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VIA HAND DELIVERY

The Honorable Kimberly D. Bose, Secretary
The Honorable Nathaniel J. Davis, Sr., Deputy Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: *ISO New England Inc*, Docket No. ER08-____-000, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2011/2012 Capability Year

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act (“FPA”),¹ ISO New England Inc. (the “ISO”) hereby submits an original and six (6) copies of this transmittal letter and related materials, which identify the Installed Capacity Requirement,² Hydro Quebec Interconnection Capability Credits (“HQICCs”) and related values for the 2011/2012 Capability Year.³ These values will be used as part of the second auction under New England’s Forward Capacity Market, which will be held on December 8, 2008. As detailed below, the ISO proposes an Installed Capacity Requirement value of 33,439 MW.⁴ This value accounts for tie benefits

¹ 16 U.S.C. § 824(d) (2000).

² Capitalized terms used but not defined in this filing are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 (“ISO Tariff”), the Second Restated New England Power Pool Agreement, and the Participants Agreement.

³ The 2011/2012 Capability Year runs from June 1, 2011 to May 31, 2012. Pursuant to Section III.12.3 of Market Rule 1, the Installed Capacity Requirement must be filed 90 days prior to the applicable Forward Capacity Auction.

⁴ In a separate filing today, the ISO is submitting its Informational Filing for qualification in the second FCA for the 2011/12 Capacity Commitment Period. There are some differences in the values that are used in each filing that reflect the amount of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources. These differences are caused by the fact



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(emergency energy assistance) assumed obtainable from New Brunswick (Maritimes) and New York of 716 MW and 173 MW, respectively, but it does not reflect a reduction in capacity requirements relating to HQICCs. The HQICC value of 911 MW per month is applied to reduce the portion of the Installed Capacity Requirement that is allocated to the Interconnection Rights Holders. Thus, the net amount of capacity to be purchased in the Forward Capacity Auction to meet the Installed Capacity Requirement, after deducting the HQICC value of 911 MW/month⁵ is 32,528 MW.⁶

The Commission approved an Installed Capacity Requirement value of 33,705 MW for the 2010/2011 Capability Year.⁷ After accounting for 1,400 MW of HQICCs, this resulted in a net purchase requirement in the first Forward Capacity Auction of 32,305. A total tie benefits value of 1,860 MW was assumed for the 2010/2011 Capability Year. However, under the methodology then in place, only 460 MW of this amount was available for the non-HQICC ties after reduction due to the HQICCs. The decrease in total tie benefits for the 2011/2012 Capability Year is due to an increase in the assumed capacity import over the HQ Phase II interconnection, which was not modeled as such in the 2010/2011 calculation of tie benefits. While the change in total tie benefits is not material, the change in tie benefits from individual directly connected neighboring control areas is significant.

The Forward Capacity Auction process requires the modeling of certain constraints, including Local Sourcing Requirements and Maximum Capacity Limits for Load Zones that may be import or export constrained. Local Sourcing Requirements for the Connecticut and Northeast Massachusetts/Boston (“NEMA/Boston”) Load Zones are 6,817 MW and 2,016 MW, respectively. While final zonal determinations for the second Forward Capacity Auction will be submitted in a separate filing, neither the Connecticut nor NEMA/Boston Load Zones are expected to be modeled as separate Capacity Zones in the second Forward Capacity Auction.⁸

that the ISO had to calculate the 2011/2012 Installed Capacity Requirement prior to the conclusion of the qualification process and therefore, assumptions regarding capacity resources were developed based upon information known at that time. Notwithstanding this difference, the Installed Capacity Requirement calculated using either set of numbers would be very similar.

⁵ The HQICC is a monthly value.

⁶ Prepared Testimony of Mr. Peter K. Wong on Behalf of ISO New England Inc. (“PKW Testimony”) (Attachment 1) at p. 9.

⁷ *ISO New England Inc. and New England Power Pool Participants Committee*, 121 FERC ¶ 61,250 (2007) (“2010/2011 ICR Order”), *order on reh’g*, 123 FERC ¶ 61,129 (2008).

⁸ The ISO notes that the ISO and stakeholders already are reviewing certain inputs into the Installed Capacity Requirement, including the determination of Local Sourcing Requirements, as part of a number of other issues that are being considered by the PSPC on a priority basis.



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The Maximum Capacity Limit for the Maine export-constrained Load Zone is 3,395 MW.⁹ The ISO requests that the Federal Energy Regulatory Commission (“Commission”) accept the values reflected herein for filing to become effective 60 days after the date of submission.

The New England Power Pool (“NEPOOL”) Participants Committee supports the HQICC values submitted in this filing, but did not vote to support the 2011/2012 Installed Capacity Requirement and related values submitted in this filing. NEPOOL is expected to submit separate comments on this filing.

I. COMMUNICATIONS

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

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

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⁹ The Local Sourcing Requirement and Maximum Capacity Limit values are used to determine whether separate zones must be modeled in the second Forward Capacity Auction. The ultimate determinations of separate zones are being submitted in a contemporaneous filing regarding numerous inputs into the Forward Capacity Auction as required by Section III.13.8.1 of the ISO Tariff.



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II. BACKGROUND AND OVERVIEW

As part of the Forward Capacity Market, the ISO is preparing to conduct the second Forward Capacity Auction for the 2011/2012 Capability Year. The auction, which will be conducted on December 8, 2008, will be to satisfy the capacity-related reliability obligations of all New England market participants within the six state footprint of the ISO.¹⁰ In this filing, the ISO is submitting for approval the 2011/2012 Capability Year values for the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limit – all of which are key inputs in the Forward Capacity Auction – and HQICCs, which are a key input into the calculation of the Installed Capacity Requirement values.

A. Installed Capacity Requirement

The Installed Capacity Requirement is a measure of the installed resources that are projected to be necessary to meet reliability standards in light of total forecasted load requirements for the New England Control Area and to maintain sufficient reserve capacity to meet reliability standards. More specifically, the Installed Capacity Requirement is the amount of resources needed to meet the reliability requirements defined for the New England Control Area of disconnecting non-interruptible customers (a loss of load expectation or “LOLE”) no more than once every ten years (an LOLE of 0.1 days per year). The methodology for calculating the Installed Capacity Requirement is set forth in Section III.12 of Market Rule 1. The Installed Capacity Requirement for the 2011/2012 Capability Year is the amount of installed capacity to be procured in the Forward Capacity Auction that will be held in December 2008.¹¹ The values for this year’s filing, as in previous years, are based on three essential components: the load forecast, unit availability, and tie benefits. The methodologies for determining projected load and resource outage rates are the same as those used in previous filings, albeit adjusted due to the need under the new Forward Capacity Market to project the Installed Capacity Requirement three years in advance.¹²

¹⁰ The December 8, 2008 Forward Capacity Auction, like future Forward Capacity Auctions, will be conducted in advance of the Capability Year in which the capacity will actually be supplied. The December 2008 Forward Capacity Auction applies to a supply commitment period that corresponds to the 2011/2012 Capability Year (*i.e.*, June 1, 2011 to May 31, 2012). Resources that clear in the Forward Capacity Auction will be obligated to supply capacity to the New England Control Area during the 2011/2012 Capability Year and load-serving entities will be obligated to pay for the capacity procured.

¹¹ Pursuant to Section III.13 of Market Rule 1, the ISO administers the Forward Capacity Auction in order “to procure the amount of capacity needed in the New England Control Area.”

¹² *See, e.g., ISO New England Inc.*, 111 FERC ¶ 61,185, *reh’g denied*, 112 FERC ¶ 61,254 (2005), *appealed on jurisdictional grounds, Conn. Dept. of Pub. Util. Control v. FERC*, 484 F.3d 558 (D.C. Cir. 2007), *reh’g denied*, 2007 U.S. App. LEXIS 17020 (July 13, 2007), *mandate issued* (July 27,

The methodology for determining tie benefits differs from that used for previous filings. In particular, the ISO adopts for this filing the tie benefits methodology filed by the ISO and NEPOOL Participants Committee on July 31, 2008 that is currently pending before the Commission in Docket No. ER08-41-002 (“July 31 Filing”). That filing was made pursuant to the Commission’s directives in its December 10, 2007 order in Docket No. ER08-41-000 (the “2010/2011 ICR Order”),¹³ as clarified in the May 6, 2008 order denying rehearing (the “May 6 Order”),¹⁴ that the ISO submit a filing in July of 2008 to summarize the results of stakeholder discussions and address any proposed changes to the methodology for calculating and allocating tie benefits for the December 2008 Forward Capacity Auction.¹⁵

As in past years, the ISO developed the initial Installed Capacity Requirement recommendation with stakeholder input which is provided in part through the NEPOOL committee processes through review by NEPOOL’s Power Supply Planning Committee (“PSPC”), the Reliability Committee and the Participants Committee. All of the load and resource assumptions needed for the Westinghouse/ABB Capacity Model Program (“Capacity Model”) were reviewed by the PSPC, a subcommittee of the NEPOOL Reliability Committee.

B. Local Sourcing Requirement and Maximum Capacity Limit

The Local Sourcing Requirements and Maximum Capacity Limits were not addressed in Installed Capacity Requirements filings preceding the Forward Capacity Market implementation. However, under the Forward Capacity Market, the ISO also must calculate Local Sourcing Requirements and Maximum Capacity Limits to be used, if necessary, in each Forward Capacity Auction. A Local Sourcing Requirement is “the minimum amount of capacity that must be electrically located within an import-constrained Load Zone.”¹⁶ A Maximum Capacity Limit is “the maximum amount of capacity that can be procured in an export-constrained Load Zone [to meet the Installed Capacity Requirement].”¹⁷ The general purpose of Local Sourcing Requirements and Maximum Capacity Limits is to ensure that capacity resources, when considered in combination with the transfer capability of the transmission system, are electrically

2007), *on remand to*, 122 FERC P 61, 144 (2008), *reh’g denied*, 122 FERC ¶ 61, 036 (2008) (2005/2006 Capability Year Installed Capacity Requirements); and *ISO New England Inc.*, 119 FERC ¶ 61,161 (2007), *reh’g denied*, 121 FERC ¶ 61, 125 (2007) (2007/2008 Capability Year Installed Capacity Requirements). *See also* 2010/2011 ICR Order; *order on reh’g*, 123 FERC ¶ 61,129 (2008).

¹³ 2010/2011 ICR Order

¹⁴ 123 FERC ¶ 61,129.

¹⁵ *Id.*

¹⁶ Section III.13 of the ISO Tariff.

¹⁷ *Id.*



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distributed within the New England Control Area in a manner that ensures that the minimum amount of resources purchased in the Forward Capacity Auction will meet the Northeast Power Coordinating Council's and Market Rule 1, Section 12's 1 day in 10 years (0.1 days per year) disconnection of firm load resource adequacy planning criterion.

For the 2011/2012 Capability Year, the ISO calculated the Local Sourcing Requirements for Connecticut and NEMA/Boston Load Zones and the Maximum Capacity Limit for the Maine Load Zone. The Local Sourcing Requirements and Maximum Capacity Limit were calculated using the same assumptions of forecasted load and resources as those used in the calculation of the Installed Capacity Requirement for the 2011/2012 Capability Year.

C. HQICCs

HQICCs are capacity credits that are allocated to the Interconnection Rights Holders, which are entities that hold certain rights over the HQ Interconnection. Pursuant to the July 31 Filing, the tie benefit value for the Hydro-Quebec Interconnection (the "HQ Interconnection") was established using the results of the probabilistic calculation of tie benefits with Quebec rather than using a deterministic calculation methodology. Moreover, as described further below, tie benefits from individual Control Areas were determined herein using an allocation approach based on the results of individual probabilistic calculations performed for each of the three neighboring Control Areas, obviating the need to reduce tie benefit values for the New Brunswick and New York Control Areas to account for the deterministically calculated HQICCs (reflecting the tie benefit value of the HQ Interconnection) as had been done previously. The ISO calculates HQICCs, which are allocated to Interconnection Rights Holders in proportion to their individual rights over the HQ Interconnection, and must file the HQICC values established for each Capability Year. The HQICC values for the 2011/2012 Capability Year are 911 MW per month. At its August 1, 2008 meeting, the NEPOOL Participants Committee voted to support these values, with one opposition and 13 abstentions noted.

D. Process for Developing Installed Capacity Requirement and Related Values

The ISO, in consultation with NEPOOL and other interested parties, developed the proposed Installed Capacity Requirement and related values for the 2011/2012 Capability Year through an extensive stakeholder process which involved more than 13 meetings during a period of 8 months. The ISO used the methodologies and assumptions for determining the Installed Capacity Requirement and related values that are set out in Section III.12 of Market Rule 1, which were approved by the Commission early last year.¹⁸ The methodology and assumptions

¹⁸ *ISO New England Inc. and New England Power Pool*, 118 FERC ¶ 61,157 (2007), *reh'g denied*, 120 FERC ¶ 61,234 (2007) (the "ICR Rules Order"), *appeal docketed*, *Connecticut Department of Public Utility Control v. Federal Energy Regulatory Commission*, Case No. 07-1375 (D.C. Cir.



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used to calculate the proposed Installed Capacity Requirement also are consistent with the approach reflected in the recent capacity requirement values submitted (and accepted) for previous Capability Years.¹⁹ There was broad agreement regarding many of the assumptions, inputs and projections for calculating the 2011/2012 Capability Year Installed Capacity Requirement and related values.

The specific Installed Capacity Requirement and related values proposed in this submittal, and the derivation of those values, is discussed further in Sections IV-VII of this filing letter and in the Testimony of Peter K. Wong. As explained in Sections IV-VII and the Testimony, the proposed Installed Capacity Requirement and related values (with the exception of the tie benefits, discussed below) were calculated based on a Commission-approved methodology and a reasonable set of assumptions. Accordingly, the Commission should accept the proposed values for filing without change to become effective 60 days after the date of submission.

E. Proposed Values

The ISO is proposing that 33,439 MW be the Installed Capacity Requirement for the 2011/2012 Capability Year. The 33,439 MW Installed Capacity Requirement value for the 2011/2012 Capability Year accounts for tie benefits (emergency energy assistance) assumed obtainable from New Brunswick (Maritimes) and New York of 716 MW and 173 MW, respectively, but it does not reflect a reduction in capacity requirements relating to HQICCs that are allocated to the Interconnection Rights Holders. The HQICC value of 911 MW per month is applied to reduce the portion of the Installed Capacity Requirement that is allocated to the Interconnection Rights Holders. Thus, the net amount of capacity to be purchased in the Forward Capacity Auction to meet the Installed Capacity Requirement, after deducting the HQICC value, is 32,528 MW.

September 21, 2007). That appeal challenges the Commission's jurisdiction to oversee establishment of the Installed Capacity Requirement, but does not challenge either: (1) the actual technical provisions of the market rules reflected in Section III.12 of the ISO Tariff that were approved by the Commission in that order and that were used to calculate the Installed Capacity Requirements and related values that are the subject of this filing; or (2) any particular set of these values that have been submitted to the Commission.

¹⁹ See, e.g., 119 FERC ¶ 61,161; 111 FERC ¶ 61,185



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The 2011/2012 Capability Year Local Sourcing Requirements for the Connecticut and NEMA/Boston Load Zones are 6,817 MW and 2,016 MW, respectively. The Maximum Capacity Limit for the Maine export-constrained Load Zone is 3,395 MW.

