March 28, 2008

Via Electronic Filing

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: *Braintree Electric Light Department, Hingham Municipal Lighting Plant, Hull Municipal Lighting Plant, Mansfield Municipal Electric Department, Middleborough Gas & Electric Department, and Taunton Municipal Light Plant*, Docket No. EL08-___-__; **REQUEST FOR COMMISSION RULING THAT INFORMATION IS NOT PROPERLY DESIGNATED AS "CRITICAL ENERGY INFRASTRUCTURE INFORMATION"**

Dear Secretary Bose:

Please find enclosed for filing the "Complaint of Braintree Electric Light Department, Hingham Municipal Lighting Plant, Hull Municipal Lighting Plant, Mansfield Municipal Electric Department, Middleborough Gas & Electric Department, and Taunton Municipal Light Plant, Requesting Fast Track Processing," supported by the "Direct Testimony and Exhibits of Whitfield A. Russell" (collectively, "the Complaint"). The Complaint includes information designated by Respondent ISO New England Inc. as **"Critical Energy Infrastructure Information" ("CEII")**. As explained herein, Complainants seek a ruling that this information need not be treated as CEII in the proceedings initiated today by the submission of the Complaint.

In support of this request, Complainants state:

The enclosed Complaint includes a copy of, and arguments related to, the July 17, 2007 "Short-Term Report of ISO New England Inc." ("Short Term Report") prepared by ISO-NE pursuant to a settlement agreement accepted by the Commission in Docket No. ER07-921-000. This Report examines the possibility of meeting applicable reliability criteria through the implementation of one of two specific load shedding arrangements instead of meeting those same reliability criteria through reliance on the out of merit operation of the two Canal generating units located in Southeastern Massachusetts. While ISO-NE has informed those receiving the Short Term Report that it contains "Critical Energy Infrastructure Information," ISO-NE has not previously filed the Short Term Report with the Commission. As such there has been no prior determination by the Commission that this Report in fact merited CEII treatment.

Complainants do not believe that the information included in the Short Term Report meets the Commission's definition of CEII. The Commission's regulations set forth a four-part test for determining whether information should be treated as CEII:

> Critical energy infrastructure information means *specific engineering, vulnerability, or detailed design information* about proposed or existing critical infrastructure that: (i) [r]elates details about the production, generation, transportation, transmission, or distribution of energy; (ii) [c]ould be useful to a person in planning an attack on critical infrastructure; (iii) [i]s exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552; and (iv) [d]oes not simply give the general location of the critical infrastructure.

18 C.F.R. § 388.113(c)(1) (emphasis added). Consistent with the terms of the regulation, the Commission has clarified that "narratives such as the descriptions of facilities and processes are generally not CEII unless they describe *specific engineering and design details of critical infrastructure*." Order No. 683, PP 6-7 (2006) (emphasis added).[1]

Complainants assert that the data contained in the Short Term Report do not meet the understandably stringent standards that the Commission has established must be met for a document to be designated as "CEII." The Short Term Report contains general information about transmission facilities and the application of reliability criteria in Southeast Massachusetts. Moreover, much of the information contained in the Short Term Report is available from other, public sources. In these circumstances, Complainants assert that the Short Term Report lacks the specificity that the regulations require in order for material to be classified as CEII, and that the Commission should find that the information should not be so classified.[2]

Pending a Commission ruling, Complainants will treat the Short Term Report (and the information contained therein that is not otherwise publicly available) in a manner consistent with the "CEII label" placed on the document by ISO-NE. In accordance with the procedures set out in 18 C.F.R. § 388.112(b), Complainants are therefore filing both a public and a confidential or redacted version of the Complaint. However, Complainants respectfully request that the Commission review the Short Term Report and find that (1) the information contained in the Short Term Report does not meet the Commission's criteria for treatment as CEII; and (2) the complete, unredacted version of the Complaint should be made publicly available.

