

For the reasons set forth in Section III, and in the context of the background discussed in Section II, the stakeholder process supports the conclusion – and the ISO recommends – that the SEMA zone should not be modified, either prospectively or for the period extending back to the refund effective date (March 28, 2008) established by the Commission in this proceeding.

This conclusion (with respect to both periods) is based on principles that were developed by the ISO and the stakeholders and reflected in a “guideline document.” Key elements of the guideline document included: (i) a recognition that a significant notice period (reflecting specific effective dates and detailed information about revised boundaries) such as 12 months is appropriate if zones are to be modified; (ii) identification of basic triggering events that could give rise for consultation among the ISO and market participants (focusing on appropriate criteria) as to the need to create a new zone or modify an existing zone, including changed market conditions, resource additions or retirements, or certain types of changes in the transmission system; and (iii) the concept that zone modification is appropriate only when triggering events create changed conditions that are expected to persist for a significant period of time beyond the presumptive 12-month notice period.

With respect to prospective modification of the SEMA zone, in applying the principles of the guideline document, the stakeholders and the ISO found to be significant the fact that “short-term” transmission upgrades being completed in the SEMA zone (virtually all of which are now in service) would largely eliminate out-of-merit generation dispatch and associated uplift, meaning that any modification of the zone would be appropriate only for a limited period of time.

With respect to the retroactive modification of the SEMA zone to merge it with another zone, the stakeholders and the ISO recognized that transmission upgrades affecting the SEMA

zone since its establishment have interacted with ongoing changes in the competitive resource mix to create a dynamic set of system changes in which elimination of the SEMA zone has not been appropriate. With respect to retroactive bifurcation of the SEMA zone, the stakeholders and the ISO found persuasive the adverse implications (in terms of cost allocation) of zones that are too small, and the reliance on existing zone boundaries by market participants.

II. BACKGROUND

A. Out of Merit Operation of the Canal Generating Station

While a more detailed recitation of the full factual background relevant to this proceeding is included in the ISO's April 28, 2008 Answer in this docket,⁴ it is useful to provide a brief overview here of the context for this Compliance Filing.

The bulk power facilities for the lower SEMA area⁵ were designed – in the context of a vertically integrated utility system – to rely on a combination of two 345 kV transmission lines and the Canal Station. The Canal Station is located in Sandwich, MA and was constructed by the predecessor to NSTAR Electric Company (“NSTAR”), which was the local distribution company in the area in 1968 and sold to a subsidiary of the Mirant Corporation at the time of electric industry restructuring.

Prior to industry restructuring in New England, Canal and all other generating units were centrally dispatched to minimize overall costs for the region, and the regional utilities split among themselves savings from that central dispatch. The cost of operating the Canal generation would have simply been included in NSTAR's bundled retail rates. With generation divestiture and during the initial period following the implementation of Standard Market Design (“SMD”)

⁴ *Answer of ISO New England Inc.*, filed April 28, 2008 in Docket No. EL08-48-000 (“Answer”), at 5-20.

⁵ A description of the SEMA and lower SEMA areas is included in the Answer at 8-9.

markets in New England in 2003, the lowest-priced generation is dispatched from a bid stack, and the operation of the Canal generation did not change significantly. That is, at least one Canal generator had been run at almost all New England load levels, because at least one Canal generator would typically clear the market as in-merit due to the cheaper running costs for Canal's oil-fired generators compared with natural gas units elsewhere on the system. The in-merit Canal generation received the market clearing price and there were no out-of-merit costs from Canal operations allocated to customers.

Beginning in January 2006, however, the Canal generation was no longer clearing regularly in economic merit order due to changes in the relative price levels of oil and natural gas. As described in greater detail in the Answer, the Canal generation was then dispatched out of merit.⁶ A dispute arose thereafter about the proper "flagging" of the out-of-merit operation for cost allocation purposes, and the ISO's determination to flag the resources as necessary for Local Second Contingency Protection ("LSCPR").⁷

B. The SEMA Settlement Agreement

The incurrence of significant LSCPR charges led to the initiation of a Commission-sponsored mediation,⁸ and eventually to a settlement agreement that resolved (for the periods specified in the agreement) all issues related to the out-of-merit operation of the Canal generation

⁶ Answer at 10-15.

⁷ Capitalized terms not otherwise defined herein have the meanings ascribed thereto in the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 (the "ISO Tariff"), the Participants Agreement or the Second Restated New England Power Pool Agreement. The ISO Open Access Transmission Tariff (the "ISO OATT") is Section II of the ISO Tariff, and Market Rule 1 is Section III of the ISO Tariff.

⁸ NEPOOL approached the ISO regarding these issues, and a number of informal meetings were held. In order to avoid a contested proceeding before the Commission, mediation at the Commission was commenced before then-Deputy Chief Administrative Law Judge Lawrence Brenner.

for LSCPR support. The settlement agreement preserved some narrowly tailored litigation rights for the participating municipal entities.

Notice of the mediation was provided through the New England Power Pool (“NEPOOL”) and the ISO, thereby affording all affected entities the opportunity to participate. Participants in the mediation included, *inter alia*, Hull Municipal Lighting Plant, Mansfield Municipal Electric Department, Middleborough Gas & Electric Department, North Attleborough Electric Department (collectively, the “MMWEC Systems”), and the Braintree Electric Light Department, Hingham Municipal Lighting Plant and Taunton Municipal Light Plant (collectively, the “Towns” and, together with the MMWEC Systems, the “Municipals”). The participants in the mediation proceeding met in numerous formal sessions with Judge Brenner, as well as in numerous informal meetings, from August 2006 through March 2007.

Ultimately, an uncontested settlement agreement (the “SEMA Settlement”) in the form of a rate schedule was reached among the parties,⁹ filed May 18, 2007 and accepted by the Commission.¹⁰ Among other things, under the terms of the SEMA Settlement, the Municipals received \$3.77 million.

Section 4.1 of the SEMA Settlement prohibits any settling parties – including the Municipals and the ISO – from seeking or supporting changes to the cost allocation methodology

⁹ The parties to the SEMA Settlement are: NSTAR Electric Company; National Grid doing business as Granite State Electric Company, Massachusetts Electric Company, New England Power Company, Nantucket Electric Company, and the Narragansett Electric Company; Constellation Energy Commodities Group, Inc.; Constellation NewEnergy, Inc.; Consolidated Edison Solutions, Inc.; SUEZ Energy Resources NA, Inc.; Direct Energy Services, Inc.; Dominion Energy Marketing, Inc.; Dominion Retail, Inc.; PSEG Energy Resources and Trade LLC; Select Energy, Inc.; Strategic Energy; TransCanada Power Marketing, Ltd.; Integrys Energy Services, Inc.; Sempra Energy Solutions; Hull Municipal Lighting Plant; Mansfield Municipal Electric Department; Middleborough Gas & Electric Department; North Attleborough Electric Department; Braintree Electric Light Department; Hingham Municipal Lighting Plant; Taunton Municipal Lighting Plant; and ISO New England Inc.

¹⁰ *ISO New England Inc.*, Docket No. ER07-921-000 (letter order issued June 21, 2007), *accepting compliance filing*, Docket No. ER07-921-002 (letter order issued Nov. 14, 2007).

for the Net Commitment Period Compensation (“NCPC”) Charges resulting from the LSCPR designation of the Canal generation during the Moratorium Period, which does not end until May 31, 2010. Further, parties to the SEMA Settlement are barred from attempting to reclassify the operation of the Canal generation as other than LSCPR when so designated by the ISO.

Specifically, Section 4.1 of the SEMA Settlement provides:

Subject to Sections 4.2(a), 5.1, 5.2, 5.4 and 7, during the Moratorium Period, all NCPC Charges for LSCPR for all reliability regions and for both the Day-Ahead and Real-Time Markets, including the SEMA NCPC Charges for LSCPR, shall be allocated (i) on the same basis that NCPC Charges for LSCPR are allocated pursuant to the allocation mechanisms in Section III of the ISO-NE Tariff in effect on the date of this Settlement, and (ii) on the basis of those provisions as amended pursuant to Section 5 of this Settlement, if and as of the date those amended provisions become effective. Subject to the exceptions in the preceding sentence, *no Party shall seek or support a different allocation mechanism prior to the end of the Moratorium Period, or seek or support reclassification of ISO-NE’s designation of Canal as an LSCPR for service during the Moratorium Period.*¹¹

As noted in Section III.F below, NEPOOL supports the ISO’s conclusion not to change the SEMA zone currently or retroactively. NEPOOL has authorized the ISO to report its support and indicated it will provide additional information in its own comments on this Compliance Filing.

The SEMA Settlement further foreclosed the use of the ISO-NE and NEPOOL stakeholder process to alter the allocation methodology for LSCPR within the Moratorium Period, providing:

No party shall propose or argue, either *to the Commission or within the ISO-NE or NEPOOL process*, for Market Rule amendments that would provide for a different mechanism for allocation of NCPC charges for LSCPR, or shall seek or support a

¹¹ Emphasis added.

reclassification of ISO-NE's designation of Canal as LSCPR during the Moratorium Period...Except for amendments authorized by Section 4.2(a), the Parties shall oppose any Market Rule amendments that would provide for a different mechanism for allocation of NCPC charges for LSCPR than provide in Section 4.1 and Sections 5.1 and 5.2 or re-classification of ISO-NE's designation of Canal as LSCPR during the Moratorium Period proposed by persons who are not Parties to the Settlement.¹²

The only "exceptions" to the foregoing were very limited. First, Section 7.1(a) of the SEMA Settlement permits the Municipals, under certain circumstances, to seek relief from SEMA NCPC Charges for LSCPR through future litigation over whether such charges should be reduced through implementation of an special protection system ("SPS") or post-first contingency switching ("PFCS") arrangement. Specifically, Section 7.1 of the SEMA Settlement provides that nothing therein prevents the Municipals:

as of January 2, 2008, from seeking relief from SEMA NCPC Charges for LSCPR through litigation against ISO-NE or the Transmission Owners over *whether consistent with Applicable Criteria as defined in Section 6.1(b) such charges could be or should be reduced through implementation of an SPS or Post-First Contingency Switching arrangement*. However, any financial relief from such excess charges shall be limited to the difference between the SEMA NCPC Charges for LSCPR imposed on the Municipals and the charges that would have been imposed if an SPS or [PFCS] arrangement had been implemented. Such relief shall be prospective from the date of filing of a proceeding seeking such relief (which date shall not be prior to January 2, 2008), except that the Municipals are entitled to seek relief for the three-month period prior to the date of initiating such proceeding.¹³

As explained below, a number of the Municipals – namely, Braintree Electric Light Department, Hingham Municipal Lighting Plant, Hull Municipal Lighting Plant, Mansfield Municipal Electric Department, Middleborough Gas & Electric Department, and Taunton

¹² SEMA Settlement at § 8(c) (emphasis added).

¹³ Emphasis added.

Municipal Light Plant (collectively, “Massachusetts Public Systems” or “MPS”) – brought such a complaint in this docket on March 28, 2008 (the “Complaint”). As detailed below, MPS’s arguments about the acceptability of a mechanism to shed the Cape Cod area load on the occurrence of a second contingency were rejected by the Commission in its July 18 Order.

