capacity ("ICAP") market, will require the ISO to also calculate the Local Sourcing Requirements for import-constrained areas and Maximum Capacity Limits for export-constrained areas, the assumptions and methodologies from which these calculations are derived were included in the ICR Filing.

In order to facilitate the calculation of ICR values for the first Forward Capacity Auction, the Market Rule provisions describing the process and general methodology for calculating ICR, Local Sourcing Requirements and the Maximum Capacity Limit had to be filed in advance of the remainder of the FCM-related rules.

The proposed ICR Rules do not significantly change the existing methodology that has been used to calculate capacity requirements for many years. Rather, the proposed provisions formalize the existing methodology for

calculating the ICR values. In particular, the proposed revisions describe key aspects of the process associated with formulating assumptions for and calculating the ICR, Local Sourcing Requirements and the Maximum Capacity Limits for use in the FCM, as well as the criteria for determining what new transmission elements will be included in the base network model for the upcoming Power Years.[3] The ICR Filing reflects essentially the same methodology used by NEPOOL[4] and the ISO for the past twenty-plus years to develop the ICR for the New England Control Area.

A number of parties filed pleadings with the Commission addressing various aspects of the proposed ICR Filing – including the Connecticut Department of Public Utility Control ("CT DPUC"), the Long Island Power Authority and its operating subsidiary Long Island Lighting Company d/b/a LIPA (jointly "LIPA"), the New York State Reliability Council LLC ("NYSRC"), Consolidated Edison Energy, Inc. ("Con Ed"), H.Q. Energy Services (US) Inc. ("HQUS"), and Constellation Energy Commodities Group, Inc. *et al.* ("Constellation Movants").[5]

[3] The ISO's Power Year runs from June 1 through May 31.

[4] Prior to the commencement of regional transmission organization ("RTO") operations by the ISO on February 1, 2005, NEPOOL was required to file the annual Objective Capability ("OC") values (now ICR) pursuant to Section 7.5(e) of the Restated NEPOOL Agreement. With the Commission's approval of RTO status for the ISO (*ISO New England Inc.*, 106 FERC ¶ 61,280, *order on reh'g*, 109 FERC ¶ 61,147 (2004), *operations authorized*, 110 FERC ¶ 61,111 (2005)), the authority and obligation to make these annual filings have been transferred to the ISO.

[5] Joining Constellation's *Motion to Intervene and Protest* are Constellation New Energy, Inc.; Cross Sound Cable Company; Mirant Energy Trading, LLC; Mirant Canal, LLC; and Mirant Kendall.

The ISO's *Answer* can be divided into three major sections. First, the ISO addresses procedural and jurisdictional issues raised by the CT DPUC and other parties. In this regard, the ISO points out that jurisdiction over ICR is a subject that is currently before the appellate courts and does not need to be re-litigated in this proceeding. Furthermore, the ISO explains that the CT DPUC was an active participant in the ICR review process and that the views of state regulators were welcomed and considered during that process.

Second, the ISO responds to a variety of concerns that have been raised about the interaction between tie benefits and capacity imports, the calculation of Local Sourcing Requirements and the treatment of capacity exports. The ISO explained at length in its initial filing why it is appropriate to limit capacity imports and reserve a portion of interconnection capacity in order to preserve tie benefits and does not repeat those arguments in this pleading. However, the ISO does address the various other new issues raised by intervenors that were not addressed in the initial filing.

Finally, the ISO addresses certain, relatively minor questions raised by intervenors concerning terminology and definitions.

II.
MOTION FOR LEAVE TO ANSWER

In this *Answer*, the ISO responds to certain arguments put forth in the respective comments and protests filed by the CT DPUC, LIPA, NYSRC, HQUS, Con Ed and the Constellation Movants. While the Commission's Rules of

Practice and Procedure allow parties to respond to comments,[6] as a general matter the Commission's rules prohibit responses to protests.[7] The Commission has the authority, however, to waive this prohibition for good cause.[8] The Commission has found good cause to permit replies where they are otherwise prohibited in various circumstances, including where the answer would assure a complete record in the proceeding,[9] provide information helpful to the disposition of an issue,[10] permit the issues to be narrowed or clarified,[11] or aid the Commission in understanding and resolving issues.[12] The ISO believes that this *Answer* will clarify the issues, assure a more complete record in this proceeding, and otherwise assist the Commission in understanding and resolving the issues raised in response to the ICR Filing. For these reasons, pursuant to Rule 212 the ISO respectfully requests that the Commission grant the ISO's *Motion* to provide the following *Answer*.

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[6] *See* 18 C.F.R. § 385.213(a)(3) (2006).

[7] *See* 18 C.F.R. § 385.213(a)(2) (2006).

[8] *See* 18 C.F.R. § 385.101(e) (2006).

[9] *See, e.g., Pacific Interstate Transmission Co.*, 85 FERC ¶ 61,378 at 62,443 (1998), *reh'g denied*, 89 FERC ¶ 61,246 (1999).

[10] *See, e.g., CNG Transmission Corp.*, 89 FERC ¶ 61,100 at 61,287 n.11 (1999).

[11] *See, e.g., PJM Interconnection, L.L.C.*, 84 FERC ¶ 61,224 at 62,078 (1998); *New Energy Ventures, Inc. v. Southern California Edison Co.*, 82 FERC ¶ 61,335 at 62,323 n.1 (1998).

[12] *See, e.g., Tennessee Gas Pipeline Co.*, 92 FERC ¶ 61,009 at 61,016 (2000).

III.
ANSWER

A. The CT DPUC's Request that the Commission Reject the ICR Filing for Lack of Jurisdiction Should Be Denied.

The CT DPUC reprises, once again, its contention that the Commission lacks jurisdiction over ICR, arguing that the Federal Power Act ("FPA") does not give the Commission the authority to establish resource adequacy requirements for the states. The CT DPUC has put forth this argument indefatigably (and unsuccessfully) in three previous Commission proceedings.[13] Therefore, the ISO will refrain from addressing this issue at length herein and will briefly state that the Commission has jurisdiction over ICR under FPA Section 205, because ICR is a wholesale charge, or at a minimum, "directly and significantly affect[s] wholesale rates" or charges.[14] ICR is also a means of ensuring reliable operations of the market as established in a Commission-approved tariff, and thus is subject to the Commission's jurisdiction as a rule or regulation significantly affecting wholesale rates pursuant to FPA Section 205.[15] The question of the Commission's

[13] *See, e.g.*, *ISO New England, Inc.*, 111 FERC ¶ 61,185 at P 33 ("[I]n light of the ISO's Tariff and the Participants Agreement the ISO has the authority to file and we have the authority to accept the ISO's proposed IC Requirements.") , *order denying reh'g and granting clarification*, 112 FERC ¶ 61,254 (2005); *Devon Power LLC*, 107 FERC ¶ 61,240, *on reh'g and clarification*, 109 FERC ¶ 61,154 (2004), *on reh'g and clarification*, 110 FERC ¶ 61,315 (2005) (rejecting the CT DPUC's jurisdictional argument, holding that the Commission has jurisdiction over the manner in which prices for capacity are determined in the wholesale market); *Devon Power LLC*, 115 FERC ¶ 61,340 at P 201 (2006) (holding that the Commission "has ample jurisdiction" to consider the "mechanism and market structure for the purchase and sale of installed capacity at wholesale in interstate commerce and to determine the prices for those sales.")