III. STANDARD OF REVIEW

The ISO submits the proposed Installed Capacity Requirement and related values pursuant to Section 205, which “gives a utility the right to file rates and terms for services rendered with its assets.”²⁰ Under Section 205, the Commission “plays ‘an essentially passive and reactive’ role”²¹ whereby it “can reject [a filing] only if it finds that the changes proposed by the public utility are not ‘just and reasonable.’”²² The Commission limits this inquiry “into whether the rates proposed by a utility are reasonable -- and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs.”²³ The Installed Capacity Requirement and related values herein “need not be the only reasonable methodology, or even the most accurate.”²⁴ As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept the ISO’s Section 205 filing if it is just and reasonable.²⁵

IV. GENERAL PROCESS FOR ESTABLISHING INSTALLED CAPACITY REQUIREMENTS

The Installed Capacity Requirement is an ISO projected measure of the capacity (*e.g.*, generation, imports and demand resources) that is necessary to satisfy the New England Control Area’s total forecasted load requirements and to maintain sufficient reserve capacity to meet reliability standards. More specifically, the Installed Capacity Requirement is the amount of capacity needed to meet the reliability requirements defined for the New England Control Area of disconnecting non-interruptible customers no more than once in every ten years (an LOLE of 0.1 days/year).

²⁰ *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002).

²¹ *Id.* at 10 (quoting *City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)).

²² *Id.* at 9.

²³ *Cities of Bethany, et al. v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984), *cert. denied*, 469 U.S. 917 (1984).

²⁴ *OXY USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995).

²⁵ *Cf. Southern California Edison Co., et al.*, 73 FERC ¶ 61,219 at 61,608 n.73 (1995) (“Having found the plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protesters.” (citing *Cities of Bethany*, 727 F.2d at 1136)).



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To develop the Installed Capacity Requirement for the 2011/2012 Capability Year, the ISO in consultation with the PSPC determined the assumptions to use to simulate the expected New England bulk power system reliability using the Capacity Model.²⁶ Many of these assumptions are specified in Section III.12 of Market Rule 1. All assumptions are developed with stakeholder review and input. The Capacity Model is a reliability modeling program that calculates system LOLE using probabilistic mathematics based on expected load and capacity conditions. Inputs to the Capacity Model are various assumptions regarding load and capacity resources. The Capacity Model has been used to establish Installed Capacity Requirements for at least the past 25 years in New England.

V. DEVELOPMENT OF THE INSTALLED CAPACITY REQUIREMENT FOR THE 2011/2012 CAPABILITY YEAR

The proposed Installed Capacity Requirement for the 2011/2012 Capability Year was determined using well established modeling methods and system modeling assumptions regarding a variety of factors, including forecast load, unit availability and tie reliability benefits. During the development of last year's Installed Capacity Requirement (for the 2010/2011 Capability Year), the ISO's recommendations resulted in consensus agreement during the stakeholder process regarding nearly all of the assumptions and modeling methods that are used to establish the proposed Installed Capacity Requirement and related values that are reflected in this filing. However, there were two exceptions to the general consensus, which involved: (1) the method to be used to calculate total tie benefits; and (2) the manner in which total tie benefits are allocated to individual ties, which could impact the capacity obligations of certain market participants. The two issues involved whether and how, in the calculation and allocation of total tie benefits, the Commission-ordered deterministic calculation of HQICCs should be reflected.

As a result of a six-month stakeholder review conducted after the Commission's order on last year's filing, the ISO and NEPOOL in the July 31 Filing in Docket No. ER08-41-002 submitted changes to Market Rule 1 concerning the methodologies for calculating and allocating tie benefits with neighboring Control Areas. As described further below, the ISO adopted the methodology for calculating and allocating total tie benefits that was introduced in the July 31 Filing in the instant filing of the proposed Installed Capacity Requirement and related values for the 2011/2012 Capability Year, in response to the Commission's directive issued in its 2010/2011 ICR Order. The general approach to calculating the proposed Installed Capacity Requirement, HQICCs and related values, including the tie benefit calculation methodology are discussed below.

A. Load Forecast

²⁶ PKW Testimony at pp. 4-6.

The forecasted peak loads of the entire New England Control Area for the 2011/2012 Capability Year are one major input into the calculation of the annual Installed Capacity Requirement detailed in this filing, and the forecast peak loads for the individual Load Zones are used to develop the associated Local Sourcing Requirements and Maximum Capacity Limit.²⁷ The ISO's 10-year load forecast, covering the years 2008 through 2017, was published in April 2008 in the ISO New England "2008 – 2017 Forecast Report of Capacity, Energy, Loads, And Transmission" ("2008 CELT Forecast").²⁸ The 2008 CELT Forecast was developed by the ISO using the same methodology used previously to develop the peak load assumptions reflected in the Commission-approved Installed Capacity Requirements,²⁹ reflecting economic and demographic assumptions as reviewed and supported by the NEPOOL Load Forecast Committee.

The 2008 CELT Forecast continues to reflect incremental improvements to the load forecasting methodology used in New England for many years. The incremental improvements were identified with the assistance of a consultant, Benchmark Forecasts, and were reviewed by stakeholders as part of a load forecasting review effort.³⁰ For example, certain modifications to the peak forecast model and the energy forecast models resulted in better specified models and improved estimates of the coefficients used to forecast the loads.

²⁷ The forecasted peak loads for the 2008/2009 Capability Year that were used in the Commission-approved Installed Capacity Requirements filing submitted on March 21, 2008 are from the same 10-year load forecast, which is updated annually and published in April, that contained the peak loads used for the development of the Installed Capacity Requirement for the 2011/2012 Capability Year. 2008/2009 Power Year Installed Capacity Requirements, *ISO New England Inc.*, Docket No. ER08-696-000 (filed Mar. 21, 2008). See also *ISO New England Inc. and New England Power Pool Participants Committee*, 123 FERC ¶ 61,196 (2008) (accepting 2008/2009 Capability Year Installed Capacity Requirements).

²⁸ Two locations on the ISO website contain more detailed information on the following: short-run and long-run forecast methodologies, models, and inputs; weather normalization; regional, state, and subarea annual electric energy and peak-load forecasts; high- and low-forecast bandwidths; and retail electricity prices. See "CELT Forecasting Details 2008," http://www.iso-ne.com/trans/celt/fsct_detail/index.html and "CELT Report 2008," <http://www.iso-ne.com/trans/celt/report/index.html>. (CELT stands for "capacity, energy, loads, and transmission.")

²⁹ See, e.g., 119 FERC ¶ 61,161 (accepting ISO-proposed Installed Capacity Requirements for the 2007/2008 Power Year); *ISO New England Inc.*, 115 FERC ¶ 61,149 (2006) (accepting ISO proposed Installed Capacity Requirements for the 2006/2007 Power Year).

³⁰ F.L. Joutz and D.R. Hale, An Evaluation of the ISO-NE Long-Run Energy and Seasonal Peak Load Forecast Methodology (Kensington, MD: Benchmark Forecasts, March 9, 2007), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2007/load_forecast_methodology_review_b_ackground.pdf.



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The projected New England Control Area 50/50 peak load (summer)³¹ for the 2011/2012 Capability Year is 29,405 MW. This represents a compound annual growth rate of 1.7% from the forecasted 50/50 peak load of 27,970 MW for the summer of 2008. The corresponding 90/10 peak load for the 2011/2012 Capability Year is 31,525 MW.³² This represents a compound annual growth rate of 1.8% from the forecasted 90/10 peak load of 29,895 MW for the summer of 2008. The forecast net annual energy for 2008 and 2011 is 135,000,000 MWh and 139,195,000 MWh, respectively. The corresponding energy growth for the calendar years 2008 through 2011 is forecast to be at a compound annual growth rate of 1%. The 2008 CELT Forecast shows that the New England Control Area would experience a decline in the annual load factor from 55.1% in 2008 to 54.0% in 2011. This is generally attributed to an increase in the air conditioning penetration, which has led to an increase in summer peak use relative to average use.

B. Resource Capacity Ratings

The 2011/2012 Installed Capacity Requirement is based on ratings of Qualified Existing Capacity Resources that have cleared the Forward Capacity Auction for the 2010/2011 Commitment Period.³³ Resource additions and attritions are not assumed in the calculation of the Installed Capacity Requirement for the 2011/2012 Capability Year pursuant to Market Rule 1 because there is no certainty that new resource additions or existing resource attritions will clear the Forward Capacity Auction. Not modeling undetermined resource additions and attritions will not have a significant effect on the calculated Installed Capacity Requirement since the availability characteristics and sizes of these resources are expected to be similar to those of the Existing Resources. The additional load carrying capability (“ALCC”) adjustments, discussed in Mr. Wong’s testimony, are designed to compensate for these uncertainties.³⁴

C. Unit Availability

The proposed 2011/2012 Installed Capacity Requirement reflects unit availability assumptions based on historical scheduled maintenance and forced outages of the capacity

³¹ The New England Control Area is a summer-peaking system, meaning that the highest load occurs during the summer. The 50/50 peak refers to the peak load having a 50% chance of being exceeded, and is expected to occur at a weighted New England-wide temperature of 90.4 °F.

³² The 90/10 peak refers to the peak load having a 10% chance of being exceeded, and is expected to occur at a weighted New England-wide temperature of 94.2 °F.

³³ In the Forward Capacity Market, capacity resources can be generation (Generating Capacity or Intermittent Power Capacity) or demand resources (On-Peak, Seasonal Peak, Critical Peak, Real-Time Demand Response and Real-Time Emergency Generation).

³⁴ PKW Testimony at pp. 6, 17.



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resources. For Generating Resources, individual unit scheduled maintenance assumptions are based on each unit's most recent historical five-year average of scheduled maintenance. If the individual resource has not been operational for five years, then NERC class average data is used to substitute for the missing annual data. The individual Generating Resource's forced outage assumptions are based on the generator's five-year historical equivalent forced outage rate data submitted to the ISO database. The NERC class average data for the same class of units is used to substitute for the missing annual data if the resource has been in commercial operation less than five years.

The Qualified Capacity of an Intermittent Power Resource is the resource's median output during the Reliability Hours averaged over a period of five years. Based on the Intermittent Power Resources rating methodology, these resources are assumed 100% available.

While the Passive Demand Response Resources are assumed 100% available in the Installed Capacity Requirement calculations, the performance assumptions for the Active Demand Resources in the Real-Time Demand Response, Critical Peak and Real-Time Emergency Generator categories are based on actual responses during all historical OP 4 events and ISO performance audits.

D. Tie Benefits

New England's Commission-approved method for establishing the Installed Capacity Requirement requires that assumptions be made regarding the tie benefits value to be used as an input in the formula. Tie benefits from neighboring control areas reduce the Installed Capacity Requirement and the need to buy capacity to meet the New England resource adequacy criterion. The tie benefits from neighboring Control Areas reflect the amount of emergency assistance that New England could rely on, without jeopardizing reliability in New England or its neighboring control areas, in the event of a capacity shortage in New England.

The Installed Capacity Requirement for the 2011/2012 Capability Year proposed by the ISO reflects total tie benefits calculated in accordance with a new methodology proposed in revisions to the ISO Tariff, submitted in the July 31 Filing to comply with the Commission's directives in its 2010/2011 ICR Order.³⁵ The new methodology is pending before the Commission in Docket ER08-41-002, and the ISO and NEPOOL's July 31, 2008 joint filing in that proceeding explains the methodology and demonstrates the justness and reasonableness of that methodology. Several comments and a protest challenging that methodology have been filed and are also pending. To the extent necessary in this proceeding, the ISO respectfully requests that the Commission take notice in this proceeding of the July 31, 2008 joint filing and

³⁵ 2010/2011 ICR Order.



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the answers filed by the ISO and NEPOOL to the protests and other pleadings filed in that proceeding.

Under the proposed modifications, HQICC values are established using the results of a probabilistic calculation of tie benefits rather than using a deterministic calculation methodology. The ISO continues using the existing methodology for calculating total tie benefits from the Quebec, New Brunswick and New York Control Areas using a probabilistic multi-area reliability model. In addition, as explained further below, these neighboring Control Areas will continue to be modeled using “At Criteria” modeling assumptions. However, under the approach proposed in the July 31 Filing, implemented herein, tie benefits from individual Control Areas are determined based on the results of individual probabilistic calculations performed for each of the three neighboring Control Areas, obviating the need for a deterministic calculation of HQICCs that arbitrarily reduces the tie benefit values from the New Brunswick and New York Control Areas.

Under the proposed allocation methodology, tie benefits from each Control Area are calculated using the same GE MARS program with “At Criteria” modeling assumptions. Using the “At Criteria” modeling assumption is consistent with applicable Commission-approved tariff provisions (namely, section III.12.9 of Market Rule 1) and with Commission precedent.³⁶

In other words, the allocation methodology for calculating Individually-Calculated Capacity Equivalents for New Brunswick and New York is applied for determining the tie benefits from Quebec as well. If the sum of the Individually-Calculated Capacity Equivalents from each of the three neighboring Control Areas does not equal the total tie benefits calculated using the multi-area reliability model, tie benefits from each Control Area will be adjusted in a pro rata manner based on a ratio of the tie benefits from each individual Control Area to the sum of the tie benefits from all Control Areas. Thus, the proposed approach does away with the use of the deterministic method for calculating HQICCs and employs the same method for calculating tie benefits from all three directly connected Control Areas.

³⁶ In the 2010/2011 ICR Order, the Commission determined:

The Filing Parties’ “at criteria” assumption reflecting a Loss of Load Expectation included in the instant filing is just and reasonable because it models potential transmission constraints on neighboring control areas. The Filing Parties’ approach recognizes that the exact system conditions of neighboring control areas are unknown three years in advance and therefore builds a conservative margin of safety into its calculation of tie benefits available. We find this to be a reasonable approach.

2010/2011 ICR Order at P 73.



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Based on the methodology described above, a total of 1,800 MW of tie benefits are assumed in the Installed Capacity Requirement calculations for the 2011/2012 Capability Year, which includes: 911 MW from Quebec, 716 MW from New Brunswick (Maritimes) and 173 MW from New York.

E. Allocation of Tie Benefits

For purposes of modeling the Local Sourcing Requirement and Maximum Capacity Limit, and to calculate the amount of capacity that may be purchased over each tie in the Forward Capacity Auction, it is necessary to allocate the contribution of the total tie benefits value among each of the interconnections between the New England Control Area and other control areas. The total tie benefits value is calculated and allocated in accordance with Market Rule 1.³⁷ The Local Sourcing Requirement and Maximum Capacity Limit proposed in this filing reflect the tie benefit allocation methodology in the July 31 Filing. As noted above, the allocation methodology used herein for calculating individual tie benefits from New Brunswick and New York is applied for determining the tie benefits from Quebec as well.

F. HQICC Values

1. Proposed HQICC Values

The ISO proposes HQICC values of 911 MW for each month of the 2011/2012 Capability Year, which were calculated using the allocation methodology proposed in the July 31 Filing in Docket No. ER08-41-002.

Further details regarding the calculation of HQICCs are included in the testimony of Peter K. Wong submitted in support of the July 31, 2008 filing in Docket ER08-41-002, and included herewith as Attachment 2. These values were developed in consultation with NEPOOL through the Power Supply Planning Committee process. At its July 21, 2008 meeting, the NEPOOL Reliability Committee voted to recommend that the Participants Committee support these HQICC values. At its August 1, 2008 meeting, the NEPOOL Participants Committee voted to support these values, with one opposition and 13 abstentions noted.

³⁷ In prior orders, the Commission has directed that the Interconnection Rights Holders be granted capacity credits in connection with their transmission rights over the HQ Interconnection regardless of whether the Interconnection Rights Holders have actually entered into any agreements to import capacity or energy over the HQ Interconnection. *See, e.g., New England Power Pool and ISO New England Inc., Order Accepting Compliance Filing*, 111 FERC ¶ 61,132 (2005). In the ISO Tariff, the capacity credits granted to the Interconnection Rights Holders are known as Hydro Quebec Interconnection Capability Credits (“HQICCs”).