The second exception is found in Section 7.2 of the SEMA Settlement, which permits the Municipals to seek a change to the definition of the SEMA Reliability Region:

The Parties, other than the Municipals, agree not to seek a change (in NEPOOL or before the Commission) in the ISO-NE definition of the SEMA Reliability Region to become effective prior to June 1, 2010; provided that the Municipals may seek such a change to become effective no earlier than January 1, 2008.

C. Background of the Current Complaint Proceeding

As noted above, on March 28, 2008, MPS filed the Complaint seeking, *inter alia*, changes to the allocation of LSCPR Charges. MPS asserted that the ISO could implement either PFCS or an SPS to shed load in the Cape Cod area on the occurrence of a second contingency, rather than operate available area generation out-of-merit, which would allow for load to continue to be served in the event of a second contingency. MPS argued, in the alternative, that the SEMA Reliability Region should be divided into two Reliability Regions.

The ISO answered the Complaint on April 28, 2008 and provided an explanation of the power system issues in the SEMA Reliability Region as well as an explanation of why the MPS position misinterpreted the ISO Tariff, and was inconsistent with NPCC guidance and good utility practice. The ISO explained that while it relied on load shedding where appropriate in the New England system – for example, in Day-Ahead operations where many other steps would be utilized prior to the use of load shedding in Real Time – it was not acceptable to rely on load shedding in the lower SEMA area in lieu of operating available generation because (1) it would

be the only available “next step” after a second contingency, (2) it would have to be relied on as that next step 365 days a year, and (3) the potential outage duration was as great as 24 hours.¹⁴

Regarding whether operating the Canal generation was “necessary,” the ISO observed that MPS’s interpretation of that term would mean that a generating unit could be flagged for LSCPR only if there is *no other means* to meet reliability criteria,¹⁵ and that if MPS’s interpretation were embraced, the ISO would shed load on a daily basis all over New England rather than dispatch available generation out of merit to support system construction, maintenance or contingencies and potential contingencies.¹⁶ In short, the ISO argued that MPS was incorrect in its assertion that, because load could be shed rather than served with generation, the use of generation was “unnecessary” under the ISO Tariff.¹⁷

In response to the Complaint, the Commission issued the July 18 Order rejecting, under the facts at issue, the Complaint’s contention that it was acceptable to rely on either PFCS or an SPS rather than available generation in the lower SEMA area.¹⁸ The Commission noted that, with regard to the boundaries of the SEMA Reliability Region, it was not clear from the record evidence whether the zone as delineated continued to be just and reasonable.¹⁹ The Commission thus set that issue for hearing and held that hearing in abeyance, directing the ISO to raise the

¹⁴ Answer at 20-22.

¹⁵ *Id.* at 23.

¹⁶ *Id.* at 24-27.

¹⁷ *Id.* at 24.

¹⁸ July 18 Order at PP 23-26.

¹⁹ *Id.* at PP 29-30.

issue in the New England stakeholder process and report back to the Commission by July 17, 2009.²⁰

The pertinent paragraphs of the July 18 Order state:

28. The SEMA reliability region was adopted by ISO-NE from the existing electric regional boundaries of NEPOOL; it was originally established by engineering analysis of interfaces and transmission constraints. *However, the SEMA regional boundary may no longer result in a just and reasonable allocation of the costs at issue here.*

29. We find that *whether or not the cost allocations resulting from the boundaries of the current SEMA region are just and reasonable* raises issues of material fact that cannot be resolved on the record before us. We therefore will set MPS's complaint for hearing. However, we will hold the hearing in abeyance because we conclude at this point that the issues set for hearing and raised in the responses regarding SEMA are more appropriately addressed in the ISO-NE stakeholder process. *The issues to be addressed in the stakeholder process include, but are not limited to, whether SEMA should be divided, and if so, how. The stakeholders may also consider other means (except for implementation of PFCS or SPS) to address the issues regarding complainants' challenges to the cost allocation in SEMA.* The stakeholder process should consider the effects, if any, of any proposal on New England's markets or other regions in the ISO-NE footprint. We require the ISO-NE to submit a filing to the Commission no later than July 17, 2009 indicating how the ISO-NE will address the cost allocation issues set for hearing. That filing will describe the stakeholder procedures undertaken as a result of this order.²¹

MPS, National Grid and NSTAR, sought rehearing of the July 18 Order.

MPS argued that the Commission need not direct use of PFCS or an SPS but simply find that it was acceptable to use those mechanisms and that, concomitantly, running the available generation was not necessary and the costs thereof should not be allocated as LSCPR. MPS also

²⁰ *Id.* at P 30.

²¹ *Id.* at PP 28, 29 (emphasis added; footnotes omitted).

argued that sending the SEMA zone issue to the stakeholder process was an impermissible delegation of the Commission's authority.

The joint rehearing request of National Grid and NSTAR (together, the "Transmission Owners") argued that the Commission should clarify that it will adhere to its policies disfavoring retroactive changes to rate design and accompanying refunds. They also sought rehearing on two additional grounds: first, that the Commission's establishment of a refund effective date was improper to the extent that it implies that LSCPR revenues are subject to refund on a retroactive basis prior to the ISO's filing of a rate change affecting such allocation; and second, the Commission's directive to the ISO to utilize a stakeholder process to resolve SEMA cost allocation was overly restrictive because it provides for division of the SEMA Reliability Region based on cost allocation criteria, rather than reliability criteria, and because it is limited to consideration of dividing the SEMA Region into two or more parts, to the exclusion of expansion or contraction of SEMA or merger with another ISO-NE Reliability Region.

On July 2, 2009, the Commission issued an order²² rejecting the requests for rehearing of the July 18 Order, holding – *inter alia* – that: (i) use of the stakeholder process was not an impermissible delegation of authority,²³ (ii) limiting the scope of the stakeholder discussions to changes in the SEMA Reliability Region boundaries was not unduly discriminatory,²⁴ (iii) the SEMA Settlement did not foreclose discussion and agreement to changes after the close of the

²² See *Braintree Elec. Light Dep't, et al., v. ISO New England Inc.*, 128 FERC ¶ 61,008 (2009) (the "Rehearing Order").

²³ Rehearing Order at P 50.

²⁴ *Id.* at P 56.

Moratorium Period,²⁵ and (iv) the Transmission Owners were premature in their concern regarding retroactive ratemaking because the ISO had not made its compliance filing.²⁶

D. Recent System Changes in SEMA

Work began in 2006 to address weaknesses in the power system in the lower SEMA area. NSTAR, National Grid and the ISO worked together to identify issues and then focused on upgrades to the system that could be made in a relatively short time period. These so-called “Short Term Upgrades” involve the following infrastructure additions:

- The new 115 kV line (the 194 line) between Auburn substation and Brook Street substation has been constructed and was placed in service in June 2008;
- A second 345/115 kV autotransformer at Carver substation has been installed and was placed in service in April 2009;
- The new 115 kV line (the 134 line) between Carver substation and Tremont substation has been constructed and was placed in service in May 2009;
- The looping of the 345 kV line from Bridgewater substation to Pilgrim Switching Station (355 Line) into the Carver substation has been constructed and was placed in service in July 2009; and
- The dynamic reactive device is scheduled to be installed at the Barnstable substation in September 2009.

As noted in the “Short Term Report” issued by the ISO on July 17, 2007 pursuant to Section 6.1(d) of the SEMA Settlement,²⁷ the Short Term Upgrades were expected to raise (from

²⁵ *Id.* at PP 51-55.

²⁶ *Id.* at P 57.

²⁷ The Short Term Report is posted (on a passworded basis due to its inclusion of Critical Energy Infrastructure Information) on the ISO’s website at http://www.iso-ne.com/trans/sys_studies/rsp_docs/pres/2007/sema_settlement_short-term_report_of_iso_new_england.pdf.

11,000 MW to 20,000 MW) the New England load level at which it was necessary to operate the Canal generation on Cape Cod, assuming all transmission elements were in service.²⁸

As further clarified in the “Long Term Report” issued by the ISO on January 20, 2009 pursuant to Section 6.1(c) of the SEMA Settlement,²⁹ without reliance on any load shedding in the area, the combined transmission upgrades listed above will eliminate the need to operate the Canal generation until a New England-wide daily peak load level of approximately 20,000 MW in the summer rating period or 24,000 MW in the winter rating period, assuming that all transmission elements are in service. To translate those levels into approximate days of commitment, for the summer rating period, the range of days of exposure using 2006 load data is between 42 to 58, and using 2007 load data, the number of days of exposure is between 44 to 52. The results of the ISO’s analysis³⁰ showed that there were no exposure days for the winter rating period using either year’s data.

Prior to the completion of the Short Term Upgrades, reliance on posturing the power system after a first contingency to shed the entire Cape Cod area to protect the greater lower SEMA area following the occurrence of a second contingency was determined not to be good

²⁸ Short Term Report at 9.

²⁹ An executive summary of the Long Term Report is posted on the ISO’s website at http://www.iso-ne.com/pubs/spcl_rpts/2009/executive_summary_sema_long_term_report.pdf, and is Attachment 3 to this Compliance Filing. The full version of the report contains Critical Energy Infrastructure Information and, accordingly, is posted on the website on a password-protected basis at http://www.iso-ne.com/trans/sys_studies/rsp_docs/rpts/2009/a_sema.pdf.

³⁰ The analysis was performed in two parts. Part 1 consisted of calculating the lower SEMA line-out (N-1-1) import capability. Part 2 determined and compared the need for Canal generation for each day in 2006 and 2007 for the existing system and for each stage of the Short Term Upgrades.

The results of the import capability analysis were: 700 – 750 MW for summer month capability; and 750 – 800 MW for winter month capability. Based on the fact that the lower SEMA load varies as a percent of the New England load on a monthly basis, the historical lower SEMA load-ratio share used in the Day-Ahead commitment was applied to historical 2006 and 2007 load levels to provide the context for the impact of the upgrades. Since it was found to be more realistic to use a range of transfer limits, a corresponding range of days of exposure was developed based on this range of import capability.

operating practice. The Short Term Report concluded that while PFCS could technically be utilized up to a New England-wide load level of approximately 17,000 MW, it should not be used³¹ to the exclusion of the operation of available generation because, given the design of the system in that area, operators would have to rely on it as their next operating step in all hours, *i.e.*, setting up for load shedding of the entire Cape Cod area would be the only available next step for operators in almost all hours of all days of the year if a first contingency were to occur.

With the completion of the Short Term Upgrades, the performance of the electrical system in the lower SEMA area has improved significantly. The ISO, NSTAR, and National Grid worked together during the construction of the transmission upgrades to revise the pertinent transmission operating guide to identify and document the system improvements and how those improvements may allow for more operating flexibility in the lower SEMA area.

The Short Term Upgrades significantly reduce the level of the overloads that would occur in the event of a second contingency without the Canal units in operation. As a result, posturing the system after the occurrence of a first contingency for post-second contingency limited load shedding becomes a viable option and much less load will need to be shed in the event of a second contingency in order to keep transmission lines within their ratings. The ISO and NSTAR will be able to posture the system after a first contingency so that load in excess of the remaining transmission capability³² can be selectively shed, rather than shedding the entire Cape Cod area, which is approximately 685 MW³³ on peak.³⁴ In the event that load is shed as a result

³¹ The Short Term Report further concluded that an SPS was not technically consistent with criteria for such systems. While the Short Term Report did not address the question of whether such a load-shedding scheme should be relied on in the lower SEMA area to the exclusion of operating available generation, the same reasons that PFCS should not be used in lieu of generation in the lower SEMA area also apply to the use of a load-shedding SPS.

