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February 26, 2007

VIA ELECTRONIC FILING

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

Re: Maine Public Utilities Commission, Complainant v. ISO New England, Inc.,  
Respondent, Docket No. EL07- -000

Dear Secretary Salas:

Transmitted herewith for electronic filing with the Commission on behalf of the Maine Public Utilities Commission, a complaint against ISO New England, Inc., together with supporting documentation, including the following:

1. Complaint captioned as indicated above, together with certificate of service; and
2. A Notice of Complaint suitable for publication in the *Federal Register*.

Please do not hesitate to contact the undersigned if there are any questions concerning the pleading and supporting documentation submitted for filing.

Respectfully,

/s/ Lisa S. Gast

Lisa S. Gast

Enclosures

cc: Parties served per Certificate of Service

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

Maine Public Utilities Commission,	)	Docket No. EL07-___
	)	
Complainant,	)	
	)	
v.	)	
	)	
ISO New England, Inc.	)	
	)	
Respondent.	)	

**COMPLAINT OF THE MAINE PUBLIC UTILITIES COMMISSION  
AGAINST  
ISO NEW ENGLAND, INC.**

Respectfully submitted,

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February 26, 2007

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**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

Maine Public Utilities Commission,	)	Docket No. EL07-____
	)	
Complainant,	)	
	)	
v.	)	
	)	
ISO New England, Inc.	)	
	)	
Respondent.	)	

**COMPLAINT OF THE MAINE PUBLIC UTILITIES COMMISSION  
AGAINST  
ISO NEW ENGLAND, INC.**

Pursuant to Sections 206 and 306 of the Federal Power Act ("FPA"), 16 U.S.C. §§ 824e and 825e (2000), and Section 206 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure, 18 C.F.R. § 385.206 (2006), the Maine Public Utilities Commission ("MPUC") hereby petitions the Commission for an order (1) finding that Schedule 2 of ISO New England, Inc.'s ("ISO-NE") Open Access Transmission Tariff ("OATT") is unjust and unreasonable; and (2) directing ISO-NE to modify Schedule 2 of its OATT as described in the instant Complaint.

The first modification MPUC is seeking is implementation of the Reliability Region Cost Allocation methodology for the Cost of Energy Produced ("PC")

component<sup>1</sup> of the Schedule 2 rate described herein. As discussed below, this change is necessary because the current system of socializing the costs of uplift for local voltage support is unjust and unreasonable, as it (1) mutes demand response price signals and (2) is inconsistent with cost causation principles.

The second modification MPUC seeks is to replace the current and proposed capital cost ("CC") component<sup>2</sup> of the Schedule 2 rate with the CC Rate Deadband Proposal described herein. As will be described fully below, the current and proposed<sup>3</sup> CC Component are unjust and unreasonable because the revenue streams provided by the CC component of the Schedule 2 rate, when combined with the payments provided to generators under the implementation of the Forward Capacity Market ("FCM") Settlement in Docket No. ER03-563-060<sup>4</sup> beginning December 1, 2006, result in a double recovery of capital costs by generators. The CC Rate Deadband Proposal curtails generators' double recovery of capital cost compensation.

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<sup>1</sup> The PC component of the Schedule 2 rate is defined in the ISO-NE OATT as "the portion of the amount paid to Market Participants in the hour for Energy produced by a generating unit that is considered under this Schedule 2 to be paid for VAR support." ISO-NE OATT, Original Sheet No. 737.

<sup>2</sup> The CC component of the ISO-NE OATT Schedule 2 rate is defined as: "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." ISO-NE OATT, Original Sheet No. 737.

<sup>3</sup> ISO-NE has submitted for filing and acceptance a proposed rate increase for the CC component of the Schedule 2 rate in Docket No. ER07-397-000. In that filing, ISO-NE has not proposed any modification to the Schedule 2 methodology or formula. See ISO New England, Inc. and New England Power Pool Participants Committee Proposed Amendments to Schedule 2 - Reactive Supply & Voltage Control of the ISO New England, Inc. Open Access Transmission Tariff, Transmittal Letter ("Docket No. ER07-397-000 Joint Filing Transmittal Letter") at 2, Docket No. ER07-397-000 (December 29, 2006).

<sup>4</sup> See *Devon Power, LLC*, 115 FERC ¶ 61,340 (June 16, 2006) ("Settlement Order"), FERC Docket Nos. ER03-563-030 and -055.

## **I. COMMUNICATIONS**

MPUC requests that correspondence, pleadings and other documents with regard to this proceeding be served on the following, whose names are to be placed on the Commission's official service list in accordance with Rule 203, 18 C.F.R. § 385.203 (2006):

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## **II. STATEMENT OF ISSUES**

Pursuant to Rule 203(a)(7) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.203(a)(7) (2006), MPUC specifies the following issues, to which it requests Commission determination:

1. Whether the rate which results from Schedule 2 of ISO-NE's OATT is unjust and unreasonable because the current cost allocation methodology of the PC component of the Schedule 2 rate socializes uplift costs in direct contravention of the recommendation of ISO-NE's Independent Market Monitoring Unit?



2. Whether the rate which results from Schedule 2 of the ISO-NE's OATT is unjust and unreasonable because the CC component of the Schedule 2 rate results in generators receiving double recovery now that the Forward Capacity Market ("FCM") Settlement in Docket No. ER03-563-030 has been implemented?
3. Whether ISO-NE should be ordered to implement the Reliability Region Cost Allocation methodology for the PC component of the Schedule 2 rate?
4. Whether ISO-NE should be ordered to implement the CC Rate Deadband Proposal for the CC component of the Schedule 2 rate?

### **III. DESCRIPTION OF MPUC, and ISO-NE**

Under Maine law, the MPUC is the state commission designated by statute with jurisdiction over rates and service of electric utilities in the state. *See* 35-A M.R.S.A. § 1.101(k) (2006). It is, therefore, a "state commission" under the Commission's regulations, 18 C.F.R. § 1,101(k) (2006).

ISO-NE is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. ISO-NE 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, ISO-NE 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").

#### **IV. EXECUTIVE SUMMARY**

This Complaint seeks an order finding that the rate which results from Schedule 2 of ISO-NE's OATT is unjust and unreasonable, and requests that the Commission order ISO-NE to make modifications to two components of Schedule 2 of the ISO-NE OATT: (1) the allocation of the Cost of Energy Produced ("PC") component of the Schedule 2 and (2) the current and proposed Capital Cost ("CC") component of Schedule 2.

##### **A. The PC Component of Schedule 2**

The current cost allocation methodology of the PC component of the Schedule 2 rate socializes uplift costs that are incurred when a generator that was not economically dispatched is directed to come on line or increase power above its economic loading point to provide local voltage support. Under the Schedule 2 rate, if the Locational Marginal Price ("LMP") is lower than the offer price, the PC component of the Schedule 2 rate compensates the generator for the difference between the LMP and its offer price for each hour the generator provides reactive power.<sup>5</sup> Under the current tariff language, PC component charges are allocated region-wide, rather than to the reliability region in which the local voltage support is needed.<sup>6</sup>

As recognized by ISO-NE's Independent Market Monitoring Unit ("IMMU") in both its 2004 and 2005 Assessments of the Electricity Markets in New England ("Market Assessments"), socializing these local costs do not send the proper price signals to reduce demand and site generation and transmission resources in the local area needing the

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<sup>5</sup> Docket No. ER07-397-000 Joint Filing Transmittal Letter at 7.

<sup>6</sup> See 2005 Assessment of the Electricity Markets in New England ("2005 Market Assessment") at 52. The 2005 Market Assessment can be found at: [http://www.iso-ne.com/pubs/spcl\\_rpts/2005/2005\\_immu\\_report\\_final.pdf](http://www.iso-ne.com/pubs/spcl_rpts/2005/2005_immu_report_final.pdf).

voltage support. The MPUC seeks to have ISO-NE implement the IMMUs long-standing recommendation that reactive service uplift costs be allocated to the local area that benefits from the provision of the voltage support. To implement the IMMUs recommendation, the MPUC seeks to have the Commission find the current cost allocation methodology of the PC component unjust and unreasonable, and order the ISO-NE to implement the Reliability Region Cost Allocation methodology described herein.

#### **B. The CC Component of Schedule 2**

With the implementation of the Forward Capacity Market (“FCM”) Settlement in Docket No. ER03-563-030,<sup>7</sup> the CC Component of Schedule 2 results in generators receiving double recovery of compensation for capacity costs. The FCM Settlement provides for several billion dollars in capacity payments to generators from December 1, 2006 to May 31, 2010 (“Transition Payments”).<sup>8</sup> After this period, generators will be paid an auction price for their capacity through a mechanism called the Forward Capacity Auction (“FCA”).<sup>9</sup> Although the level of capacity payments paid to generators under the FCA is not yet known, for the first year of the market, 2010-2011, the auction price will have a floor of \$4.50 per kW month, and a ceiling of \$10.50 per kW month.<sup>10</sup>

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<sup>7</sup> See *Devon Power, LLC*, 115 FERC ¶ 61,340 (June 16, 2006) (“Settlement Order”), FERC Docket Nos. ER03-563-030 and -055.

<sup>8</sup> *Id.* at P 30. See also Affidavit of Dr. Thomas Austin (“Austin Affidavit”) at ¶¶ 7-9. Dr. Austin’s affidavit is attached hereto as Attachment A.

<sup>9</sup> See *Devon Power, LLC*, 115 FERC ¶ 61,340 (June 16, 2006) (“Settlement Order”), FERC Docket Nos. ER03-563-030 and -055, at P 16.

<sup>10</sup> See *id.* at P 19.