In accordance with Rules 2001(a)(iii) and 2003(c) of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.2001(a)(iii) and 2003(c), Complainants hereby submit via electronic filing a public and a confidential version of the Complaint. Additionally, in

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[1] The phrase "specific engineering, vulnerability, or detailed design" was added to the CEII regulations in response to concerns that "many submitters over utilize the [CEII] designation" and in order to "better inform companies of what constitutes CEII to limit the amount of material which constitutes CEII." Order No. 683 at P 6.

[2] As explained by the Commission, "CEII was intended only to protect *detailed* information that would aid a terrorist attack …." Order No. 683 at P 6, emphasis added.

accordance with Rules 206(c) and 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.206(c) and 2010, Complainants are concurrently serving the confidential version of the Complaint on the Respondent and a public version of the Complaint on each person on the service list compiled by the Secretary in Docket No. ER07-921-000.

Thank you for your attention to this matter.

Sincerely,

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Enclosures

cc: Raymond Hepper, Esq.
(w/encls.)

PUBLIC VERSION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Braintree Electric Light Department, Hingham Municipal Lighting Plant, Hull Municipal Lighting Plant, Mansfield Municipal Electric Department, Middleborough Gas & Electric Department, and Taunton Municipal Light Plant, Complainants,	
v.	Docket No. EL08-___
ISO New England Inc. Respondent.	

COMPLAINT OF BRAINTREE ELECTRIC LIGHT DEPARTMENT, HINGHAM MUNICIPAL LIGHTING PLANT, HULL MUNICIPAL LIGHTING PLANT, MANSFIELD MUNICIPAL ELECTRIC DEPARTMENT, MIDDLEBOROUGH GAS & ELECTRIC DEPARTMENT, AND TAUNTON MUNICIPAL LIGHT PLANT REQUESTING FAST TRACK PROCESSING

1. Pursuant to Sections 206 and 306 of the Federal Power Act ("FPA"), 16 U.S.C. §§ 824e, 825e, and Rule 206 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.206, Braintree Electric Light Department, Hingham Municipal Lighting Plant, Hull Municipal Lighting Plant, Mansfield Municipal Electric Department, Middleborough Gas & Electric Department, and Taunton Municipal Light Plant (collectively, "Massachusetts Public Systems," "MPS" or "Complainants") file this complaint against ISO New England Inc. ("ISO" or "ISO-NE").[1]

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[1] As stated in the Transmittal Letter accompanying this Complaint, Complainants, despite reservations, will abide by ISO-NE's characterization of certain information included herein as "Critical Energy

2. As set forth below, ISO-NE overcharged MPS approximately $24 million in 2006 and 2007, and is on pace to overcharge MPS more than $13.5 million in 2008, by characterizing as "local second contingency protection resource" charges, contrary to its tariff, costs that ISO-NE did not need to incur in order to meet applicable second-contingency requirements. The costs were incurred not to meet the applicable requirements but, rather, to avoid the small chance of controlled load shedding on Cape Cod following a second contingency that the applicable criteria permit. MPS do not insist that Cape Cod customers must be exposed to those risks, but the costs of avoiding them must be borne by those customers—as the ISO's tariff requires. This case is not about degrading system reliability; it is about cost allocation and ensuring compliance with the ISO's tariff. MPS ask the Commission to enforce the ISO-NE tariff and direct the ISO to refund amounts that it has improperly collected from MPS since December 28, 2007 (*i.e.*, three months prior to the filing of this complaint, as contemplated by the settlement accepted by the Commission in Docket No. ER07-921-000).[2]

3. MPS request that the Commission address the issues raised in this Complaint through its "Fast Track" processing procedures. As explained *infra*, such action is appropriate because of the importance of the matters at issue, the substantial

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Infrastructure Information" ("CEII") and are therefore filing both public and confidential versions of this Complaint in accordance with the procedures set out in 18 C.F.R. § 388.112(b). However, Complainants respectfully request that the Commission review this document and find that (1) the information herein does not meet the Commission's criteria for treatment as CEII, and (2) the complete, unredacted version of the complaint should be made publicly available.