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VI. DEVELOPMENT OF THE LOCAL SOURCING REQUIREMENTS AND MAXIMUM CAPACITY LIMIT

Under the Forward Capacity Market, the ISO also must calculate Local Sourcing Requirements and Maximum Capacity Limits to be used in each Forward Capacity Auction, if necessary. A Local Sourcing Requirement is the minimum amount of capacity that must be electrically located within an import-constrained Load Zone, and a Maximum Capacity Limit is the maximum amount of capacity that can be procured in an export-constrained Load Zone to meet the Installed Capacity Requirement. Local Sourcing Requirements and Maximum Capacity Limits are calculated using the same load and resource assumptions as those used in calculating the Installed Capacity Requirement.

These values will determine the amount of capacity that is needed in each Load Zone. Local Sourcing Requirements and Maximum Capacity Limits help to ensure that capacity resources are distributed geographically within the New England Control Area in a manner that ensures compliance with reliability criteria. The amount of Existing Resources in each Load Zone, which are used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirement and Maximum Capacity Limit, are presented in the attached Testimony Peter K. Wong (Attachment 1).³⁸ The calculation of the Local Sourcing Requirements and the Maximum Capacity Limits used the same load and resource assumptions that were used to calculate the Installed Capacity Requirement for 2011/2012, except that they are distributed to the Load Zones according to their electrical connection.

The 2011/2012 Capability Year Local Sourcing Requirements for the Connecticut and NEMA/Boston Load Zones are 6,817 MW and 2,016 MW, respectively. The Maximum Capacity Limit for the Maine export-constrained Load Zone is 3,395 MW. This is the amount of capacity resources that the second Forward Capacity Auction can procure from the Maine Capacity Zone, including capacity resource imports over the New Brunswick ties. This number also reflects the tie benefits assumed available over the New Brunswick ties. That is, the Maximum Capacity Limit is reduced to reflect the flows required to receive the assumed tie benefits from New Brunswick to assist the New England Control Area at times of capacity shortage. Allowing more purchases of capacity from Maine could preclude the energy flows required to realize these tie benefits.

VII. POTENTIAL DOUBLE PRORATION OF CAPACITY REGARDING MAXIMUM CAPACITY LIMIT IN MAINE

Pursuant to Section III.12.4(a), as an export-constrained Load Zone, Maine will be modeled as a separate Capacity Zone. The Maximum Capacity Limit for Maine has dropped

³⁸ PKW Testimony at 15-16, Table Nos. 1-3.



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materially under the new tie benefits methodology being applied in the instant filing. Thus, Maine's Maximum Capacity Limit of 3,395 MW is the maximum amount of capacity that the second FCA can procure from resources located in the Maine Capacity Zone. It should be noted that if the price floor is reached in the second FCA, there could be more capacity resources located in Maine than the Maximum Capacity Limit. If such a condition occurs, it would require "double pro ration" of capacity resources electrically located in the Maine Load Zone – once for meeting the Maximum Capacity Limit and, if necessary, once for meeting the total New England Installed Capacity Requirement. There are 3,623 MW of qualified Existing Capacity Resources in Maine. In addition, there are 509 MW of qualified New Capacity Resources located in Maine of which 444 MW have submitted an offer below 0.75 time CONE. Thus, assuming that all of the available resources remain in the auction to the floor price, Maine's market participants will need to elect whether to keep their full Capacity Supply Obligation with a reduced payment rate or to reduce their Capacity Supply Obligation and maintain the original Capacity Clearing Price because without such proration the Maine Maximum Capacity Limit would be exceeded. Further, if the Rest-of-Pool Capacity Zone also has excess capacity, there will also be a similar decision faced by all market participants within the Rest-of-Pool Capacity Zone. Thus, market participants' resources in Maine could be subject to double pro rationing, which would result in the dollar per megawatt payment to resources in the Maine Capacity Zone falling below the dollar per megawatt payment to resources in the Rest-of-Pool Capacity Zone.

VIII. STAKEHOLDER PROCESS

A. 2011/2012 HQICCs

The HQICCs were developed through the tie benefits study. The ISO worked with the stakeholders to develop the total tie benefits and the tie benefits from the three directly interconnected neighboring control areas. Several meetings with the PSPC and the Reliability Committee were held to review the assumptions for the tie benefits study and its results including the resulting HQICC values. At its July 21, 2008 meeting, the NEPOOL Reliability Committee voted to recommend that the Participants Committee support these HQICC values. At its August 1, 2008 meeting, the NEPOOL Participants Committee voted to support these values, with one opposition and 13 abstentions noted.



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B. 2011/2012 Installed Capacity Requirement and Related Values

The Reliability Committee at its July 21, 2008 meeting reviewed and considered the outcome of the PSPC's efforts with respect to the development of the 2011/2012 Installed Capacity Requirement and Related Values. A motion to recommend that the Reliability Committee recommend that the Participants Committee support the ISO's proposed Installed Capacity Requirements and related values that are the subject of this filing failed to pass (54.55% vote in favor). At its August 1, 2008 meeting, a motion that the NEPOOL Participants Committee support these proposed Installed Capacity Requirement and related values also failed to pass (59.97% vote in favor). As a general matter, during the stakeholder process there were some stakeholders that supported a higher Installed Capacity Requirement and some that supported a lower requirement.

IX. REQUESTED EFFECTIVE DATE

The ISO requests that the Commission accept the proposed Installed Capacity Requirement and related values to be effective 60 days after the date of submission. The proposed values will be used as part of the Forward Capacity Auction to be conducted on December 8, 2008.

X. ADDITIONAL SUPPORTING INFORMATION

This filing identifies Installed Capacity Requirement and related values for the 2011/2012 Capability Year, and is made pursuant to Section 205 of the FPA. Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of cost-of-service rates.³⁹ However, the proposed Installed Capacity Requirements and related values are not traditional "rates" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the ISO requests waiver of Section 35.13 of the Commission's regulations. Notwithstanding its request for waiver, the ISO submits the following additional information in compliance with the identified filing regulations of the Commission applicable to Section 205 filings.

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

- ♦ This transmittal letter;
- ♦ Attachment 1: Testimony of Peter K. Wong;

³⁹ 18 C.F.R § 35.13 (2008).



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- ♦ Attachment 2: Testimony of Peter K. Wong, filed in Docket No. ER08-41-002 (July 31, 2008);
- ♦ Attachment 3: List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been sent.

35.13(b)(2) – the ISO respectfully requests that the Commission accept this filing to become effective 60 days after the date of submission.

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at http://www.iso-ne.com/regulatory/ferc/nepool/gov_prtcpts_eserved.pdf. A paper copy of this transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states which comprise the New England Control Area, and to the New England Conference of Public Utility Commissioners, Inc. The names and addresses of these governors and regulatory agencies are shown in Attachment 5. In accordance with Commission rules and practice, there is no need for the entities identified on Attachment 5 to be included on the Commission's official service list in the captioned proceedings unless such entities become intervenors in this proceeding.

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

35.13(b)(5) - The reasons for this filing are discussed in the background section to this transmittal letter.

35.13(b)(6) - As explained above, the ISO has sought the advisory input from Governance Participants pursuant to Section 11.4 of the Participants Agreement.

35.13(b)(7) - The ISO has no knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

35.13(c)(2) - The ISO does not provide services under other rate schedules that are similar to the sale for resale and transmission services it provides under the ISO Tariff.

35.13(c)(3) - No specifically assignable facilities have been or will be installed or modified in order to supply service with respect to the proposed Installed Capacity Requirement and related values.



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XI. CONCLUSION

The ISO requests that the Commission accept the Installed Capacity Requirement and related values reflected in this submission for filing without change to become effective 60 days after the date of submission.

Please acknowledge receipt of the foregoing by date-stamping the enclosed extra copies of this filing and returning them to the courier delivering the filing.

Respectfully submitted,

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Attachments

cc : Entities listed in Attachment 3

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document and attachments upon each person identified in Attachment 3 of the attached transmittal letter, in the manner specified in the transmittal letter.

Dated at Washington, D.C., this 9th day of September, 2008.



Sherry A. Quirk

DCV7107522.1

ATTACHMENT 1

Testimony of Peter K. Wong

1 operating arm of the New England Power Pool (“NEPOOL”), and for the ISO
2 after the staff of NEPOOL was transferred to the ISO.

3

4 I have worked with NEPOOL and the ISO for more than 33 years. During this
5 time, in addition to my most recent duties described above, I have also held
6 various positions in the Power Supply Planning department of New England
7 Power Planning (“NEPLAN”), the planning arm of NEPOOL. My last position at
8 NEPLAN was Manager of Power Supply Planning. During my 15 years with
9 NEPLAN Power Supply Planning, I was involved in all matters related to
10 NEPOOL Objective Capability (Installed Capacity Requirement) and resource
11 adequacy. I currently serve as the Chair of the NEPOOL Power Supply Planning
12 Committee, which is the NEPOOL technical committee charged with the review
13 and/or development of all assumptions used for the calculation and development
14 of Installed Capacity Requirements, Local Sourcing Requirements and Maximum
15 Capacity Limits for the ISO markets.

16

17 **Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

18 **A.** My testimony discusses the derivation of the Installed Capacity Requirement and
19 related values (Local Sourcing Requirements, Maximum Capacity Limit and
20 Hydro Quebec Interconnection Capability Credits (HQICCs)) for the 2011/2012
21 Capability Year. The 2011/2012 Capability Year starts on June 1, 2011 and ends
22 on May 31, 2012.

23

1 **INSTALLED CAPACITY REQUIREMENT**

2 **Q: WHAT IS THE “INSTALLED CAPACITY REQUIREMENT?”**

3 **A.** The Installed Capacity Requirement is the level of capacity required to meet the
4 reliability requirements defined for the New England Control Area. This
5 requirement is documented in Section 2 of ISO New England Planning Procedure
6 No. 3, Reliability Standards for the New England Area Bulk Power Supply
7 System,¹ which states:

8
9 “**Resources** will be planned and installed in such a manner that, after
10 due allowance for the factors enumerated below, the probability of
11 disconnecting noninterruptible customers due to **resource** deficiency,
12 on the average, will be no more than once in ten years. Compliance
13 with this criteria shall be evaluated probabilistically, such that the loss
14 of load expectation [LOLE] of disconnecting noninterruptible
15 customers due to resource deficiencies shall be, on average, no more
16 than 0.1 day per year.

- 17
- 18 a. The possibility that load forecasts may be exceeded as a result
19 of weather variations.
 - 20
 - 21 b. Immature and mature **equivalent forced outage rates**
22 appropriate for generating units of various sizes and types,
23 recognizing partial and full outages.
 - 24
 - 25 c. Due allowance for scheduled outages and deratings.
 - 26
 - 27 d. Seasonal adjustment of **resource** capability.
 - 28
 - 29 e. Proper maintenance requirements.
 - 30
 - 31 f. Available operating procedures.
 - 32
 - 33 g. The reliability benefits of interconnections with systems that
34 are not Governance Participants.
 - 35
 - 36 h. Such other factors as may from time-to-time be appropriate.”

¹ Copy available at http://www.iso-ne.com/rules_proceeds/isone_plan/PP3_R3.doc (emphasis in original).

1 The Installed Capacity Requirement reflects estimated tie benefits, and has
2 associated Local Sourcing Requirements and Maximum Capacity Limits that
3 ensure that the required capacity is appropriately located.

4

5 **Q: PLEASE EXPLAIN THE GENERAL PROCESS FOR ESTABLISHING**
6 **THE INSTALLED CAPACITY REQUIREMENT.**

7 **A.** The Installed Capacity Requirement for the 2011/2012 Capability Year was
8 established by the ISO in consultation with stakeholders and in accordance with
9 the calculation methodology as prescribed in Section III.12 of Market Rule 1,
10 except for the allocation of total tie benefit contributions from the three directly
11 interconnected neighboring Control Areas. The stakeholder process consisted of
12 NEPOOL Power Supply Planning Committee's ("PSPC") review and comments
13 on the ISO's development of load and resource assumptions, and the ISO's
14 calculation of the Installed Capacity Requirement and associated values for the
15 2011/2012 Capability Year. The PSPC is a technical committee under the
16 Reliability Committee charged with reviewing the Installed Capacity
17 Requirement, Local Sourcing Requirements and Maximum Capacity Limits,
18 including appropriate load and resource assumptions for modeling the expected
19 system conditions. The PSPC consists of representatives of NEPOOL members
20 and the committee is chaired by a representative of the ISO. Staffs of the six New
21 England States' public utilities regulatory commissions also participate in the
22 PSPC meetings. After the PSPC's review and comment, the ISO developed a
23 recommendation regarding the Installed Capacity Requirement and associated

1 values for the 2011/2012 Capability Year and presented this recommendation,
2 along with the associated load and resource assumptions, to the Reliability
3 Committee for its review, comment and action. The ISO then presented its
4 Installed Capacity Requirement recommendation and the results of the Reliability
5 Committee action to the Participants Committee for its review and action. After
6 considering the Participants Committee's comments and action, the ISO is filing
7 the Installed Capacity Requirement and related values for the 2011/2012
8 Capability Year with the Commission.

9
10 **Q: PLEASE EXPLAIN THE METHODOLOGY FOR ESTABLISHING THE**
11 **INSTALLED CAPACITY REQUIREMENT.**

12 **A.** The Installed Capacity Requirement was established using the
13 Westinghouse/ABB Capacity Model Program ("Capacity Model") developed by
14 Westinghouse Electric Corporation. The Capacity Model is a computer program
15 that uses probabilistic mathematics to simulate the random behavior of load and
16 resources of a power system and calculates the expected days per year that the
17 electric system would not have adequate resources to meet the daily peak loads.
18 Inputs to the Capacity Model are various assumptions regarding load and capacity
19 resources. The Capacity Model is a one bus model and the New England
20 transmission system is assumed to have no constraints in this simulation. In other
21 words, all the modeled resources are assumed to be deliverable to meet forecasted
22 load anywhere in the New England Control Area. The program compares, on a
23 weekly basis, the available capacity resources with the range of expected daily
24 peak loads to determine the weekly Loss of Load Probability ("LOLP").

1 Summation of the weekly LOLP over the Capability Year (June 2011 – May
2 2012) gives the Loss of Load Expectation (“LOLE”). The calculation process
3 starts with the determination of the system LOLE with existing and known
4 resource additions to meet the expected load. If the system is more reliable than
5 the resource-adequacy criterion (*i.e.*, the system LOLE is less than or equal to 0.1
6 days per year), additional resources are not required. However, if the system is
7 less reliable than the resource-adequacy criterion (*i.e.*, the system LOLE is greater
8 than 0.1 days per year), additional resources are needed to meet the criterion.
9 Once resources are at least adequate to meet the reliability criterion, the Installed
10 Capacity Requirement is determined by increasing loads (additional load carrying
11 capability or “ALCC”) so that New England’s LOLE is exactly at 0.1 days per
12 year. This is how the single number termed Installed Capacity Requirement is
13 established. The modeled New England system must meet the reliability
14 criterion. Under the condition in which New England is forecasted to be less
15 reliable than the resource-adequacy criterion, proxy resources are used within the
16 model to meet this additional need.

17
18 Proxy resources reflect the New England system’s average availability
19 characteristics and are determined based on the average availability and size of all
20 New England resources.² Specifically, each proxy resource has size and
21 availability characteristics such that when proxy resources are used in place of all
22 the resources assumed to be available to the system, the resulting LOLE is

² A presentation made to the Installed Capacity Working Group on this topic can be found at:
http://www.iso-ne.com/committees/comm_wkgrps/othr/icsp/mtrls/2006/apr132006/expansion_units.pdf

1 unchanged. The use of proxy resources for calculating the Installed Capacity
2 Requirement is a methodology that avoids discontinuities associated with the
3 addition of specific resources; this approach has been supported by New England
4 stakeholders since the establishment of a regional installed capacity/reserve
5 requirement in the 1970's and has been used in the Commission-approved ICR
6 calculations.