The CC component of the Schedule 2 rate also provides a stream of revenues to generators to compensate for capital costs. Since the equipment needed to generate electricity is generally the same as that needed to provide reactive service,<sup>11</sup> the effect of the two streams of revenue is a double recovery of capacity payments by generators. Therefore, one reasonable approach would be to eliminate the CC component of the Schedule 2 rate. However, in the spirit of compromise, MPUC took a middle ground in the stakeholder process and proposed a limited capacity compensation mechanism (the CC Rate Deadband Proposal). In the instant Complaint, MPUC continues to propose the CC Rate Deadband Proposal rather than requesting, as would be justified, that the CC component be eliminated.

The CC Rate Deadband Proposal would compensate generators to the extent they invest in *additional* equipment beyond that required to provide reactive service within the established power factor range (“deadband”) set forth in their interconnection agreements and in Schedule 22 to the ISO-NE OATT (the Standard Large Generator Interconnection Procedures). The CC Rate Deadband Proposal has the benefit of reducing the degree to which generators are being compensated twice for the capital costs of the same equipment, while still providing generators an appropriate incentive to invest in equipment needed to increase the amount of reactive service provided outside of the deadband. In addition, the proposal to limit reactive service payment to the capability to

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<sup>11</sup> Affidavit of Wayne Whittier (“Whittier Affidavit”) at ¶ 22. Mr. Whittier’s affidavit is attached hereto as Attachment B.

provide reactive service only outside of the deadband is consistent with (although not required by) the provisions of Order No. 2003.<sup>12</sup>

## **V. BACKGROUND AND DESCRIPTION OF CURRENT METHODOLOGY**

### **A. Schedule 2**

Schedule 2 of the ISO-NE OATT sets forth the rules that govern eligibility for compensation and payment for reactive power supply and voltage control service in New England.<sup>13</sup> To the extent a generation facility is directed by ISO-NE to produce or absorb reactive power, that facility is compensated under the Schedule 2 rate for its provision of reactive power and for the energy costs associated with the reactive power provided. The generator also is compensated for the capability to provide reactive service.

The existing rate design under Schedule 2 of the OATT consists of a fixed capacity cost ("CC") component and three variable components: (1) Lost Opportunity Cost ("LOC"), which compensates a generator for the lost opportunity in the energy market when the generator would otherwise be economically dispatched but is directed by ISO-NE to reduce real power output to provide more reactive power; (2) the cost of energy consumed ("SCL"), which compensates for the cost of energy consumed by a generator solely to provide reactive power support;<sup>14</sup> and (3) the Cost of Energy Produced ("PC") component which compensates a generator that was not economically dispatched when it is directed to come on line or increase power above its economic loading point to provide local reactive support. The PC component compensates the

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<sup>12</sup> *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 68 Fed. Reg. 49,845 (Aug. 19, 2003), FERC Stats. & Reg., Regulations Preambles ¶ 31,146 at P 540-42. (2003) ("Order No. 2003").

<sup>13</sup> See Schedule 2 to ISO-NE's OATT at Original Sheet No. 735.

<sup>14</sup> This Complaint does not propose changes to the LOC or SCL components of Schedule 2.

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. The PC component of the Schedule 2 rate was implemented prior to the beginning of standard market design, and thus pre-dates LMP in New England.

At the time the CC component was negotiated, the monthly capacity payment that would be applicable if the load serving entity had not purchased sufficient capacity through the bilateral market<sup>15</sup> was \$0.17/kW month.<sup>16</sup> In the NEPOOL filing implementing the original negotiated CC component of the Schedule 2 rate, advocates for a reactive capacity charge asserted that “...the capital costs covered by the CC charge are not necessarily recoverable in the market-based real power markets and therefore it is appropriate to establish an administratively set rate to allow generators to recover such costs and be incentivized to provide VAR support capability and service.”<sup>17</sup> In comparison to the \$0.17/kW month 2001 ICAP deficiency charge, the capacity Transition Payments under the FCM Settlement are in the range of \$3.05 to \$4.10 per kW month.<sup>18</sup>

#### **B. The VAR Working Group**

In December of 2004, the Transmission Committee established the VAR Working Group 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. Cost

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<sup>15</sup> This payment was called the Installed Capacity (“ICAP”) deficiency charge.

<sup>16</sup> *Sithe New England Holdings, LLC v. FERC*, 308 F.3<sup>rd</sup> 71 (2002).

<sup>17</sup> New England Power Pool Seventy-Third Agreement Amending the Restated NEPOOL Agreement, Docket No. ER01-2161-000 at 10 (May 29, 2001).

<sup>18</sup> *See Devon Power, LLC*, 115 FERC ¶ 61,340 at P 30 (June 16, 2006) (“Settlement Order”), FERC Docket Nos. ER03-563-030 and -005 at P 30.

allocation was one of the items that the group addressed. ISO-NE, in fact, questioned whether the current cost allocation under Schedule 2 could be improved. *See* Attachment C at 13, appended hereto.<sup>19</sup>

As described by ISO-NE and NEPOOL, the VAR Working Group was a stakeholder working group that met regularly to develop recommendations for the Transmission Committee:

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.<sup>20</sup>

Representatives of both Central Maine Power Company ("CMP") and the MPUC participated in the VAR Working Group.

On December 19, 2005, CMP proposed a change in cost allocation for the PC component of the Schedule 2 rate. *See* Attachment D, appended hereto. CMP proposed that VAR uplift costs should be allocated each month to the local area or reliability region causing the out-of-merit payments. This proposal was later identified as the Reliability Region Cost Allocation proposal.

On April 25, 2006, the VAR Working Group presented to the Transmission Committee its report on the various compensation and allocation issues with which it had been tasked.

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<sup>19</sup> Specifically, ISO-NE asked the following questions: "Are some of the current generator VAR costs sub-regional in nature, such that certain elements of these costs should be charged to the sub-region of New England in which the generator is located? For example, should: CC costs be charged regionally, and PC, LOC and SCL charged sub-regionally?" *Id.* at slide 13.

<sup>20</sup> Docket No. ER07-397-000 Joint Filing Transmittal Letter at 19, fn 31.

On June 6, 2006, the MPUC provided the chair of the VAR Working Group an alternative proposal for CC compensation. This proposal, which was later identified as the CC Rate Deadband Proposal, stated as follows:

The "Base VAR Rate" shall be zero for reactive support provided by generators between a .95 leading and a .95 lagging power factor. For power factors below .95 leading or .95 lagging, the "Base VAR Rate" shall be \$2.32/kVAR-yr commencing January 1, 2007. The .95 power factor exclusion shall not apply to non-generator sources of reactive support. The Base VAR Rate shall be examined no later than July 1, 2011 to determine whether the Base VAR Rate is still appropriate or whether it should be changed commencing January 1, 2012.

See Attachment E at 2, appended hereto.

On September 19, 2006, the Transmission Committee voted on the various proposals, including the Reliability Region Cost Allocation proposal developed by CMP and the CC Rate Deadband Proposal developed by the MPUC.

On October 13, 2006, the NEPOOL Participants Committee voted on changes to the Schedule 2 rate, including MPUC's and CMP's proposed amendments to address PC cost allocation and CC double recovery concerns. CMP's Reliability Region Cost Allocation proposal received 57.59% of the vote<sup>21</sup> while the MPUC's CC Rate Deadband Proposal failed on a show-of-hands vote. The NEPOOL Participants Committee approved a rate increase to the CC component of Schedule 2.

On December 29, 2006, in a joint filing at the Commission, ISO-NE and NEPOOL proposed the increase to the CC component of the Schedule 2 rate which had been approved by the NEPOOL Participants Committee at the October 13<sup>th</sup> NEPOOL

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<sup>21</sup> See ISO New England, Inc. and the New England Power Pool, Motion for Leave to Answer and Answer ("Joint Answer to Protests") at 6, Docket No. ER07-397-000 (February 5, 2007).



meeting. The proposed rate would increase the original negotiated rate from \$1.05 to \$2.32/kVAR-year.<sup>22</sup> The MPUC, CMP and the New Hampshire Public Utilities Commission protested the CC component rate increase.<sup>23</sup> The MPUC also protested the fact that the cost allocation of the PC component had not been changed despite repeated advice by the IMMUC to do so.<sup>24</sup> ISO-NE and NEPOOL responded to the protest on the cost allocation by asserting that eventually they would consider the cost allocation issue through another stakeholder process.<sup>25</sup>

## **VI. THE PROPOSALS**

### **A. Reliability Region Cost Allocation Proposal**

MPUC requests that the Commission order ISO-NE to modify the cost allocation for the PC component of the Schedule 2 rate. As discussed below, this change has been recommended by the IMMUC in both of the two most recent Market Assessments. Like

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<sup>22</sup> Docket No. ER07-397-000 Joint Filing Transmittal Letter at 3.

<sup>23</sup> See Notice of Intervention and Protest of the Maine Public Utilities Commission, Notice of Intervention and Protest of the New Hampshire Public Utilities Commission, and Motion to Intervene and Protest of the Central Maine Power Company in Docket No. ER07-397-000.

<sup>24</sup> See Notice of Intervention and Protest of the Maine Public Utilities Commission at 6-7.