[14] *Mississippi Industries v. FERC*, 808 F.2d 1525, 1542 (D.C. Cir.), *vacated in part on other grounds*, 822 F.2d 1104 (1987). *See also* 16 U.S.C. §§ 824d, 824e (2000); *Municipalities of Groton v. FERC*, 587 F.2d 1296 (D.C. Cir. 1978).

[15] 16 U.S.C. § 824d(a) (2000). Section III.8.1 of the ISO Tariff and Section 11.4 of the Participants Agreement, each of which were previously filed with and approved by the Commission, require the ISO to make annual filings of ICR values with the Commission pursuant to FPA Section 205.

authority over ICR is currently before the United States Court of Appeals for the District of Columbia Circuit, a proceeding wherein the ISO has intervened on behalf of the Commission.[16] Accordingly, the ISO attaches hereto as Attachment A the respective briefs of the Commission and the ISO.

B. The CT DPUC's Allegations that It Was Denied Adequate Process Are Without Merit.

The CT DPUC argues that "state regulators like the CT DPUC have only one limited opportunity – before this Commission – to correct flaws in the proposed market rules. The Commission may not further trample on states' jurisdiction to set ICR by deferring entirely to whatever market rules ISO-NE proposes and the NEPOOL Participant Committee approves."[17] As a result, the CT DPUC claims that the ISO and NEPOOL should only be accorded limited deference. There are, however, at least two critical flaws in the CT DPUC's assertions in this regard.

First, the CT DPUC's assertions grossly understate the highly substantive nature of its involvement in the ICR-review process. The CT DPUC was provided much more than a "limited opportunity" to participate in the ICR-review process. The CT DPUC, like the other state regulators, are not Governance Participants and therefore could not make amendments to and vote on the final ICR Rules in exactly the same manner as other Market Participants. Nevertheless, the CT

[16] *See Connecticut Department of Public Utility Control v. Federal Energy Regulatory Commission*, Docket No. 05-1411.

[17] CT DPUC *Protest* at p. 8.

DPUC was provided much more than a "limited opportunity" to participate in the ICR-review process. The ISO and NEPOOL actively sought the participation of state regulators in the ICR-review process. Indeed, one of the CT DPUC's own members, Jack Goldberg, served as vice chairman of the Installed Capacity Working Group ("ICWG") – that is, the stakeholder working group formed to undertake the detailed substantive review of the ICR process and methodology. This working group was formed outside of the NEPOOL process to specifically give the state regulators a process and voice to raise their issues and concerns to all stakeholders. Specifically, the ICWG held approximately 18 meetings. In addition, after the ICWG concluded its work the proposed ICR Rules went to the NEPOOL Reliability Committee, where all state regulators were also encouraged to participate and indeed a CT DPUC representative was present during these meetings.

Additionally, the CT DPUC itself readily acknowledges that it "actively participated in the ICWG in development of a Design Basis Document ("DBD"), and in review of draft proposed Rules."[18] Thus, the CT DPUC's claims of deficient process are patently false, as the ICR-review (consistent with Commission policy) was an "open, transparent, and collaborative stakeholder process."[19]

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[18] *Id.* at p. 5.

[19] *Midwest Independent Transmission System Operation, Inc.*, 114 FERC ¶ 61,106 at P 24, *order on reh'g*, 117 FERC ¶ 61,241 at P 21 (2006) ("[w]e find that due consideration should be given to a stakeholder

Moreover, as it is fully aware (and has done on numerous occasions in the past), the CT DPUC can work directly with the ISO to ensure its concerns are met. The ISO has worked extremely hard throughout the ICR-review process in an attempt to address the concerns raised by the CT DPUC and other state regulators. The ISO also provided status updates to state regulators during the routine monthly briefings to ensure that they were aware of scheduled stakeholder events. The ISO also routinely provided the CT DPUC and other state regulators with individual notice of all ICR-related meetings. In short, the CT DPUC's participation in the ICR process was substantial and welcome.

Finally, the FCM Settlement Agreement requires that the ICR filing "be subject to the stakeholder process for Market Rules that provides for consultation with state utility regulatory agencies."[20] As explained above, the CT DPUC's participation in the ICWG and other stakeholder processes during the development of the ICR rules was fully consistent with the provisions of the FCM Settlement Agreement.

C. The ICR Filing Should Be Reviewed Under the "Just and Reasonable" Standard.

The ISO submitted the ICR Filing pursuant to FPA Section 205. However, in its *Protest*, Con Ed asserts that the "just and reasonable" standard applies to utility rates, not system adequacy or reliability standards. As a result, Con Ed

process that is open to all interested parties and allows representatives of the various stakeholder sectors to participate.")

[20] FCM Settlement Agreement at § 3(d).

contends that the appropriate ICR methodology, and the Commission's treatment of the same, are subject to the Administrative Procedure Act's "substantial evidence" standard.[21]

Con Ed is incorrect in its assertion that the applicable standard of review is "substantial evidence" rather than "just and reasonable." Indeed, based on the very nature of the ICR Filing, it is readily apparent that the "just and reasonable" standard applies. As the ISO stated in the ICR Filing's Transmittal Letter, Section III.8.1 of the ISO's Tariff and Section 11.4 of the Participants Agreement both require the ISO to make an annual ICR-values filing (which will be calculated according to the methodology described in the ICR Filing) pursuant to Section 205 of the FPA,[22] which requires (in relevant part) that:

> [a]ll rates and charges made . . . by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, . . .shall be just and reasonable.

Because wholesale capacity charges to each Market Participant under the Commission-approved ISO Tariff and Market Rules are the product of (1) the price per MW-month of capacity and (2) the difference between that Participant's allocated share of ICR and the amount of capacity entitlements credited to that

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[21] In support of its argument, Con Ed cites *Bangor Hydro-Electric Co. v. FERC*, 78 F.3d 659, 663 n. 3 (D.C. Cir. 1998) ("*Bangor*"). That case, however, sheds no light on the standard-of-review issue in the case *sub judice*. In fact, *Bangor* does not even relate to the Commission's regulation of electricity under Part II of the FPA. Rather, that case involved a utility's challenge to a Commission Order issued under its FPA Part I authority relating to regulation of hydroelectric facilities. The utility challenged the Commission's directive requiring it to comply with Department of Interior requirements concerning fishing near a hydroelectric facility.

[22] 16 U.S.C. § 824d(a) (2000).

Participant (either because it owns or has purchased generation or receives capacity credit for reducing peak demand), ICR is a wholesale charge, or at a minimum, "directly and significantly affect[s] wholesale rates" or charges.[23] Therefore, ICR and the methodology from which it is calculated are subject to review under the FPA Section 205 "just and reasonable" standard.[24]

D. The Respective Arguments of the CT DPUC and LIPA Regarding the Proposed Local-Sourcing-Requirements Provisions Should Be Rejected.

(1) The CT DPUC's requested clarification is unnecessary.

The CT DPUC argues that, in modeling external Control Area support from tie benefits, proposed Section III.12.2.1 (which describes the calculation of Local Sourcing Requirements) is not clear that Connecticut's Local Sourcing Requirement should reflect the locational tie benefits that accrue from the Cross Sound Cable ("CSC") and the 1385 Cable – both of which connect Connecticut electrically with Long Island. In support of its position, the CT DPUC asserts that the Commission has recognized the enhanced reliability benefit that these cables

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[23] *Mississippi Industries v. FERC*, 808 F.2d 1525, 1542 (D.C. Cir.), *vacated in part on other grounds*, 822 F.2d 1104 (1987). *See also* 16 U.S.C. §§ 824d, 824e; *Municipalities of Groton v. FERC*, 587 F.2d 1296 (D.C. Cir. 1978).