7
8 Once the annual system LOLE is calculated to be equal to or less than the
9 criterion, the Installed Capacity Requirement is determined based on the amount
10 of capacity resources needed to exactly meet the criterion using ALCC, as
11 discussed previously.

12

13 **Q: IS THIS THE SAME STAKEHOLDER PROCESS AND CALCULATION**
14 **METHODOLOGY PREVIOUSLY USED TO DETERMINE THE**
15 **INSTALLED CAPACITY REQUIREMENT IN NEW ENGLAND?**

16 **A.** Yes, the same stakeholder review process and calculation methodology (except
17 for the allocation of tie benefit contributions from the neighboring Control Areas)
18 for establishing the Installed Capacity Requirement for the 2010/2011 Capability
19 Year have been used to develop the New England Installed Capacity Requirement
20 for 2011/2012.

21

22

23

1 **Q: WHAT ARE THE MAIN ASSUMPTIONS UPON WHICH THE**
2 **INSTALLED CAPACITY REQUIREMENT VALUE FOR THE 2011/2012**
3 **CAPABILITY YEAR IS BASED?**

4 **A.** One of the first steps of the process in determining the Installed Capacity
5 Requirement is for the ISO to identify reasonable assumptions relating to
6 forecasted load, resources, and certain transmission limits for the 2011/2012
7 Capability Year. These assumptions include a weekly distribution of expected
8 daily peak loads; the available capacity resources; the expected performance of
9 these capacity resources (such as forced and scheduled outage rates); changes in
10 system resource capacity due to expected additions and attritions; and the amount
11 of load and/or capacity relief obtainable from certain actions of Operating
12 Procedure No. 4, Action During a Capacity Deficiency (“OP 4”), including the
13 amount of possible emergency assistance obtainable from New England’s
14 interconnections with neighboring Control Areas.

15
16 **Q: PLEASE IDENTIFY THE INSTALLED CAPACITY REQUIREMENT**
17 **VALUE ESTABLISHED BY THE ISO FOR THE 2011/2012 CAPABILITY**
18 **YEAR.**

19 **A.** The Installed Capacity Requirement value established by the ISO for the
20 2011/2012 Capability Year is 33,439 MW.

21
22
23

1 **Q: HAS THE AMOUNT OF TIE BENEFITS ASSUMED FOR ICR**
2 **CALCULATIONS CHANGED FROM YEAR TO YEAR?**

3

4 A. The amount of total tie benefits assumed for the 2010/2011 Capability Year is
5 1,860 MW as compared to the 1,800 MW assumed for the 2011/2012 Capability
6 Year. The decrease in total tie benefits for the 2011/2012 Capability Year is due
7 to an increase in the assumed capacity import over the HQ Phase II
8 interconnection, which was not modeled as such in the calculation of tie benefits
9 for the 2010/2011 Capability Year. While the change in total tie benefits is not
10 material, the change in tie benefits from individual directly connected neighboring
11 Control Areas is significant. The revised assumptions relating to tie benefits are
12 detailed later in this testimony.

13

14 **Q: WILL THE ISO PURCHASE 33,439 MW OF INSTALLED CAPACITY**
15 **FOR THE 2011/2012 CAPABILITY YEAR?**

16 A. No, the 33,439 MW does not reflect the treatment relating to HQICCs. After
17 counting the 911 MW of interconnection capability credit associated with
18 HQICCs, the net amount of installed capacity to be purchased for the 2011/2012
19 Capability Year would be 32,528 MW.

20

21

22

1 **Q: THE INSTALLED CAPACITY REQUIREMENT HAS DECREASED**
2 **COMPARED WITH THE INSTALLED CAPACITY REQUIREMENT**
3 **FOR THE 2010/2011 CAPABILITY YEAR. PLEASE EXPLAIN.**

4 **A.** The Installed Capacity Requirement and the net Installed Capacity Requirement
5 for the 2010/2011 Capability Year were 33,705 MW and 32,305 MW,
6 respectively. The decrease in the 2011/2012 Installed Capacity Requirement from
7 the 2010/2011 Installed Capacity Requirement is mainly due to the decrease in
8 capacity credits associated with the tie benefits afforded to the 2,000 MW (name
9 plate rating) direct-current, high-voltage transmission interconnection that
10 connects Quebec with the New England region. This decrease in capacity credit
11 has a direct impact on the amount of Installed Capacity Requirement for the region
12 because it is a direct add-on to the Installed Capacity Requirement. In the
13 2010/2011 Installed Capacity Requirement calculations, the HQICCs were assumed
14 to be 1,400 MW and in the 2011/2012 Installed Capacity Requirement calculations,
15 the HQICCs were assumed to be 911 MW. The reduction of HQICCs by 489 MW
16 decreases the Installed Capacity Requirement by the same amount if all else is
17 equal. In addition to the impact of lower HQICCs assumed for the 2011/2012
18 Capability Year, the load growth projection from the 2008 load forecast has also
19 decreased as compared to the load growth projections developed in 2007. Last
20 year's annual peak load forecast for the 2007 to 2016 period projected an annual
21 compound growth rate of 1.7 percent for the forecast period. For this year, the
22 annual peak load forecast for the 2008 to 2017 period projected an annual
23 compound growth rate of 1.2%. This lower projected growth rate translated into

1 approximately 150 MW of lower annual peak load growth for the 2011/2012
2 Capability Year as compared to last year's load forecast. This lower peak load
3 growth also contributed to a smaller increase in Installed Capacity Requirement
4 from one year to the next. Under the old forecast the increase was larger.
5 However, the net Installed Capacity Requirement of 32,528 MW for 2011/2012,
6 which reflects the HQICCs and represents the amount of capacity that needs to be
7 purchased in the second Forward Capacity Auction, is higher than the net Installed
8 Capacity Requirement of 32,305 MW for the 2010/2011 Capability Year.

9

10 **Q: PLEASE EXPLAIN HOW THE ISO DERIVED THE LOAD DATA USED**
11 **IN DEVELOPING THE INSTALLED CAPACITY REQUIREMENT AND**
12 **RELATED VALUES FOR THE 2011/2012 CAPABILITY YEAR.**

13 **A:** The ISO develops, for each state, a forecasted distribution of typical daily peak
14 loads for each week of the year based on each week's historical weather
15 distribution, and an econometrically estimated monthly (for summer) or seasonal
16 (for winter) model of typical daily peak loads. Each weekly distribution of typical
17 daily peak loads includes the full range of daily peaks that could occur over the
18 full range of weather experienced in that week and their associated probabilities.

19

20 The models, for each of the six New England states, were estimated using up to
21 15 years of weekday daily peaks, the weather conditions at the time of the daily
22 peak, a seasonal relationship that captures the change in peak load response to
23 weather over time, and a seasonal relationship that captures the change in peak

1 load response to base load energy (and therefore economic and demographic
2 factors) over time. The weather response relationships are forecasted to grow at
3 their historical rates but adjusted for expected changes in appliance saturations.
4 The base load relationships are forecasted to grow at the same rate as the energy
5 forecast. The weather is represented by over 35 years of historically-based
6 weekly weather.

7
8 The energy forecast, for each state, is econometrically estimated using forecasts
9 of the real price of electricity and either real income or real gross state product.

10

11 The New England Control Area's load is the sum of the six states' load. It is
12 important to know, however, that the Installed Capacity Requirement itself is not
13 a summation of single state Installed Capacity Requirements; rather, the
14 calculation is based on an analysis of the entire region; further, as noted earlier,
15 the Installed Capacity Requirement is not a summation of state values but, rather,
16 a regional projection of resource adequacy needs.

17

18 **Q: PLEASE DESCRIBE THE FORECASTED LOAD WITHIN LOAD ZONES**
19 **FOR THE 2011/2012 CAPABILITY YEAR.**

20 **A.** There are three Load Zones of interest for the 2011/2012 Capability Year. They
21 are the Connecticut and Northern Massachusetts/Boston ("NEMA/Boston") Load
22 Zones for Local Sourcing Requirement calculations and the Maine Load Zone for
23 Maximum Capacity Limit calculations. The forecasted loads for the Connecticut
24 and Maine Load Zones are the forecasted loads for the states of Connecticut and

1 Maine. The forecasted load for the NEMA/Boston Load Zone is developed using
2 a load share ratio of the NEMA/Boston load to the forecasted load for the entire
3 state of Massachusetts. The load share ratio is based on detailed bus load data
4 from the network model for NEMA/Boston as compared to all of Massachusetts.

5
6 **Q: PLEASE DESCRIBE THE PROJECTED PEAK LOADS FOR THE**
7 **2011/2012 CAPABILITY YEAR.**

8 **A.** The projected New England peak loads for the 2011/2012 Capability Year for
9 ICR calculations are represented by a probability distribution of New England's
10 non-holiday weekday daily peak loads for each week of the year. These weekly
11 distributions are represented in the Capacity Model with three parameters: the
12 expected value (mean), the standard deviation, and the skewness³ from the peak
13 load forecast model. While the mean represents the most likely value of the
14 weekly distributions, the standard deviation represents how widely spread the
15 values in the distribution are and the skewness is a measure of the asymmetry of
16 that distribution.

17
18 When applied to the load forecast, these three moments of the distribution are
19 used to model the most likely peak forecast (mean), the effect of weather
20 uncertainty (standard deviation), and the frequency of high loads not present in a
21 normal distribution (skewness). Monthly and seasonal peak loads are simply
22 points on these distribution curves. For example, both the 50/50 and the 90/10
23 summer peak load forecast values are points on the curve. These 50/50 and the

³ Skewness is represented in the model by the Third Cumulant which is Skewness*Standard Deviation³.

1 90/10 values are referenced for information purposes to facilitate any discussions
2 relating to the projected peak loads. The projected New England Control Area
3 50/50 peak load⁴ (summer) for the 2011/2012 Capability Year is 29,405 MW. The
4 corresponding 90/10 peak load⁵ for the 2011/2012 Capability Year is 31,525 MW.

5
6 **Q: PLEASE DESCRIBE THE TYPE OF RESOURCE DATA USED AS**
7 **INPUTS TO DEVELOP THE INSTALLED CAPACITY REQUIREMENT**
8 **AND RELATED VALUES FOR THE 2011/2012 CAPABILITY YEAR.**

9 **A.** The Installed Capacity Requirement and related values for the 2011/2012
10 Capability Year are based on ratings of Qualified Existing Capacity Resources
11 that have cleared the Forward Capacity Auction for the 2010/2011 Commitment
12 Period. In the Forward Capacity Market, capacity resources can be generation
13 (Generating Capacity or Intermittent Power Capacity), import resources or
14 demand resources (On-Peak, Seasonal Peak, Critical Peak, Real-Time Demand
15 Response and Real-Time Emergency Generation).⁶

16
17
18
19

⁴ The 50/50 peak refers to the peak load having a 50% chance of being exceeded, and is expected to occur at a weighted New England-wide temperature of 90.4 °F.

⁵ The 90/10 peak refers to the peak load having a 10% chance of being exceeded, and is expected to occur at a weighted New England-wide temperature of 94.2 °F.

⁶ For a detailed definition of these resources, please see Section III.1.3 of Market Rule 1, at: http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

1 **Q: WHAT ARE THE RESOURCE DATA RESULTS FOR EXISTING**
 2 **CAPACITY RESOURCES?**

3 **A.** The following tables show the assumed 34,811 MW of resources qualified as
 4 Existing Capacity Resources⁷ in the Installed Capacity Requirement calculations.

5 **Table 1 – Qualified Existing Generating Capacity by Load Zone (MW)**

Load Zone	Generation	
	Summer	Winter
MAINE	2,995.753	3,216.081
NEW HAMPSHIRE	3,994.957	4,172.503
VERMONT	918.882	968.365
CONNECTICUT	7,022.167	7,426.099
RHODE ISLAND	2,323.893	2,620.834
SOUTH EAST MASSACHUSETTS	6,052.625	6,540.417
WEST CENTRAL MASSACHUSETTS	3,867.045	4,150.674
NORTH EAST MASSACHUSETTS & BOSTON	3,251.688	3,698.884
Total New England	30,427.010	32,793.857

6
 7 **Table 2 – Qualified Existing Intermittent Power Resources by Load Zone (MW)**

Load Zone	Intermittent	
	Summer	Winter
MAINE	248.137	297.464
NEW HAMPSHIRE	119.698	146.124
VERMONT	66.403	113.522
CONNECTICUT	416.052	434.971
RHODE ISLAND	4.855	8.763
SOUTH EAST MASSACHUSETTS	80.523	86.151
WEST CENTRAL MASSACHUSETTS	36.591	59.308
NORTH EAST MASSACHUSETTS & BOSTON	67.385	70.751
Total New England	1,039.644	1,217.054

8
⁷ In a separate filing today, the ISO is submitting its Informational Filing for qualification in the second FCA for the 2011/2012 Capacity Commitment Period. There are some differences in the values that are used in each filing that reflect the amount of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources. These differences are caused by the fact that the ISO had to calculate the 2011/2012 Installed Capacity Requirement prior to the conclusion of the qualification process and therefore, assumptions regarding capacity resources were developed based upon information known at that time. Notwithstanding this difference, the Installed Capacity Requirement calculated using either set of numbers would be very similar.

1

Table 3 – Qualified Existing Demand Resources by Load Zone (MW)

Load Zone	On-Peak	Seasonal Peak	Critical Peak	RT Demand Response	RT Emergency Gen	Total
MAINE	22.81	-	105.29	163.55	35.02	326.6
NEW HAMPSHIRE	38.34	-	1.35	26.12	39.14	104.9
VERMONT	50.47	-	-	20.66	18.12	89.2
CONNECTICUT	74.52	120.45	14.47	240.42	300.20	750.0
RHODE ISLAND	39.89	-	5.35	36.72	93.08	175.0
SOUTH EAST MASSACHUSETTS	76.43	-	2.08	60.65	77.24	216.4
WEST CENTRAL MASSACHUSETTS	67.47	10.23	18.02	98.03	101.04	294.8
NORTH EAST MASSACHUSETTS & BOSTON	116.26	-	49.92	117.17	143.16	426.5
Total New England	486.20	130.69	196.49	763.31	807.00	2,383.6

2

3

Table 4 – Qualified Existing Import Resources and Know Sales (MW)

Name	Transmission Interface	Type	MW
NYPA - CMR	NY AC Ties	Import	68.800
NYPA - VT	NY AC Ties	Import	15.300
VJO - Highgate	Highgate	Import	225.000
VJO - Phase I/II	Phase II	Import	110.000
Erie Boulevard Hydropower - Import	NY AC Ties	Import	641.000
LIPA via Cross Sound Cable	Cross Sound Cable	Export	-100.000
Total			960.100

4

5

Please note that although capacity resource data are tabulated under the eight

6

Load Zones used for financial settlement purposes, only the Load Zones of

7

Connecticut, NEMA/Boston and Maine were considered for the FCM.

8

9 **Q:**

WHAT ARE THE DATA RESULTS FOR RESOURCE ADDITIONS AND ATTRITIONS?

10

11 **A.**

Resource additions and attritions are not assumed in the calculation of the Installed Capacity Requirement for the 2011/2012 Capability Year per Market Rule 1 because there is no certainty that new resource additions or existing resource attritions will clear the Forward Capacity Auction.