<sup>25</sup> Joint Answer to Protests at 7. Specifically, ISO-NE and NEPOOL stated:

Nevertheless, the ISO and NEPOOL agree that this [57.59%] level of support justifies further review of the current cost allocation methodology through the stakeholder process. If a change acceptable to ISO and/or NEPOOL emerges from that process, the VAR costs allocation methodology can be modified accordingly in a Section 205 filing. The ISO, NEPOOL, and the New England Conference of Public Utility Commissioners, Inc. ("NECPUC") already have created a working group to address certain cost allocation methodologies reflected in the Tariff. The ISO will ask the working group to address the VAR cost allocation issue following the conclusion of the working group's ongoing review of the cost allocation for Local Second Contingency Protection Resources. Specifically, the ISO will discuss the VAR cost allocation 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 whether any changes should be proposed to the current just and reasonable method for allocating such costs within New England.

the allocation for second contingency uplift costs, the uplift costs for providing reactive service to maintain local voltage support would be allocated to the reliability region in which the local voltage support is provided.<sup>26</sup>

The Transmission Committee provided the tariff language to effect this change to the NEPOOL Participants Committee meeting of October 13, 2006. A copy of this tariff language is appended hereto as Attachment F. As noted above, the proposal gained support of 57.59% of the Participants at the NEPOOL meeting.<sup>27</sup>

#### **B. CC Rate Deadband Proposal**

In light of the substantial payments from the FCM Settlement that are and will continue to be made to generators to compensate them for generator capital costs, one reasonable approach would be to eliminate the CC component of Schedule 2. However, consistent with the proposal made in the stakeholder process, MPUC requests that the Commission order ISO-NE to modify the CC component such that it will provide compensation only for capability to provide reactive service *beyond* the level the generator is required to provide under Order Nos. 2003 and 2003-A. The language to implement this proposal is appended hereto as Attachment E.

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<sup>26</sup> For a discussion on uplift costs from First Contingency, Second Contingency and Voltage Support, see the 2005 Assessment at pp.50-56. While the IMMU notes that uplift from First Contingency also is incurred for the purpose of meeting local reliability needs and should therefore be allocated to the local reliability region for whose benefit the costs were incurred, this Complaint does not seek to reallocate these costs locally at this time. However, since First Contingency Cost allocation also is a matter flagged by the IMMU as a market flaw that should be corrected, MPUC requests that the Commission direct the ISO-NE to add this issue to its work priority list.

<sup>27</sup> Joint Answer to Protests at 6, Docket No. ER07-397-000 (February 5, 2007).

As set forth in the attached Affidavit of Wayne Whittier, the same equipment necessary for running the generator and for providing reactive service within the required power range.

In order to be part of a power system network, a synchronous generator must be built with equipment necessary to provide voltage control and reactive power. The generator must have an exciter and the generator's windings must be sized to carry reactive current, as must be the associated step-up transformer and substation equipment. Even when producing power at unity power factor (no reactive power), a synchronous generator must have an exciter to provide the direct current to create an electromagnetic field necessary for producing the alternating current of the generator.<sup>28</sup>

Thus, the proposal to limit capacity payments to capability outside the required deadband will curtail the double recovery of capital costs for the same equipment, but to the extent the generator owner has invested in equipment that provides for capability outside of the required power range, the proposal will provide compensation. The CC Rate Deadband Proposal is estimated to reduce CC payments from the current level of approximately \$12.2 million annually<sup>29</sup> (which NEPOOL and ISO-NE in Docket ER07-

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<sup>28</sup> Whittier Affidavit at ¶ 22.

<sup>29</sup> See Docket No. ER07-397-000 Joint Filing Transmittal Letter at 13.

397-000 propose to increase to an amount that could reach \$31 million annually),<sup>30</sup> to approximately \$6 million annually.<sup>31</sup>

## VII. COMPLAINT

### A. The PC Component of Schedule 2

#### 1. **The PC Component of Schedule 2 Is Unjust and Unreasonable Because the Socialization of Uplift Costs Incurred to Provide Local Voltage Support is Inconsistent With Cost Causation Principles And Does Not Provide The Proper Incentives For Demand Response And Local Siting of Resources.**

The socialization of uplift costs incurred to provide local voltage support is unjust and unreasonable. The fact that this methodology is inconsistent with cost causation principles and does not provide the proper incentives, especially for encouraging demand response, has been recognized and highlighted in the IMMU's two most recent annual market assessments.

In the 2004 Market Assessment,<sup>32</sup> the IMMU found that "97 percent of the uplift for voltage support was incurred from committing units in NEMA/Boston, but since these costs are shared by all network load, only 27 percent of the charges are assessed there."<sup>33</sup>

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<sup>30</sup> See Whittier Affidavit at 20. In Docket No. ER07-397-000, ISO-NE and NEPOOL suggest that the proposed rate increase will raise the annual charge to approximately \$27.3 million annually. See Joint Transmittal Letter at 13. However, in their estimate, they have not accounted for the addition of any of the 9,000 MW of new generation that is in the generation interconnection queue as of January 2007. See ISO-NE Exhibits to Testimony Provided to the Maine Utilities and Energy Committee of the Maine Legislature. These exhibits can be found at the following link. [http://www.iso-ne.com/pubs/pubcomm/pres\\_spchs/2007/iso\\_new\\_england\\_exhibits\\_to\\_testimony\\_maine\\_legislature.pdf](http://www.iso-ne.com/pubs/pubcomm/pres_spchs/2007/iso_new_england_exhibits_to_testimony_maine_legislature.pdf).

<sup>31</sup> Whittier Affidavit at ¶ 19.

<sup>32</sup> The 2004 IMMU Assessment can be found at [http://www.iso-ne.com/pubs/spcl\\_rpts/2004/2004\\_immu\\_report-final\\_6\\_30.pdf](http://www.iso-ne.com/pubs/spcl_rpts/2004/2004_immu_report-final_6_30.pdf).

<sup>33</sup> *Id* at 55.

Thus, the current methodology is inconsistent with cost causation principles.<sup>34</sup> Because this cost allocation does not produce the right incentives, the IMMU recommended that ISO-NE:

Allocate uplift for voltage support commitments in the same manner as local reliability uplift is allocated. Currently, uplift for voltage support commitments is assessed to all New England load, although voltage support primarily benefits load in the local area. Assessing this uplift to the local area will provide appropriate incentives to upgrade the transmission system. This change is currently being considered by the NEPOOL Tariff Committee.<sup>35</sup>

Again, in the 2005 Market Assessment, the IMMU recommended that ISO-NE:

Reconsider how NCPC<sup>36</sup> costs associated with supplemental commitments for local contingencies and voltage support commitments are allocated. In particular, we recommend that the ISO consider allocating the costs of voltage support commitments to in the affected area and the costs of 1st contingency transmission constraint commitments (if they can be distinguished from market-wide capacity commitments) to the real-time load in the constrained area. These changes would improve incentives

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<sup>34</sup> See, e.g., Staff Report: Principles of Efficient and Reliable Reactive Power Supply and Consumption (Docket No. AD05-1-000), available at <http://www.ferc.gov/EventCalendar/Files/20050310144430-02-04-05-reactive-power.pdf>, at 73. ("Identifying those entities responsible for the need for reactive power is an important aspect in evaluating reactive power pricing policy.")

<sup>35</sup> *Id.* at 59-60 and 54.

<sup>36</sup> NCPC is an acronym for Net Commitment Period Compensation, which the ISO-NE defines as: "Make-whole" payments made to resources whose hourly commitment and dispatch by ISO-NE resulted in a shortfall between the resource's offered value in the Energy and Regulation Markets and the revenue earned from output over the course of the day. Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area. ISO-NE Chief Operating Officer Report to NEPOOL Participants Committee Meeting, January 5, 2007. This report can be found at the following link: [http://www.iso-ne.com/committees/comm\\_wkerps/prtcpnts\\_comm/prtcpnts/mtrls/2007/jan52007/coo\\_report\\_jan.pdf](http://www.iso-ne.com/committees/comm_wkerps/prtcpnts_comm/prtcpnts/mtrls/2007/jan52007/coo_report_jan.pdf).

for virtual trading and price-responsive load scheduling in the day-ahead market.<sup>37</sup>

The Commission Staff has also recognized that there should be a locational component to reactive service charges. The FERC Staff report on reactive power states that “[r]eactive Power reliability needs should be assessed locally, based on clear national standards” and that those who benefit from the reactive power should be charged for it.<sup>38</sup>

The Staff Report also noted:

A basic economic principle, whether in cost allocation or market design requires those causing costs to pay them; likewise, those incurring the cost should be compensated. The determination of efficient reactive power prices should reflect the marginal costs of reactive power service. Otherwise, there are subsidies and poor to bad incentives to behave efficiently and an increased probability of system failure.<sup>39</sup>

The report also states that:

In many cases load response and load-side investment could reduce the need for reactive power capability in the system, but incentives to encourage efficient participation by load are limited.<sup>40</sup>

Implementing the long-standing IMMU recommendation would provide additional incentives for load pockets to reduce the need for reactive power capability in the system through demand response and energy efficiency.

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<sup>37</sup> 2005 Market Assessment at xi.

<sup>38</sup> See Staff Report: Principles of Efficient and Reliable Reactive Power Supply and Consumption (Docket No. AD05-1-000), available at <http://www.ferc.gov/EventCalendar/Files/20050310144430-02-04-05-reactive-power.pdf>, at 6.

<sup>39</sup> *Id.* at 73, fn. 70.

<sup>40</sup> *Id.* at 5.

**2. The IMMU's Recommendation to Localize Uplift Costs Incurred to Provide Local Voltage Support Should Be Adopted Without Further Delay.**

ISO-NE has failed to act on the IMMU's recommendation even though the IMMU's Market Assessment identified this cost allocation as a market flaw for two consecutive years. Now ISO-NE suggests that this issue be vetted yet again through a second stakeholder process which would not even begin until another cost allocation matter is finalized. The Commission should not countenance further delays. Over the course of almost two years, CMP and the MPUC participated in the VAR Working Group process in good faith and submitted proposals to the VAR Working Group, the Transmission Committee and, finally, the Participants Committee to change the cost allocation. There is simply no justification for requiring yet another stakeholder process.