[24] Under FPA Section 205, the Commission "plays 'an essentially passive and reactive' role" and "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'" *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 10 (D.C. Cir. 2002) (quoting *City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)). The Commission's inquiry is limited "to whether the rates proposed by a utility are reasonable – and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs." *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984). The changes proposed in the ICR Filling "need not be the only reasonable methodology, or even the most accurate." *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995). As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept the ISO's Section 205 filing if it is just and reasonable. *Cf. Southern California Edison Co.*, 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).

provide, citing *ISO New England Inc.*, 111 FERC ¶ 61,185 at P 30 (2005) ("2005 ICR Order") for the proposition that the Commission, therein, "[found] that the ties between Connecticut and Long Island 'are stronger with the addition of new direct current lines and new generation resources' and directing ISO to increase tie benefits for purposes of the ICR."[25] As further support, the CT DPUC cites the Initial Decision in *Devon Power*,[26] claiming that the Presiding Administrative Law Judge ("ALJ") "recommended that ISO-NE be required to calculate Connecticut's capacity transfer limits to reflect the reliability benefits provided by the Cross Sound and 1385 Cables."[27] For these reasons, the CT DPUC entreats the Commission to clarify that in assessing the Local Sourcing Requirement for Connecticut, the ISO will include the tie benefits attributable to the CSC and the 1385 Cable.

The CT DPUC's requested clarification is unnecessary because the Market Rule provisions proposed in the ICR Filing already require the ISO to reflect in Connecticut's Local Sourcing Requirement any locational tie benefits that exist due to all transmission ties, including the CSC and 1385 Cable. Specifically, Section III.12.2.1 states that areas modeled when determining the Local Sourcing Requirements shall include "external Control Area support from tie benefits on the import-constrained side of the interface, if any." Similarly, proposed Section

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[25] CT DPUC Protest at 15 (quoting *ISO New England Inc.*, 111 FERC ¶ 61,185 at P 30 (2005)).

[26] *Devon Power LLC*, 111 FERC ¶ 63,063 at P 743 (2005) ("*Devon Power* Initial Decision").

[27] *Id.*

III.12.9 provides that "at least once every three years, the ISO shall perform a tie benefits study" and "the results shall be updated if the ISO determines that New England Control Area or external Control Area system conditions may change the results from the study." Thus, it is clear that under the Market Rule revisions proposed in the ICR Filing, the ISO will include the tie benefits attributable to the CSC or 1385 Cable – if any – in its assessment of Connecticut's Local Sourcing Requirement.

With that said, the ISO would be remiss if it did not now briefly address the CT DPUC's misleading characterizations of the 2005 ICR Order and the *Devon Power* Initial Decision. The CT DPUC alleges that the Commission, in the 2005 ICR Order, "[found] that the ties between Connecticut and *Long Island* 'are stronger with the addition of new direct current lines and *new generation resources*' and direct[ed] [the] ISO to increase tie benefits for purposes of the ICR,"[28] citing this as support for its assertion that "the Commission has recognized the enhanced reliability benefit that these cables [*i.e.*, the CSC and the 1385 Cable] provide."[29] However, in actuality, the Commission found that the ties between "New England and New York," not Connecticut and Long Island, had become stronger as a result of new direct current lines and generation resources[30] – which is consistent with the ISO's then (and current) models that assign the entire value

[28] CT DPUC Protest at 15 n.43 (quoting *ISO New England Inc.*, 111 FERC ¶ 61,185 at P 30 (2005). (Emphasis added).

[29] *Id.* at p. 15.

[30] 2005 ICR Order at P 30.

of tie benefits arising from all interconnections with the New York Control Area (*i.e.*, 600 MW) to the entire New England Control Area. Therefore, the 2005 ICR Order neither expressly nor implicitly found that the CSC or 1385 Cable confers a reliability benefit specifically on Connecticut. While the CT DPUC was correct in stating that the Order "direct[ed] [the] ISO to increase tie benefits for purposes of the ICR," the purpose of that directive was not to reflect putative tie benefits bestowed on Connecticut from the CSC or 1385 Cable. Rather, the Commission ordered the ISO to increase overall tie line benefits from 1800 MW to 2000 MW because it found that the ISO's study supported a total tie line benefit of 2000 MW and that the 1800 MW level was unsupported.[31]

The CT DPUC's contention that the Presiding ALJ in the *Devon Power* Initial Decision "recommended that ISO-NE be required to calculate Connecticut's capacity transfer limits to reflect the reliability benefits provided by the Cross Sound and 1385 Cables"[32] is equally misleading and inaccurate. Although the Presiding ALJ did, in fact, recommend that the Commission direct the ISO to calculate the capacity transfer limits for the constrained Rest of Connecticut and Southwest Connecticut Locational Installed Capacity ("LICAP") Zones to reflect the reliability benefits provided by the CSC and the 1385 Cable, the Presiding ALJ erred as a matter of fact and law by basing her decision on an erroneous interpretation of the 2005 ICR Order.

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[31] *See id.*

[32] CT DPUC *Protest* at p. 15.

Even though neither the 1800 MW or 2000 MW tie-benefits values ascribed reliability-benefit levels to the CSC or 1385 Cable, the Presiding ALJ found, in error, that "[t]his addition, 200 MW more than the 1800 MW proposed by the ISO pursuant to stakeholder vote, *includes Long Island reliability benefits*."[33] However, the 2005 ICR Order neither expressly nor implicitly made such a finding. In fact, it would have been impossible for the Commission to make such a finding because the ISO's 2005 ICR-values filing, as per the Commission's directive in *NSTAR Electric and Gas Corporation v. New England Power Pool*,[34] solely identified the monthly ICR established by the ISO for the 2005/2006 Power Year.

That is to say, the ISO did not propose any specific allocation of benefits or credits for the CSC and 1385 Cable, either at the 1800 MW level proposed in the filing or at the 2000 MW level approved by the Commission –a fact acknowledged by the Commission on rehearing of its 2005 ICR Order:

> [T]here is nothing in the record that indicates that any portion of the 600 MW tie-line benefit assigned to New York that was included in the February 2003 Tie Reliability Benefits Study was attributable to the CSC.[35]

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[33] *Devon Power* Initial Decision at P 743 (emphasis added).

[34] *NSTAR Elec. and Gas Corp. v. New England Power Pool*, 103 FERC ¶ 61,093 at P 23 (2003) ("*NSTAR Electric*") (directing NEPOOL – a responsibility now assigned to the ISO – to file pursuant to FPA Section 205 the monthly OC values – now IC Requirements – and HQICC values starting with the 2005/2006 Power Year and for each Power Year thereafter).

[35] *ISO New England, Inc.* 112 FERC ¶ 61,254 at P 14 (2005).

Therefore, notwithstanding the CT DPUC's intimations to the contrary, the Commission's 2005 ICR Order did not establish "precedent ordering the ISO to incorporate the reliability benefits provided by the Cross Sound Cable and 1385 Cable in the ISO's IC requirements,"[36] nor did the Commission-approved 2000 MW level contained therein "include[] Long Island reliability benefits."[37] Consequently, the Presiding ALJ's preliminary ruling would almost certainly have been reversed by the Commission on exceptions had the underlying *Devon Power* proceeding not been settled. For these reasons, the *Devon Power* Initial Decision is devoid of precedential or probative value.