14

1 Not modeling undetermined resource additions and attritions will not have a
2 significant effect on the calculated Installed Capacity Requirement since the
3 availability characteristics and sizes of these resources are expected to be similar
4 to those of the Existing Resources. The proxy resource and the ALCC
5 adjustments, discussed previously, are designed to stabilize the Installed Capacity
6 Requirement and make it nearly irrelevant to whether these units are included.
7

8 **Q: PLEASE EXPLAIN THE RESOURCE AVAILABILITY ASSUMPTIONS**
9 **UNDERLYING THE INSTALLED CAPACITY REQUIREMENT AND**
10 **RELATED VALUES FOR THE 2011/2012 CAPABILITY YEAR.**

11 **A.** Unit availability modeling reflects the projected scheduled maintenance and
12 forced outages of the capacity resources. For Generating Resources, individual
13 unit scheduled maintenance assumptions are based on each unit's most recent
14 historical five-year average of scheduled maintenance. If the individual resource
15 has not been operational for five years, then North American Electric Reliability
16 Corporation ("NERC") class average data is used to substitute for the missing
17 annual data. An individual Generating Resource's forced outage assumptions are
18 based on the resource's most recent historical five-year average data from the
19 ISO's database and NERC average data for the same class of units, if the
20 individual resource has not been operational for five years.

21
22 The Qualified Capacity of an Intermittent Power Resource is the resource's actual
23 median output during the Reliability Hours averaged over a period of the most

1 recent five years. The Reliability Hours are specific defined hours during the
2 summer and the winter and hours in which the ISO has declared a system-wide or
3 a Load Zone specific shortage event. Since this method already takes into
4 account the resource's availability, these resources are assumed to be 100%
5 available in the models at their "Qualified Capacity" and not based on
6 "nameplate" ratings. "Qualified Capacity" is the amount of capacity a New
7 Capacity Resource, Existing Capacity Resource, Import Capacity Resource, or
8 Demand Resource may provide in the summer or winter in a Capacity
9 Commitment Period, as determined in the FCM qualification process.

10

11 Performance of Demand Resources in the Real-Time Demand Response, Critical
12 Peak and Real-Time Emergency Generator categories is measured by actual
13 response during all historical OP 4 events and performance audits. To calculate
14 historical availability, the actual load curtailed or generation provided during
15 such events is divided by the total amount (MW) of resources enrolled within
16 the program.

17

18 Demand Resources in the On-Peak Demand and Seasonal Peak Demand
19 categories are non-dispatchable resources that reduce load across pre-defined
20 hours, typically by means of energy efficiency. These types of Demand
21 Resources are assumed to be 100% available.

22

1 **Q: PLEASE EXPLAIN THE ROLE OF EXTERNAL TRANSMISSION**
2 **IMPORT TRANSFER CAPABILITIES IN DEVELOPING INSTALLED**
3 **CAPACITY REQUIREMENT AND RELATED VALUES FOR THE**
4 **2011/2012 CAPABILITY YEAR.**

5 **A.** External transmission import transfer capabilities are not an input to the Installed
6 Capacity Requirement calculations. However, they do impact the tie benefit
7 assumptions used in the Installed Capacity Requirement calculations. Tie benefits
8 represent the possible emergency energy assistance from the directly connected
9 neighboring Control Areas when a capacity shortage occurs. The external
10 transmission import transfer capabilities would impact the amount of emergency
11 energy, if available, that could be imported into New England. In modeling the
12 import transfer capabilities for tie benefits calculations, the total interface import
13 limit with each neighboring Control Area is adjusted to reflect grandfathered
14 Existing Import Capacity Resources. A grandfathered Existing Import Capacity
15 Resource is an existing capacity resource offered to provide capacity in the New
16 England Control Area from an external Control Area and recognized in ISO New
17 England Manual 20, Installed Capacity.⁸ The other use of the external transmission
18 import transfer capabilities in the FCM is to limit the amount of total capacity that
19 can be imported into New England from the neighboring Control Areas.

⁸ A copy of Manual 20 can be viewed at http://www.iso-ne.com/rules_proceeds/isone_mnls/M20/index.html.

1 **Q: PLEASE INDICATE THE EXTERNAL TRANSMISSION IMPORT**
2 **TRANSFER CAPABILITIES ASSUMED IN THE CALCULATION OF**
3 **THE INSTALLED CAPACITY REQUIREMENT AND RELATED**
4 **VALUES FOR THE 2011/12 CAPABILITY YEAR.**

5 A: The following table shows the import transfer capabilities assumed for calculating
6 tie benefits for 2011/2012.

7 **Table 5 - External Transmission Import Transfer Capability Limits (MW)**

Interface	Summer Limit	Winter Limit
Hydro-Québec to New England (Highgate)	200	200
Hydro-Québec to New England (Phase II)	1,400	1,400
New Brunswick to New England	1,000	1,000
New York to New England (AC Interface)	1,525	1,600
New York to New England (Cross Sound Cable DC Interface)	330	330

8
9

10 **Q: PLEASE DESCRIBE THE ROLE OF INTERNAL TRANSMISSION**
11 **INTERFACE TRANSFER CAPABILITIES IN DEVELOPING**
12 **INSTALLED CAPACITY REQUIREMENT AND RELATED VALUES**
13 **FOR THE 2011/12 CAPABILITY YEAR.**

14 A. Internal transmission interface transfer capabilities are not used to develop the
15 2011/2012 Capability Year Installed Capacity Requirement since the
16 methodology reflected in the market rule assumes internal transmission
17 constraints in New England are alleviated by Local Sourcing Requirements for
18 import-constrained Load Zones and Maximum Capacity Limit for export-
19 constrained Load Zones. Internal transmission interface import transfer
20 capabilities of 2,500 MW for the Connecticut and 4,900 MW for NEMA/Boston

1 Load Zones are used to calculate the Local Sourcing Requirements for these two
2 Load Zones. Internal transmission interface export transfer capabilities of 1,575
3 MW for the Maine Load Zone are used to calculate its Maximum Capacity Limit.

4

5 **Q: PLEASE DISCUSS THE ISO'S ASSUMPTIONS REGARDING OP 4**
6 **ACTIONS IN DEVELOPING THE INSTALLED CAPACITY**
7 **REQUIREMENT AND RELATED VALUES FOR THE 2011/2012**
8 **CAPABILITY YEAR.**

9 **A.** The New England resource planning reliability criterion requires that adequate
10 capacity resources be planned and installed such that disconnection of firm load
11 would not occur more often than once in 10 years due to a capacity deficiency
12 after taking into account the load and capacity relief obtainable from
13 implementing actions of OP 4. In other words, load and capacity relief assumed
14 obtainable from implementing OP 4 actions are direct substitutes for capacity
15 resources for meeting the once in 10 years disconnection of firm load criterion.
16 Therefore, OP 4 load and capacity relief assumed obtainable from calling on
17 emergency assistance (tie benefits) from neighboring control areas and
18 implementing voltage reductions are used in developing the Installed Capacity
19 Requirement for the 2011/2012 Capability Year.

20

21

22

23

1 **TIE BENEFITS**

2 **Q: PLEASE EXPLAIN TIE BENEFITS.**

3 **A.** Requesting emergency energy assistance from neighboring Control Areas (tie
4 benefits) is one of the actions of OP 4. Therefore, the amount of tie benefits
5 assumed obtainable from the interconnected neighboring Control Areas directly
6 displaces that amount of installed capacity resources needed to meet the resource
7 planning reliability criterion. When determining the amount of tie benefits to
8 assume in Installed Capacity Requirement calculations, it is necessary to
9 recognize that while reliance on tie benefits to reduce capacity resource needs can
10 reduce the Installed Capacity Requirement, over-reliance on tie benefits decreases
11 system reliability. System reliability would decrease since each time emergency
12 assistance is requested, there is a possibility that the available assistance will not
13 be sufficient to meet the capacity deficiency. The more tie benefits used to meet
14 the resource reliability criterion, and the greater the amount of assistance
15 requested, the greater the possibility that it will not be available or sufficient to
16 avoid implementing deeper actions of OP 4, including interrupting firm load. For
17 example, some of the resources that New York has available to provide tie
18 benefits are demand response resources which have limits on the number of times
19 they can be activated.

20

21

1 **Q: PLEASE DESCRIBE THE TIE BENEFITS ASSUMPTIONS**
2 **UNDERLYING THE INSTALLED CAPACITY REQUIREMENT AND**
3 **ASSOCIATED VALUES FOR THE 2011/2012 CAPABILITY YEAR.**

4 **A.** A total of 1,800 MW of tie benefits are assumed in the Installed Capacity
5 Requirement calculations for the 2011/2012 Capability Year. The breakdown of
6 this total value is as follows: 911 MW from Quebec, 716 MW from New
7 Brunswick (Maritimes) and 173 MW from New York. The total tie benefits
8 assumption was obtained from the results of a probabilistic study assuming that
9 New England and the three directly interconnected neighboring Control Areas of
10 Quebec, New Brunswick and New York are at their reliability criterion of one
11 disconnection of firm load in 10 years, enforced as 0.1 days per year.

12
13 **Q: PLEASE EXPLAIN THE ISO'S METHODOLOGY FOR DETERMINING**
14 **TOTAL TIE BENEFITS.**

15 **A.** The tie benefits study for the 2011/2012 Capability Year was conducted using the
16 probabilistic General Electric ("GE") Multi-area Reliability Simulation
17 ("MARS") program to model the expected system conditions of New England
18 and its directly interconnected neighboring Control Areas of Quebec, New
19 Brunswick and New York. All of these Control Areas were assumed to be "At-
20 Criteria," which means that the capacity of all of these interconnected Control
21 Areas was adjusted so that they would each have a LOLE of once in ten years (0.1
22 days per year LOLE). The "At-Criteria" approach was applied to represent the
23 expected amounts of capacity in each Control Area. While it is possible that a

1 Control Area may have more capacity available than the “At-Criteria” amount,
2 the “At-Criteria” approach provides the proper assumption to prevent an over-
3 estimate of available tie benefits since the exact system conditions of the
4 neighboring Control Areas are not known for the Capability Year 2011/2012.
5 However, it is reasonable to assume each Control Area should have minimum
6 installed capacity to meet the 0.1 days per year disconnection of firm load criterion.
7 Any amount of capacity above this minimum could be contracted to a third party
8 and become inaccessible to New England without any prior notice or warning.

9
10 Total tie benefits were calculated using the results of a probabilistic analysis that
11 determines LOLE indices for the New England system and surrounding Control
12 Areas. LOLE calculations were first done on an interconnected basis that
13 included all existing connections between New England’s directly connected
14 neighboring Control Areas. This established the minimum amount of capacity
15 that each area needed in order to attain the Northeast Power Coordinating Council
16 (“NPCC”) resource adequacy requirements of 0.1 days per year LOLE.

17
18 These LOLE calculations were then repeated with New England isolated from all
19 neighboring Control Areas, except for allowing the capability to import Existing
20 Import Capacity Resources. This was done by reducing the transfer capability of
21 the interconnections into New England to the point that they only allowed
22 modeled Existing Import Capacity Resources to flow with no remaining
23 transmission capability available.

1 Limiting the import capabilities of the external ties to only importing Existing
2 Import Capacity Resources effectively eliminates the tie benefits, causing the
3 calculated New England LOLE to increase. The tie benefits are quantified by
4 adding firm capacity resources within the isolated New England area until the
5 LOLE is returned back to 0.1 days per year. The amount of resources added to
6 return New England to a 0.1 days per year LOLE are called “firm capacity
7 equivalents” and are New England’s total tie benefits.

8

9 **Q: DOES THIS CALCULATION METHODOLOGY CONFORM WITH**
10 **INDUSTRY PRACTICE AND COMMISSION FILED MARKET RULES?**

11 **A.** Yes. This probabilistic calculation methodology is widely used by the electric
12 industry. Regional reliability councils such as the NPCC and the PJM have been
13 using the methodology for many years. The ISO has been using this specific
14 probabilistic calculation methodology based on GE MARS for tie benefits
15 calculations since 2002 and similar methodologies in previous years.

16

17 The ISO’s calculation methodology was reviewed and supported by NEPOOL
18 and state regulators through the Installed Capacity Requirement methodology
19 review stakeholder process. The calculation methodology was previously filed
20 with and approved by the Commission. Specifically, it conforms to the
21 Commission-approved Section III.12.9 of Market Rule 1, Standard Market Design
22 which states: “The ISO shall calculate tie benefits, using a probabilistic multi-area
23 reliability model. The method of calculating the tie benefits associated with the

1 interconnections between the New England Control Area and adjacent Control
2 Areas shall be based on the LOLE calculated before and after interconnecting the
3 New England Control Area to the surrounding Control Areas”

4

5 **Q. PLEASE DESCRIBE THE ALLOCATION METHODOLOGY USED TO**
6 **DETERMINE TIE BENEFITS FROM EACH OF NEW ENGLAND’S**
7 **NEIGHBORING CONTROL AREAS**

8 **A.** The allocation process used to calculate tie benefits from each of the New
9 England directly connected neighboring Control Areas is the same one which was
10 filed with the Commission in response to the Commission’s directives in its
11 December 10, 2007 order in Docket No. ER08-41-000.⁹

12

13 Under the allocation methodology filed with the Commission, tie benefits from
14 each Control Area would be calculated using the same GE MARS program with
15 “At Criteria” modeling assumptions that are used for calculating the total tie
16 benefits discussed above. Tie benefits for each of the three Control Areas would
17 be determined based on the LOLE calculated before and after removing import
18 capability, for importing emergency assistance, of the direct interconnections
19 between New England and the target Control Area. In other words, only the
20 import capability of the direct interconnections needed to import modeled
21 Existing Import Capacity Resources would remain. All additional import
22 capability would be removed. The change in New England LOLE value with and

⁹ *ISO New England Inc. and New England Power Pool Participants Committee*, 121 FERC ¶ 61,250 (2007), *reh’g denied*, 123 FERC ¶ 61,129 (2008).

1 without the transfer capability of the interconnections to import emergency
2 assistance from the target Control Area would represent the reliability
3 contribution of the target Control Area's emergency assistance. This reliability
4 contribution would be quantified in terms of equivalent capacity by identifying
5 the amount of firm capacity needed to bring the LOLE (when calculated without
6 connections to the target Control Area) to the same level it was at prior to removal
7 of the interconnections with the target Control Area. In the likely event the sum
8 of the Individually-Calculated Capacity Equivalents from each of the three
9 neighboring Control Areas does not exactly equal the total tie benefits calculated
10 using the multi-area reliability model, tie benefits from each Control Area will be
11 adjusted in a pro rata manner based on a ratio of the tie benefits from each
12 individual Control Area to the sum of the tie benefits from all Control Areas.

13

14 **Q: PLEASE EXPLAIN HYDRO-QUEBEC INTERCONNECTION**
15 **CAPABILITY CREDIT ("HQICC") VALUES**

16 **A.** HQICC values are credits in the form of reduced capacity requirements that are
17 allocated to the Interconnection Rights Holders, which are entities that hold
18 certain rights over the Hydro-Quebec Interconnection.

19

20

21

22

1 **Q: PLEASE INDICATE THE HQICC VALUES AND TIE BENEFITS FROM**
2 **NEW BRUNSWICK AND NEW YORK, FOR THE 2011/2012**
3 **CAPABILITY YEAR, AS CALCULATED USING THE RECENTLY**
4 **FILED TIE BENEFITS ALLOCATION METHODOLOGY.**

5 **A.** Using the recently-filed allocation methodology for allocating total tie benefits,
6 the HQICC values and the tie benefit values from New Brunswick and New York
7 are calculated to be 911 MW, 716 MW and 173 MW, respectively. These values
8 are annual values meaning that they are applicable for every month of the year.