[2] Alternatively, if the Commission were to find that the ISO's tariff currently permits it to charge all load in the Southeast Massachusetts reliability zone for costs that are not necessary to meet applicable second contingency requirements and that benefit only a subset of load in that zone, then the tariff is unjust and unreasonable and must be modified.

financial considerations at stake, and the potential complications that a delay may entail in ensuring the provision of timely, complete and effective relief to the Complainants.

I. INTRODUCTION AND SUMMARY

4. Since January 2006, ISO-NE's decision to operate two old, inefficient, and dirty generating units to satisfy reliability criteria that could be met by much cheaper, more dependable, and more environmentally-sound means, has caused the incurrence of hundreds of millions of dollars in unnecessary out-of-pocket costs, and the needless emission of tons of pollutants. Specifically, ISO-NE has operated one or both of the 1960s- or 1970s-era Canal Generating Units,[3] out of economic merit order and at inefficient output levels, in order to satisfy post-contingency operating requirements.[4] These requirements could be addressed at a fraction of the cost and with no adverse

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[3] Located in Sandwich, Massachusetts, near Cape Cod, Canal Electric Generating Unit No. 1 is a residual fuel oil-fired steam turbine that entered commercial operation on July 1, 1968. Its sister unit, Canal Electric Generating Unit No. 2, is a residual fuel oil-fired steam turbine unit that is also capable of operating on natural gas and which entered commercial operation on February 1, 1976. Each of the two units has a summer capacity rating of 559 MW, while the winter capacity rating for each of them is approximately 562-564 MW. Both Canal Units are owned by Mirant Canal LLC ("Mirant").

[4] *See* ISO-NE Operating Procedure No. 19 (Transmission Operations), *available at* http://www.iso-ne.com/rules_proceds/operating/isone/op19/op19_rto_final.pdf; NPCC Document A-2 (Basic Criteria for Design and Operation of Interconnected Power Systems), available at http://www.npcc.org/viewDoc.aspx?name=A-02.pdf&cat=regStandCriteria; and NPCC Document A-03 (Emergency Operation Criteria), *available at* http://www.npcc.org/viewDoc.aspx?name=A-03.pdf&cat=regStandCriteria.

environmental impact through the adoption of a "Post-First Contingency Switching" ("PFCS") arrangement[5] or the installation of a Special Protection System ("SPS").[6]

5. As explained in the attached testimony of Mr. Russell, analysis of hourly data indicates that ISO commits at least one Canal Unit in most hours of the year. At the same time, Mirant's 2006 annual report states that the capacity factor for the Canal Generating Station was just 17 percent.[7] ISO's unnecessary reliance on the frequent out of merit operation of Canal at low operating levels imposes tremendous costs. During 2006 and 2007, ISO incurred and passed through to consumers more than $100 million *per year* in Canal-related, above-market uplift costs. In addition, despite its low capacity factor, the Canal Generating Station emitted 4,876,581 tons of carbon dioxide in 2007 — the second most CO_2 emissions of all power plants in New England.[8]

6. Virtually all of these costs were avoidable. **[**BEGIN CEII**]**

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[5] PFCS is a pre-planned sequence of manual procedures designed to react to potential contingencies by isolating the faulted element from the system. The contingency events are detected by, and the load switching procedures are implemented by, transmission system personnel. *See* attached Testimony of Whitfield A. Russell ("Russell Testimony") at 23.

[6] An SPS is a set of relays and telecommunication devices that independently (*i.e.*, without human intervention) trigger "special" protective actions, meaning actions that go beyond the customary protective actions triggered by typical protective schemes. *See* Russell Testimony at 36-37.