Finally, the CT DPUC requests that the Commission clarify that the ISO must use "As-Is" assumptions for the purposes of modeling all resources in all auctions except for the modeling of tie benefits with adjacent Control Areas for auctions before the Annual Reconfiguration Auction closest to the relevant Capacity Commitment Period. There is no need for the requested clarification. Under proposed Section III.12.2 of the ICR Rules, all resources (pursuant to Section III.12.7) will be included in the modeling assumptions for determining Local Sourcing Requirements. This includes all resources that are expected to be available plus additional proxy units that may be needed to meet the Loss of Load Expectation ("LOLE") criterion for that Power Year. These provisions describe a calculation that is (as much as is possible more than three years in advance) an

[36] *Devon Power* Initial Decision at P 743.

[37] *Id.* at 742.

"As-Is" calculation based on the best estimate of resources that are expected to be available. Thus, there is no need for clarification.

(2.) The Local-Sourcing-Requirements Provisions Proposed in the ICR Filing Comport with the FCM Settlement Agreement.

LIPA claims that the ICR proposal violates Section III.A.8 of the FCM Settlement Agreement[38] by failing to include provisions in the calculation of the Local Sourcing Requirements to account for exporting capacity from an unconstrained area within New England across a New England import-constrained region to an adjoining Control Area. LIPA is incorrect.

As explained below, the provisions contained in the ICR Filing regarding the calculation of ICR and Local Sourcing Requirements are consistent with the FCM Settlement Agreement – which states "[w]here zonal separation is determined to exist, Market Rules shall specify a process for an Export both from or through the import-constrained zone over tie lines to external regions."[39] The proposed ICR Rules appropriately consider any exports that may exist for the relevant Commitment Period under study during the calculation of the capacity requirements by not including capacity associated with an accepted Administrative Export De-List Bid in the calculation of the Local Sourcing Requirements or the ICR. This is sufficient to ensure that New England does not rely on capacity

[38] FCM Settlement Agreement § III.A.8 provides:

> Where zonal separation is determined to exist, Market Rules shall specify a process for an Export both from or through the import-constrained zone over tie lines to external regions.

[39] FCM Settlement Agreement at § III.A.8.

obligated for export to a neighboring Control Area. Details about the real-time scheduling of energy from resources designated to provide capacity exports are beyond the scope of the ICR Rules.

LIPA maintains that properly accounting for capacity that is exported through a constrained zone should increase the Local Sourcing Requirement for the constrained zone. However, in a locationally-based capacity market it is not appropriate (or required by the FCM Settlement Agreement) for a capacity export that originates from a resource located outside of an import-constrained zone to result in an increase in the Local Sourcing Requirement for the import-constrained zone. In other words, a capacity export that originates from a generating resource located in western Massachusetts and is delivered to Long Island via a transmission line between Connecticut and Long Island would not automatically result in an increase in the Local Sourcing Requirement for Connecticut. In a locational capacity market, purchasing capacity from a resource located in an unconstrained zone simply provides a right to use that capacity within the unconstrained zone. It does not provide a priority right to "export" across any specific path. LIPA's proposed "export" treatment would be tantamount to allowing an entity serving load in Connecticut to purchase capacity from a resource located in western New York on the export-constrained side of New York's Central/East interface, and then import that capacity into Connecticut on a transmission line between Connecticut and Long Island, thus increasing the Local

Sourcing Requirements attributable to load-serving entities in Long Island in order to reliably ensure "delivery" of the western New York capacity to Connecticut.

In order for a Market Participant to export capacity, the Market Participant must de-list capacity from a resource in New England. If this capacity were to come from a resource located within an import-constrained zone, the total amount of capacity available to meet the zone's Local Sourcing Requirement would be reduced. This has the same effect as increasing the Local Sourcing Requirement under LIPA's construct because more resources must be added to the area to satisfy the Local Sourcing Requirement. Furthermore, it places the burden of obtaining locationally-appropriate resources on the exporter and eliminates any undue preference for the export capacity over native load that is located in the import-constrained area.

Finally, LIPA contends that once a facility is de-listed (in whole or in part), New England cannot rely on the de-listed capacity to meet the ICR of the New England Control Area. LIPA maintains that the failure to address this issue leaves the ISO free to prevent exports of capacity from New England to adjoining Control Areas, even in instances when the owner of the generation to be exported de-lists the capacity from the New England Control Area in advance, resulting in a clear violation of the FCM Settlement Agreement and constituting undue discrimination under the FPA. Therefore, LIPA argues that, in effect, the ISO intends to convert what ought to be non-recallable capacity into recallable capacity and thus will render capacity and energy exports from New England less reliable

for purchasers such as LIPA in adjoining Control Areas. LIPA, again, misses the mark.

The ICR Rules clearly exclude capacity associated with an accepted Administrative Export De-List Bid in the calculation of Local Sourcing Requirements. Specifically, proposed Section III.12.7.2 states, in relevant part, that "capacity associated with Export Bids cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period" will be excluded from the Local-Sourcing-Requirements calculation. Moreover, pursuant to proposed Section III.12.7.2, capacity associated with Export Bids cleared in previous Forward Capacity Auctions will be excluded also when calculating the ICR and the Local Sourcing Requirements for the New England Control Area. In addition, consistent with Section III.A.3 of the FCM Settlement Agreement, and most importantly from LIPA's perspective, capacity associated with an accepted Administrative Export De-List Bid is excluded from the calculation described in proposed Section III.12.4, describing the calculation used to compare an import-constrained area's Local Sourcing Requirement with the resources in that area, which, in turn, determines the capacity zones that are to be modeled in the Forward Capacity Auction. When determining which resources can or cannot meet the Local Sourcing Requirements established pursuant to this proposed ICR Rule, the ISO has developed rules as part of the FCM Rules, which are to be filed with the Commission in mid-February.

Finally, LIPA's non-specific concerns that the ISO might inappropriately prevent capacity exports or convert non-recallable capacity into recallable capacity are beyond the scope of the ICR Filing. LIPA itself notes that these operational issues are currently the subject of ongoing discussions among LIPA, the New York Independent System Operator ("NYISO") and the ISO. In this regard, the ISO intends to continue working with LIPA and other interested parties to ensure a common and clear understanding of real-time operational issues associated with capacity exports.

E. The Parties' Remonstrances Regarding the Tie-Benefits Provisions Proposed in the ICR Filing Should Be Rejected.

(1) The Currently-Proposed ICR Rules Already Allow the ISO to Perform Tie-Benefits Studies in Less Than 3 Years.

The CT DPUC requests that the Commission direct the ISO to perform a new tie benefits study if there is a change to the Northeast Power Coordinating Council ("NPCC")-area electrical system that may materially affect tie benefits in the New England Control Area. The CT DPUC argues that the ISO should not be permitted to wait three years to conduct a new study if the physical reality of the system has already made prior studies obsolete.

The CT DPUC's argument is without merit and should therefore be rejected. As currently written, the provisions proposed in the ICR Filing will already allow for an update in the event that the NPCC-area electrical system

experiences changes. Specifically, proposed Section III.12.9 states, in relevant part:

> At least once every three years, the ISO shall perform a tie benefits study . . . [and] [the] results shall be updated if the ISO determines that New England Control Area or external Control Area system conditions may change the results from the study.