9

10 **Q: EARLIER IN YOUR TESTIMONY YOU SHOWED THAT TRANSFER**
11 **CAPABILITY FROM NEW YORK AC TIES IS 1,525 MW AND FROM**
12 **NEW BRUNSWICK IS 1,000 MW; WHY ARE THE TIE BENEFITS**
13 **FROM NEW YORK SO MUCH LOWER THAN FROM NEW**
14 **BRUNSWICK?**

15

16 **A:** The reason the tie benefits from New York are so much lower than tie benefits
17 from New Brunswick is because New York, like New England, is a summer
18 peaking system. When New England experiences high loads, it is likely that New
19 York would also be experiencing high load . Such conditions would mean that
20 New York would meet its own needs first and then send any surplus capacity to
21 assist New England. On the other hand, New Brunswick (like Quebec) is a winter
22 peaking system. During the summer when New England experiences high loads,
23 New Brunswick's loads would be very low and their system would have much

1 more surplus capacity than New York, which could be sent to assist New England
2 in meeting its load.

3

4 **Q: RECENTLY, THE SECOND TIE CONNECTING MAINE AND NEW**
5 **BRUNSWICK (THE NORTHEAST RELIABILITY INTERCONNECT)**
6 **WAS PLACED IN SERVICE; DOES THIS INCREASE TIE BENEFITS**
7 **FOR THE REGION?**

8 A: Yes, the addition of the Northeast Reliability Interconnect not only has increased
9 transfer capability but also has contributed to the increase in tie benefits. In
10 calculating tie benefits for the 2010/2011 and 2011/2012 Capability Years, the
11 ISO has modeled the transmission import capability from New Brunswick to be
12 1,000 MW. The total tie benefits are in the 1,800 MW to 1,860 MW range. If the
13 transmission transfer capability from New Brunswick were to remain at 700 MW,
14 the total tie benefits would have ranged between 1,600 to 1,700 MW.

15

16 **LOCAL SOURCING REQUIREMENT FOR IMPORT-**
17 **CONSTRAINED LOAD ZONES AND MAXIMUM CAPACITY**
18 **LIMIT FOR EXPORT-CONSTRAINED LOAD ZONES**

19

20 **Q: WHAT ARE IMPORT-CONSTRAINED LOAD ZONES?**

21 A. Import-constrained Load Zones are areas within New England that may not have
22 adequate local resources and transmission import capability to reliably serve local
23 demand. The Load Zones to be modeled as import-constrained zones were
24 discussed as part of the stakeholder process and any change to the Load Zones
25 would be made in accordance with Section III.2.7(g) of Market Rule 1.

1 **Q: WHAT IS THE LOCAL SOURCING REQUIREMENT?**

2 **A.** The Local Sourcing Requirement is the minimum amount of capacity that must be
3 electrically located within an import-constrained Load Zone after taking into
4 consideration the amount of transfer capability into the zone from the rest of New
5 England. Market Rule 1, Section III.12.2 describes the calculation methodology.

6

7 **Q: WHAT ARE EXPORT-CONSTRAINED LOAD ZONES?**

8 **A.** Export-constrained Load Zones are areas within New England where the available
9 resources, after serving local load, may exceed the area's transmission capability
10 to export excess resource capacity. The Load Zones to be modeled as export-
11 constrained zones were discussed as part of the stakeholder process and any
12 change to the Load Zones would be made in accordance with Section III.2.7(g) of
13 Market Rule 1.

14

15 **Q: WHAT IS THE MAXIMUM CAPACITY LIMIT?**

16 **A.** The Maximum Capacity Limit is the maximum amount of resources that can be
17 procured from an export-constrained Load Zone to meet the Installed Capacity
18 Requirement. Generally speaking, this is the amount of capacity that can be used
19 to fully meet the needs within the export-constrained Load Zone plus that amount
20 which can be exported from the Load Zone to meet regional needs. The
21 Maximum Capacity Limit is applied to export-constrained Load Zones within
22 New England. It is a mechanism designed to limit the amount of capacity to be

1 procured in an export constrained area to avoid purchasing “bottled-in” capacity
2 that is unavailable to the rest of New England.

3

4 **Q: PLEASE DESCRIBE THE METHODOLOGY FOR CALCULATING THE**
5 **LOCAL SOURCING REQUIREMENTS.**

6 **A.** The Local Sourcing Requirements are calculated using the same assumptions of
7 forecasted load and resources as those used in the calculation of the Installed
8 Capacity Requirement. In order to determine the locational requirements of the
9 system, the Local Sourcing Requirements are calculated using a multi-area
10 reliability model. This multi-area model is configured based on an approximation
11 of the electrical topology of the system, as required by Section III.12.2. of Market
12 Rule 1. The electrical topology is determined based on the forecasted network
13 topology that is produced in advance of the calculation of the resource
14 requirements.

15

16 For each import-constrained zone, the Local Sourcing Requirement is determined
17 by modeling the zone under study vis-à-vis the rest of New England. This, in
18 effect, turns the modeling effort into a two-area reliability simulation. The
19 reliability target of this analysis is a system-wide LOLE of 0.105 days per year
20 when the transmission constraints between the two zones are included in the
21 model. Because the Local Sourcing Requirement is the minimum amount of
22 resources that must be electrically located in a zone to meet the system-reliability
23 requirements for a zone with excess capacity, the process to calculate this value

1 involves shifting capacity out of the zone under study until the reliability
2 threshold, or target LOLE, is achieved. If a zone has insufficient capacity, capacity
3 would be shifted into that zone. Shifting capacity, however, may lead to skewed
4 results, as capacity is not homogeneous. For example, one MW of capacity from a
5 nuclear plant is not necessarily the same as one MW of capacity from a wind
6 turbine in terms of their load carrying capability due to their expected forced outage
7 rates. Consequently, in order to model the effect of shifting capacity, firm load is
8 shifted. Specifically, as one MW of load is added to an import-constrained zone, a
9 MW of load is subtracted from the rest of New England, thus keeping the entire
10 system's load constant and the LOLE constant. If a zone has insufficient capacity,
11 load is shifted out of that import-constrained zone. This process continues until the
12 LOLE of the New England Control Area is equal to 0.105 days per year. At this
13 point, if additional capacity were to be shifted out of the zone (or additional load
14 were added), the LOLE criterion would not be met.

15
16 The Local Sourcing Requirement is calculated using the value of shifted load and
17 the existing resources in the zone. The load that was shifted must be subtracted
18 from the total resources (including proxy units, if any) to determine the minimum
19 amount of resources that are required in that zone. Before the shifted load is
20 subtracted, it is first converted to equivalent capacity by using the average resource-
21 unavailability rate in the zone. Thus, the Local Sourcing Requirement is the
22 existing resources in the zone, minus the unavailability-adjusted, load-shift amount.

23

1 As this load shift test is being performed over a transmission interface internal to
2 the New England Control Area, an allowance for transmission-related LOLE must
3 be applied. An LOLE of 0.105 days per year is the point at which it becomes
4 clear that the resources within the zone under study are becoming sufficient.
5 Further reduction in local sources would cause the LOLE in New England to
6 rapidly increase above the criterion.

7

8 **Q: PLEASE DESCRIBE THE METHODOLOGY FOR CALCULATING THE**
9 **MAXIMUM CAPACITY LIMIT.**

10 **A.** Another aspect of the FCM is a method to model export-constrained zones.
11 Because of transmission constraints out of these zones, not all potentially available
12 resources can simultaneously supply capacity to the export-constrained zone and to
13 the “Rest of New England.” Rest of New England refers to all areas except the
14 export-constrained Load Zone under study. Export-constrained zones are
15 incorporated into the FCM through the calculation of the Maximum Capacity Limit.

16

17 In order to determine the Maximum Capacity Limit, the New England total Installed
18 Capacity Requirement and the Local Sourcing Requirements of the Rest of New
19 England are needed. Given that the Installed Capacity Requirement is the total
20 amount of resources that need to be purchased in New England, and the Local
21 Sourcing Requirement for the Rest of New England is the minimum amount of
22 resources required for that area to satisfy its reliability criterion, the difference

1 between the two is the maximum amount of resources that can be purchased within
2 the export-constrained zone without purchasing “bottled-up” capacity.

3

4 **Q: PLEASE DESCRIBE THE LOCAL SOURCING REQUIREMENTS FOR**
5 **THE 2011/2012 CAPABILITY YEAR.**

6 **A.** The 2011/2012 Capability Year Local Sourcing Requirements for the Connecticut
7 and NEMA/Boston Load Zones are 6,817 MW and 2,016 MW, respectively.

8

9 **Q: PLEASE DESCRIBE THE MAXIMUM CAPACITY LIMIT FOR THE**
10 **MAINE LOAD ZONE FOR THE 2010/11 CAPABILITY YEAR.**

11 **A.** The Maximum Capacity Limit for the Maine Load Zone for the 2011/2012
12 Capability Year is 3,395 MW. This is the amount of capacity resources that the
13 second Forward Capacity Auction can procure from the Maine Capacity Zone,
14 including capacity resource imports from the New Brunswick ties.

15

16 **Q: FOR THE 2010-2011 CAPABILITY YEAR THE MAXIMUM**
17 **CAPACITY LIMIT FOR MAINE WAS 3,855 MW; WHY HAS THIS**
18 **VALUE DECREASED SO SIGNIFICANTLY FOR 2011/2012**
19 **CAPABILITY YEAR?**

20 **A:** The main reason for the decrease is due to the increase in the assumed tie benefits
21 from New Brunswick for the 2011/2012 Capability Year. Since the transmission
22 interface transfer capability is allocated using tie benefits first and then capacity
23 resources second in meeting New England regional Installed Capacity

1 Requirements, the 356 MW increase in tie benefits from New Brunswick would
2 result in a corresponding decrease in the amount of capacity in Maine that could
3 be used to contribute toward meeting the New England resource needs, if all else
4 is equal.

5
6 **Q: WILL THIS MATERIAL CHANGE IN THE MAXIMUM CAPACITY**
7 **LIMIT FOR MAINE HAVE CONSEQUENCES IN THE SECOND FCA?**

8 A: There is a significant possibility that it will. The total existing resources in Maine
9 are 3623 MW – and there are 509 MW of qualified New Capacity Resources
10 located in Maine of which 444 have submitted an offer below 0.75 time CONE.
11 These resources will be competing to fill the 3,395 MW limit for Maine.
12 Assuming that imports are maximized and that market participants do not seek to
13 de-list any resources during the auction, Maine’s resource owners will need to
14 elect either to keep their full Capacity Supply Obligation and receive reduced
15 payment, or pro-rate their Capacity Supply Obligation and keep the Capacity
16 Clearing Price. Further, if the Rest of Pool Capacity Zone also has excess
17 capacity, a similar election will need to be made there as well. Thus, Maine’s
18 resources could be subject to a so-called double pro rationing election which
19 would make Maine’s capacity price lower on a per megawatt basis than the price
20 in the Rest of Pool Capacity Zone.

21

22

1 **Q: DOES ALL THIS MEAN THAT THERE IS SIGNIFICANT**
2 **CONGESTION COMING OUT OF MAINE?**

3 A: The existence of a Maximum Capacity Limit to cap the amount of resources
4 electrically located in the Maine Load Zone toward meeting the New England
5 Installed Capacity Requirements does not necessarily translate to having
6 significant congestion coming out of Maine. Generally, congestion is discussed
7 with respect to energy flows, which is a function of energy prices, from a certain
8 region. Historically, there has been relatively little such congestion coming out of
9 Maine. When computing the Installed Capacity Requirement and Maximum
10 Capacity Limit however, we are dealing with a different problem – the ability of
11 the region to rely on all the resources (energy prices would have minimum or no
12 impact during such conditions because every resource would be needed) at peak
13 conditions. If the amount of capacity purchased from Maine is higher than the
14 transferability of the transmission system, after accounting for tie benefits, then
15 this capacity would be locked in and the region would not be able to use it to meet
16 the load.

17

18

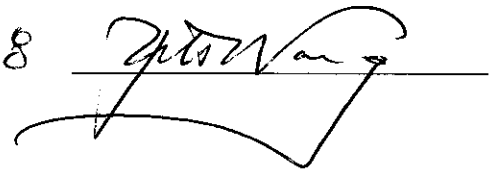
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Q: Does this conclude your testimony?

A: Yes.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on: SEPTEMBER 9, 2008 

ATTACHMENT 2

Testimony of Peter K. Wong in Docket No. ER08-41-002

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

**ISO New England Inc. and) Docket No. ER08-41-___
New England Power Pool)**

TESTIMONY OF PETER K. WONG

1 **I. INTRODUCTION**

2 ***Q. Please state your name, title and business address.***

3 **A.** My name is Peter K. Wong. I am the Manager of Resource Adequacy with ISO New
4 England Inc. (the “ISO”). My business address is One Sullivan Road, Holyoke,
5 Massachusetts 01040.

6
7 ***Q. Please describe your qualifications and relevant experience within the energy***
8 ***industry.***

9 **A.** I have worked with the New England Power Pool (“NEPOOL”) and the ISO for more
10 than 33 years. I have been the Manager of Resource Adequacy for the ISO since
11 1999. Before that I served for about seven years as the Manager of Operations
12 Planning & Analysis for the staff of the New England Power Exchange (“NEPEX”),
13 the operating arm of NEPOOL, and for the ISO after the staff of NEPEX was
14 transferred to the ISO. I also held various positions in the Power Supply Planning
15 department of New England Power Planning (“NEPLAN”), the planning arm of
16 NEPOOL. My last position at NEPLAN was Manager of Power Supply Planning.
17 During my 15 years in Power Supply Planning at NEPLAN, I was involved in all

1 matters related to NEPOOL Objective Capability (currently referred to as Installed
2 Capacity Requirements) and resource adequacy. I hold a Bachelor of Science degree
3 in Electrical Engineering and a Master of Business Administration degree.

4
5 ***Q. Please describe how your responsibilities relate to the proposed changes to Market
6 Rule 1 to modify the methodology used to calculate tie benefits.***

7 **A.** As the Manager of Resource Adequacy, I have oversight of the resource adequacy
8 planning activities of the ISO. These activities include the calculation of Installed
9 Capacity Requirements (“ICR”), Local Sourcing Requirements (“LSR”), Maximum
10 Capacity Limits (“MCL”) and tie benefits for the New England wholesale electricity
11 market, as well as the development of assumptions and methodologies used for
12 performing these calculations. Currently, I also serve as the Chairman of the
13 NEPOOL Power Supply Planning Committee (“PSPC”), which is the NEPOOL
14 technical committee charged with the review of the current tie benefits calculation
15 and allocation methodologies for use in calculating the Installed Capacity
16 Requirements, Local Sourcing Requirements, Maximum Capacity Limits and other
17 resource adequacy studies.

18
19 ***Q. Please provide an overview of your testimony.***

20 **A.** My testimony supports proposed changes to Market Rule 1 concerning the
21 methodologies for calculating and allocating tie benefits with neighboring Control
22 Areas. These proposed changes are the result of a six-month stakeholder review, in
23 which stakeholders in the New England wholesale electricity market identified and

1 evaluated four methodologies for calculating and allocating tie benefits. This review
2 process was undertaken at the instruction of the Commission in its December 10,
3 2007 Order in Docket No. ER08-41-000. In that order, the Commission ruled upon
4 the ISO's proposed values for the ICR, LSR, MCL, Hydro-Quebec Interconnection
5 Capability Credits ("HQICCs") and tie benefits for the 2010/2011 Capacity
6 Commitment Period. (The 2010/2011 Capability Commitment Period is the same as
7 the 2010/2011 Capability Year. It starts on June 1, 2010 and ends on May 31, 2011.)
8 While the Commission accepted the ISO's proposed values, it also noted the
9 considerable issues identified during stakeholder review of the calculations of the
10 Installed Capability Requirement and associated values for 2010/2011. In particular,
11 stakeholders raised questions regarding the continued use of a deterministic
12 calculation methodology for calculating HQICC values, and the tie benefit allocation
13 methodology that deducts the full value of the HQICCs for allocation as tie benefits
14 from Quebec, and allocates the remainder as tie benefits from New Brunswick and
15 New York. The Commission directed the ISO to undertake a stakeholder process to
16 review these methodologies and determine whether changes are necessary in light of
17 the implementation of the Forward Capacity Market.