³² In other words, less load would be set up to be shed at lower load levels than at higher load levels.

³³ This is the 2009 “90/10” load forecast for the Cape Cod area, meaning that there is a ninety percent
(continued...)

of a second contingency, the improved system performance that results from the Short Term Upgrades should allow load to be restored as peak loads subside below the 20,000/24,000 MW levels noted above, the outage is rotated to a different part of Cape Cod or the cause of the contingency is repaired.

Finally, rather than having to rely on load shedding as the next step following a second contingency in almost all hours and all days of the year, the need to rely on load shedding as the next operational step following a second contingency will be reduced to a limited number of hours, *i.e.*, the peak periods, during a limited number of summer days.

As noted in the Long Term Report, because of the dramatically reduced number of days and hours that load shedding would be relied upon, the reduced level of exposed load, and the reduced potential duration of any outage, the ISO believes that the lower SEMA area can be operated reliably and within criteria after the completion of the Short Term Upgrades without the need to operate the generation at the Canal Station.³⁵

The final transmission line element was placed in service on July 3, 2009 and the ISO and NSTAR began operating under the terms of the revised operating guide on that date.³⁶ Thus,

(...continued)

probability that the annual peak load will be at or below this value and a ten percent probability that the peak load will exceed this value.

³⁴ The ability to selectively shed load is limited up to approximately 1/3 of the current Cape Cod load, which would allow for the Cape Cod area to be operated without reliance on the Canal units up to an approximate New England regional load of 30,000 MW.

³⁵ As load levels rise over time, the operating headroom afforded by the Short Term Upgrades will be reduced. As a result, additional system reinforcements in the area, either in the form of supply or transmission, will need to be put in place in order to operate the area reliably in future years without reliance on the current Canal generation.

³⁶ The voltage device is the only item that remains as part of the Short Term Upgrade package that has not yet been placed in service, but it is not necessary to have it in place for the Summer of 2009 in order to start operating the area in accordance with the revised transmission operating guide, *i.e.*, with reliance on limited post second contingency load shedding at summer system load levels above 20,000 MWs.

while the Canal generation may operate when in merit or if self-schedules are submitted to the ISO, the Canal generation is no longer being regularly operated out-of-merit for second contingency protection. Therefore, the uplift (*i.e.*, LSCPR) charges that originally gave rise to the SEMA Settlement proceeding and the Complaint were greatly reduced for April, May and June 2009,³⁷ and should be virtually eliminated with the completion of the looping of the 345kV line described above.³⁸

III. DESCRIPTION OF THE STAKEHOLDER PROCESS AND ITS RESULTS

As directed by the July 18 Order, the ISO convened a stakeholder process focused on the issue identified by the Commission: whether the boundaries of the SEMA zone³⁹ as drawn continued to be appropriate and result in a just and reasonable allocation of the LSCPR costs. As the Commission stated:

The issues to be addressed in the stakeholder process include, but are not limited to, whether SEMA should be divided, and if so, how. The stakeholders may also consider other means (except for implementation of PFCS or SPS) to address the issues regarding complainants' challenges to the cost allocation in SEMA. The stakeholder process should consider the effects, if any, of any

³⁷ Indeed, with the reduction in load levels beginning in October 2008, LSCPR charges began to drop as the positive impacts of the installation of the new 194 line between the Auburn and Brook Street substations became evident.

³⁸ The ISO describes the effect of the Short Term Upgrades as “virtually” eliminating the LSCPR charges for the out-of-merit operation of the Mirant Canal station because while as a general matter the units should not be needed for system reliability, as long as they are available there may be a system condition where operators could anticipate system problems such that it would make sense to dispatch a Canal resource out-of-merit for reliability reasons. For example, a large coastal storm may lead system operators to review what tools they have to ensure service to load.

³⁹ What is referred to herein as the “SEMA zone” is the SEMA Load Zone, which is the same under the ISO Tariff as the SEMA Reliability Region. “Reliability Region” is defined under the ISO Tariff to be “any one of the regions identified on the ISO’s website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.” ISO Tariff, Section § III.1.3.

proposal on New England's markets or other regions in the ISO-NE footprint.⁴⁰

This section of the Compliance Filing: (A) describes the structure and scope of the stakeholder process; (B) provides background on the genesis of the existing Reliability Regions in New England; (C) explains the formulation of the "Guideline Document" for modification of existing Reliability Regions; (D) summarizes stakeholder input and the ISO's assessment of whether to alter the SEMA zone on a going-forward basis; (E) summarizes stakeholder input and the ISO's assessment of whether to alter the SEMA zone for the period back to March 28, 2008 (the refund effective date in this proceeding); and (F) details stakeholder voting on the various proposals.

A. Structure and Scope of the Stakeholder Process

In consultation with NEPOOL counsel and the chairs of the NEPOOL Reliability and Markets Committees, the Markets Committee was selected as the best venue for the stakeholder process pursuant to the July 18 Order. This selection was made, in large part, because Reliability Regions do not generally affect how the system is operated, but instead are used for cost allocation and other market purposes.

The stakeholder process commenced, at the Markets Committee meeting held November 12, 2008, with a presentation by counsel for MPS. As part of that presentation, MPS explored whether the cost allocation for LSCPR charges stemming from the operation of the Canal generation could be modified. Suggestions for shifting the cost allocation were (1) to allocate to the entire New England region the out-of-merit costs of resources that were operated to avoid voltage collapse; (2) to allocate to the entire New England region the Canal generation-related

⁴⁰ July 18 Order at P 30.

LSCPR charges; or (3) to allocate the LSCPR charges in question to the load at risk of being shed but for the operation of the generation.

In commenting on the presentation, ISO and NEPOOL counsel both pointed to Section 8(c) of the SEMA Settlement and noted that parties to that agreement would not be able to seek or support a change to the ISO's designation of the Canal generation as LSCPR or to the allocation methodology for LSCPR that would take effect during the SEMA Settlement's Moratorium Period.

The ISO made its first full presentation regarding the SEMA zone at the December 11, 2008 meeting of the Markets Committee.⁴¹ At that meeting, the ISO sought to lay the foundation for a stakeholder review of the SEMA zone. In order to do so, the ISO reviewed for the committee the background of the SEMA reliability requirements. The ISO also provided an overview of the Short Term Upgrades, including the nature of the upgrades and their expected operational effect. As part of its presentation, the ISO highlighted that the Short Term Upgrades in conjunction with revisions to the applicable operating guide may be sufficient to resolve out-of-merit cost issues in the lower SEMA area.⁴²

The ISO also reviewed the relevant terms of the SEMA Settlement and the Commission's July 18 Order as a precursor to discussing the scope of the stakeholder process. The ISO noted that: "The objective of this stakeholder process is to comply with the FERC order and seek consensus on: whether the SEMA Reliability Zone should be change or remain the same."⁴³ The

⁴¹ A copy of that presentation (the "December 11 ISO Presentation") is included with this Compliance Filing as Attachment 1 hereto.

⁴² See December 12 ISO Presentation at 8-9.

⁴³ *Id.* at 17.

ISO highlighted that a change to the SEMA zone could be bifurcation of the zone, as had been suggested by MPS, or merging the SEMA zone into the West-Central Massachusetts zone.

The ISO also proposed a structure for discussions that would cover a series of topics during the course of the stakeholder process. These topics were to:

- Confirm and document the criteria that had been used to define Reliability Regions initially
- Establish guidelines for changing existing zones, including appropriate notice provisions and considering:
 - Planned changes to the transmission system
 - Market impacts
 - Impacts to other reliability zones

These discussions were designed to assist parties in considering the central question before the group, whether the SEMA zone was delineated appropriately for the two periods of time: (1) the period between March 28, 2008 (the refund effective date established in the July 18 Order) and the completion of the Short Term Upgrades, and (2) the period from the completion of the Short Term Upgrades going forward.

B. The Original Delineation of New England Reliability Regions

In order to facilitate preparation of a guideline document that would set out general principles to be considered when creating or changing a zone, the ISO first discussed with the Markets Committee how the current Reliability Regions were originally determined.

The Reliability Regions were first developed in the NEPOOL stakeholder process leading up to the submission to the Commission of an initial proposal for day-ahead and real-time markets with locational marginal pricing in New England. This proposal, referred to as the “congestion management and multisettlement system,” (or “CMS/MSS”) was submitted to the

Commission by the ISO on March 31, 2000, in Docket No. EL00-62. SEMA was one of the initially drawn Reliability Regions.

As stated in the ISO's proposal, a Reliability Region was defined as follows:

Reliability Region is, as of March 31, 2000, any one of the regions identified in Attachment B to the Agreement, as amended from time to time; provided that, in accordance with NEPOOL System Rules and following consultation with the Reliability Committee, the System Operator may reconfigure Reliability Regions and add or subtract Reliability Regions as necessary over time to reflect changes to the grid or changes in patterns of usage and intra-zonal Congestion. Reliability Regions reflect the operating characteristics of, and the major transmission constraints on, the NEPOOL Transmission System.⁴⁴

In general, the boundaries of Reliability Regions were dictated by balancing the following factors: (1) the zones should not be too small in terms of MW load or number of buses; (2) the zones should have relatively little internal congestion; (3) the zones should not cross state boundaries if at all possible; and (4) there should be a reasonably small number of load zones. In the context of SEMA, a primary consideration was the presence of transmission constraints that limited exports from the SEMA region.

The Reliability Regions were carried forward for use in connection with the SMD markets. Similar criteria for revising the Reliability Regions were carried forward as well. Specifically, the definition of Reliability Region in Section III.1.3.2 of the ISO Tariff carries forward the principle from the CMS/MSS proposal that Reliability Regions "are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System."

Further, similar to the CMS/MSS proposal, Section III.2.7(g) of the ISO Tariff provides:

⁴⁴ Emphasis added.

After consulting with the Market Participants, the ISO may reconfigure Reliability Regions, Load Zones and Reserve Zones and add or subtract Reliability Regions, Load Zones and Reserve Zones as necessary over time to reflect changes to the grid, patterns of usage, changes in local TMOR contingency response requirements and intrazonal Congestion. The ISO shall file any such changes with the Commission.

Reliability Regions were also made the Load Zones for zonal energy pricing for load.

That is, pursuant to the New England Market Rules, Reliability Regions and Load Zones comprise the same geographic area.⁴⁵ The defined Reliability Regions/Load Zones serve two primary purposes under the current New England markets construct. They aggregate costs for pricing energy for load, and they are used as the basis for allocating reliability costs (*i.e.*, certain uplift and other out of market charges). The allocation of reliability costs is reflected in charges assessed to transmission companies for recovery through the ISO OATT (from network load) or assessed to load-serving entities through the provisions of Market Rule 1.