Accordingly, the CT DPUC's requested relief should be denied.

(2) LIPA's Request for Establishing a Methodology to Calculate Tie Benefits for the CSC and the Phase II Interconnection with Hydro-Quebec in the Same Manner Should Be Denied.

LIPA claims that the ISO's proposed ICR Filing is unjust and unreasonable because it fails to establish a methodology to calculate tie benefits comparably for similarly-situated, controllable transmission resources. LIPA argues that, although the CSC between New York and New England and the Phase II Interconnection with Hydro-Quebec ("HQ Interconnection") between New England and Quebec are both controllable, direct-current ("DC") facilities, the ICR Filing contains a proposed provision for determining only the Hydro Quebec Interconnection Capability Credits ("HQICC") for the HQ Interconnection and does not include a similar provision for determining the alleged reliability benefits of the CSC. Moreover, LIPA maintains that, while proposed Section III.12.9 describes how tie benefits are to be determined using a probabilistic methodology, proposed Section III.12.9.2 states that a deterministic methodology will be used to calculate HQICCs. As privately-owned, controllable inter-ties, LIPA asserts that the

methodology to compute tie benefits for both the CSC and the HQ Interconnection should be equivalent. For a number of reasons, the ISO disagrees.

LIPA's request for a specific treatment of the CSC should be rejected because it is premature. LIPA, by requesting preferable treatment and priority claims over any capacity credits for the alleged tie benefits that the CSC may provide the New England Control Area, is intimating that the CSC actually confers unique reliability benefits on New England in general or Connecticut in particular that are not available to these regions absent the CSC. However, LIPA has proffered no evidence to support such a supposition. By failing to provide such evidence but yet concomitantly advocating in favor of capacity credits, LIPA is essentially arguing that the mere fact that the CSC is directly connected to Connecticut bestows capacity benefits on the New England Control Area. However, this assumption clearly should not be reflected in the generic ICR Rules, since it relies on factual analysis of circumstances that change over time, but should be addressed during consideration of specific ICR and Local Sourcing Requirement determinations.

The fact of the matter is that transmission, by itself, does not provide a capacity benefit.[40] Transmission is a necessary component in the ability to move

[40] The ISO respectfully requests, to the extent necessary for Commission deliberation on this issue, that the Commission take administrative notice of pleadings (and any attachments thereto) filed in the ISO's annual ICR-values proceedings in Docket Nos. ER05-715-000 and ER06-656-000, as well as the related proceedings involving the determination of HQICCs in Docket Nos. EL02-61-000, EL02-70-000, EL03-25-000, ER03-114-000, and ER03-894-000. *See City of Bedford, et al. v. Appalachian Power Company*, 68 FERC ¶61,004 (1994) (taking administrative notice and incorporating into the record of the current proceeding the entire record in a prior proceeding in which issues pertinent to the current proceeding were addressed).

capacity and energy from one location to another where it is needed. However, determining the capacity benefits of an interconnection depends on an assessment of generating resources located on either side of the interconnection and the ability of those resources to provide emergency energy in the event it is needed.

While the ISO's annual ICR-values filings for the 2005/2006[41] and 2006/2007[42] Power Years included 600 MW as the overall tie-benefit value for the entire New York Control Area, the ISO "did not make any explicit inclusion of the CSC or 1385 Cable"[43] in the value because, to date, Long Island has lacked surplus generation resources.[44] This is because Long Island's own needs require virtually all of its native resources to serve its native load. Indeed, the New York ISO currently requires Long Island to satisfy 99% of its peak installed capacity requirements with local resources, which, as LIPA Witness Bolbrock testified during the *Devon Power* proceeding, only leaves Long Island with "marginal excess" after satisfying its Local Sourcing Requirement.[45]

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[41] *See* annual ICR-values filing for 2005/2006 Power Year filed in Docket No. ER05-715-000 at p. 13.

[42] *See* annual ICR-values filing for 2006/2007 Power Year filed in Docket No. ER06-656-000 at p. 12.

[43] *Devon Power LLC*, Docket No. ER03-563-030, LaPlante, Mar. 28, 2005, Tr. at 4108:21-4109:7. *See also ISO New England, Inc.* 112 FERC ¶ 61,254 at P 14 (2005) ("[T]here is nothing in the record that indicates that any portion of the 600 MW tie-line benefit assigned to New York that was included in the February 2003 Tie Reliability Benefits Study was attributable to the CSC.")

[44] *See* Peter Wong Affidavit at p. 10 (filed as Attachment to April 20, 2005 *Motion for Leave to Answer and Answer of ISO New England Inc.* in Docket No. ER05-715-000).

[45] *Devon Power LLC*, Docket No. ER03-563-030, Bolbrock, Tr. at 3791:19-25.

As further testified by LIPA Witness Bolbrock, Long Island's power supply will be "relatively tight" over the next few years[46] – so tight, in fact, that "if no capacity is imported from New England over the Cross Sound Cable, we are expecting that LIPA will experience small (about 100 megawatts or less) surpluses and deficits in capacity until 2007."[47] Given the uncertainty over time of the availability of surplus generation to date, it is appropriate to exclude the CSC and similar facilities from special consideration in the generic rules describing the calculation of ICR and Local Sourcing Requirements.

However, as stated in proposed Section III.12.9 of Market Rule 1, "at least once every three years, the ISO shall perform a tie benefits study" and "the results shall be updated if the ISO determines that New England Control Area or external Control Area system conditions may change the results from the study." Therefore, the ISO will continue to consider on a periodic basis what, if any, tie reliability benefits the CSC (along with the other interties connecting New England to adjacent Control Areas) confers on New England.

Finally, while LIPA is correct in stating that the CSC and HQ Interconnection are both merchant-owned, controllable inter-ties, LIPA completely disregards several critical differences between these two lines and the calculation of HQICCs versus tie benefits. Most notably, HQICCs are the result of previous proceedings where, after finding that the HQ Interconnection provided

[46] *Devon Power LLC*, Docket No. ER03-563-030, Exh. LIP-8 at 13:3-4. *See also* Bolbrock Tr. at 3796:3-3797.

[47] *Devon Power LLC*, Docket No. ER03-563-030, Exh. LIP-8 at 13:4-6.

significant reliability benefits to the New England Control Area the Commission ordered that the entities in New England that support the HQ Interconnection be given installed capacity credits.[48] There has been no such determination regarding the CSC. Consequently, establishing a generic rule providing capacity credits for the CSC without considering its actual reliability contributions is neither just nor reasonable.

There are also key differences between the *ad hoc* calculation of HQICCs and the calculation of tie benefits for all of the other ties between New England and other Control Areas, some of which, like the CSC, also share similarities with the HQ Interconnection. In general, tie benefits are based on an assessment of the probable availability of generation within New England and an adjacent Control Area. In contrast, HQICCs (per the Commission's directive) are based on a determination of how much excess capacity Quebec will have each month, regardless of the likelihood of New England having any need for emergency assistance from Quebec during the applicable month.