18 The stakeholder process culminated in a vote by the NEPOOL Reliability
19 Committee and the NEPOOL Participants Committee in support of a proposal to
20 maintain the current methodology for calculating total tie benefits with the three
21 directly interconnected neighboring Control Areas—New Brunswick, New York and
22 Quebec—and to revise the methodology for allocating total tie benefits from among
23 these three Control Areas. The proposal would replace the current practice of using a

1 deterministic approach to calculate tie benefits for Quebec and a probabilistic
2 approach to calculate and allocate tie benefits from New Brunswick and New York
3 with an approach that allocates tie benefits from all three directly interconnected
4 neighboring control areas based solely on the results of a probabilistic calculation of
5 tie benefits from each Control Area.

6

7 **II. BACKGROUND**

8 ***Q. What are tie benefits?***

- 9 **A.** The New England resource planning reliability criteria require that adequate capacity
10 resources be planned and available such that disconnection of firm load would not
11 occur more often than once in 10 years due to a capacity deficiency (referred to as
12 having a Loss of Load Expectation, or “LOLE,” of no greater than once in 10 years or
13 0.1 days per year) after taking into account the following:
- 14 a. The possibility that load forecasts may be exceeded as a result of weather
15 variations.
 - 16
 - 17 b. Immature and mature equivalent forced outage rates appropriate for generating
18 units of various sizes and types, recognizing partial and full outages.
 - 19
 - 20 c. Due allowance for scheduled outages and deratings.
 - 21
 - 22 d. Seasonal adjustment of resource capability.
 - 23
 - 24 e. Proper maintenance requirements.
 - 25
 - 26 f. Available operating procedures. (For example, the ISO takes into account load
27 and capacity relief from implementing ISO New England Operating Procedure
28 No. 4, Action During a Capacity Deficiency, in determining resources needed to
29 meet the once in ten years LOLE.)
 - 30

1 g. The reliability benefits of interconnections with systems that are not participants
2 in the New England wholesale electricity market.

3

4 h. Such other factors as may from time to time, be appropriate.

5

6 Item g. above, “The reliability benefits of interconnections with systems that
7 are not participants in the New England wholesale electricity market,” refers to the tie
8 benefits from direct interconnections with neighboring Control Areas, which are
9 treated as direct substitutes for capacity resources for meeting the once in 10 years
10 disconnection of firm load criterion. Tie benefits are the quantification in MW of the
11 *emergency assistance* assumed to be obtainable by New England from neighboring
12 Control Areas.

13 The amount of tie benefits assumed obtainable from the directly
14 interconnected neighboring Control Areas displaces approximately the same amount
15 of installed capacity resources needed by New England to meet its resource planning
16 reliability criterion. When determining the amount of tie benefits to assume in ICR
17 calculations, it is necessary to recognize that while reliance on tie benefits can reduce
18 capacity resource needs, over-reliance on tie benefits decreases system reliability.
19 System reliability decreases because each time New England requests emergency
20 assistance there is a possibility that the available assistance will not be sufficient to
21 meet the capacity deficiency. The more tie benefits used to meet the resource
22 reliability criterion, and the greater the amount of assistance requested, the greater the
23 possibility that it will not be available or sufficient to avoid implementing other
24 operator actions, including interrupting firm load to mitigate the capacity shortage
25 and preserve the integrity of the interconnected bulk power system.

1 ***Q.*** *Please explain the ISO’s current methodology for calculating total tie benefits.*

2 **A.** Under current market rules, tie benefits are calculated for New England’s
3 interconnections with its three directly interconnected neighboring Control Areas of
4 Quebec, the Canadian Maritime provinces (New Brunswick) and New York. The tie
5 benefits calculation is conducted using the probabilistic General Electric Multi-area
6 Reliability Simulation (“GE MARS”) program to model the expected system
7 conditions of New England and its three directly interconnected neighboring Control
8 Areas using a Monte Carlo simulation approach. This approach contrasts with a
9 “deterministic” approach, which I discuss in more detail below. For purposes of
10 calculating New England’s tie benefits, all the interconnected Control Areas are
11 assumed to be “At Criteria,” which means that the capacity of each interconnected
12 Control Area is adjusted so that each will have a LOLE of once in ten years (0.1 days
13 per year LOLE) simultaneously. This is done to approximate the planning process
14 that each Control Area will undertake in determining the amount of resources the
15 respective area will need. One exception to this methodology applies: When
16 calculating the ICR, LSR and MCL for the annual reconfiguration auction that
17 immediately precedes the Capacity Commitment Period, “As Is” modeling
18 assumptions are employed, rather than “At Criteria” modeling assumptions.

19 Under Section III.12.9 of Market Rule 1, the ISO calculates the total tie
20 benefits using the GE MARS program with “At Criteria” modeling assumptions to
21 determine the LOLE value for the New England system and the three neighboring
22 Control Areas simultaneously. The ISO first performs the LOLE calculations on an
23 interconnected basis with the three directly interconnected neighboring Control

1 Areas. This calculation establishes the minimum amount of capacity that each of the
2 Control Areas needs in order to attain the resource adequacy requirement of 0.1 days
3 per year LOLE simultaneously. The ISO then repeats the LOLE calculations with
4 New England isolated from all neighboring Control Areas, with the exception of
5 maintaining the capability to import grandfathered existing import capacity resources.
6 To accomplish this, transmission capability over interconnecting ties is reduced to the
7 point where there is only enough capability for modeled existing import capacity
8 resources to flow, so that there is no transmission capability remaining to support tie
9 benefits. Limiting the import capabilities of the external ties to existing import
10 capacity resources effectively eliminates the tie benefits, causing the calculated New
11 England LOLE to increase. The ISO then quantifies tie benefits by adding firm
12 capacity resources within the isolated New England Control Area until the LOLE is
13 returned back to 0.1 days per year. The amount of resources added to return New
14 England to 0.1 days per year LOLE are called “firm capacity equivalents” and
15 constitute New England’s total tie benefits.

16
17 ***Q. Why is the “At Criteria” modeling assumption used to calculate tie benefits?***

18 **A.** The “At Criteria” modeling assumption provides a reasonable estimation of the
19 expected amount of emergency assistance that may be available from each directly
20 interconnected neighboring Control Area. While it is possible that a Control Area
21 may have more or less capacity available than the amount that is calculated under “At
22 Criteria” assumptions, the “At Criteria” approach provides a reasonable
23 approximation of the amount of installed capacity available in the Control Area for

1 which the tie benefits evaluation is performed, and helps to prevent overestimating or
2 underestimating available tie benefits. This approach does not rely on assumptions
3 about exact system conditions of the neighboring Control Areas, which are often
4 difficult to know so far in advance of a Capacity Commitment Period, since tie
5 benefit calculations may be conducted up to three to four years prior to the Capability
6 Commitment Period. Instead, using the “At Criteria” approach, it is assumed that, at
7 a minimum, each Control Area will have adequate installed capacity to meet the once
8 in 10 years disconnection of firm load criterion.

9

10 ***Q. When did the ISO start to use the probabilistic simulation methodology for***
11 ***calculating tie benefits?***

12 **A.** The ISO has always used a probabilistic simulation methodology for calculating tie
13 benefits. In the past, due to computer program limitations, the ISO could not model
14 all the directly interconnected neighboring Control Areas simultaneously in a single
15 simulation to obtain total tie benefit results. The tie benefits calculation program only
16 allowed modeling two Control Areas at a time. Therefore, multiple simulations using
17 a round robin process were used to develop tie benefits from directly interconnected
18 neighboring Control Areas. In 2002, the ISO began to use the GE MARS program,
19 which has the capability to simulate multiple interconnected Control Areas and
20 determine the resource adequacy of all those Control Areas simultaneously using a
21 Monte Carlo simulation approach.

1 **Q.** *Does this methodology for calculating total tie benefits conform with industry*
2 *practice?*

3 **A.** Yes, the probabilistic calculation methodology employed by the ISO is widely used
4 by the electric industry for purposes of calculating tie benefits. Regional reliability
5 councils such as the NPCC and ISO/RTOs such as the New York ISO and PJM
6 Interconnections are using this probabilistic calculation approach. As a matter of fact,
7 these organizations also use the GE MARS program to calculate tie benefits.

8
9 **Q.** *What is the ISO's methodology for allocating tie benefits to individual*
10 *interconnected neighboring control areas?*

11 **A.** Once the total tie benefits value for a Capacity Commitment Period has been
12 established as set forth above, the amount of tie benefits from each of New England's
13 directly interconnected neighboring Control Areas must then be allocated based on
14 the total tie benefits value. The results of this allocation are used in the modeling of
15 LSRs and MCLs, and to limit the amount of capacity that may be purchased over
16 each tie in a Forward Capacity Auction. Thus, the amount of capacity imports that
17 can be purchased from a Control Area in a Forward Capacity Auction is limited by
18 the transfer capability of the interconnection(s) between that Control Area and New
19 England *after* reflecting the reduction in transfer capability that is necessary to
20 support the emergency assistance that is assumed available in the form of tie benefits.

21 Under Sections 12.9.1 and 12.9.2 of Market Rule 1, neighboring Control Area
22 tie benefit contributions are allocated first to Quebec by deducting the full amount of

1 the HQICCs from the total tie benefits value calculated from all neighboring Control
2 Areas. HQICCs are capacity credits allocated to the Interconnection Rights Holders
3 that hold certain rights over the 2000 MW HQ Phase I/II HVDC-TF (the “HQ
4 Interconnection”). Under the rules currently in effect, HQICCs are calculated using a
5 deterministic methodology that employs forecasted load and capacity for the Quebec
6 Control Area and the assumed HQ Interconnection transfer limit.

7 Once tie benefit contributions equal to the HQICCs are allocated to Quebec,
8 the remaining tie benefit contributions are allocated to New Brunswick and New
9 York on a pro rated basis. First, tie benefits from each of New Brunswick and New
10 York are calculated using the GE MARS program with “At Criteria” modeling
11 assumptions that are used for calculating total tie benefits from all three directly
12 interconnection Control Areas simultaneously. Similar to the calculation of total tie
13 benefits, a probabilistic analysis is first performed to determine the LOLE for the
14 New England system with all three directly interconnected Control Areas connected
15 to New England. However, for purposes of calculating the tie benefits from each
16 Control Area individually, the LOLE analysis is repeated with only the
17 interconnections from *one* of the three directly interconnected neighboring Control
18 Areas removed, with this same step being repeated for both New Brunswick and New
19 York to establish two separate LOLE calculations for New England with each of
20 these two target Control Areas disconnected. The change in the New England
21 LOLEs, with and without the interconnections with the target Control Area (in this
22 case, New Brunswick or New York), represents the reliability contribution of the
23 target Control Area’s emergency assistance. This reliability contribution is quantified

1 in terms of equivalent capacity by identifying the amount of firm capacity needed to
2 bring the two LOLE values to the same level they were at prior to removal of the
3 interconnections with the target Control Area. For convenience, I refer to these
4 capacity equivalents as the “Individually-Calculated Capacity Equivalents” below, to
5 distinguish them from the total, or gross, tie benefit value that is calculated for all
6 three directly interconnected neighboring Control Areas by comparing the LOLE for
7 New England with these three Control Areas all connected to the LOLE for New
8 England with the three Control Areas disconnected simultaneously (which is
9 described above).

10 In all probability, the resulting reliability contribution from the New
11 Brunswick and New York Control Areas (quantified as the Individually-Calculated
12 Capacity Equivalents), when combined with the HQICC value, will not equal the total
13 tie benefits calculated for all Control Areas simultaneously. This is because, in
14 establishing the LOLE for New England with only a single Control Area (either New
15 Brunswick or New York) disconnected for purposes of calculating the Individually-
16 Calculated Capacity Equivalents, a number of assumptions are made about the impact
17 of the interconnections with the other two Control Areas (assumptions that do not
18 apply in calculating total tie benefits by disconnecting all three Control Areas
19 simultaneously). For example, in the simulations used for calculating total tie
20 benefits for all three control areas simultaneously, New England is isolated from all
21 the Control Areas, reflecting the removal of *all* emergency assistance available to
22 New England. Alternatively, in the simulations used for calculating the Individually-
23 Calculated Capacity Equivalents, only the direct interconnection(s) between New

1 England and the target Control Area are removed. As a result, the possibility remains
2 that capacity will reach New England from the target Control Area via other
3 interconnected paths. In this event, the LOLE value for New England modeled with
4 only the target Control Area disconnected from New England would be lower than if
5 all the resources from the target Control Area were not able to reach New England,
6 and this would, in turn translate into a lower Individually-Calculated Capacity
7 Equivalent value.

8 As a result, Individually-Calculated Capacity Equivalents for New Brunswick
9 and New York are used to establish a *ratio* for allocating tie benefit contributions to
10 New Brunswick and New York. First, the HQICC value is removed from the total tie
11 benefits (calculated for all three Control Areas simultaneously) to establish the
12 remaining tie benefit contributions to be allocated to New Brunswick and New York.
13 Second, that remaining tie benefit contribution value is allocated between New
14 Brunswick and New York based on the ratio of the Individually-Calculated Capacity
15 Equivalents for the target Control Area to the sum of the Individually-Calculated
16 Capacity Equivalents for the two Control Areas.

17 This approach to developing individual Control Area tie benefits from the
18 total tie benefits is the same methodology that has been used for the last four years in
19 calculating the Commission-approved Installed Capacity Requirements for the
20 Capability Years 2005/2006 through 2008/2009.

1 ***Q.*** *Please explain how HQICCs are calculated and how that calculation is translated*
2 *into the allocation of tie benefits for Quebec.*

3 **A.** The HQICC values are developed through the Installed Capacity Requirement
4 stakeholder process using the Commission-approved deterministic calculation
5 methodology reflected in Section 12.9.2 of Market Rule 1. The HQICC values are
6 intended to reflect the amount of emergency assistance (tie benefits) available on a
7 monthly basis over the HQ Interconnection. The HQICC values are based on the
8 ISO’s evaluation of the monthly Capacity Potentially Available for Sales (“CPAS”)
9 from Quebec, based on a deterministic evaluation of the projected capacity situation
10 in Quebec during the relevant Capacity Commitment Period for which the HQICC
11 values are being calculated.

12 To calculate CPAS using the deterministic methodology, the ISO collects
13 forecasted monthly load and capacity data for the Quebec Control Area in order to
14 assess expected system conditions during the applicable time period. The ISO
15 informs the stakeholders of these assumptions for developing HQICC values as a part
16 of the stakeholder process during meetings of the PSPC. The following bulleted
17 information describes the data that is received from Quebec and the assumptions used
18 to develop CPAS.

- 19 • Installed Capacity (InstCap) – The total monthly installed capacity (MW) and
20 a breakdown by unit type as obtained from Hydro-Quebec.
- 21 • Scheduled Maintenance (Maint) – The total monthly scheduled generator
22 outages (MW) and restrictions (i.e. water restrictions) as obtained from
23 Quebec.