The established Reliability Regions / Load Zones are as follows:

- Maine
- New Hampshire
- Vermont
- Rhode Island
- Connecticut
- Northeast Massachusetts (“NEMA”)
- West Central Massachusetts (“WCMA”)

⁴⁵ Section III.1.3 of Market Rule 1 defines “Load Zone” as follows: “Load Zone is a Reliability Region except as otherwise provided in Section III.2.7.” Section III.1.3 of Market Rule 1 defines “Reliability Region” as follows: “Reliability Region shall mean any one of the regions identified on the ISO’s website. Reliability Regions reflect the operating characteristics of, and major transmission constraints on, the New England Transmission System.” Section III.2.7(b) states “Each Load Zone shall initially be coterminous with a Reliability Region.”

- SEMA.

As can be observed from review of the established zones, the general principles noted above result in zones that may be smaller than the political boundaries of states to reflect constraints, but in the absence of constraints, a single zone does not exceed that political boundary.

C. Formulation of a Guideline Document Regarding Modification of Existing Reliability Regions

Having reviewed the principles that informed the formation of the established zones, the ISO worked with the Markets Committee during meetings in January, February, April and May of 2009 to review these principles and to update them in a written document. This document was intended to facilitate discussions that would evaluate the SEMA zone, and that could assist the evaluation of other zones, as well.

A copy of the final version of that document, entitled “Guidelines for Modifying Existing Reliability Regions” (the “Guideline Document”) is included with this filing at Attachment 2. In developing the Guideline Document, the concept that the maximum boundaries for a Reliability Region / Load Zone will be contiguous with state boundaries if at all possible was retained from the approach used in determining the original zones, in order to ensure “that the entire retail load served within a particular Load Zone is also within one state jurisdiction.”⁴⁶

A key component of the Guideline Document – of particular relevance to the Commission’s directive in the July 18 Order that the stakeholder process consider the New England market impacts of changes to zones – is its recognition that a significant notice period is appropriate if zones are to be modified. The Guideline Document reflects that the notice

⁴⁶ Guideline Document at 2.

provided should not only alert market participants that change is coming, but should provide (1) the specific effective date of the change and (2) detailed information regarding the revised boundaries.⁴⁷

A significant notice period and detailed information are both highly desirable for market participants to take changes to zones into account in their commercial arrangements. For example, a market participant may have entered into certain contracts on the basis of a set of zonal boundaries. If those boundaries are to change, the market participant needs time for the existing contracts that were based on a prior understanding to expire. Without some assurance of reasonable notice, market participants are likely to price the additional risk of boundary changes into their contracts, to the potential detriment of consumers. While a twelve-month period may not be sufficient to modify all potentially affected commercial arrangements, the feedback received from the Markets Committee suggests that a one-year notice period reflects an appropriate balance between the desire for flexibility on the one hand, and certainty in contracting for power on the other hand.

The ISO and the Markets Committee also discussed what events might give rise to the need to create a new zone or modify an existing zone. The following basic triggering events were identified:

- changed market conditions;
- resource additions or retirements;
- changes in the transmission system, which
 - cause a sub-region of a state to experience market differences consistent with those that would warrant establishing a Reliability Region; or

⁴⁷ *Id.*

- cause a designated sub-region of a state to no longer experience the conditions that previously led to that area being designated as a separate Reliability Region.⁴⁸

Because of the short-term nature of many system conditions (*e.g.* uplift caused by lines taken out of service for transmission construction) and the massive effort required to modify zones – including the modification of software and models, and accounting for the impact on commercial arrangements noted above – the Guideline Document states that zone modification is appropriate only when the above-identified triggering events create changed conditions that “are expected to persist for a significant period of time beyond the [12 month notice period].”⁴⁹ Indeed, the Guideline Document recognizes that a zone change may not be appropriate even where the foregoing changed conditions are present, and that the ISO would be expected to consult with market participants and evaluate whether a zone or zones should be changed, taking into account the following two guidelines:

[1.] The maximum boundaries for Reliability Region/Load Zones will be contiguous with state boundaries. This ensures that the entire retail load being served within a particular Load Zone is also within one state jurisdiction.

[2.] Potential subdivisions within a state will be considered based on significant interfaces monitored by system operations and the potential for meaningful market differences, either LMP or uplift, between subdivided areas. For each of the potential subdivisions within a particular state, the following guidelines will be used to determine whether a separate zone or zones should be established:

[a.] The resulting subdivision has a reasonably high expectation of periodically experiencing congestion or needing dispatch of resources out of economic merit order in order to comply with reliability criteria based on system operating limits.

[(1)] System operating limits are based upon certain operating criteria including, but not limited to, pre- and post-contingency facility ratings, transient stability limits, voltage stability limits, and

⁴⁸ Guideline Document at 1.

⁴⁹ *Id.*

system voltage limits. Interfaces are operated to ensure that the system can be re-dispatched within 30 minutes using the N-1-1 operating criteria and satisfying the most limiting of the prescribed operating criteria.

[b.] The resulting subdivision is of sufficient size to:

[(1)] Provide a reasonably predictable pricing zone for energy including recognition of potential risk of incurring reliability cost allocations.

[(2)] Encompass a sufficient number of resources that could contribute to meeting the reliability need as effectively as possible for the hours of need.⁵⁰

The sub-guideline in 2.b(1) above brings forward – from the criteria used to draw the existing zones – the concept that zones should not be any smaller than necessary. The larger the zone, the more stable a pricing zone it provides for energy. As noted, this provides stability for reliability cost allocations: with a larger area, more load can share the costs of reliability cost allocations. Conversely, a reduction in the size of a zone could concentrate these costs and make them more burdensome to individual market participants. Moreover, while different costs may be located in one part of a zone in a given instance, other costs are likely to be incurred in other areas over time. This is important, as “perfect” cost causation is not achievable on a zonal basis and pursuit of that aspiration would involve the constant alteration of zones.

The other sub-guideline (in 2.b(2) above) highlights the preference for competition between resources within a zone where possible. As a general matter, the smaller the zone is, the less likely that is to occur.

A third guideline was developed, as well:

Adjustments to the boundaries of the proposed Reliability Region may be considered to address local Distribution Company service territory boundaries and

⁵⁰ *Id.* at 2.

other stakeholder considerations including input from state regulatory authorities. Persistent needs will be addressed through the Regional System Planning Process to provide transmission or market solutions, or a combination thereof. Consideration will be given to whether the identified solutions will be implemented in a time frame that would obviate the need to create a separate reliability zone.⁵¹

D. The Committee’s Input and the ISO Assessment of Whether to Alter the SEMA Zone Going Forward

As the Guideline Document was developed, it served as a means to help evaluate the current delineation of the SEMA zone. The motivation for considering whether the SEMA zone should be bifurcated or combined into another zone has been the uplift (*i.e.*, LSCPR) charges paid for the out-of-merit operation of the Canal generation on Cape Cod. As noted above, during the December 11, 2008 meeting of the Markets Committee, the ISO reviewed with the committee the history of how the power system was designed in the SEMA area and the factors that led to the out-of-merit operation of generation in the lower SEMA area.

At the December Markets Committee meeting, the ISO also informed the committee of its ongoing analysis regarding the impact of the Short Term Upgrades on the need to operate generation, and the corresponding impact on potential out-of-market payments. After the ISO’s review with NSTAR⁵² of a draft of this analysis – the “SEMA Long Term Report”⁵³ – it was posted to the password-protected Planning Advisory Committee web page on January 20, 2009.⁵⁴

⁵¹ *Id.*

⁵² The ISO worked with NSTAR regarding the analysis of the impacts of the Short Term Upgrades because it is NSTAR’s transmission system that is primarily affected, and NSTAR that would have to take the on-the-ground operating actions to set up for any load shedding. It was therefore critical to work with NSTAR to determine what the effects of the Short Term Upgrades would be and how these effects would impact service in the lower SEMA area, as well as the steps NSTAR could take in terms of transmission operation.

⁵³ “Long Term Report of ISO New England Inc. Required Pursuant to Section 6.1(c) of the SEMA Settlement Agreement,” January 20, 2009.

⁵⁴ As noted above, the SEMA Long Term Report contains Critical Energy Infrastructure Information. http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/index.html.

The SEMA Long Term Report indicated that the Short Term Upgrades would have a very significant impact on the need to operate generation for second contingency protection in the SEMA area.⁵⁵ For this reason, the ISO and NSTAR developed an operating guide that will rely on certain post-second contingency actions in lieu of the need to operate generation out-of-merit.

As noted in the background section of this Compliance Filing, the Markets Committee was advised that the need to operate out-of-merit generation in the lower SEMA zone should be virtually eliminated by the completion of the Short Term Upgrades and the adoption of the area operating guide that will rely on post-second contingency actions.⁵⁶ As a result, the SEMA area should not have “a reasonably high expectation of experiencing congestion or needing dispatch of resources out of economic merit order to comply with reliability criteria based on system operating limits.”⁵⁷ In this case, the termination of the issue was in sight during the stakeholder process. It was therefore a question whether it made sense to alter the SEMA zone for what the ISO and stakeholders understood to be a limited amount of time. As noted in the Guideline Document, because of the work involved in changing a zone and the impact such a change may have on commercial arrangements, changes are suggested to be considered where the specific issue is “expected to persist for a significant period of time beyond the [12 month notice period].”⁵⁸ The ISO and stakeholders understood in this case that the issue would be resolved by September 2009 at the latest and as early as June 2009. As noted above, the final line section of

⁵⁵ See Executive Summary of the SEMA Long Term Report, Attachment 3 hereto.

⁵⁶ Canal generation was not dispatched out-of-merit during May and June, except during a few days in May to support transmission line outages.

⁵⁷ Guideline Document at 2.

⁵⁸ *Id.* at 1.

the Short Term Upgrades was energized in early July and the new transmission operating guide for the area was put in effect on July 3, 2009.

Based on the facts described above, the Markets Committee concluded (as described in the stakeholder voting discussion in Section III.F., below) that the SEMA zone should not be changed prospectively at this time, and that conclusion was presented to and confirmed by the Participants Committee. The ISO concurs with this conclusion. With the virtual elimination of the uplift caused by a need to operate Canal generation out of merit, there is not a reason to bifurcate the zone based on the previously identified lower SEMA import constraint, and the existence of the zone as it is now defined does not create other market-related problems. The ISO notes that it will review the existence of the SEMA zone after some operational experience is gained with the Short Term Upgrades and may, with appropriate notice and stakeholder discussion, recommend eliminating the zone altogether at a future time.

E. The Committee's Input and the ISO Assessment of Whether to Alter the SEMA Zone Retroactively to March 28, 2008

With regard to changing the SEMA zone back to the March 28, 2008 refund effective date, the Markets Committee recommended and the Participants Committee agreed (as described in the stakeholder voting discussion in Section III.F., below), that the zone not be changed for that for that period. The ISO agrees with that input.

First, the ISO is recommending that the SEMA zone *not* be merged with another zone for the period back to March 28, 2008. The SEMA zone was created because of certain transmission constraints and voltage issues, along with the mix of resources that existed at that point in time. Since that time, as is the case in other areas of New England, the transmission infrastructure has been continually changing as the region worked to reduce or eliminate congestion constraints and improve overall efficiency.

A list follows of the transmission-related work that has been performed that affects the SEMA zone since that zone was originally defined. The cumulative impact of this work has significantly improved the operability of the area. This system work is in addition to the Short Term Upgrades in lower SEMA that were described in Section II.D, above.