Given the differences between the CSC and HQ Interconnection and the calculation of HQICCs and tie benefits, it would be inappropriate to use the same

[48] *PG&E National Energy Group, et al. v. ISO New England*, 99 FERC ¶ 61,187, *order granting reh'g in part and denying reh'g in part*, 100 FERC ¶ 61,227 (2002). This is just one of a series of orders issued by the Commission addressing disagreements among the Participants regarding how to calculate monthly HQICC values. *See, e.g., NSTAR Electric and Gas Corporation v. New England Power Pool*, 102 FERC ¶ 61,107, *order granting reh'g in part and denying reh'g*, *NSTAR Electric and Gas Corporation v. New England Power Pool*, 103 FERC ¶ 61,093 (2003) (resolving disputes regarding HQICC values for the 2002/2003 Power Year); *PG&E National Energy Group, PG&E Generating, USGen New England, Inc., PG&E Energy Trading – Power, L.P., and The United Illuminating Company v. New England Power Pool*, 103 FERC ¶ 61,112 (2003) (resolving disputes regarding HQICC values for the 2003/2004 Power Year); *New England Power Pool*, 104 FERC ¶ 61,218 (2003) (resolving disputes regarding HQICC values for the 2004/2005 Power Year).

methodology to determine the tie benefits for the HQ Interconnection and the CSC, respectively. Specifically, LIPA's proposed preferential treatment for the CSC should not be granted without considering how to harmonize the treatment of all of the other interconnecting transmission facilities in New England. The CSC and the HQ Interconnection are not the only facilities that are controllable and/or not supported through the Regional Network Service charge. If the Commission finds that the CSC should be treated differently, then it will also be necessary and appropriate to consider the treatment of all of the other interconnecting transmission facilities in order to ensure a consistent and harmonious result.

(3) Using the "As-Is" Methodology to Determine the Tie Benefits of Neighboring Control Areas Will not Produce an Artificially Low ICR and Local Sourcing Requirement for New England at the Expense of Its Neighboring Control Areas.

The NYSRC alleges that the ISO's proposal to use the "At-Criterion" methodology to model load and resource assumptions for Control Areas directly connected to New England and to use the "As-Is" methodology in the annual reconfiguration auction immediately preceding the relevant Capacity Commitment Period to determine the tie benefits available from adjacent Control Areas will deleteriously affect the New York Control Area. The NYSRC claims that the use of this inconsistent modeling approach to determine tie benefits will result in an unreasonably low ICR and locational requirements for the New England Control Area that will diminish the reliability of neighboring Control Areas. Specifically, the NYSRC argues that by assuming unrealistically large amounts of outside

emergency assistance from neighboring regions to support New England, this proposal will detrimentally affect New York's reliability. The NYSRC states that it is inappropriate for the ISO to over depend on emergency assistance imports from the New York Control Area. The NYSRC is also concerned that the ICR Filing fails to reference the Joint Tie Benefit study that has been undertaken by the NYSRC/NYISO and the ISO. The NYSRC's claims miss the mark.

Given that the final Annual Reconfiguration Auction will take place approximately two months before the Capacity Commitment Period, "As-Is" assumptions are likely to be more accurate than "At-Criterion" assumptions. This is because under the "As-Is" methodology Control Areas will be modeled with all forecasted resources available to serve the forecasted load, without regard to whether the Control Area has surplus or deficient resources to meet the LOLE criterion. Therefore, the amount of tie benefits that are calculated at this time could either be more or less than that which was previously calculated assuming "At-Criterion," resulting in an ICR that is lower or higher than the earlier calculation.

Moreover, based on the import-capacity resources that clear in prior auctions and that are obligated for the relevant Capacity Commitment Period, the results of prior auctions may limit the amount of tie benefits that result from the Annual Reconfiguration Auction update using "As-Is" assumptions. This is required as the total amount of tie benefits plus import capacity resources cannot exceed the physical interface limit of that tie.

The use of "As-Is" tie benefits in the final Annual Reconfiguration Auction closest to the Capacity Commitment Period may reduce the amount of capacity that is required through an increased amount of tie benefits, but only to the extent that there is capacity available above the "At-Criterion" level in neighboring Control Areas and that there is room on the ties for increased tie benefits after accounting for already accepted capacity import contracts.

Further, the NPCC does not require that the Control Areas develop tie benefits based on "At-Criterion." The NPCC CP-8 working group studies the tie assistance available only in order to make a qualitative statement that the control areas either are (or are not) over relying on ties. The "As-Is" case is one of those cases considered in their evaluation. In addition, as long as the reliability of each area is better than the LOLE criterion, then over-reliance is not demonstrated – although the magnitude of reliance may be a source of concern and discussion.

The ISO recognizes that the Joint New England/New York reliability study assumes that all Control Areas are brought to criterion. While this is an important study, it does not require the ISO to use the results for any specific purposes. The role of this study is to provide guidance and help develop analytical insights about tie benefits and the impact of specific interconnection points.

(4) The NYSRC's Assertion that It Is Inappropriate to Model Tie Lines for Emergency Assistance Without Regard to New York Firm Purchases Is Unavailing.

The NYSRC expresses concern that the modeling of firm export capacity directly impacts the NYCA IRM and associated locational capacity requirements

calculations. In particular, the NYSRC argues that, in order to maximize emergency assistance benefits, the ISO is proposing to ignore firm export capacity commitments to neighboring Control Areas when determining ICR and locational requirements. The NYSRC claims the curtailment of firm capacity contracts is inconsistent with NYISO market rules and may jeopardize New England Market Participant's participation in the New York market. The NYSRC's assertions are of no moment.

The NYSRC's concern is unwarranted because the proposed ICR Rule will treat firm capacity exports to New York in a manner that is consistent with NYISO market rules. When performing the ICR calculations, delisted capacity that is supporting a capacity export is removed from the complement of available resources. New England has no claim against the resource; thus, New York will have unfettered access to that capacity from the location in which it is interconnected. New York participants may elect to select a capacity resource within any capacity zone of its choosing recognizing that while curtailment of this capacity to New York is unlikely, curtailment at a specific external node that is located within an import constrained zone bears a greater risk if the Administrative Export De-Listed resource is in a different zone. Accordingly, the NYSRC's *Comments* on this issue are without merit.

(5) Con Ed's Contention that the ISO Ignores Internal Constraints when Calculating Tie Benefits Is Unsupported.

Con Ed states that, while the ISO's proposed ICR methodology considers internal transmission constraints when calculating Local Sourcing Requirements, the ISO ignores those constraints when computing the level of tie benefits. By ignoring internal constraints, Con Ed claims that the calculated LOLE assumes that there are sufficient resources available to the ISO to meet the aggregate load, and that there is no loss of load. However, Con Ed maintains that this simplification ignores the possibility that the available resources may be constrained by internal transmission limits. Con Ed further states the calculation of Local Sourcing Requirements does not obviate the need to consider internal constraints when calculating LOLE. Con Ed's assertions should be rejected.

The ISO addresses internal transmission constraints by ensuring that capacity is distributed in a way that alleviates those constraints. Local Sourcing Requirements will be used to ensure that there is adequate capacity in import-constrained zones. When Local Sourcing Requirements are calculated, tie benefits are assumed to accrue in the zone to which the relevant interface interconnects. This locationally-appropriate capacity alleviates the effect of transmission constraints on tie reliability benefits that was discovered in the ISO's 2003 Tie Reliability Benefits Study, the most recent such study performed to date. Accordingly, the Commission should deny Con Ed's *Protest*.

(6) It Is Appropriate for the ISO to Reserve A Portion of the Control-Area Interface for the Sake of Tie Benefits.