Further, ISO-NE has never contested the IMMU's findings. Simply defending its inaction (in concert with NEPOOL) by stating that there was insufficient stakeholder support to warrant proposing a change to the allocation because 57.59% of Market Participants supported the change, instead of the 66.67% needed for NEPOOL approval, is inconsistent with ISO-NE's obligation to operate the markets *independently* of Market Participants. The Commission has corrected ISO-NE if it cedes to the wishes of market participants when the popular approach is not supported by the evidence.<sup>41</sup> ISO-NE has failed to act independently here by suggesting that an identified market flaw should not get corrected until Market Participants agree to the correction. ISO-NE's reliance on

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<sup>41</sup> See *ISO New England, Inc.*, 111 FERC ¶61,185 at P 30 (2005) (ISO-NE's proposal for the amount of tie benefits counted in determining installed capacity requirements rejected by FERC where it was not supported by any study and was simply a compromise reached by "consensus" at NEPOOL), *affirmed on rehearing*, *ISO New England Inc.*, 112 FERC ¶61,254 (2005), *appeal pending on other grounds*.

stakeholder opinion to determine whether there is a market flaw<sup>42</sup> and when to correct that flaw, rather than acting on the repeated advice of an independent market monitor, should not be countenanced here.

**3. These Uplift Costs Have Been Significant in the Past and May Be Again.**

The delay in acting on the IMMU recommendation in a timely manner has already cost Maine ratepayers, on average, approximately \$3.6 million per year over the past five years.<sup>43</sup> While some may argue that no action need be taken now because current uplift costs have decreased, this would be a nearsighted approach for several reasons. First, there is an identified market flaw that should be corrected; simply because the current effect of the flaw may not be large does not justify a failure to fix the market. Second, there is no guarantee that the current level of uplift payments for local voltage support will continue. In fact, the extent of underground transmission in some recently completed projects, as well as some that are still under construction in Southern New England, may cause new voltage stability concerns that may cause the levels of uplift to increase. Finally, fixing a market flaw while there is little impact on any one party is the ideal time to implement the change. If the Commission were to order ISO-NE to fix this market flaw now, the appropriate cost allocation mechanism would be in place if these costs again become significant, and, in the short term, there will be minimal immediate impact on areas such as Northeast Massachusetts, which previously incurred sizeable reactive power uplift costs.

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<sup>42</sup> It is significant that ISO-NE has never contested the IMMU's findings or recommendations. Its inaction here is, thus, even harder to comprehend.

<sup>43</sup> See MPUC Interim Report at 16, available electronically at [http://www.maine.gov/mpuc/staying\\_informed/legislative/2006legislation/ISO-NEInterimReport.doc](http://www.maine.gov/mpuc/staying_informed/legislative/2006legislation/ISO-NEInterimReport.doc).



## B. The CC Component of Schedule 2

### 1. The CC Component of the Schedule 2 Rate Is Unjust and Unreasonable Because It Results in A Double Recovery Of Capital Cost Compensation For Generating Equipment Used to Generate Energy and Provide Reactive Service.

The implementation of the FCM Settlement now provides for several billion dollars<sup>44</sup> in capacity payments to generators during the Transition Period alone.<sup>45</sup> These payments to generators compensate for investment in generation equipment<sup>46</sup> which is used to both produce energy and to provide reactive service.<sup>47</sup> Because these payments already provide a compensatory revenue stream, one reasonable approach would be to eliminate the capacity component from Schedule 2 to prevent a double recovery of capacity payments. As discussed below, the CC Rate Deadband Proposal does not

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<sup>44</sup> See Austin Affidavit at ¶ 8.

<sup>45</sup> In Docket No. ER07-397-000, ISO-NE and NEPOOL suggest that the FCM transition rates may be below the cost of new entry and thus the transition payments may not be adequate to cover “the actual cost of providing both installed capacity and VAR.” Docket No. ER07-397-000 Joint Answer to Protests at 12. These claims fail to consider that in determining the actual costs, sources of revenue must be considered and that here the two streams of revenue compensate for the same equipment. Moreover, the Commission’s finding that the transition payments provide just and reasonable compensation for existing generation undercuts the concern about inadequate capital cost compensation. *Devon Power, LLC*, 115 FERC ¶61,340 at P 89.

<sup>46</sup> See *Devon Power, LLC*, 115 FERC ¶ 61,340 (June 16, 2006) (“Settlement Order”), FERC Docket Nos. ER03-563-030 and -055 at P 30.

<sup>47</sup> See Whittier Affidavit at ¶ 22. See also *Calpine Oneta Power, L.P.*, 113 FERC ¶ 63,015 at P 115 (2006). In the Initial Decision, the ALJ made the following findings:

All synchronous generators are built with reactive power capability. ..There is no evidence to suggest that it is possible to build a synchronous generator without that capability or even that the capability to produce reactive power can be enhanced in constructing the generator. And, certainly, there was no evidence submitted in this proceeding that there was an enhanced reactive power capability built into any reactor on the SPP system. The only expenditure made during construction of generators that was directed towards reactive power capability was a *minor* one, on the Automatic Voltage Regulator, used to *control* reactive power, rather than produce it. *Id.* (internal citations omitted.)

In its Order on the Initial Decision, the Commission neither adopted nor rejected these findings, concluding that the issue to which they were addressed was outside of the scope of issues set for hearing. *Calpine Oneta Power, L.P.*, 116 FERC ¶ 61,282 (2006).

eliminate the CC component, but instead limits it to the capability provided by generators outside of the range required by Order 2003-A.

**2. Order 2003-A Makes Clear that Generators Are Not Entitled to Payment for Providing Reactive Service within the Deadband.**

Generators that receive capacity payments under the FCM Settlement are already required to provide reactive service within a specified power range. This requirement is specified in Order No. 2003<sup>48</sup> and in Schedule 22 to the ISO-NE OATT.<sup>49</sup> In *Calpine Oneta Power, L.P.*, the Commission, in reviewing its policy on reactive power compensation, stated:

The Commission has emphasized that an interconnecting generator should *not* be compensated for reactive power when operating *within* the established power factor range, since it is *only* meeting its obligation. Generators interconnected to a transmission provider's system need only be compensated where the transmission provider directs the generator to operate *outside* the established power factor range.<sup>50</sup>

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<sup>48</sup> See Order No. 2003 at P 546 ("We agree that the Interconnection Customer should not be compensated for reactive power when operating its Generating Facility within the established power factor range, since it is only meeting its obligation.") Order 2003-A clarified that if a transmission provider pays its own or its affiliated generators for reactive power within the established range, it must also pay the interconnection customer. Order 2003-A at P 416.

<sup>49</sup> See ISO-NE OATT Schedule 22 § 9.6.1

**Power Factor Design Criteria.** Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the System Operator or Interconnecting Transmission Owner has established different requirements that apply to all generators in the Control Area on a comparable basis and in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. The requirements of this paragraph shall not apply to wind generators.

<sup>50</sup> *Calpine Oneta Power, L.P.*, 116 FERC ¶ 61,282 (2006) at P 26 (emphasis in original).

While an RTO or ISO may *choose* to allow compensation, a generator is not entitled to the compensation except when the transmission provider compensates its own affiliated generators for reactive power within the range.<sup>51</sup> In *Calpine* the Commission also expressed a willingness to consider new approaches on a going forward basis.<sup>52</sup> Here, a new approach is warranted because of the double recovery of capacity revenues from the implementation of the FCM Settlement and the CC component of Schedule 2.

**3. The CC Rate Deadband Proposal Is a Reasonable Alternative to Either the Existing CC component of the Schedule 2 rate or the Proposed Increase to the CC component of Schedule 2.**

The CC Rate Deadband Proposal is a reasonable alternative to either the existing rate, or the rate proposed in Docket No. ER07-397-000, both of which are unreasonable because they provide for a double recovery of compensation for capital costs. It is also an alternative to eliminating the CC component of the Schedule 2 rate. Another alternative, one that would require more extensive litigation (which the MPUC does not

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<sup>51</sup> *Id.* In their Joint Answer to Protests in Docket No. ER07-397-000, ISO-NE and NEPOOL assert that Order No. 2003 and *Calpine Oneta* support continuation of the CC rate because this case does not *prohibit* an RTO from allowing compensation for capability within the deadband. However, the issue here and in Docket No. ER07-397-000 is whether continuing the payment for capacity within the deadband is just and reasonable, when there is now a revenue stream that compensates generators for their capital costs to produce energy and meet the interconnection standard required under Order 2003. ISO-NE and NEPOOL also appear to cite *Calpine Oneta* for the proposition that *as an RTO*, the Southwest Power Pool, ("SPP") was required to compensate the generator for capability within the established power range. This is not the holding of *Calpine Oneta*. In *Calpine Oneta*, the requirement for the reactive service payment was based on the *comparability* holding of Order 2003-A. SPP's Schedule 2 allowed the generators of the parent of the utility to which Calpine was interconnected to receive compensation within the established power factor range. Under the *comparability* principle of Order 2003-A, the generator seeking reactive service payments was entitled to compensation. In fact in *Calpine Oneta*, the Commission recognized that under certain circumstances, alternative approaches might be more appropriate. SPP has recently filed a proposal that does *not* allow compensation within the 0.95 leading/0.95 lagging power factor deadband. See *Southwest Power Pool, Inc.* Docket No., ER07-371-000 and *Calpine Oneta Power, L.P.*, Docket No. ER03-765-000, Transmittal Letter of Southwest Power Pool to Submission of Tariff Revisions, dated December 26, 2006.

<sup>52</sup> *Id.* at P 50.

submit as the preferred alternative), would be to determine the cost-of-service for each generator seeking reactive service payments. Determining the cost-of-service for each generator seeking reactive service payments would allow each generator to recover its net capital costs for the provision of reactive service, but would require a revenue requirement determination for each generator (including information on both costs and revenues) and a determination of what portion of the revenue requirement should be allocated to reactive service. While these proceedings might be time consuming, they would, at least, address ISO-NE's and NEPOOL's concern expressed in their Joint Answer to Protests in Docket No. ER07-397-000 that under the CC Rate Deadband Proposal generators will under-recover the capital costs of generation equipment needed to produce energy and provide reactive service.<sup>53</sup> The CC Rate Deadband Proposal provides a less administratively burdensome approach to address the double recovery problem.