- Independent Pole Breaker replacement program at key 345 kV substations increase area stability export capability;
- The addition of internal SEMA generation: Fore River, Tiverton, Dighton (units greater than 100 MW);
- NEMA Upgrades (reference: ISO OATT Schedule 12A NEMA Upgrades) – Some of these upgrades also resulted in increases to SEMA area export/import capability;
 - Framingham 230/115kV autotransformer and breaker replacement
 - Upgrade Framingham to West Medway 230 kV line (240-601)
 - Add Mystic 345kV breaker #101S
 - West Walpole 345/115kV autotransformer and breaker replacement
 - Rebuild Speen Street to Sudbury 115kV line (342-507) and replace breakers at both ends
 - Waltham 230/115kV autotransformer and breaker replacement
 - Upgrade Waltham to West Medway 230 kV line (282-602)
 - Upgrade Framingham to Speen Street 115kV line (433-507) and replace breakers at Framingham
 - Add a third Waltham 115kV phase shifting transformer
 - Upgrade Sherborn 115kV station equipment
 - Merrimack (New Hampshire) 230/115kV autotransformer replacement;
- Stoughton 345 kV cable additions – these also increased SEMA area export/import capability; and
- NSTAR/National Grid transmission capacitor additions and Load Power factor correction upgrades (relieve Canal generation must-run requirements for low voltage).

Competitive forces have also brought more efficient supply into the resource mix, changing the way power flows on the system. Each transmission infrastructure upgrade, coupled with the ongoing changes in the competitive resource mix, resulted in incremental changes to the operational constraints to meet reliability requirements. Given the dynamic nature of these system changes in the area over the past few years, the ISO has not recommended the elimination of the SEMA zone to date.

Second, the ISO is recommending that the SEMA zone should not be bifurcated for the period back to the March 28, 2008 date. Application of the general guidelines reflected in the Guideline Document counsels against creating zones that are too small. Zones that are too small may be of insufficient size to provide a reasonably predictable pricing zone for structuring longer term energy contracts, such as those needed to serve state specific standard offer service, that account for risk of reliability cost allocations. Very local reliability needs that may emerge from time to time because of transmission or transmission outages, or due to construction, may be better suited to a broader sharing of costs.

Finally, while the Commission selected March 28, 2008 as the refund effective date in this proceeding, which signaled that the zone could change at that time in one way or another, *i.e.*, be bifurcated or merge into another zone, the ISO is recommending that zones only be changed with significant advance notice, generally a year, which would include specific detail regarding the zonal change that would occur and only in circumstances where the new zone definition would be expected to persist for a period of years following the notice period. As explained in Section III.C., above, a significant notice period allows parties sufficient time to incorporate the impact of a zone change in their commercial arrangements.

The ISO believes that its recommendations that the SEMA zone not be changed back to March 28, 2008 avoids the direct impacts to Participants who relied on the rules that were in effect and avoids the potential longer-term adverse impact on New England markets or other regions in the ISO's footprint that may result from incorporating in power pricing the additional risk of retroactive changes to how reliability costs are allocated.⁵⁹

F. Stakeholder Meetings and Voting

The SEMA zone issues were discussed at the following meetings of the Markets Committee:

- November 12, 2008 (agenda item 4)
- December 11, 2008 (agenda item 10)
- January (13-15), 2009 (agenda item 8)
- February (10-11), 2009 (agenda item 5)
- April 23, 2009 (agenda item 5)
- May 12, 2009 (agenda item 4)

The meetings were well-attended by all sectors of Market Participants and by state regulators.⁶⁰

After conducting the discussions described above, a memorandum was distributed for the May 12, 2009 meeting of the Markets Committee. That memorandum, Attachment 4 to this Compliance Filing, reviewed the discussions at prior Markets Committee meetings and set forth ISO-recommended positions regarding the SEMA zone. The following motion was circulated for the May 12, 2009 meeting:

RESOLVED, that the Markets Committee recommends that the Participants Committee support the ISO recommendation, which

⁵⁹ Standard offer contracts, for example, are often priced on an "all-in" basis. Thus, they would have reflected cost allocation methodologies in place at the time of execution. Some stakeholders noted that the possibility of retroactive change in load zones would mean that higher risk premiums would have to be included in their standard offer contract prices to reflect the potential of not being able to rely on existing cost allocation rules.

⁶⁰ The ISO also briefed state regulators separately in order to keep them apprised of developments.

recommendation is to be submitted by ISO as part of its Report of Compliance to the FERC required by the June 18, 2008 FERC Order in Docket No. EL08-48-000, not to alter the ISO definition of the Southeastern Massachusetts (SEMA) Reliability Region, either retroactively to become effective March 28, 2008 or prospectively at this time, without prejudice to any future recommendations regarding the ISO definition of the SEMA Reliability Region to be made by the Participants Committee.

Based on a show of hands, the motion passed. 6 abstentions within the Generation Sector, 7 abstentions within the Supplier Sector, 3 oppositions and 34 abstentions within the Publicly Owned Entity Sector, and 2 abstentions within the End User Sector were recorded.

Based on this action by the Markets Committee, the matter was considered by the NEPOOL Participants Committee at its June 5, 2009 meeting. Included in the Consent Agenda for that meeting was the following item:

2. Support the ISO recommendation, to be submitted by ISO as part of its Report of Compliance to the FERC required by the June 18, 2008 FERC Order in Docket No. EL08-48-000, not to alter the ISO definition of the Southeastern Massachusetts (SEMA) Reliability Region, either retroactively to become effective March 28, 2008 or prospectively at this time, without prejudice to any future recommendations regarding the ISO definition of the SEMA Reliability Region to be made by the Participants Committee, as recommended by the Markets Committee at its May 12-13, 2009 meeting.

The committee voted on Consent Agenda items by show of hands. With the unrelated "Centralized Tariff Definitions" item removed, the Consent Agenda was approved with oppositions from the Municipals, and abstentions by Conservation Services Group, Inc.; the Connecticut Office of Consumer Counsel; Constellation New Energy Inc., EPIC Merchant Energy NE, LP; Gas Recovery Systems, LLC; the New Hampshire Office of Consumer Advocate; NRG Power Marketing, LLC; Vermont Energy Investment Corporation; the Small Distributed Generation Group Member, the Small Load Response Group Member, and the remaining members of the Publicly Owned Entity Sector who were present and had not

otherwise noted their opposition. The abstaining AR Sector members explained that their abstention related to an unrelated change to ISO New England Operating Procedure No. 8 that was also on the Consent Agenda. With the only oppositions in the Publicly Owned Entity Sector, and that Sector completely opposed, the percentage in favor on that item (and the entire Consent Agenda) was 82.84%.

IV. COMMUNICATIONS

Correspondence and communications regarding this filing should be addressed to the undersigned as follows:

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V. ATTACHMENTS

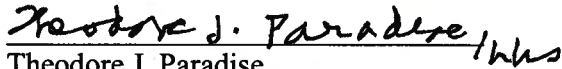
Attached to this Compliance Report are the following documents:

- the December 11 ISO Presentation (Attachment 1);
- the Guideline Document (Attachment 2);
- the executive summary of the Long-Term Report (Attachment 3); and
- the ISO memorandum for the May 12, 2009 meeting of the NEPOOL Markets Committee (Attachment 4).

VI. CONCLUSION

WHEREFORE, given the facts and circumstances set forth in this Compliance Filing, the ISO requests that the Commission accept this Compliance Filing and find that the SEMA zone is acceptable as delineated for the period between March 28, 2008 and July 3, 2009 and prospectively from July 3, 2009, given the facts at this time and without prejudice to future issues that may affect the boundary of the SEMA zone.

Respectfully submitted,



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July 17, 2009

ATTACHMENT 1

SEMA Reliability Zone FERC Order EL08-48-000

Kevin A. Kirby
Vice President, Market Operations

Table of Contents

- Background on SEMA Reliability Requirements
- Short-Term Upgrades
- Revisions to Operating Guides
- SEMA Settlement
- FERC order setting out compliance requirement.
- Stakeholder Process
- Next Steps

Background on SEMA Reliability Requirements

- The lower SEMA area was designed based on a Canal unit being on-line.
- Prior to 2006 a Canal unit was normally on-line in merit.
 - This in-merit dispatch satisfied reliability requirements.
- In early 2006 rising fuel costs resulted in Canal falling out of merit order.
- ISO determined that it was necessary to operate Canal to meet reliability criteria for SEMA when New England load levels exceeded approximately 10,500 MWs.

Background on SEMA Reliability Requirements - continued

- ISO-NE evaluated alternatives to the continued operation of Canal given the transmission system design in the area and determined that:
 - Post-second contingency load shedding as an operating response was not appropriate for SEMA.
- ISO and NSTAR developed a plan to upgrade the transmission infrastructure to eliminate or mitigate the costs resulting from the out of merit operation of area generation.
 - Short-term transmission system upgrades are in progress.
 - Carver upgrades scheduled for completion June 2009.
 - Barnstable SVC scheduled for completion September 2009.

Background on SEMA Reliability Requirements - continued

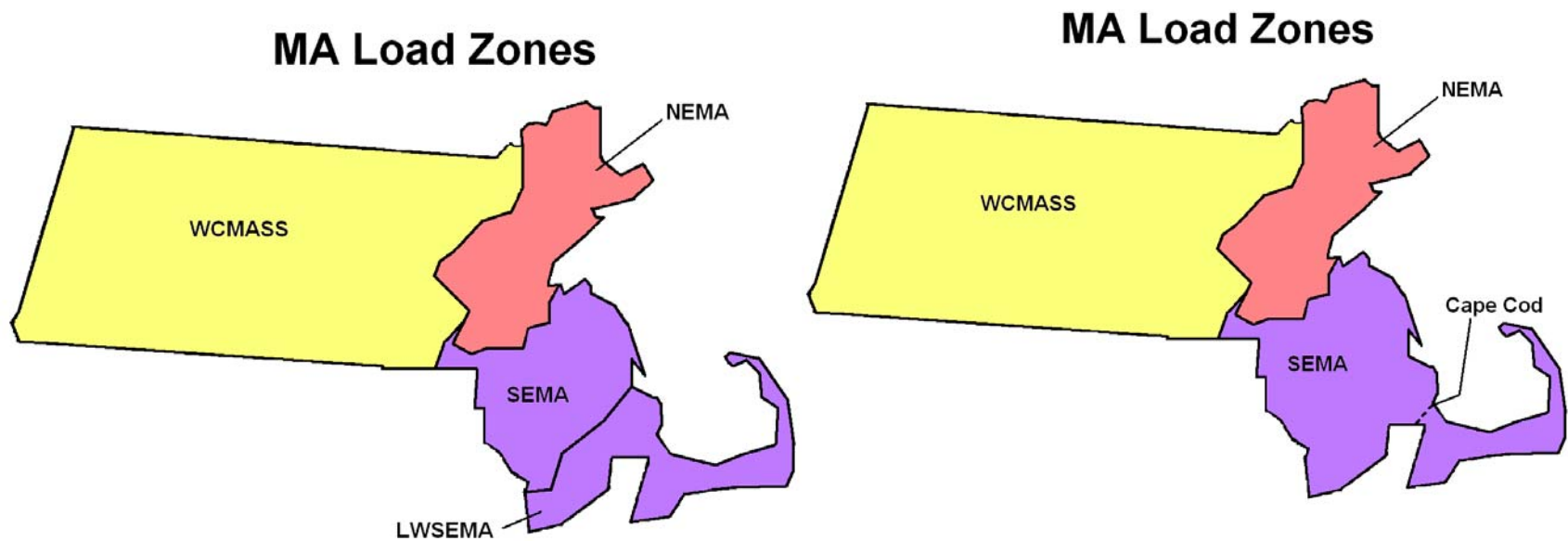
- In 2007, preliminary analysis indicated that the short-term upgrades would eliminate the need to operate a Canal Unit for New England load levels $<19,000$ MW.
 - For load levels $>19,000$ MW additional means, such as 360 MW of fast start generation or demand response, would be required to eliminate the need to operate the Canal Units.
- The most recent analysis indicates that the short-term upgrades will increase the summer load level to above 21,000 MW (summer) and 24,000 MW (winter) before actions are needed to meet second contingency protection criteria.