Constellation Movants and HQUS[49] take exception with the ICR Filing's proposal to continue the ISO's current practice of reserving a portion of the Control Area interface for tie benefits. Constellation Movants and HQUS contend that, because import transactions are backed by contracts, whereas tie benefits are based on a probabilistic determination that capacity may be available during an emergency, allowing imports up to the transfer limit of the Control-Area interface would enhance the reliability of the New England Control Area.

The ISO addressed this issue at length in its initial filing in this proceeding.[50] Pursuant to the terms of the FCM Settlement Agreement,[51] the total amount of tie benefits *assumed* over an interface plus the import capacity resources cannot exceed the transfer capability of that interface.[52] Therefore, in order for tie benefits to occur, a portion of the interface must be free from capacity commitments, as firm capacity contracts require a portion of a tie to be reserved. Put differently, firm imports over ties effectively lower transfer limits available to support tie benefits. Because all New England customers pay Network Load charges for the transmission-system interconnections that ultimately provide the means to purchase emergency assistance from neighboring Control Areas (*i.e.*, tie

[49] HQUS also joined Constellation Movant's *Protest* on this issue.

[50] *See* Transmittal Letter at 12-13.

[51] *See* FCM Settlement Agreement at § III.D.4(a).

[52] The limit on import contracts is for planning purposes only. The calculation of the ICR does not in any way limit the ability of energy to flow over the interface in real-time.

benefits), these consumers should have the right to retain a portion of the Control-Area interface so that they can avail themselves of the benefits that result from the connection of two networks. Accordingly, the ISO asks that the Commission deny Constellation Movant's and HQUS' requests for it to reject the tie benefits model included in the ICR Filing.

F. The CT DPUC's Arguments Regarding the Determination of Capacity Zones Put Forth in the ICR Filing Are Without Merit.

The CT DPUC asserts that the proposed rule for determining whether an import-constrained Capacity Zone will be modeled in the Forward Capacity Auction (*i.e.*, Section III.12.4(b) of Market Rule 1) is incongruous because, on the one hand, it requires the ISO to ascertain the total amount of capacity that is projected to be installed in the Load Zone in question before the start of the relevant Capacity Commitment period. While, on the other hand, only Existing Capacity Resources, resources cleared in previous Forward Capacity Auctions, existing Demand Resources, and previously cleared Import Capacity Resources obligated for the relevant Commitment Period are counted. As a result, the CT DPUC alleges that this proposed rule will not correctly establish the total amount of projected installed capacity that will be available at the start of the Capacity Commitment Period and does not reflect the terms of the FCM Settlement Agreement because it ignores Intermittent Resources. The CT DPUC's contention is of no moment.

Intermittent Resources will be included in the ISO's assessment of projected installed capacity due to the fact that extant Market Rule 1 defines a "Resource" as a "generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction." Because an Intermittent Resource is a "generating unit," it will be one of the resources included in the ISO's determination of the total amount of capacity that is projected to be installed in the Load Zone in question. As for the FCM Settlement Agreement's requirement that special rules be developed to determine the Qualified Capacity of Intermittent Resources,[53] this work has been completed and will be included in the FCM market rules (Calculation of Qualified Capacity Value for Intermittent Resources) by the ISO on February 15, 2007.

The CT DPUC next argues that the ISO failed to comport with the FCM Settlement Agreement's requirement that, for purposes of the first Forward Capacity Auction, any resource that is under construction and within 12 months of its expected commercial operations date must be treated as Existing Capacity.[54] The CT DPUC's assertion, however, misses the mark because this is indeed the intent of the ISO and is detailed in the proposed definition of an "Existing Capacity Resource" and further defined in the draft FCM rules, which will be filed by the ISO on February 15, 2007. The forthcoming FCM rules also describe how these resources can be classified as an Existing Capacity Resource (if they so

[53] *See* FCM Settlement Agreement § 11.II.E.1.a.

[54] *See Id.* at § 11.II.D.1.

choose) or are required to be treated as Existing Capacity Resources pursuant to contract.

Lastly, the CT DPUC states that proposed Section III.12.7.2 of Market Rule 1 omits both Intermittent Resources and New Capacity Resources that qualify for the FCM and should therefore be included as resources expected to be in service by the first day of the Commitment Period. This argument, however, if accepted, would cause the over-counting of expected resources by the ISO's proposed ICR Rule.

It is not the intent of the ISO, and it would not be appropriate, to include those New Capacity Resources that are only qualified to participate in the Forward Capacity Auction in the agglomeration of resources available to meet a Local Sourcing Requirement prior to an Forward Capacity Auction. This is because doing so would mean including resources that have only expressed an interest in providing capacity to New England but are under no obligation to become operational by the Capacity Commitment Period until they have actually cleared within an auction. Thus, including these resources before they have an obligation to become operational could overstate the actual reliability of the system and would undermine the very market mechanisms designed to ensure that these resources are built. For these reasons, the CT DPUC's protestations should be disregarded.

G. The CT DPUC's Proposed Definitions Should Be Rejected.

(1) Determination of Capacity Zones

The CT DPUC raises several arguments regarding the various definitions proposed by the ISO in the ICR Filing. For instance, the CT DPUC alleges that the ISO's proposed definition of "Capacity Zone" as a geographic sub-region of the New England Control Area is potentially inconsistent with other parts of the proposed ICR Rules (*e.g.*, Sections III.12.2, III.12.2.2.1(d), III.12.2.2(a)) that each make the electrical location of a resource controlling. As result, the CT DPUC requests that the Commission direct the ISO to define "Capacity Zone" as "an electrical sub-region of the New England Control Area, as determined in accordance with Section III.12.4 of this Market Rule."[55] However, the CT DPUC's proposed definition is unnecessary because when read within the context of (and contemporaneously with) other proposed provisions in the ICR Filing and current Market Rule 1 definitions, it becomes manifest that the ISO's suggested definition already reflects the electrical location of a resource.

Indeed, the ICR Filing defines "Capacity Zone" as "a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of this Market Rule." Proposed Section III.12.4 of Market Rule 1, in turn, states that Capacity Zones will be modeled as export-constrained, import-constrained and adjacent "Load Zones" – which are defined in extant Market Rule 1 as "a Reliability Region, except as otherwise provided for in Section III.2.7 of

[55] CT DPUC Protest at 13.

this Market Rule." The current Market Rule 1 defines "Reliability Region" as "any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System." Consequently, when read within the context of (and contemporaneously with) other proposed provisions in the ICR Filing and current Market Rule 1 definitions, it is manifest that the ISO's suggested definition already indicates that the electrical location of a resource is controlling. Accordingly, the CT DPUC's requested definition is unnecessary and should be rejected.

(2) Definition of Existing Capacity Resource

The CT DPUC submits that the proposed definition of "Existing Capacity Resource" put forth in the ICR Filing is infirm because it fails to include language that would allow a New Capacity Resource to elect to be treated as an Existing Capacity Resource. As a result, the CT DPUC requests that the Commission direct the ISO to revise its proposed definition accordingly.

The CT DPUC's assertion is unavailing because this is indeed the intent of the ISO and is detailed in the proposed definition of an "Existing Capacity Resource" and further defined in the draft FCM Qualification Rules, which will be filed by the ISO on February 15, 2007. The forthcoming FCM rules also describe how these resources can be classified as an Existing Capacity Resource (if they so choose) or are required to be treated as Existing Capacity Resources pursuant to contract.