The just and reasonable course, however, cannot be to simply ignore the substantial new revenue stream from the FCM Settlement capacity payments and simply *assume* that there is no double recovery (during the Transition Period) as suggested by ISO-NE and NEPOOL.<sup>54</sup> The substantial FCM capacity payments must be accounted for in some way in determining the just and reasonable level of CC payments under the existing CC rate, or the CC rate increase proposed in Docket No. ER07-397-000.

#### **VIII. DISPUTE RESOLUTION PROCEDURES**

The MPUC has not used the Commission's Enforcement Hotline or Dispute

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<sup>53</sup> Docket No. ER07-397-000 Joint Answer to Protests at 12.

<sup>54</sup> *Id.*

Resolution Service with respect to this matter. As this Complaint reflects, MPUC has already spent substantial effort and resources attempting to effect a mutually agreeable resolution of its dispute with ISO-NE. The MPUC raised this proposal first with the VAR Working Group, then with the Transmission Committee and finally with NEPOOL Participants Committee. The Reliability Region Cost Allocation proposal gained majority support at the Participants Committee, though it did not meet the two-thirds majority needed for passage. ISO-NE and NEPOOL's suggestion in their Joint Answer to Protests in Docket No. ER07-397-000 that "review of the current cost allocation methodology should occur through the stakeholder process," would only duplicate the stakeholder process that has already occurred. The MPUC participated in this process in good faith, and with the expectation that if their concerns were not addressed, they could, and would, bring the matter to the Commission for resolution under section 206 of the FPA. A second stakeholder process would only serve to further delay a change recommended for two successive years by the IMMU. The MPUC has also worked through the stakeholder process in developing and presenting the CC Rate Deadband Proposal. The MPUC believes that Dispute Resolution under the Commission's supervision is unlikely to assist the parties in their efforts to resolve the issues set forth in this Complaint, nor does MPUC believe that mediation of this legal issue would be effective.

**IX. OTHER INFORMATION REQUIRED BY RULE 206(b)**

To the extent not already provided above, the MPUC provides the following information required by Rule 206(b):

- Rule 206(b)(6) -- As explained in detail above, the issues presented are pending in an existing Commission proceeding, Docket No. ER07-397-000. However, as the

instant Complaint seeks to modify the existing methodology used in Schedule 2 of the ISO-NE OATT, and ISO-NE is requesting a Schedule 2 rate increase without a change in the methodology, resolution in that forum can not be achieved.

- Rule 206(b)(7), (8) -- The specific relief requested is as set forth in more detail in the body of this Complaint. Documents supporting the facts set forth herein include the attached Affidavits of Mr. Wayne Whittier and Dr. Thomas Austin, and other supporting documents.

#### **X. REQUEST FOR RELIEF**

The MPUC respectfully requests that the Commission find the current ISO-NE OATT Schedule 2 rates unjust and unreasonable insofar as they (1) fail to implement the repeated recommendation of the IMMUC with regard to uplift for local voltage support and (2) include a double recovery of reactive power capacity costs. The MPUC further requests that the Commission order ISO-NE to replace the rate methodology for the PC component of Schedule 2 with the Reliability Region Cost Allocation methodology, and replace the rate methodology for the CC component of Schedule 2 with the CC Rate Deadband Proposal.

## **XI. CONCLUSION**

Wherefore, for these reasons stated above, the MPUC requests that the Commission find the ISO-NE OATT Schedule 2 rates unjust and unreasonable, and order ISO-NE to implement the modifications to Schedule 2 of its Open Access Transmission Tariff described herein above.

Dated: February 26, 2007

Respectfully submitted,

/s/ Lisa S. Gast

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# **ATTACHMENT A**



**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

<b>Maine Public Utilities Commission</b>	)	<b>Docket No. EL07-____</b>
	)	
<b>Complainant,</b>	)	
	)	
<b>v.</b>	)	
	)	
<b>ISO New England, Inc.</b>	)	
	)	
<b>Respondent.</b>	)	

**AFFIDAVIT OF WAINE WHITTIER  
ON BEHALF OF  
THE MAINE PUBLIC UTILITIES COMMISSION**

Affiant, being duly sworn, states as follows:

**Purpose of Affidavit**

1. My name is Mr. Waine Whittier. I am a Principal of Energy Advisors, LLC, a utility consulting firm based in the state of Maine. I am also the president of Vienna Ventures, Inc., a Maine-based utility consulting firm. My professional address is 321 Tower Road, Vienna, Maine, 04360.

2. The purpose of my Affidavit is to provide factual evidence supporting the Maine Public Utilities Commission's ("MPUC") Complaint against ISO New England, Inc.

**Educational and Professional Background**

3. I graduated from the University of Maine with a Bachelor of Science Degree in Electrical Engineering in 1973.

4. I have been with Energy Advisors since 2001, and I formed Vienna Ventures in 2000. My engagements with these firms have included financial planning and decommissioning contractor evaluation for the Maine Yankee nuclear power plant, analysis of electric futures market practices of Sierra Pacific Power Company and Nevada Power Company, review of construction and O&M expenditure practices of a Connecticut utility for the Connecticut Office of Consumer Council, solicitation and evaluation of bids to buy the output of a waste energy recovery plant in Maine, analysis of electric and gas commodity programs for utilities in New York and Connecticut, and monitoring wholesale electric market activities for the Maine Public Utilities Commission.

5. I have over three decades of utility management, planning and engineering experience, including 27 years at Central Maine Power Company. Some of my assignments at Central Maine Power Company were substation control design, resource planning, and management of the electrical engineering department. I have also conducted numerous resource and financial planning studies. In the early 1990s, I was a member of the Northeast Power Coordinating Council's Reliability Coordinating Committee, and I have six years of international consulting experience.

6. I have presented expert testimony in state regulatory proceedings on avoided costs, unit sale contracts, marginal transmission costs, and utility expenditures. I am a Registered Professional Engineer in the State of Maine and am active in both professional and community organizations.

7. Relevant to the instant Complaint being filed by the Maine Public Utilities Commission, I have been active on ISO-NE's VAR Working Group since June

of 2005, participating in about twenty meetings. I first presented the "CC Rate Deadband Proposal" described below in June of 2006.

8. In addition to my participation in the ISO-NE's VAR Working Group, I have also reviewed the FERC Staff report "Principles for Efficient and Reliable Reactive Power Supply and Consumption" in Docket No. AD05-1-000 dated February 4, 2005.

9. A more detailed account of my experience, my resume is available on Energy Advisor's website at [www.energyadvisorsllc.com](http://www.energyadvisorsllc.com).

### **Background**

#### **Schedule 2 of the ISO-NE OATT**

10. Schedule 2 of the ISO-NE Open Access Transmission Tariff ("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 ISO-NE to produce or absorb reactive power, that facility is compensated under the Schedule 2 rate for its provision of reactive power and for the energy costs associated with the reactive power provided. The generator also is compensated for the capability to provide reactive service.

11. The existing rate design under Schedule 2 of the OATT consists of a fixed Capacity Cost ("CC") component and three variable components: (1) Lost Opportunity Cost ("LOC"), which compensate a generator for the lost opportunity in the energy market when the generator would otherwise be economically dispatched but is directed by the ISO-NE to reduce real power output to provide more reactive power; (2) the cost of energy consumed ("SCL"), which compensates for the cost of energy

consumed by a generator solely to provide reactive power support; and (3) the Cost of Energy Produced ("PC") component which compensates a generator that was not economically dispatched when it is directed to come on line or increase power above its economic loading point to provide local reactive support.

The VAR Working Group

12. In December of 2004, the Transmission Committee established the VAR Working Group 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. Cost allocation was one of the items that the group addressed. I participated in the VAR Working Group.

13. On April 25, 2006, the VAR Working Group presented its report on the various compensation and allocation issues with which it had been tasked by the Transmission Committee.

14. On June 6, 2006, I, representing the MPUC, provided the chair of the VAR Working Group an alternative proposal for CC compensation. This proposal, identified herein as the CC Rate Deadband Proposal, will be described in detail below.

15. On September 19, 2006, the Transmission Committee voted on the various proposals, including the CC Rate Deadband Proposal. The Transmission Committee approved the rate increase to the CC Component of Schedule 2 that had been recommended by the VAR Working Group. The VAR Working Group voted on the alternative CC Rate Deadband Proposal that I developed, but it did not adopt it.

16. On October 13, 2006, the NEPOOL Participants Committee voted on changes to the Schedule 2 rate, including the CC Rate Deadband Proposal. The CC Rate Deadband Proposal failed on a show-of-hands vote. Instead, the Participants Committee adopted the CC component rate increase approved by the Transmission Committee.

**The CC Rate Deadband Proposal**

17. In early 2006, it became clear that the VAR Working Group would be recommending a change to the CC component of the Schedule 2 rate in a manner that would significantly increase the payments being made to generators.<sup>1</sup> During the same time period that the VAR Working Group was having meetings and developing a recommended course of action, the MPUC was also participating in settlement discussions in FERC Docket No. ER03-563.<sup>2</sup>

18. I had concerns that the implementation of the FCM Settlement approved in Docket No. ER03-563, in combination with the VAR Working Group recommendation with respect to the CC component of the Schedule 2 rate (which was ultimately filed in ER07-397-000), would result in a double recovery of certain capacity costs by generators. Hence, I developed what is now called the "CC Rate Deadband Proposal" to address the double recovery issue with the VAR Working Group.

19. The CC Rate Deadband Proposal, which I presented on June 6, 2006, is that the "Base CC Rate" component of Schedule 2 shall be set to zero for

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<sup>1</sup> The VAR Working Group's recommendation ultimately became the basis for the ISO-NE's December 29, 2006 filing in ER07-397-000.