Short Term Upgrades

- When completed the short-term upgrades will have two major impacts:
 - Shift the lower SEMA transmission interface towards Cape Cod, reducing the amount of load and area impacted.
 - Increase the thermal transfer capability, significantly reducing the operating conditions that would require post-second contingency actions.

Short-term Upgrades

Lower SEMA interface shifts to Cape Cod after short-term upgrades are completed



Revisions to Operating Guides

- In accordance with the Transmission Operating Agreement ISO-NE, in consultation with NSTAR, initiated several studies for the purpose of revising the operating guides for lower SEMA to reflect the inclusion of the short term transmission upgrades.
 - The draft operating guides are under review.
- Additional planning studies will be undertaken to assess the longer term reliability requirements
 - The normal planning and stakeholder process will identify if any further improvements are needed to meet planning criteria.

Revisions to Operating Guides

- The short-term upgrades in conjunction with revised operating guides are being evaluated to determine if:
 - The need to operate area generation out of merit to meet second contingency protection criteria can be eliminated through the use of targeted post-second contingency load shedding at high loads.
 - The need to run area generation for high voltage control at low loads can be eliminated once the seasonal boost of the Canal autotransformers no-load tap changers is discontinued.
 - The need to run area generation for low voltage support at peak loads can be eliminated once the Barnstable SVC is completed.
- The assessment and revised operating guides should be completed within the next few weeks.

SEMA Settlement

- SEMA Settlement:
 - Concluded a long series of settlement conferences at the FERC.
 - Filed May 18, 2007 by the ISO on behalf of the settling parties in Docket No. ER07-921.
 - The settlement was accepted by FERC as a rate schedule on June 21, 2007.

SEMA Settlement - continued

- The SEMA Settlement Highlights:
 - Transmission Owners paid LSEs and Munis \$20.5 million and \$3.77 million, respectively.
 - Imposed certain restrictions during a moratorium period. Key restrictions are briefly reviewed in following slides.
 - Changes to the Market Rule that provided for a trigger point above which LSCPR charges would be reimbursed to those serving Real Time Load Obligation from those serving Network Load.
 - ISO obligated to produce a short-term report to examine the use of switching or an SPS and long-term report that examines system upgrades needed to avoid out of merit operation of Canal units for reliability purposes.
 - Summarized the obligations of transmission owners to move forward with short -term upgrades.

SEMA Settlement - continued

Discussion of SEMA Settlement Restrictions:

- Section 4.1 states that during the Moratorium Period [January 1, 2007 through May 31, 2010], all NCPC charges for all reliability regions and for both Day-Ahead and Real-Time Markets, including SEMA NCPC charges for LSCPR shall be allocated (i) on the same basis that NCPC charges for LSCPR are allocated pursuant to the allocation mechanisms in Section III of the ISO-NE Tariff in effect on the date of this Settlement, and lii) on the basis of those provisions as amended pursuant to Section 5 of this Settlement if and as of the date those amended provisions become effective. Subject to the exceptions in the preceding sentence, **no Party shall seek or support** a different allocation mechanism prior to the end of the Moratorium Period, or seek or support a reclassification of ISO-NE's designation of Canal as LSCPR for service during the Moratorium Period.

SEMA Settlement - continued

- Section 4.2 states: Section 4.1 shall not prevent submission or support of proposed Market Rule amendments, in addition to those contemplated by Section 5, affecting NCPC charges for LSCPR that (1) do not increase the allocation of NCPC Charges for LSCPR to any Party, including but not limited to Network Load customers of the Transmission Owners, or (2) propose to exclude only Real-Time Load Obligation associated with Dispatchable Asset Related Demand pumps of pumped-storage generating resources from the Real-Time Load Obligations for the purpose of allocating Real-Time NCPC Charges for LSCPR.
- Section 7.2 states: The Parties, other than the Municipals, agree not to seek a change (in NEPOOL or before the Commission) in the ISO-NE definition of the SEMA Reliability Region to become effective prior to June 1, 2010; provided the Municipals may seek such a change to become effective no earlier than January 1, 2008.

SEMA Settlement - continued

- Section 8(c) states: No party shall propose or argue, either to the Commission or within the ISO-NE or NEPOOL process, for Market Rule amendments that would provide for a different mechanism for allocation of NCPC charges for LSCPR, or shall seek or support a reclassification of ISO-NE's designation of Canal as LSCPR during the Moratorium Period ... Except for amendments authorized by Section 4.2(a), the Parties shall oppose any Market Rule amendments that would provide for a different mechanism for allocation of NCPC charges for LSCPR than provided in Section 4.1 and Sections 5.1 and 5.2 or re-classification of ISO-NE's designation of Canal as LSCPR during the Moratorium Period proposed by persons who are not Parties to the Settlement.

SEMA Settlement - continued

- Section 7.2 regarding changes to the SEMA boundary is a little more flexible. It says that no party other than the municipal electric companies shall “seek” to change the boundaries of SEMA prior to June 1, 2010.

FERC Order Setting Out Compliance Requirement

- Order in Docket No. EL08-48-000 States the following:

The SEMA reliability region was adopted by ISO-NE from the existing electric regional boundaries of NEPOOL; it was originally established by engineering analysis of interfaces and transmission constraints. However, the SEMA regional boundary may no longer result in a just and reasonable allocation of the costs at issue here.

We find that whether or not the cost allocations resulting from the boundaries of the current SEMA region are just and reasonable raises issues of material fact that cannot be resolved on the record before us. We therefore will set MPS's complaint for hearing. However, we will hold the hearing in abeyance because we conclude at this point that the issues set for hearing and raised in the responses regarding SEMA are more appropriately addressed in the ISO-NE stakeholder process. The issues to be addressed in the stakeholder process include, but are not limited to, whether SEMA should be divided, and if so, how. The stakeholders may also consider other means (except for implementation of PFCS or SPS) to address the issues regarding complainants' challenges to the cost allocation in SEMA. The stakeholder process should consider the effects, if any, of any proposal on New England's markets or other regions in the ISO-NE footprint. We require the ISO-NE to submit a filing to the Commission no later than July 17, 2009 indicating how the ISO-NE will address the cost allocation issues set for hearing. That filing will describe the stakeholder procedures undertaken as a result of this order.

For example, if data show that the proposed resolution impacts the markets or costs for regions other than SEMA, those issues should be considered in any proposed resolution. footprint or other issues that do not arise as a result of the proposed resolution... .

Stakeholder Process

- The objective of this stakeholder process is to comply with the FERC order and seek consensus on:
 - Whether the SEMA Reliability Zone should be changed or remain the same.
 - Bifurcate;
 - Merge SEMA with adjacent zone(s).
- The transmission upgrades and their impact will be processed through the technical committees normally used for reliability and planning issues.
 - Informational updates will be provided to this committee as they become known.

Stakeholder Process – continued

- In support of the primary objective, the ISO proposes that the discussions be structured to cover the following topics over the next few months:
 - Confirm and document the criteria to be used to define zones.
 - Establish guidelines for changing existing zones, including appropriate notice provisions, with consideration to:
 - Planned changes to the transmission system;
 - Market Impacts;
 - Impacts to other reliability zones.
 - Appropriateness of SEMA zone for the periods:
 - After the completion of the short-term transmission upgrades;
 - From March 2008 to before the completion of the short-term transmission upgrades.

Stakeholder Process - continued

- The ISO is seeking agreement at the December MC meeting on:
 - The agenda for the stakeholder meeting in January and preliminary agendas for the meetings thereafter.
 - The analysis that will be needed to inform and support the agreed to agenda topics at each of the meetings.

Next Steps

- The ISO in consultation with NSTAR will complete the revisions to the operating guides to reflect the inclusion of the Short term upgrades.
 - Results will be provided at the January MC meeting.
- The ISO will provide draft criteria for defining reliability/load zones for discussion and input at a future MC meeting.
 - Draft to be provided at January or February MC meeting.

Guidelines For Modifying Existing Reliability Regions

Pursuant to the New England Market Rules, Reliability Regions and Load Zones comprise the same geographic area.¹ The defined Reliability Region/Load Zone serves two primary purposes under the current New England markets construct. They aggregate costs for pricing energy for load and they are used as the basis for allocating reliability costs (certain uplift and other out of market charges). The latter is in turn subdivided into charges directed to transmission companies for recovery through the transmission tariff (network load) or directed to Load serving entities through the provisions of Market Rule 1. The established Reliability Regions/Load Zones are as follows:

- Maine
- New Hampshire
- Vermont
- Rhode Island
- Connecticut
- Northeast Massachusetts (NEMA)
- West Central Massachusetts (WCMA)
- Southeast Massachusetts (SEMA)

Changed market conditions, resource additions or retirements, or changes in the transmission system may:

- a) cause a sub-region of a state to experience market differences consistent with those that would warrant establishing a Reliability Region, or
- b) cause a designated sub-region of a state to no longer experience the conditions that had previously led to that area being designated as a separate Reliability Region.

If the causes of such changed conditions are expected to persist for a significant period of time beyond the notice period described below, then after consultation with Participants the ISO may evaluate the potential for changing the zone or zones within the affected state using the following guidelines:

¹ Market Rule 1 defines "Load Zone" to mean: "Load Zone is a Reliability Region except as otherwise provided in Section III.2.7." Market Rule 1 defines "Reliability Region" to mean: "Reliability Region shall mean any one of the regions identified on the ISO's website. Reliability Regions reflect the operating characteristics of, and major transmission constraints on, the New England Transmission System." Section III.2.7(b) states "Each Load Zone shall initially be co-terminus with a Reliability Region." Section III.2.7(g) states: "After consulting with Market Participants, the ISO may reconfigure Reliability Regions, Load Zones and Reserve Zones as necessary over time to reflect changes to the grid, patterns of usage, changes in local TMOR contingency response requirements and intrazonal Congestion. The ISO shall file any such changes with the Commission."