[7] Mirant, *2006 Annual Report and Notice of 2007 Annual Meeting and Proxy Statement*, at 37 (available at http://www.mirant.com/investor_relations/pdfs/annual_report_2006.pdf).

[8] Comparative CO_2 emission data is published by CARMA: Carbon Monitoring for Action, and plant-specific data for the Canal Generating Station is available at http://carma.org/plant/detail/6898 (last visited Mar. 18, 2008). According to CARMA (http://carma.org/blog/about, last visited Mar. 18, 2008), the database "is produced and financed by the Confronting Climate Change Initiative at the Center for Global Development, an independent and non-partisan think tank located in Washington, DC," based upon "data reported to the Environmental Protection Agency by the plant operators themselves as required by the Clean Air Act."

[END CEII**]** Mr. Russell explains, **[**BEGIN CEII**]** **[**END CEII**]** and a PFCS arrangement likely would satisfy applicable reliability criteria up to considerably higher load levels. **[**BEGIN CEII**]**

[END CEII**]** Moreover, as Mr. Russell observes, ISO and the region's transmission owners have previously defended the use of PFCS arrangements as a means of avoiding unnecessary out-of-merit generation charges elsewhere in New England.

7. Out-of-merit Canal costs also could have been avoided through the installation of an SPS — either instead of or in addition to a PFCS arrangement. Mr. Russell explains that, **[**BEGIN CEII**]** **[**END CEII**]** an SPS could be designed and installed consistent with applicable reliability criteria, and would provide more dependable protection against the most serious system risks than is achieved by relying on generating units that are more than thirty years old. Mr. Russell states that an SPS could be designed and installed for a one-time cost of approximately $1 million.

8. Both a PFCS arrangement and an SPS involve a very small risk of controlled load shedding under a narrow and improbable set of circumstances. In the unlikely event that both 345-kV transmission lines feeding Cape Cod were lost at a time when the Canal generating units were not operating, a PFCS arrangement or an SPS would allow the ISO to shed Cape Cod load quickly and in a controlled manner, as permitted by applicable reliability criteria. The already low risk of such an occurrence

could be further minimized by starting the Canal units preemptively when severe weather is forecast or when planned transmission outages are scheduled to occur. And even if either a PFCS or SPS were activated, service to the Cape likely would be restored quickly upon the earlier of the synchronization of the Canal Units with the grid or the resolution of the transmission contingencies.

9. **[**BEGIN CEII**]**

[END CEII**]** Moreover, as noted, this case is not intended to force any customer to accept an increased outage risk; it is about enforcing the ISO tariff and requiring the customers who wish to avoid risks that are permitted by the applicable criteria to pay the costs of doing so.[9]

10. ISO-NE has acted contrary to its Transmission, Markets & Services Tariff ("Tariff")[10] by characterizing the unnecessary costs associated with running the Canal Units out-of-merit as "Local Second Contingency Protection Resource" ("LSCPR")

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[9] Not only has ISO's approach charged MPS millions of dollars for unnecessary costs from which they do not benefit, the reliance on out-of-merit generation operation in lieu of a PFCS arrangement or SPS actually exposes MPS and other customers outside Cape Cod to *greater* reliability risks, as an SPS or PFCS arrangement would be a more dependable means of protecting those customers against voltage collapse than is the ISO's current reliance on operating very old generating units.

[10] *Available at* http://www.iso-ne.com/regulatory/tariff/index.html.

charges. Such charges are allocated based on real-time or day-ahead load obligations in the Southeast Massachusetts Reliability Region ("SEMA").[11] As Mr. Russell explains, SEMA consists of two electrically distinct sub-regions: "Upper SEMA"[12] and "Lower SEMA."[13] The MPS systems are all located in *Upper SEMA*, while ISO operates the Canal Units **[**BEGIN CEII**]**

[END CEII**]** ISO's Tariff socializes among all load in a reliability region only those costs that are "necessary" to satisfy applicable reliability criteria. Specifically, Section III.6.1 of ISO's Tariff defines LSCPRs as those resources that are "necessary" to fulfill second contingency requirements under applicable reliability standards. Additional and more expensive steps may be taken at the request of a Transmission Owner, but such additional costs must be borne by that Transmission Owner, and not by other systems in the reliability region.