- 1 • Forced Outage Amounts (FO) – Monthly forced outage rates by unit type in
2 percentage and MW amounts as obtained from Quebec. The sum of the unit
3 type forced outages in MW is used in calculating CPAS.
- 4 • Purchases (Purch) and Sale (Sales) – Firm purchases and sales data (MW) as
5 received from Quebec. The purchases and sales data are aggregated to
6 determine the total purchases and total sales into/from the area and used in
7 calculating CPAS.
- 8 • Forecasted Load (Mpeak) – The monthly forecasted load (MW) is provided
9 by Quebec and includes low, medium, and high forecasts. The peak load
10 exposure approach, used by the ISO for operable capacity analyses of the New
11 England Control Area, is applied for the months of December, January, and
12 February. In addition, consistent with the assumption used in the
13 development of prior HQICC values, the high load forecast is used. This peak
14 load exposure approach assumes that the annual peak load could occur during
15 any month of the peak load season.
- 16 • Operating Reserve Requirements (OpRes) – Monthly 30-minute, 10-minute,
17 and spinning reserve requirements (MW) are received from Quebec for its
18 Control Area. The value used in the calculation of CPAS is equal to the sum
19 of the 30-minute and 10-minute requirements.

20 Using the data described above, the ISO calculated monthly CPAS in MW
21 using the following formula:

$$22 \quad \text{CPAS} = (\text{InstCap}) - (\text{Maint}) - (\text{FO}) + (\text{Purch}) - (\text{Sales}) - (\text{Mpeak}) - (\text{OpRes})$$

1 The formula does not reflect internal transmission constraints, if any, or the impact of
2 expected reservoir levels in the Quebec Control Area.

3 Based on its calculations of CPAS, the ISO determines the amount of monthly
4 surplus capacity in the Quebec Control Area for the Capacity Commitment Period,
5 and that monthly surplus capacity value constitutes the HQICC or tie benefits value
6 for the corresponding month of the period in question. The HQICC value associated
7 with the month of the New England annual 50/50 peak is used for reference purposes
8 when discussing HQICCs or tie benefits.

9

10 ***Q. What is the difference between using a deterministic versus a probabilistic***
11 ***methodology to calculate tie benefits?***

12 **A.** Total tie benefits, similar to the Installed Capacity Requirement, are calculated
13 probabilistically, though an estimate can be made using a deterministic approach that
14 has no explicit confidence interval around it. A deterministic approach to calculating
15 tie benefits uses specific defined system conditions to provide an answer for a
16 particular problem. The result is that the calculation depends solely on a model of a
17 Control Area, which is based upon one possible state of the world to represent the
18 typical outcome for a large range of possible future conditions. This approach
19 ignores the existence of many unknown or unknowable future conditions,
20 disturbances (variations) or external “shocks” that will determine future conditions.
21 For calculations of tie benefits, these unknown future conditions, disturbances and
22 external shocks include, but are not limited to, load growth uncertainty, resource
23 performance uncertainty and expected transmission constraints. Using a deterministic

1 approach to project tie benefits decreases the chance that the results are representative
2 of the many possible outcomes. As a result, there is a much smaller probability that
3 tie benefits calculated deterministically will reasonably approximate the outcome than
4 is the case with tie benefits calculated using a probabilistic approach that employs a
5 Monte Carlo simulation.

6 A probabilistic approach with Monte Carlo simulations produces better
7 expected results because they capture the uncertainties associated with the demand
8 and resource availability that a deterministic approach does not capture. A Monte
9 Carlo simulation is a probabilistic approach based on thousands of scenarios that each
10 represents an explicit deterministic calculation of the possible outcome. In other
11 words, the Monte Carlo simulation derives the expected outcome by capturing all of
12 the possible deterministic calculations of combinations of uncertainties relating to
13 load and capacity resource availability that form a probabilistic approach.

14

15 **III. CONCERNS WITH THE CURRENT ALLOCATION METHODOLOGY**

16 ***Q. You noted above that there is dissatisfaction with the use of the deterministic***
17 ***calculation methodology for establishing HQICCs. Could you please explain these***
18 ***issues?***

19 **A.** Concerns have been raised by both stakeholders and the ISO regarding use of the
20 deterministic calculation methodology for calculating HQICCs or tie benefits from
21 Quebec. For the Forward Capacity Market, the calculation of HQICCs using the
22 deterministic methodology relies upon extrapolations of capacity and load data from
23 Quebec up to three to four years into the future. Concerns have been raised with the

1 use of a methodology that relies upon fixed load and capacity projections up to three
2 to four years in advance of the actual Capacity Commitment Period and with treating
3 the results as a certainty, given the potential difficulties in developing accurate
4 forecasts. It has also been noted that in calculating HQICCs using a deterministic
5 method and then allocating the entire HQICC value to tie benefits from Quebec, the
6 ISO assumes that all Quebec capacity reflected in the HQICC value will be available
7 for New England's use in the event of an emergency. It has been argued that this
8 assumption ignores that in many instances the circumstances causing the need for
9 emergency assistance in New England are likely to occur in other neighboring
10 Control Areas as well, and that those Control Areas will also be relying on Quebec
11 for emergency assistance.

12 Concerns have also been raised that the deterministic approach ignores New
13 England's relative need for emergency assistance under certain scenarios. Thus, it
14 has been argued that the deterministic calculation focuses solely on the amount of
15 capacity potentially available for sales in Quebec and disregards whether New
16 England actually needs that capacity. Ignoring New England's need for emergency
17 assistance could overstate the tie benefits from Quebec. In addition, concerns have
18 been expressed with using an outcome-based deterministic calculation methodology,
19 on grounds that the assumptions used for the calculation during the winter months of
20 December through February are too conservative and therefore result in lower tie
21 benefits from Quebec than are actually available. This concern derives from
22 questions about the load forecast assumption used for the winter months.
23 Stakeholders are concerned that using the high winter load forecast for a deterministic

1 calculation may overstate Quebec’s resource needs during those months, given the
2 relatively low probability of peak load forecasts actually occurring, and thus
3 understate the available capacity potentially available for sales during those months.
4

5 ***Q. You also noted above that there are problems with the current methodology of***
6 ***allocating the full value of the HQICCs as the tie benefits from Quebec, and then***
7 ***pro rating the tie benefit from New Brunswick and New York based on an***
8 ***allocation process. Could you explain these issues as well?***

9 **A.** Conceptually, there is no basis for carving out the deterministically calculated
10 HQICCs to serve as the tie benefit value from Quebec and then assuming that the
11 remainder of the total tie benefits accurately captures the available tie benefits from
12 New Brunswick and New York. From the standpoint of evaluating emergency
13 assistance to New England, using one approach to calculate tie benefits from Quebec
14 and another approach to calculate tie benefits from New Brunswick and New York
15 simply does not make sense.

16 Furthermore, the current allocation methodology can have a direct, adverse
17 impact on the calculation of LSR and MCL values within New England. The LSR for
18 a Load Zone is a statement of the minimum capacity that must be located within an
19 import-constrained Load Zone within New England, and the MCL reflects the
20 maximum capacity that New England can procure from an export-constrained Load
21 Zone within New England. The calculation of a MCL or LSR for a Load Zone takes
22 account of tie benefit values, and in particular the tie benefit values for any
23 neighboring Control Areas that directly interconnect with the New England Load

1 Zone in question. The current methodology for allocating tie benefit contributions
2 reduces the tie benefits from New Brunswick and New York in order to preserve the
3 deterministically calculated HQICCs for the Quebec Control Area. Any LSR and
4 MCL values calculated using the current tie benefit allocations may not accurately
5 reflect the tie benefits available from the three neighboring Control Areas. For
6 example, as noted by certain constituents during the proceedings for calculating the
7 2010/2011 ICR Values, by reducing the tie benefits assumed available from New
8 Brunswick in order to preserve the deterministically calculated HQICCs for Quebec,
9 the MCL for the Maine Load Zone is increased (i.e., the amount of capacity that can
10 be procured from Maine for the New England Control Area is increased) because less
11 capability on the interconnections between Maine and the rest of New England needs
12 to be preserved for emergency assistance from New Brunswick. The result is that the
13 locational aspects of the Forward Capacity Market, which are reflected in LSR and
14 MCL values, are distorted.

15

16 **IV. THE PROPOSED MODIFICATIONS TO THE ALLOCATION**

17 **METHODOLOGY**

18 *Q. Please describe the proposed modifications to the allocation methodology.*

19 **A.** Under these proposed modifications, HQICC values would be established using the
20 results of a probabilistic calculation of tie benefits rather than using a deterministic
21 calculation methodology. The ISO would continue using the existing methodology
22 for calculating total tie benefits from the Quebec, New Brunswick and New York
23 Control Areas using a probabilistic multi-area reliability model. In addition, these

1 neighboring Control Areas would continue to be modeled using “At Criteria”
2 modeling assumptions. However, under the proposed approach, tie benefits from
3 individual Control Areas would be determined based on the results of individual
4 probabilistic calculations performed for each of the three neighboring Control Areas
5 (these outcomes were referred to above as Individually-Calculated Capacity
6 Equivalents), obviating the need for a deterministic calculation of HQICCs that
7 arbitrarily reduces the tie benefit values from the New Brunswick and New York
8 Control Areas.

9 Under the proposed allocation methodology, tie benefits from each Control
10 Area would be calculated using the same GE MARS program with “At Criteria”
11 modeling assumptions that are used for the other probabilistic calculations discussed
12 above. Tie benefits for each of the three Control Areas would be determined based
13 on the LOLE calculated before and after removing the direct interconnections
14 between New England and the target Control Area. The change in New England
15 LOLE value with and without the interconnections with the target Control Area
16 would represent the reliability contribution of the target Control Area’s emergency
17 assistance. This reliability contribution would be quantified in terms of equivalent
18 capacity by identifying the amount of firm capacity needed to bring the LOLE (when
19 calculated without connections to the target Control Area) to the same level it was at
20 prior to removal of the interconnections with the target Control Area. In other words,
21 the allocation methodology for calculating Individually-Calculated Capacity
22 Equivalents as described above for New Brunswick and New York would be applied
23 for determining the tie benefits from Quebec as well. In the likely event the sum of

1 the Individually-Calculated Capacity Equivalents from each of the three neighboring
2 Control Areas does not equal the total tie benefits calculated using the multi-area
3 reliability model, tie benefits from each Control Area will be adjusted in a pro rata
4 manner based on a ratio of the tie benefits from each individual Control Area to the
5 sum of the tie benefits from all Control Areas.

6

7 ***Q. The proposed approach does away with the use of the deterministic method for***
8 ***calculating HQICCs and employs the same method for calculating tie benefits for***
9 ***all three directly interconnected Control Areas. Please explain why this approach***
10 ***is appropriate.***

11 **A.** The proposed approach to calculating and allocating tie benefit contributions to
12 individual Control Areas is similar to the approach used under the current
13 methodology for determining the amount of tie benefit contributions to be allocated to
14 the New Brunswick and New York Control Areas after deduction of the HQICCs.
15 Unlike the current methodology, the proposed approach utilizes a consistent method
16 for allocating tie benefits for all three neighboring interconnected Control Areas,
17 which is just and reasonable. This methodology eliminates the need to evaluate
18 whether the potential emergency assistance, as reflected in the tie benefits value
19 calculated for a Control Area using the probabilistic calculation methodology, is more
20 or less probable than the potential emergency assistance available from another
21 Control Area. Accordingly, this change addresses a concern that the methodology
22 being used inappropriately weights more favorably the tie benefits from one Control
23 Area over the others.

1 The proposed methodology for allocating tie benefits from each neighboring
2 Control Area also entails a consistent approach to ensuring that the allocation of the
3 sum of the tie benefits from the three neighboring Control Areas equals the total tie
4 benefits calculated using the multi-area reliability model. Under the proposed
5 approach, the tie benefits from each Control Area are adjusted in a pro rata manner
6 based on a ratio of the individual tie benefits from each Control Area to the sum of
7 the tie benefits from all Control Areas. Unlike the current methodology, which
8 arbitrarily sets aside the tie benefits from Quebec allocated based on the
9 deterministically calculated HQICCs and directs the reduction solely to tie benefits
10 from New Brunswick and New York, the proposed approach preserves the relative
11 contributions of tie benefits from each Control Area on a non-discriminatory basis.

12
13 ***Q. The proposed methodology continues to model Control Areas “At Criteria” rather***
14 ***than “As Is.” Please explain why this modeling approach is appropriate.***

15 **A.** Using “At Criteria” modeling assumptions for adjacent Control Areas requires the
16 ISO to rely on the reasonable assumption that these neighboring Control Areas will,
17 at the very least, meet the NPCC-mandated one day in ten years LOLE reliability
18 standard. Therefore, the ISO is not required to rely on assumptions about system
19 conditions in neighboring Control Areas, of which the ISO can only obtain limited
20 and imperfect knowledge. Accordingly, continuing to calculate total tie benefits
21 using “At Criteria” modeling assumptions provides a reasonable approximation of the
22 expected amount of capacity in each Control Area to prevent an over-estimate or
23 under-estimate of available tie benefits.

1 Alternatively, modeling Control Areas on an “As Is” basis requires making
2 assumptions about the eventual availability of resources that are, at best, in their planning
3 stages. Where capacity calculations are being made up to three to four years in advance
4 of the Capacity Commitment Period, it is very difficult to determine with certainty
5 whether planned resources will be constructed and operational, and whether any such
6 increase in capacity will be offset by the retirement of resources that are currently in use.
7 Similarly, currently available capacity that is in excess of the amount needed to meet a
8 Control Area’s capacity requirement would be unavailable during the period between the
9 calculation of tie benefits and the commencement of the Capacity Commitment Period if,
10 for example, that resource were to enter into a capacity contract with another Control
11 Area, or even with New England. In the event a firm contract is entered into for capacity
12 that is otherwise assumed available for tie benefits, there could be double counting of
13 capacity because the capacity in question would be supporting both the tie benefits and
14 the firm capacity contract. In short, using “As Is” modeling to calculate tie benefits
15 creates an unreasonable risk of overstating tie benefits.

16
17 ***Q. Does this conclude your testimony?***

18 **A.** Yes.

19
20 DC\7103689.1

1 I declare under penalty of perjury that the foregoing is true and correct.

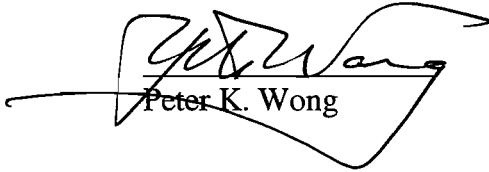
2 Executed on: July 28, 2008

3

4

5

6



Peter K. Wong

ATTACHMENT 3

List of governors and utility regulatory agencies in New England

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

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

Maine Public Utilities Commission
State House, Station 18
242 State Street
Augusta, ME 04333.0018

The Honorable John E. Baldacci
One State House Station
Rm. 236
Augusta, ME 04333.0001

The Honorable Deval Patrick
Office of the Governor
Rm. 360 State House
Boston, MA 02133

Massachusetts Dept. of Public Utilities
One South Station
Boston, MA 02110

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

New Hampshire Public Utilities Commission
21 South Fruit Street
Ste. 10
Concord, NH 03301.2429

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

Rhode Island Public Utilities Commission
89 Jefferson Blvd.
Warwick, RI 02888

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

Vermont Public Service Board
112 State Street, Drawer 20
Montpelier, VT 05620.2701

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

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

Harvey L. Reiter, Esq.
Counsel for New England Conference
Of Public Utilities Commissioners, Inc.
c/o Stinson Morrison Hecker LLP
1150 18th Street, N.W., Ste. 800
Washington, DC 20036.3816

Power Planning Committee
New England Governors' Conference Inc.
76 Summer Street, 2nd floor
Boston, MA 02110.1226