- The maximum boundaries for Reliability Region/Load Zones will be contiguous with state boundaries. This ensures that the entire retail load being served within a particular Load Zone is also within one state jurisdiction.
- Potential subdivisions within the state will be considered based on significant interfaces monitored by system operations and the potential for meaningful market differences, either LMP or uplift, between subdivided areas. For each of the potential subdivisions within a particular state, the following guidelines will be used to determine whether a separate zone or zones should be established:
 - The resulting subdivision has a reasonably high expectation of periodically experiencing congestion or needing dispatch of resources out of economic merit order in order to comply with reliability criteria based on system operating limits.
 - System operating limits are based upon certain operating criteria including, but not limited to, pre- and post-contingency facility ratings, transient stability limits, voltage stability ratings, and system voltage limits. Interfaces are operated to ensure that the system can be re-dispatched within 30 minutes using the N-1-1 operating criteria and satisfying the most limiting of the prescribed operating criteria.
 - The resulting subdivision is of sufficient size to:
 - Provide a reasonably predictable pricing zone for energy including recognition of potential risk of incurring reliability cost allocations.
 - Encompass a sufficient number of resources that could contribute to meeting the reliability need as effectively as possible for the hours of need.
- Adjustments to the boundaries of the proposed Reliability Region may be considered to address local Distribution Company service territory boundaries and other stakeholder considerations including input from state regulatory authorities. Persistent needs will be addressed through the Regional System Planning Process to provide transmission or market solutions, or a combination thereof. Consideration will be given to whether the identified solutions will be implemented in a time frame that would obviate the need to create a separate reliability zone.

If a change to the a Reliability Region is warranted, a significant notice period, normally no less than one year prior to the change effective date, will be required before the change to the Reliability Region goes into effect unless a shorter notice is warranted based on stakeholder discussions or compliance actions under FERC Order. The notice shall include the revised boundaries for the affected regions/zones.



Executive Summary Excerpt from the Long-Term Report of ISO New England Inc.
Required Pursuant to Section 6.1(c) of the
SEMA Settlement Agreement

ISO New England Inc.
January 20, 2009

This is an excerpt only. The full Long Term Report contains Critical Energy Infrastructure Information and is available through ISO New England Customer Service using the following form:

http://www.iso-ne.com/support/custsvc/forms/external_ceii_request.doc

I. INTRODUCTION AND EXECUTIVE SUMMARY

This “Long Term Report” is required by a settlement agreement between ISO New England Inc. (“ISO”) and several other entities¹ that resolved certain issues regarding the out of economic merit operation of the Canal generating units² on Cape Cod, Massachusetts (the “Settlement Agreement”).³ That Settlement Agreement directed the preparation of this Long Term Report to identify technically feasible projects that would allow the lower Southeastern Massachusetts (“SEMA”) area to operate in compliance with applicable criteria without the need to operate the current Canal generation. Currently, the lower SEMA area⁴ is served by either the Canal generating units or power imported by two 345kV transmission lines and lower capacity 115kV lines. Currently, without at least one of the Canal generating units operating, if two contingencies occur (the loss of both the 345kV lines) the 115kV system cannot support Cape

¹ The parties to the SEMA Settlement Agreement are: NSTAR Electric Company; National Grid doing business as Granite State Electric Company, Massachusetts Electric Company, New England Power Company, Nantucket Electric Company, and the Narragansett Electric Company; Constellation Energy Commodities Group, Inc.; Constellation NewEnergy, Inc.; Consolidated Edison Solutions, Inc.; SUEZ Energy Resources NA, Inc.; Direct Energy Services, Inc.; Dominion Energy Marketing, Inc.; Dominion Retail, Inc.; PSEG Energy Resources and Trade LLC; Select Energy, Inc.; Strategic Energy; TransCanada Power Marketing, Ltd.; Integrys Energy Services, Inc.; Sempra Energy Solutions; Hull Municipal Lighting Plant; Mansfield Municipal Electric Department; Middleborough Gas & Electric Department; North Attleborough Electric Department; Braintree Electric Light Department; Hingham Municipal Lighting Plant; Taunton Municipal Lighting Plant; and ISO New England Inc.

² The Canal generating units were constructed in 1968 and are currently owned and operated by a subsidiary of the Mirant Corporation. Canal 1 has a summer and winter rating of 573/573 MW, and Canal 2 has a summer and winter rating of 545.12/562 MW.

³ The Settlement Agreement was accepted by the Commission in a letter order dated June 21, 2007 in Docket No. ER07-921-000.

⁴ The lower SEMA area includes all of Cape Cod and the towns to the north (as far as Marshfield) and west (as far as Freetown and Westport) of the Cape Cod Canal.

Cod's load and the entire lower SEMA area⁵ would lose power. As a result, the ISO operates at least one Canal unit to protect the area in case of a second contingency.

In order to address the power system limitations described above and in greater detail in this Long Term Report, NSTAR and National Grid are currently constructing significant upgrades to the transmission system in the lower SEMA area. In compliance with the Settlement Agreement, the ISO issued a "Short Term Report" in July of 2007 that examined the issue of shedding load in the area on the occurrence of a second contingency rather than operating Canal generation. That report looked at the system as it existed at the time, that is, prior to the construction of the short term upgrades. The Short Term Report concluded that while a post-first contingency switching ("PFCS")⁶ could technically be utilized up to a New England-wide load level of approximately 17,000 MW, it should not be used⁷ to the exclusion of the operation of available generation because, given the design of the system in that area, operators would have to rely on it as their next operating step in all hours, *i.e.*, setting up for load shedding of the entire Cape Cod area following a second contingency would be the only available next step for operators in almost all hours of all days of the year if a first contingency were to occur.⁸

⁵ The lower SEMA area has a peak load of approximately 1150 MW.

⁶ Post-first contingency switching does not shed load on the occurrence of a first contingency, but rather it is the process of setting up the electric system so that load is shed automatically on the occurrence of a second contingency.

⁷ The Short Term Report further concluded that an SPS was not technically consistent with criteria for such systems. While the Short Term Report did not address the question of whether such a load-shedding scheme should be relied on in lower SEMA to the exclusion of operating available generation, the same reasons that PFCS should not be used in lieu of generation in the lower SEMA area also apply to the use of a load-shedding SPS.

⁸ The ISO's determination that use of an SPS or PFCS was not appropriate prior to the addition of the short term upgrades to the lower SEMA area system was affirmed by the Federal Energy Regulatory Commission in an order issued on July 18, 2008. *See, Braintree Electric Light Dept., et al. v. ISO New England Inc.*, 124 FERC ¶ 61,061 (2008).

As explained in greater detail in the body of this report, the completion of the short term upgrades will significantly improve system performance in the lower SEMA area. Prior to the construction of the short term upgrades, Canal generation had to be run whenever regional load levels exceeded 10,500 MW, which in combination with Canal's operating characteristics required operation of one of the units every day of the year. The short term upgrades significantly reduce the level of the overloads that would presently occur in the event of a second contingency with both Canal units off-line. Even without consideration for the additional operational steps to eliminate reliance on the existing area generation discussed in this report, the short term upgrades result in not needing to have a Canal generating unit on-line until regional load⁹ levels exceed a level of 20,000 MW in the summer and 24,000 MW in the winter; approximately 42 to 58 days a year.

As a result of the improvements that result from the short term upgrades, posturing the system after the occurrence of a first contingency for post second contingency load shedding becomes a viable option and much less load will need to be shed in the event of a second contingency in order to keep power lines within their ratings. The ISO and NSTAR will be able to posture the system after a first contingency so that load in excess of the remaining transmission capability¹⁰ is selectively shed, rather than shedding the entire Cape Cod area, which is approximately 685 MW on peak.¹¹ In the event that load is shed as a result of a second contingency, the improved system performance that results from the short term upgrades allows

⁹ Regional loads levels do not directly correlate to load levels in SEMA, which are the load levels that determine operations for the area. However, regional load levels are used in this report as an approximate proxy for ease of discussion.

¹⁰ In other words, less load would be set up to be shed at lower load levels than at higher load levels.

¹¹ The ability to selectively shed load is limited up to approximately 1/3 of the current Cape Cod load, which would allow for the Cape Cod area to be operated without reliance on the Canal generation up to an approximate New England regional load of 30,000 MW.

load to be restored as peak loads subside below the 20,000 MW / 24,000 MW levels noted above, the outage is rotated to a different part of Cape Cod, or the cause of the contingency is repaired.

Because of the dramatically reduced number of days and hours that load shedding would be relied upon, the significantly reduced level of exposed load, and the reduced potential duration of any outage, the ISO believes that the lower SEMA area can be operated reliably and within criteria after the completion of the short term upgrades without the need to operate the generation at Canal station at current system load levels. The ISO is currently working with NSTAR and National Grid on the details of operating the system in a manner that incorporates reliance on limited load shedding, and a transmission operating guide will be developed prior to the completion of the short term upgrades that will implement that operating change. The reliance on limited load shedding will be implemented no later than at the time the dynamic reactive device is placed in service, which is scheduled for September of 2009, and potentially as early as June 2009 when the 345 kV work at Carver substation and the 115 kV line between the Carver and Tremont substations is scheduled to be completed.

While load shedding can be relied upon for a few years, as load continues to grow the operational headroom afforded by the short term upgrades will be reduced and additional reinforcements in the area, either transmission or generation, will be necessary in order to operate the area reliably without reliance on the Canal generation.

In compliance with the Settlement Agreement, the ISO, NSTAR and National Grid have also studied the transmission system upgrades that would be needed to reliably operate the lower SEMA area without reliance on load shedding. Several potential solutions were reviewed. The results of that review indicate that a 345 kV line between the Carver and Sandwich substations

and associated work is the most cost-effective long term transmission system enhancement solution.

To: NEPOOL Markets Committee

From: Kevin Kirby

Date: May 5, 2009

Subject: Overview of proposed compliance filing approach and motion seeking Markets Committee support of that approach.

I. Overview and Key Questions

Over the past few months, the ISO has discussed with the Market Committee the issue of whether the Reliability Region / Load Zone¹ for the Southeastern Massachusetts (“SEMA”) zone should be modified. That discussion has largely focused on (1) whether the SEMA zone should be bifurcated into an upper-SEMA and lower-SEMA zone, (2) whether the zone should be eliminated so that it would become part of the West-Central Massachusetts zone, or (3) whether the SEMA zone should remain as it currently is delineated. The ISO has discussed these questions with this committee in the context of looking forward as well as looking back to a date of March 28, 2008.²

II. Context for the Discussion with the Markets Committee and Review of Discussions to Date

The ISO began this discussion with the Markets Committee following a determination by the Federal Energy Regulatory Commission (the “Commission” or “FERC”) in an order denying a complaint in Docket No. EL08-48-000 (“July 18 Order”). In that order, the Commission noted that it was not clear if the boundaries of SEMA continued to be just and reasonable. The Commission directed the ISO to examine the issue in a stakeholder process:

The SEMA reliability region was adopted by ISO-NE from the existing electric regional boundaries of NEPOOL; it was originally established by engineering analysis of interfaces and transmission constraints. However, the SEMA regional boundary may no longer result in a just and reasonable allocation of the costs at issue here.

We find that whether or not the cost allocations resulting from the boundaries of the current SEMA region are just and reasonable raises issues of material fact that cannot be resolved on the record before us. We therefore will set MPS’s complaint for hearing. However, we will hold the hearing in abeyance because we conclude at this

¹ *Settlement of Dispute over SEMA Charges*, Docket No. ER07-921-000. Filed with the Federal Energy Regulatory Commission (“Commission”) on May 18, 2007. (“SEMA Settlement”) The Settlement was approved by the Commission by letter order dated June 21, 2007.