11. Mr. Russell testifies that in most circumstances running the Canal Units out of merit order is *not* necessary to meet applicable second contingency criteria, because they could be satisfied by the implementation of a PFCS arrangement or the installation of an SPS. **[**BEGIN CEII**]**

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[11] Tariff Section III.1.3.2 defines a "Reliability Region" as "any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System."

[12] Upper SEMA is located well west of Cape Cod on the Massachusetts mainland, outside the Plymouth and New Bedford Districts of the NSTAR system. *See* Russell Testimony at 10.

[13] Though the ISO has provided inconsistent descriptions of Lower SEMA, its load and generation, for the purposes of this Complaint and as described below in more detail, Lower SEMA encompasses the geographic area of New Bedford, Plymouth and Cape Cod, Massachusetts. *See* Russell Testimony at 10.

[END CEII**]** Mr. Russell estimates that at least 30 percent of Canal uplift charges — or approximately $63 million in 2006 and 2007 — could have been avoided if the ISO had implemented a PFCS arrangement at New England-wide load levels below **[**BEGIN CEII**]** **[**END CEII**]** Even greater amounts could have been avoided if an SPS had been installed or a PFCS arrangement had been available and implemented at even higher load levels, as Mr. Russell contends could have been done consistent with applicable reliability criteria. Because these costs were not "necessary" to meet applicable second contingency requirements, ISO contravened the requirements of its tariff by characterizing them as LSCPR charges and allocating them to all SEMA load.[14]

12. Alternatively, if the Commission finds that the Tariff permits the ISO to assess LSCPR charges for "elective" second contingency reliability measures, then the Tariff is unjust and unreasonable and must be modified. As explained in further detail below, the allocation of such costs to SEMA load is either over- or under-inclusive, depending on which of the risks asserted by ISO-NE forms the basis for operating the Canal units out of merit order. If ISO is operating the Canal units out of merit in order to avoid **[**BEGIN CEII**]**

[END CEII**]** then the allocation of Canal

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[14] Ordinarily, remedies for tariff violations may reach back to when the violation began. In this case, the availability of relief is limited to some extent by a Settlement Agreement entered into in Docket No. ER07-921-000 (May 18, 2007) (*available at* eLibrary accession no. 20070523-0023) ("Settlement Agreement") and accepted by letter order dated June 21, 2007. MPS seek relief only to the extent consistent with the Settlement Agreement, which reserved the litigation rights that MPS seek to exercise in this Complaint. *See* Settlement Agreement §§ 7.1(a) and 7.2.

uplift costs to all of SEMA is over-inclusive. Upper SEMA customers, such as the MPS, do not create the need for the ISO to operate the Canal Units out-of-merit in lieu of using a PFCS arrangement to meet second contingency reliability criteria, and the MPS systems derive no benefit from relying on Canal uplift instead of a PFCS arrangement or an SPS. Even more important, the MPS have no ability to address and resolve the reliability issues that motivate the ISO to operate the Canal units on an out-of-merit basis. Thus, the imposition of the LSCPR charges on MPS is nothing more than a penalty for conduct in which they did not engage and which, going forward, they have no ability to change. On the other hand, **[**BEGIN CEII**]**

[END CEII**]** then such charges should be allocated region-wide; imposing them exclusively on SEMA load would be under-inclusive.[15]

13. In these circumstances, if the Commission finds that the Tariff permits ISO to classify the Canal uplift costs as LSCPR charges and allocate them to MPS, then the Commission should find that the ISO's Tariff is unjust and unreasonable and order that it be modified to ensure that Canal Unit out-of-merit charges are either (i) not imposed upon Upper SEMA customers, or (ii) allocated to the entire New England

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[15] **[**BEGIN CEII**]**

. **[**END CEII**]** Reliance on the Canal units rather than an SPS to protect against the loss of the 345-kV lines feeding Cape Cod thus exposes the rest of New England to a *greater* risk of voltage collapse.

region. Alternatively, another way in which to provide relief would be to subdivide SEMA into two Reliability Regions: Lower SEMA and Upper SEMA.