<sup>2</sup> Those settlement discussions ultimately culminated in a settlement ("FCM Settlement") filed with the Commission on March 6, 2006 in Docket NO. ER03-563-030, and approved by the Commission on June 16, 2006.

reactive support provided by generators between a 0.95 leading and a 0.95 lagging power factor. Commencing January 1, 2007, for power factors below 0.95 leading or 0.95 lagging, the "Base CC Rate" shall be \$2.32/kVAR-yr, and, if that change is implemented on January 1, 2008 as proposed by ISO-NE, changing to the "Adjusted Base CC Rate" for a split between leading and lagging. Under the CC Rate Deadband Proposal, the 0.95 power factor exclusion shall not apply to non-generator sources of reactive support. Moreover, under the CC Rate Deadband Proposal, the "Base CC Rate" shall be examined no later than July 1, 2011 to determine whether the "Base CC Rate" is still appropriate, or whether it should be changed commencing January 1, 2012.

20. My estimate of the cost impact of this proposal is that annual CC payments to generators would be approximately \$6.1 million per year, rather than rising from the current amount of about \$12.6 million per year, to between \$27.8 million and \$31.3 million per year under the rate increase proposed in Docket No. ER07-397-000. These amounts are derived by applying the different rates to a 30,000 MVA system with 12,000 MVAR of reactive capacity, the values assumed by the VAR Working Group. Thus:

- Under the current Schedule 2 rate, the CC component would be:  $\$1.05/\text{kVAR-yr} \times 12,000 \text{ MVAR} = \$12.6 \text{ million/year}$
- Using ISO-NE's ER07-397-000 proposal (which was the recommendation of the VAR Working Group):  $\$2.32^*/\text{kVAR-yr} \times 12,000 \text{ MVAR} = \$27.8 \text{ million/year}$
- Using the CC Rate Deadband Proposal: the amount of reactive capacity above a 0.95 power factor for a 30,000 MVA system can be shown mathematically to be 9,367 MVAR. Therefore, using the CC Rate Deadband Proposal the payment is:

$\$2.32/\text{kVAR}\cdot\text{yr.} \times (12,000 - 9,367) \text{ MVAR} = \$6.1 \text{ million/year}$

- \* The rate of  $\$2.32/\text{kVAR}\cdot\text{yr.}$  is the rate that was recommended by the VAR Working Group and was filed by ISO-NE on December 29, 2006 in Docket No. ER07-397-000.

21. The upper range of the CC payment is calculated by adjusting the amount calculated above for the ISO-NE (ER07-397-000) proposed rate (\$27.8 million) upwards for an estimate of the cap on VAR CC payments described in Section 4 of ISO-NE OATT Schedule 2. The calculation is:  $[(27,143 \text{ MW} \times 1.2)/28,946 \text{ MW}] \times \$27.8 \text{ million} = \$31.3 \text{ million}$ . The qualified generator reactive resources have to increase only 3,626 MW above the current level of 28,946 MW to reach the capped amount.

This "upper range" scenario is very likely in my view, because, according to ISO-NE, there are 9,000 MWs of new generation in the generation interconnection queue. While not all of these projects are likely to be constructed, only 40% of the 9,000 MW in the queue would need to be constructed to reach the \$31.3 million capped level of payments.

#### **Schedule 2 Payments Result In Double Recovery Of Capital Cost**

22. The ability to produce reactive power is inherent in the construction of a synchronous generator and therefore will be compensated through the overall capacity market.

23. In order to be part of a power system network, a synchronous generator must be built with equipment necessary to provide voltage control and reactive power. The generator must have an exciter and the generator's windings must be sized to carry reactive current, as must be the associated step-up transformer and substation equipment. Even when producing power at unity power factor (no reactive power), a

synchronous generator must have an exciter to provide the direct current to create an electromagnetic field necessary for producing the alternating current of the generator.

24. This equipment is essential to maintain synchronous stability when several generators are connected in parallel. Additionally, voltage control and reactive reserve benefit all parts of the system, including generators, by guarding against widespread blackouts following system disturbances.

25. It is industry standard for generator manufacturers to offer power factor capability of about 0.90.

26. Interconnection Agreements in New England generally require generators to have power factor capability down to at least 0.95. Schedule 22 of the ISO-NE OATT (the Standard Large Generator Interconnection Procedures) contains the same requirement.

27. Even though there is currently a double recovery because of the revenue that generators receive from (1) the FCM Settlement payments and (2) the CC component of the Schedule 2 rate, it may be desirable to provide an incentive to generators to provide reactive capacity in excess of what would be provided under a typical interconnection agreement that requires capability at the 0.95 power factor level. Therefore, a payment schedule that provides no extra capacity compensation for reactive power capability within a deadband of 0.95, leading to 0.95 lagging power factor, but provides compensation for reactive capacity outside of that range, is appropriate.



County of Kennebec  
State of Maine

)  
)

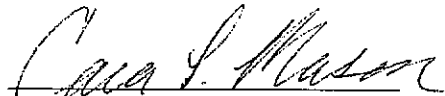
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Respectfully submitted,



Wayne Whittier

Subscribed and sworn to before me this  
23<sup>rd</sup> day of February, 2007.



Notary Public

**CARA L. MASON**  
My Commission Expires  
Notary Public, State of Maine  
My Commission Expires  
March 12, 2009

## **ATTACHMENT B**

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

<b>Maine Public Utilities Commission</b>	)	<b>Docket No. EL07-_____</b>
	)	
<b>Complainant,</b>	)	
	)	
<b>v.</b>	)	
	)	
<b>ISO New England, Inc.</b>	)	
	)	
<b>Respondent.</b>	)	

**AFFIDAVIT OF DR. THOMAS D. AUSTIN**

Affiant, being duly sworn, states as follows:

**Purpose of Affidavit**

1. My name is Dr. Thomas D. Austin. I am employed as an economist for the Maine Public Utilities Commission ("MPUC"), 242 State St., Station 18, Augusta, ME, 04333.

2. The purpose of my Affidavit is to provide factual evidence supporting the Maine Public Utilities Commission's ("MPUC") Complaint against ISO New England, Inc.

**Educational and Professional Background**

3. I earned a Ph.D. in economics from Clark University in 1982. Since 1980, I have been continuously employed as an economist focusing on issues related to the electric industry and, to a lesser extent, the natural gas industry.

4. From 1980 to 1985, I worked at a consulting firm, ESRG (now the Tellus Institute), on issues related to generation planning and rate design. During this

period, I testified before approximately ten state public utility commissions as well as the Federal Energy Regulatory Commission (“FERC”).

5. From 1985 to 1992, and from 2000 to date, I worked for the MPUC in a variety of capacities involving both the electric and gas industries. Since 2000, I have been continually involved with the issues of capacity adequacy and installed capacity (“ICAP”) in New England.

6. Finally, in 1992, I co-founded the Regulatory Assistance Project (“RAP”), a non-profit organization which provides assistance and training to public utility commissions around the country on a variety of issues, particularly electric industry restructuring and resource planning. I left RAP at the end of 1999.

**Forward Capacity Market Settlement (“FCM Settlement”)**

7. The FCM Settlement submitted to FERC on March 6, 2006, and accepted on June 16, 2006, in Docket No. ER03-563-030 and ER03-563-055, among other things:

provides for a transition period—beginning December 1, 2006, ending June 1, 2010—during which, fixed payments will be made to all installed capacity. Below is a table that details the level of the payment as it increases over time during the transition period:

**Transition Payments**

<u>Period</u>	<u>Payment (\$/kW-month)</u>
December 1, 2006 - May 31, 2007	\$3.05
June 1, 2007 – May 31, 2008	\$3.05
June 1, 2008 – May 31, 2009	\$3.75
June 1, 2009 – May 31, 2010	\$4.10 <sup>1</sup>

---

<sup>1</sup> See *Devon Power, LLC*, 115 FERC ¶ 61,340 (June 16, 2006) (“Settlement Order”), FERC Docket Nos. ER03-563-030 and -055 at P 30.

### Analysis of Payments to Generators During Transition Period

8. The Transition Period will result in between \$4.6 billion and \$5 billion in payments to generators. The table below provides a low-end estimate of the total capacity payments:

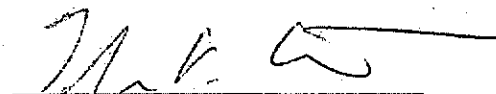
Year	IC Purchased (MW)	Capacity Price (\$/Kw-mo)	Capacity Expense (\$ millions)
2006-07	31,877	3.05	551
2007-08	32,537	3.05	1,125
2008-09	32,537	3.75	1,383
2009-10	32,537	4.10	1,512
<b>Total</b>			<b>4,571</b>

Notes:

1. For 2006-07, IC Purchased is average of Monthly IC requirements for 12/06 to 5/07 from ISO New England Installed Capacity Requirement for the 2006-2007 Power Year, p. i
2. For 2007-08 to 2009-20, IC Purchased is the average of Monthly IC requirements for 6/07 to 5/08 - [www.iso-ne.com/committees/comm\\_wkgrps/reblty\\_comm/pwrsuppln\\_comm/mtrls/2007/jan262007/draft\\_icr0708\\_01-23-2006.pdf](http://www.iso-ne.com/committees/comm_wkgrps/reblty_comm/pwrsuppln_comm/mtrls/2007/jan262007/draft_icr0708_01-23-2006.pdf)
3. Capacity expense assumes an average forced outage rate of 5.54% from ISO New England Installed Capacity Requirement for the 2006-2007 Power Year, p. 21

9. This table understates the likely costs by assuming that there will be no increase in the amount of Installed Capacity ("IC") purchased for the 2008-09 or 2009-10 Power Years. The primary factor that could increase the amount of payments is the amount of capacity offered during the transition period. While I cannot predict how much more capacity will be offered during the Transition Period, I do note that the FCM Settlement provides for payment to all capacity offered without any cap. Therefore, it is likely that the level of capacity offered will be higher than the installed capacity requirements during the Transition Period.