² March 28, 2008 is the refund effective date set for the complaint filed in Docket No. EL08-48-000.

point that the issues set for hearing and raised in the responses regarding SEMA are more appropriately addressed in the ISO-NE stakeholder process. The issues to be addressed in the stakeholder process include, but are not limited to, whether SEMA should be divided, and if so, how. The stakeholders may also consider other means (except for implementation of PFCS or SPS) to address the issues regarding complainants' challenges to the cost allocation in SEMA. The stakeholder process should consider the effects, if any, of any proposal on New England's markets or other regions in the ISO-NE footprint. We require the ISO-NE to submit a filing to the Commission no later than July 17, 2009 indicating how the ISO-NE will address the cost allocation issues set for hearing. That filing will describe the stakeholder procedures undertaken as a result of this order.

For example, if data shows that the proposed resolution impacts the markets or costs for regions other than SEMA, those issues should be considered in any proposed resolution.

The ISO began the process by reviewing the Commission's July 18 Order with the Committee and the restrictions regarding the SEMA that were agreed to as part of the settlement related to SEMA, which several participants, including the ISO and the municipal entities that brought the original complaint, are parties to.³ Among other things, the SEMA Settlement directed that:

...no party shall seek or support a different allocation mechanism [for LSCPR] prior to the end of the Moratorium Period [Jan 1, 2007 through May 31, 2010], or seek or support a reclassification of ISO-NE's designation of Canal as LSCPR for service during the Moratorium Period.⁴

The settlement further provided:

No party shall propose or argue, either to the Commission or within the ISO-NE or NEPOOL process, for Market Rule amendments that would provide for a different mechanism for allocation of NCPC charges for LSCPR, or shall seek or support a reclassification of ISO-NE's designation of Canal as LSCPR during the Moratorium Period...Except for amendments authorized by Section 4.2(a), the Parties shall oppose any Market Rule amendments that would provide for a different mechanism for allocation of NCPC charges for LSCPR than provide in Section 4.1 and Sections 5.1

³ The parties to the SEMA Settlement Agreement are: NSTAR Electric Company; National Grid doing business as Granite State Electric Company, Massachusetts Electric Company, New England Power Company, Nantucket Electric Company, and the Narragansett Electric Company; Constellation Energy Commodities Group, Inc.; Constellation NewEnergy, Inc.; Consolidated Edison Solutions, Inc.; SUEZ Energy Resources NA, Inc.; Direct Energy Services, Inc.; Dominion Energy Marketing, Inc.; Dominion Retail, Inc.; PSEG Energy Resources and Trade LLC; Select Energy, Inc.; Strategic Energy; TransCanada Power Marketing, Ltd.; Integrys Energy Services, Inc.; Sempra Energy Solutions; Hull Municipal Lighting Plant; Mansfield Municipal Electric Department; Middleborough Gas & Electric Department; North Attleborough Electric Department; Braintree Electric Light Department; Hingham Municipal Lighting Plant; Taunton Municipal Lighting Plant; and ISO New England Inc.

⁴ SEMA Settlement at Section 4.1.

and 5.2 or re-classification of ISO-NE's designation of Canal as LSCPR during the Moratorium Period proposed by persons who are not Parties to the Settlement.⁵

The SEMA Settlement allowed the municipal parties to the settlement to seek a change to the definition of the SEMA Reliability Region prior to May 31, 2010 but no earlier than January 1, 2008.⁶

With those restrictions in mind, the ISO focused its discussion with the Markets Committee on whether the SEMA zone should be altered prospectively and/or retroactively back to the March 18, 2008 date.

The driver for considering whether the SEMA zone should be bifurcated or combined into another zone has been the uplift for the out-of-merit operation of the Mirant Canal generating resources located on Cape Cod. The ISO reviewed with the Markets Committee the history of how the power system was designed in the SEMA area and the factors that lead to the out-of-merit operation of generation in the lower SEMA area. Briefly, the lower SEMA area was designed based on a Canal resource being on-line. This was typically the case prior to 2006 when rising oil prices resulted in the Canal units falling out of economic merit order. The resources have been needed on-line when New England load levels exceeded approximately 10,500 MWs.

The ISO also reviewed information with the Markets Committee regarding near term changes that were being put in place in SEMA that would largely address the out-of-merit operation of resources in lower SEMA. In short, the transmission system in the SEMA area was assessed in 2006 and so-called "short-term" upgrades were identified that would significantly increase the load level at which generation would be needed in the lower SEMA area. Those upgrades have been under construction and the ISO and NSTAR had been working together to assess the impacts of those system improvements. At the December MC meeting, the ISO informed the Markets Committee that it was working on an analysis which it expected to conclude in the near future regarding the impact of the short-term upgrades on the need to operate generation, and thus the impact on potential out-of-market payments. The ISO concluded that review with NSTAR and noted in its "SEMA Long Term Report"⁷, posted to the password protected Planning Advisory Committee web page on January 20, 2009,⁸ that the short-term upgrades would have a very significant impact on the need to operate generation for second contingency protection in the SEMA area. As a result of that fact, the ISO and NSTAR have developed an operating guide that will rely on certain post-second contingency actions in lieu of the need to operate generation out-of-merit.

⁵ SEMA Settlement at Section 8(c).

⁶ Section 7.2 of the SEMA Settlement states: The Parties, other than the Municipals, agree not to seek a change (in NEPOOL or before the Commission) in the ISO-NE definition of the SEMA Reliability Region to become effective prior to June 1, 2010; provided the Municipals may seek such a change to become effective no earlier than January 1, 2008.

⁷ "Long Term Report of ISO New England Inc. Required Pursuant to Section 6.1(c) of the SEMA Settlement Agreement", January 20, 2009.

⁸ The SEMA Long Term Report contains Critical Energy Infrastructure Information. http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/index.html

To assist the Committee in considering the issue of whether to alter the SEMA zone, the ISO researched and reviewed the general guiding principles that were utilized when the zones were created. Further, the ISO discussed those guidelines with the Committee in order to update them for use in considering when the boundaries of a zone should be altered or a new zone created or removed going forward. The Committee's feedback has been incorporated into that general guideline document. Those guidelines are included with this memorandum as Attachment 1.

As noted above, the need to operate out-of-merit generation in the lower SEMA zone is largely eliminated by the completion of the short-term upgrades and the adoption of the area operating guide that will rely on post-second contingency actions. As a result, the SEMA area should not have "a reasonably high expectation of experiencing congestion or needing dispatch of resources out of economic merit order to comply with reliability criteria based on system operating limits."⁹

III. Committee input and ISO Assessment on Change to SEMA Zone Going Forward

The input provided to the ISO indicates a majority support the view that the zone should not be changed prospectively at this time. The ISO concurs with this view. With the elimination of the uplift, there does not appear to be a reason to bifurcate the zone and the existence of the zone as it is now defined does not create other problems. The ISO notes that it will review the existence of the zone after some operational experience is gained with the short-term upgrades and may, with appropriate notice and stakeholder discussion, recommend eliminating the zone altogether at a future time.

IV. Committee Input and ISO Assessment for the Period back to March 28, 2008

With regard to changing the SEMA zone back to the March 28, 2008 date, the majority of input received to date from the Markets Committee indicates that there is not support for changing the zone for that period. The ISO concurs with that input.

First, the ISO is recommending that the SEMA zone should not be merged with another zone for the period back to March 28, 2008. The SEMA zone was created because of certain transmission constraints and voltage issues. The following is a list of work that has been done in the area since the zone was defined and the sum of this work has been, among other things, the elimination of the original constraints. However, with each upgrade has come the need to gain operational experience with the impact of the system changes. Given the dynamic nature of system changes in the area over the past few years, the ISO has not recommended the elimination of the zone to date.

Post SEMA zone definition upgrades that affect area reliability performance

⁹ Zone Guidelines document at p. 2.

- Independent Pole Breaker replacement program at key 345 kV substations increase area stability export capability
- Increase in internal SEMA generation; Fore River, Tiverton, Dighton (units > 100 MW)
- NEMA Upgrades (reference schedule 12A NEMA Upgrades) – Some of these upgrades also resulted in increase to SEMA area export/import capability
 - Framingham 230/115kV autotransformer and breaker replacement
 - Upgrade Framingham to West Medway 230 kV line (240-601)
 - Add Mystic 345kV breaker #101S
 - West Walpole 345/115kV autotransformer and breaker replacement
 - Rebuild Speen Street to Sudbury 115kV line (342-507) and replace breakers at both ends
 - Waltham 230/115kV autotransformer and breaker replacement
 - Upgrade Waltham to West Medway 230 kV line (282-602)
 - Upgrade Framingham to Speen Street 115kV line (433-507) and replace breakers at Framingham
 - Add a third Waltham 115kV phase shifting transformer
 - Upgrade Sherborn 115kV station equipment
 - Merrimack (New Hampshire) 230/115kV autotransformer replacement
- Stoughton 345 kV cable additions – these also increased SEMA area export/import capability
- Lower Southeast Massachusetts reinforcements (Carver area upgrades – remove Canal n-1-1 commitment requirement, rely on load posturing past NE load >20K)
- NSTAR/NGRID transmission capacitor additions and Load Power factor correction upgrades (relieve Canal generation must run requirements for low voltage)

Second, the SEMA zone should not be bifurcated for the period back to the March 28, 2008 date. Application of the general guidelines counsels against creating zones that are too small. Zones that are too small may be of insufficient size to provide a reasonably predictable pricing zone for structuring longer term energy contracts, such as those needed to serve state specific standard offer service, that account for risk of reliability cost allocations. Very local reliability needs that may emerge from time to time because of transmission or transmission outages or due to construction may be better suited to a broader sharing of costs.

Finally, while the Commission noticed a refund effective date of March 28, 2008 which signaled that the zone could change in one way or another, *i.e.*, be bifurcated or merge into another zone, the ISO has recommended that zones only be changed with significant advanced notice, generally a year, which would include specific detail regarding the zonal change that would occur. This notice provision is intended to allow parties sufficient time to incorporate the impact of an alternation on their commercial arrangements.

V. Conclusion

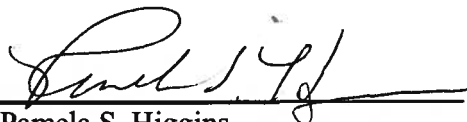
Based on the feedback received regarding this issue and the ISO's own review, the ISO proposes to recommend to the Commission that the SEMA zone remain unchanged going forward for a time until additional experience with the short-term upgrades is gained in the SEMA area. Further, based on the input received to date and for the other reasons stated above, the ISO proposes recommending to the Commission that the SEMA zone remain unchanged from the present time back to March 28, 2008.

The ISO is seeking the Market Committee's feedback regarding its compliance submission and has included a motion in the materials for the May 12 meeting, which states that the Committee concurs with the determinations not to alter the SEMA zone at this time as stated in this memorandum.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in these proceedings.

Dated at Washington, D.C. this 17th day of July, 2009.

A handwritten signature in black ink, appearing to read "Pamela S. Higgins", written over a horizontal line.

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