14. In sum, this case is not about exposing any customers to potential blackouts, whether brief or extended, in return for the incurrence of lesser charges for services required to ensure system reliability. It is about deciding which customers should pay the cost of avoiding the risk of service outages through the out-of-merit operation of Canal. Although Applicable Criteria would permit use of PFCS or an SPS, Complainants are not arguing that ISO must implement either option. However, whether or not either option is implemented, their existence and viability means that the additional cost of operating Canal out of merit cannot reasonably be imposed upon MPS customers as an LSCPR charge.

15. MPS request that the Commission process this Complaint and the ensuing proceeding under its "fast track" standards due to the substantial, unjust LSCPR charges that are being, and will continue to be, incurred by MPS. In the absence of expeditious resolution of this matter, the Municipals (and their customers) may face charges in excess of $13.5 million this year in addition to the roughly $24 million in unnecessary charges that have already been paid. The LSCPR charges are a significant financial burden on the Complainants warranting fast track processing. Moreover, fast-tracking the Complaint will minimize the need for retroactive relief, and the potential administrative complications it entails and help to send a timely signal to NSTAR Electric Company

("NSTAR") to employ all prudent and diligent means to complete needed Lower SEMA transmission improvements.[16]

II. PARTIES

16. The parties to this proceeding are:

A. Complainants

17. Complainants are Massachusetts municipal lighting plants, organized and existing under and by virtue of Mass. Gen. Laws ch. 164, §§ 34-69, as amended.

18. Each of the MPS provides or represents systems that provide electric service at retail to consumers within SEMA. Each of the MPS incurred or represents systems that incurred significant costs as a result of ISO-NE's determination to operate one or both of the Canal Units out of economic order as its preferred means of satisfying applicable post-contingency operating criteria, at a cost currently averaging more than $8 million per month, and ISO-NE's classification of those costs as LSCPR charges to be allocated to SEMA load.

19. Two of the MPS (Braintree and Hingham) are interconnected with the NSTAR Electric Corporation transmission system at 115 kV. These systems are physically remote from, and are not affected by, the transmission contingencies in anticipation of which ISO-NE has chosen to operate the Canal Units out of merit order.

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[16] Although they are sometimes referred to as NSTAR's "Short Term Package," the transmission improvements planned for Lower SEMA — originally slated for completion in October 2008 — are not scheduled to be completed until the third quarter of 2009. Once placed in service, the Short Term Package improvements will reduce but not eliminate the need to either to operate the Canal Units or potentially to shed load upon the occurrence of a second 345-kV line contingency.

Three of the other four MPS municipal lighting plants (Mansfield, Middleborough, and Taunton) are interconnected with the National Grid transmission system at 115 kV. These systems are also physically remote from, and are not affected by, the transmission contingencies in anticipation of which ISO-NE has chosen to operate the Canal Units out of merit order. Hull, a lower voltage wholesale customer of National Grid, is dependent upon its taps into NSTAR's 115 kV transmission system.

B. Respondent

20. ***ISO-NE*** is a FERC-jurisdictional "public utility" and a Commission-approved "Regional Transmission Organization" serving the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. ISO is an independent, not-for-profit corporation formed in 1997. ISO provides minute-to-minute reliable operation of New England's bulk electric power system, providing centrally dispatched direction for the generation and flow of electricity across the region's interstate high-voltage transmission lines; development, oversight and administration of New England's wholesale electricity marketplace; and management of comprehensive bulk electric power system and wholesale markets' planning processes.