Being first duly sworn, I declare that I have reviewed the foregoing in its entirety, and I further declare that it is true and accurate to the best of my knowledge, information and belief.

  
Dr. Thomas D. Austin.

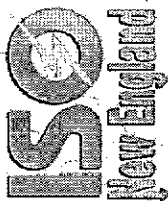
Subscribed and sworn to before me this 26th day of February, 2007.

  
Notary Public

My Commission Expires:  
[SEAL]

**CARA L. MASON**  
Notary Public, State of Maine  
My Commission Expires  
March 12, 2009

# **ATTACHMENT C**

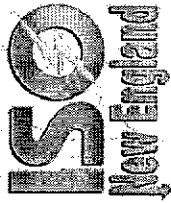


# VAR Settlement under Section II of the ISO-NE Tariff (Schedule 2 - VARs)

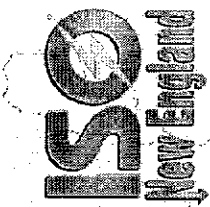
VAR WG – 06/16/05 <sup>v3</sup>



## **Schedule 2 - Reactive Supply and Voltage Control from Generation Sources Service**



- Schedule 2 sets forth how:
  - generators providing this service will be compensated; and
  - how the costs of providing this service will be paid.
- 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 System Operator to operate to produce or absorb reactive power.
- To the extent that they are directed to produce (or absorb) reactive power, generation facilities are compensated for certain costs related to VAR control.

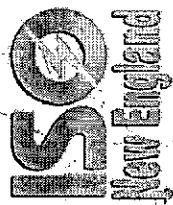


## What Costs are Compensated for under Schedule 2?

- Schedule 2 compensates for four (4) types of costs related to VAR control:
  - Capacity Cost (CC)
  - Lost Opportunity Cost (LOC)
  - Cost of Energy Consumed (SCL)
  - Cost of Energy Produced (PC)

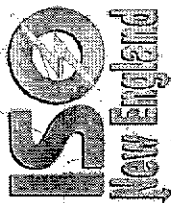
## Capacity Cost (CC)

- Is a payment that compensates generators for the equipment needed to deliver VARs to the system.
- CC VAR Rate - annual formula rate calculation, established at beginning of yr., in effect for calendar yr.
  - CC VAR Rate = Base VAR Rate \* Factor
  - Base VAR Rate = \$1.05 / kVAR-yr
  - Factor equals 1 or less than 1, if there is "excess" generator VAR capability.
- Monthly compensation
  - based only on the generator's lagging capability.
  - calculated at a generator's NX-12D Lagging VAR value \* (CC VAR Rate / 12).



# Capacity Cost (CC) Requirements

- Be in the ISO-NE Market System.
- Have an NX-12D form and an NX-9B database on file at ISO-NE.
  - NX-12D form - Generator Reactive Data (OP14)
  - NX-9B database - ISO New England Transmission Facility Rating, Characteristic, and Operational Data Implementation Form – Transformer - Fixed/GSU/TCUL (OP16)
- Conduct a VAR demonstration test.
  - Requirements established under the Reactive Supply and Voltage Control from Generation Sources Service Business Procedure.

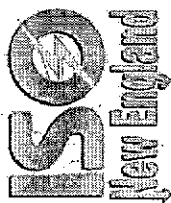


## Lost Opportunity Cost (LOC)

- Is a payment that compensates generators if ISO, a Local Control Center or a “dispatch center” reduces the output of an on-line hydro, pumped storage or thermal generating unit for the purpose of VAR control.

- LOC:

- ✓ is a variable compensation mechanism.
- ✓ compensation equals (the energy that the generator would have sold in an hour had it not been backed down for VAR control)  
\* (LMP in that hour).

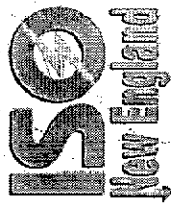


## Cost of Energy Consumed (SCL)

- Is a payment that compensates hydro and pumped storage generators if ISO, a Local Control Center or a “dispatch center” motors an off-line hydro or pumped storage generating unit for the purpose of VAR control.
- SCL:
  - is a variable compensation mechanism
  - compensation equals (the energy consumed in an hour) \* (‘LMP’ or ‘the energy rate under a retail power agreement’ in that hour).
  - Generator must submit an invoice for SCL costs.

## Cost of Energy Consumed (SCL) <sup>cont.</sup>

- SCL also applies to Synchronous Condensers (SC) and Static Controlled VAR Regulators (SCV).
  - SCL is set to zero (\$0); and
  - The cost of energy for VAR control by the Chester SCV will be treated as losses on the New England Transmission System.
  - “Placeholder” that can be revisited on an as-needed basis (*e.g.*, upon the addition of a new SC or SCV within the New England Control Area).



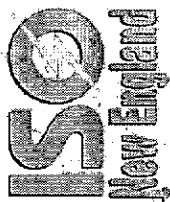
## Cost of Energy Produced (PC)

- Is a payment that compensates a hydro, pumped storage or thermal generating unit if ISO, a Local Control Center or a “dispatch center” brings the unit on line (and the unit produces real power) for the purpose of VAR control.
- PC:
  - ✓ is a variable compensation mechanism
  - ✓ compensation equals the uneconomic energy (based on the difference between the generator’s offer price and LMP) that the generator sold in an hour due to its being brought on line for VAR control.



## Who Pays for VAR Expenses?

- The hourly VAR costs are allocated on a pro rata basis to Transmission Customers with:
  - Monthly Regional Network Load (HL), and/or
  - Through and Out Service Reservations (RC).
- The hourly VAR costs equals for each hour:
  - $(CC + LOC + SCL + PC) * (HL_n + RC_n) / (Sum RC + HL)$ ; where
    - the monthly CC cost is converted to an hourly cost; and
    - Monthly Regional Network Load is used as a value for each hour.
- Note that this is a regionalized distribution of costs.

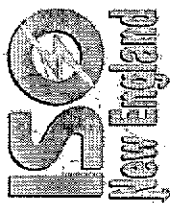


# **VAR Costs**

## **January 2004 through April 2005\***

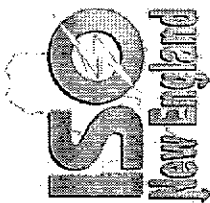
\*(January through April 2005 preliminary values)

- Total monthly VAR costs for this 16-month period have averaged roughly \$7.9 million/month or roughly \$134 million for the period.
- CC costs run roughly \$1.04 million/month.
- LOC + SCL + PC costs have ranged:
  - from a low of \$0.6 million/month (02/04)
  - to a high of \$15.4 million/month (04/05)



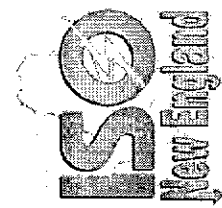
## Impact on Regional Network Load

- For the period between January 2004 and April 2005\*, Regional Network Load paid roughly \$134 million under Schedule 2. \* (January through April 2005 preliminary values)
  - BECO Regional Network Load paid \$22.2 million.
  - Bangor Regional Network Load paid \$1.7 million.
  - ComElec Regional Network Load paid \$4.8 million.
  - CMP Regional Network Load paid \$9.4 million.
  - NEP Regional Network Load paid \$37.9 million.
  - NU Regional Network Load paid \$47.8 million.
  - UI Regional Network Load paid \$4.6 million.
  - Velco Regional Network Load paid \$5.5 million.



## - Current VAR Cost Allocation Questions - Room for Improvement?

- Are some of the current generator VAR costs sub-regional in nature, such that certain elements of these costs should be charged to the sub-region of New England in which the generator is located?
  - For example, should:
    - ✓ CC costs be charged regionally, and
    - ✓ PC, LOC and SCL charged sub-regionally?
  - Schedule 2 provides a price signal but does it provide the appropriate incentives?



## - Current VAR Cost Allocation Questions - Room for Improvement? <sup>cont.</sup>

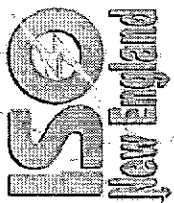
- Recognizing the need to compensate generators for their VAR costs, is it appropriate to allocate all VAR costs to entities with Network Load or T/Out Service Reservations?
  - Should VAR costs be allocated (in part or in total) to entities who have the ability to pursue solutions to VAR problems in the region?
  - Do entities with Network Load or T/Out Service Reservations have this ability to “realistically” pursue such solutions?
- Should a portion of the VAR costs be charged to entities other than those with Network Load or T/Out Service Reservations to encourage resolution of VAR problems in the region?
- Other suggestions?