(3) Definition of Loss of Load Expectancy

The CT DPUC argues that the ISO's proposed definition of "Loss of Load Expectation" is overly simplistic and fails to convey the full scope of the NPCC resources adequacy design criterion. Accordingly, the CT DPUC requests that the ISO's proposed definition be modified to reflect the NPCC definition. Once again, the CT DPUC's argument is baseless.

The ISO, in its ICR Filing, proposed to define "Loss of Load Expectation" as "the probability of disconnecting non-interruptible customers due to a resource deficiency." The ISO purposely proposed this truncated definition because the entire purpose of the ICR Rule is to describe how the LOLE criterion is implemented in New England. Therefore, including the much-less detailed NPCC calculation would be superfluous. Accordingly, the CT DPUC's requested definition should be rejected as unnecessary.

(4) Definition of Permanent De-List Bid

The CT DPUC alleges that the ISO's proposed definition of "Permanent De-List Bid" is tautological and fails to define the term. Accordingly, the CT DPUC puts forth a more detailed definition of "Permanent De-List Capacity," which it asks the Commission to adopt. However, as with the CT DPUC's other proposed definitions, this, too, is unnecessary.

The ISO proposed to define "Permanent De-List Bid" as "a bid submitted in the Forward Capacity Auction by an Existing Capacity Resource to permanently de-list capacity." Similar to the ISO's proposed definition of "Loss

of Load Expectation," the ISO was purposefully laconic because a much more expansive, detailed definition will be put forth in the FCM market rules. The definition proposed in the ICR Filing was intended to briefly describe the consequence of a cleared permanent de-list bid. As such, the CT DPUC's request that the Commission order the ISO to adopt a more detailed definition of "Permanent De-List Capacity" should be denied.

H. CT DPUC's Arguments Regarding Generation Modeling Assumptions Are Baseless.

The CT DPUC claims that proposed Section III.12.6(a)iii of Market Rule 1, which states (in relevant part), "a valid Interconnection Request for which a draft Interconnection Feasibility Study report has been submitted to the Interconnection Customer," is neither reasonable nor necessary and should be modified or deleted. According to the CT DPUC, the ISO's completion of a draft Interconnection Feasibility Study report is not a relevant criterion for determining whether a new resource will be in service no later than the first day of the relevant Capacity Commitment Period. The CT DPUC further alleges that the requirement for a draft Interconnection Feasibility Study so far in advance of the Capacity Commitment Period may be inconsistent with the qualification criteria for the Forward Capacity Auction. The CT DPUC argues that the only relevant basis for determining whether a generating resource is expected to be in service no later than the first day of the relevant Capacity Commitment Period should be

qualification for the Forward Capacity Auction. The CT DPUC misses the point of the referenced Section of the rules.

The purpose of proposed Section III.12.6(a)iii of Market Rule 1 is to set the standards for the network model used to (1) set transfer limits and (2) study interconnection requests. This proposed Section does not, for example, determine which units are assumed to be available to meet a Local Sourcing Requirement. The forthcoming FCM rules will determine which generators are to be assumed in-service when performing overlapping impact analysis.

The network model is essentially an electronic representation of the transmission system (*e.g.*, transmission lines, breakers, substations). When generators interconnect, they may change the transmission system, for instance, by adding breakers. These kinds of material modifications to the transmission system should be included where possible, as they may affect transfer limits or the ability of other generators to interconnect. However, exactly what these modifications are is not known until the completion of a draft Feasibility Study. For these reasons, asking to include transmission modifications in the network model before they are identified is nonsensical, and the request of the CT DPUC should be denied.

I. CTDPUC's Arguments Regarding Transmission Interface Limits Are Unavailing.

Because transmission interface limits are a crucial input for determining Local Sourcing Requirements, the CT DPUC contends that the ISO's detailed methodology should be transparent and subject to Commission and public scrutiny. Because of this, the CT DPUC avers that material aspects of the ISO's analysis should not be relegated to the ISO's Manuals and Administrative Procedures. To this end, the CT DPUC requests that the Commission clarify that any change to the ISO's Manual or Administrative Procedures that affects its analysis of transmission interface limits must be filed with the Commission under FPA Section 205. This request should be denied given the nature of the ICR Rules as describing the general parameters of calculations that themselves will be separately filed for review by the ISO.

As mentioned in the ICR Filing's Transmittal Letter, the ISO will still continue to make its annual ICR-values filings with the Commission. As has been (and will continue to be) the case, these filings will involve a detailed review before both the stakeholders and the Commission of the various factual determinations reflected in the annual filing. Any and all points of contention regarding the ISO's annual ICR filing – including the ISO's determination of transmission interface limits – can be addressed at that time. Thus, the CT DPUC's requested relief should be denied as unnecessary.

J. CTDPUC's Arguments Regarding the ISO's Proposed Methodology for Establishing A Transmission Network Model Are Baseless.

Pursuant to proposed Section III.12.6.2 of Market Rule 1, the ISO will include a transmission project in its network model only if it meets all of the following initial threshold requirements: (a) a critical path schedule showing an in-service date no later than the start of the relevant Capacity Commitment Period; (b) at the time of the milestone review, siting and permitting processes are on schedule as shown on the critical path schedule; (c) engineering is on schedule as shown on the critical path schedule; and (d) a certification from a transmission company's officer that the schedule is achievable and the owner intends to build in accordance with that schedule. The CT DPUC, however, avers that these criteria are too rigid and may exclude transmission resources that will, in fact, be in place to reduce the ICR or the Local Sourcing Requirements, causing customers to have to purchase an unjust and unreasonable amount of capacity.

The CT DPUC is particularly concerned that criteria (b)-(d) could be used to exclude a transmission project from the network model based solely on immaterial deviations from its projected schedule. As a result, it requests that the Commission direct the ISO to move criteria (b)-(d) from proposed Section III.12.6.2 of Market Rule 1 to Section III.12.6.3, the provisions of which the CT DPUC asserts allows the ISO to exercise more flexibility when determining whether a transmission project will be in-service by the start of the relevant Capacity Commitment Period. The CT DPUC's request is devoid of merit.

The CT DPUC's remonstrations notwithstanding, the threshold requirements in proposed Section III.12.6.2 are not overly restrictive. Rather, these criteria were carefully drafted so as to enable the ISO to ensure the accuracy of the in-service dates of the projects upon which its transmission network model will be based. The ISO cannot over emphasize the importance of getting a transmission in-service date forecast correct. Otherwise, if the ISO were to forecast that a project will be in-service by a particular date and the transmission resource fails to be in place in time, system reliability could be severely imperiled.

Further, given that transmission projects lack the financial assurances of generation projects in the New England Control Area, it is even more necessary to subject such projects to a well-defined standard. The inclusion of a well-defined standard of what projects go into the model and what projects stay out also allows less room for subjectivity down the line. Thus, given the necessity for such assurances, it is clear that the proposed criteria are not overly restrictive. Accordingly, the CT DPUC's request should be denied.

IV.
CONCLUSION

For the foregoing reasons, the ISO respectfully requests that the Commission: (i) grant the ISO's *Motion for Leave to Answer*; and (ii) reject the protests and comments discussed herein in their entirety.

Respectfully submitted,

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Dated: February 1, 2007

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2010 (2004), upon each person designated on the official service list in this proceeding as compiled by the Secretary of the Federal Energy Regulatory Commission.

Dated at Washington, D.C., this 1st day of February, 2007.

/s/ Travis R. Smith
Travis R. Smith

ATTACHMENT A