# Upcoming Changes that could Impact VAR Settlement

- VAR demonstration test.
  - Schedule 2 and the Reactive Supply and Voltage Control from Generation Sources Service Business Procedure state that the VAR demonstration test will include multi-point (MW output) tests of both lagging and leading VAR capability in 2008.
- NERC or FERC requirements:
  - FERC NOPR on VARs (based on FERC Staff paper on Reactive Power Supply and Consumption)
  - NERC Standards (4<sup>th</sup> Qtr 2005)
    - ✓ Voltage Support and Reactive Power (static/dynamic reactive power resources on the transmission system ensuring system performance)
    - ✓ Verification of Reactive Power Capability (generators)
- VAR WG recommendations

## Questions / Additional Discussion



# **ATTACHMENT D**



# VAR COST ALLOCATION (Non-CC Components)

NEW ENGLAND  
VAR WORKING GROUP  
December 19, 2005



Central Maine Power



An Energy East Company

# CURRENT COST ALLOCATION METHOD

VAR costs are allocated each month on a pro-rata basis to Regional Network Service (“RNS”) Load and Through and Out Service (“T&O”) Reservations (i.e. Socialized)



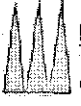
Central Maine Power



An Energy East Company

## PROPOSED COST ALLOCATION METHOD

Unless system VARs are required (i.e. for through and out transactions) VAR costs should be allocated each month to the RNS Load within the local area or reliability region causing the out-of-merit payments (i.e. Localized Uplift)



# REASONS FOR CHANGE

- Pricing Signals
- Physical / Geographic Limitations
- Inconsistent with Other Related Tariff Charges for Reliability



Central Maine Power



An Energy East Company

## PRICING SIGNALS

- Socialization distorts pricing signals for investment decisions related to minimizing VAR uplift and is a design flaw of the current wholesale electricity market in N.E.
- Not based on cost causation; out of merit generation dispatch required for local area needs
- Benefits to customers throughout New England disproportionate to costs incurred



## PRICING SIGNALS (CONT)

- Localized consumption, investment and operation decisions are incompatible with regionalized unit commitment/dispatch decisions for out of merit resources
- Inefficient with little to no incentive to mitigate as costs are socialized
- Cost/benefit analysis flawed when total impact of costs is not imposed on area creating the need or receiving the benefit
  - Causes delays in system improvements needed to mitigate uneconomic payments



## PHYSICAL / GEOGRAPHIC

- Reactive power losses in transmission lines are high, so VARs generally cannot travel far
- Distance limited to perhaps not more than 1 or 2 buses away from source.
- Therefore reactive power usually must be procured from suppliers located in close geographical proximity to where voltage support is needed.



# INCONSISTENT

- Socialization is inconsistent with the allocation methods for all other out-of-merit payments related to reliability under the ISO Tariff:
- Second Contingency Commitments
- Reliability Must Run - Fixed Costs
- Special Constraint Resources





## NEXT/OTHER POSSIBLE STEPS

- Develop and file tariff amendments necessary to allocate VAR uplift costs locally ASAP
- Identify and quantify local and regional VAR capacity requirements within the NE control area
- Identify areas of lacking / surplus VAR capacity
- Consider differentiating the capacity price by location
- Investigate market pricing enhancements for optimizing resources to increase efficiency and decrease uneconomic costs



# **ATTACHMENT E**

RRC = the aggregate Reserved Capacity for Through or Out Service of all Transmission Customers for the hour within the affected Reliability Region(s)."

#### **"IV. ALLOCATION OF VAR SERVICE COSTS**

"The costs related to the CC component of the VAR Service charge shall be paid by each Transmission Customer that receives either Regional Network Service or Through or Out Service. The lost opportunity cost ("LOC"), cost of energy consumed ("CEC") and cost of energy produced ("CEP") components of the charge for VAR Service shall be paid by each Transmission Customer that has either Regional Network Service Load within or load receiving Through or Out Service associated with the affected Reliability Region(s) where reliability criteria must be met."

\*\*\*\*\*

[Note: Sections V(a) of Schedule 2 as distributed to the Participants Committee for the 10/13/06 meeting would be modified with the highlighted language below if the Participants Committee agrees to the changes regarding the "CC Rate Deadband Proposal" that might be proposed at the meeting.]

#### **"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 Rate" will be established each year as of January 1 on a prospective basis for that calendar year and shall be the Base VAR Rate \* Min (1, (1.2 \* Forecast Peak Adjusted Reference Load for the year / (SUM of all Qualified Reactive Resource 's summer Seasonal Claimed Capability))).
4. The "Base VAR Rate" shall be zero for dynamic reactive support provided by Qualified Generator Reactive Resources between a .95 leading and a .95 lagging power factor. For power factors below .95 leading or .95 lagging, the "Base VAR Rate" shall be \$2.32/kVAR-yr, commencing January 1, 2007 and shall not be changed pursuant to Section 205 of the Federal Power Act until January 1, 2012. The .95 power factor exclusion shall not apply to Qualified Non-Generator Reactive Resources. An examination of the of the Base VAR Rate shall be completed no later than July 1, 2011; such examination shall determine whether the Base VAR Rate is still appropriate or whether it should be changed commencing January 1, 2012. On an annual basis, the Base VAR Rate shall be converted into an Adjusted Base

VAR Rate, expressed in the form of \$/kVAR-yr., representing the amount to be paid for leading and lagging capability. The Adjusted Base VAR Rate shall be calculated in accordance with the following formula: Adjusted CC Rate (CCRateadjusted): shall equal  $(CCRatebase * \text{Current Total Aggregate Lagging VARs}) / (\text{Current Total Aggregate Lagging VARs} + \text{Current Total Aggregate Leading VARs})$ . The basis of each such formula element and methodology for calculation is set forth in the VAR Payment Implementation Rule contained in Appendix 1 to this Schedule 2. 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.

5. The "Forecast Peak Adjustment Reference Load" shall be the value published in the then-most recently published CELT report at the time the VAR Rate is established for a year.
6. "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 of each Qualified Reactive Resource's VAR Payment.
8. A Qualified Reactive Resource's VAR Payment shall equal  $(1/12) * (\text{VAR Rate} * \text{Qualified VARs})$  adjusted for the exclusion of payment for reactive support provided by a

generator between a 0.95 leading and a 0.95 lagging power factor.

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.
11. "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.
  - (b). Qualified VARs of an untested Qualified Generator Reactive Resource shall be equal to the sum 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 for reactive power absorbed by the generator step-up transformer. Qualified VARs of an untested

Qualified Non Generator Reactive Resource shall be equal to the sum 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 losses incurred for such VARs to reach the high side of the step-up transformer.”

**DRAFT**



# **ATTACHMENT F**

**Alternative Sections for Schedule 2 Amendments**

(To be used in connection with a potential motion to amend the main motion regarding the Schedule 2 Amendments.)

[Note: Sections III and IV below would be substituted for what is in Sections III and IV of Schedule 2 as distributed to the Participants Committee for the 10/13/06 meeting if the Participants Committee agrees to the Reliability Region Cost Allocation Proposal that might be proposed at the meeting. The highlighted language in Section III shows differences from what is in TC approved version. All of Section IV below is different from the TC approved version.]

**“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:

$$CH = CC (HL_1 + RC_1) / (HL + RC) + (LOC + CEC + CEP) * (RRL_1 + RRC_1) / (RRL + RRC)$$

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 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 used in the hour by a dynamic reactive power resource in order to provide VAR Service to meet reliability criteria within one or more Reliability Regions;

HL<sub>i</sub> = 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<sub>i</sub> = the Reserved Capacity for Through or Out Service of the Transmission Customers for the hour;

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

RRL<sub>i</sub> = the Regional Network Load of the Transmission Customer within its Reliability Region for the hour;

RRL = the aggregate of Regional Network Load of all Transmission Customers for the hour within the affected Reliability Region(s);

RRC<sub>i</sub> = the Reserved Capacity for Through or Out Service of the Transmission Customer within the affected Reliability Region(s) within the hour; and

RRC = the aggregate Reserved Capacity for Through or Out Service  
of all Transmission Customers for the hour within the affected Reliability  
Region(s)."

#### **"IV. ALLOCATION OF VAR SERVICE COSTS**

"The costs related to the CC component of the VAR Service charge shall be paid by  
each Transmission Customer that receives either Regional Network Service or Through or  
Out Service. The lost opportunity cost ("LOC"), cost of energy consumed ("CEC") and cost  
of energy produced ("CEP") components of the charge for VAR Service shall be paid by  
each Transmission Customer that has either Regional Network Service Load within or load  
receiving Through or Out Service associated with the affected Reliability Region(s) where  
reliability criteria must be met."

\*\*\*\*\*

[Note: Sections V(a) of Schedule 2 as distributed to the Participants Committee for the  
10/13/06 meeting would be modified with the highlighted language below if the Participants  
Committee agrees to the changes regarding the "CC Rate Deadband Proposal" that might be  
proposed at the meeting.]

#### **"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.

# **FORM OF NOTICE**

UNITED STATES OF AMERICA  
FEDERAL ENERGY REGULATORY COMMISSION

Maine Public Utilities Commission,	)	
	)	
Complainant,	)	
	)	
v.	)	
	)	Docket No. EL07-____
ISO New England, Inc.,	)	
	)	
Respondents.	)	

NOTICE OF COMPLAINT

(                      )

Take notice that on February 26, 2007, the Maine Public Utilities Commission filed a formal complaint against ISO New England, Inc. pursuant to Sections 206 and 306 of the Federal Power Act, 16 U.S.C. §§ 824e and 825e (2000), and Section 206 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure, 18 C.F.R. § 385.206 (2006), alleging that two components of the ISO-NE Open Access Transmission Tariff Schedule 2 are unjust and unreasonable and should be modified.

The Maine Public Utilities Commission certifies that copies of the complaint were served on the contacts for ISO New England, Inc. as listed on the Commission's list of Corporate Officials.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions, or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at <http://www.ferc.gov>. Persons unable to file electronically should submit an original and 14 copies of the

protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at <http://www.ferc.gov>, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email [FERCOnlineSupport@ferc.gov](mailto:FERCOnlineSupport@ferc.gov), or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).

Magalie R. Salas  
Secretary

## **CERTIFICATE OF SERVICE**

Pursuant to the requirements of Rule 206(c) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.206(c), I hereby certify that I have, contemporaneously with the filing of the foregoing document, caused to be served a copy of the foregoing document upon the Respondent by electronic mail. I have also caused to be served a copy of the foregoing document by electronic mail, upon the Representatives of the Public Utilities Commissions of the New England States.

Dated at Washington, DC this 26th day of February, 2007.

/s/ Harry Dupre

Harry Dupre

Duncan, Weinberg, Genzer  
& Pembroke, P.C.

1615 M Street, NW, Suite 800  
Washington, D.C. 20036  
(202) 467-6370