III. COMMUNICATIONS

21. All communications concerning this filing should be addressed to:

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IV. BACKGROUND

22. Lower SEMA encompasses the geographic area of New Bedford, Plymouth and Cape Cod, Massachusetts, and its load (a maximum of 1000 MW) constitutes approximately 28% of the overall SEMA reliability region load. Russell Testimony at 10. Overall, Lower SEMA load constitutes between 3.0% and 3.5% of all New England load. *Id.* Loads in Lower SEMA are served by local generators (including Canal) and four transmission lines into the area — two 115 kV circuits and two key 345 kV transmission lines. *Id.* at 17.

23. Upper SEMA is located well north and west of Cape Cod on the Massachusetts mainland, outside the Plymouth and New Bedford Districts of the NSTAR system. Russell Testimony at 10. In electrical terms, the loads in Upper SEMA are served from substations that are "upstream" of the substations serving Lower SEMA loads. *Id.*

24. Until January 2006, the Canal Units tended to be dispatched either in economic merit order or for reactive power (VAr) protection, the costs of which have historically been allocated to all load in New England. Russell Testimony at 12. Beginning around January 2006, NSTAR installed a reactive power compensation device that eliminated the need to run the Canal Units for reactive power purposes. *Id.* Also, according to ISO, the Canal Units were no longer in merit in most hours because of changes in relative fuel prices for No. 6 fuel oil (the Canal Units' primary fuel supply) versus natural gas. *Id.* Consequently, ISO-NE was required to assess whether, and if so, under what circumstances and for what reasons it was necessary to operate one or more

of the Canal units. ISO-NE apparently concluded that reliability in SEMA and the broader region could be maintained during many hours without operating Canal because the ISO did not dispatch the Canal Units out-of-merit to meet reliability requirements initially. *Id.*

25. The local transmission owner, NSTAR, which has an affiliated distribution company that serves retail load in SEMA, apparently disagreed with that conclusion and requested that ISO run one or both of the Unit(s). Russell Testimony at 12. ISO-NE subsequently dispatched the Canal units as requested by NSTAR, and classified each unit during such out-of-merit operation as a "Special Constraint Resource" ("SCR"). *Id.*

26. Under the Tariff, an SCR is a resource that would not be operated "above its Economic Minimum Limit (as described in Market Rule 1) *but for* the request of the Transmission Owner or distribution company." Tariff Schedule 19 at 1st Rev Sheet No. 890 (emphasis added). SCR charges are assigned to the Transmission Owner requesting such operation. *Id.* From January 27 through April 14, 2006, the Canal Units were flagged by the ISO as SCRs, and the associated out-of-merit charges were allocated to NSTAR network transmission loads in SEMA. Russell Testimony at 12.

27. NSTAR challenged the SCR classification by submitting Requested Billing Adjustments ("RBAs") to ISO-NE. On April 15, 2006, the ISO reclassified, on both a retrospective and prospective basis, the Canal Units' out-of-merit charges as LSCPR. *Id.* at 13. In contrast to an SCR, an LSCPR is a resource "identified by the ISO on a daily basis as *necessary* for the provision of Operating Reserve requirements and

adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region." ISO-NE Tariff § III.6.1 (emphasis added).

28. The reclassification was accompanied by enormous financial consequences. Unlike SCR charges, LSCPR charges are spread to all day-ahead and real-time load in the relevant Reliability Region (in this case, SEMA). *See* ISO-NE Tariff § III.F.3.1. During 2006, Canal LSCPR charges to the SEMA region (which includes consumers served by NSTAR, National Grid, MPS, and others) exceeded $80 million, of which MPS customers paid approximately $10.2 million. Russell Testimony at 15. MPS estimates that their 2007 Canal LSCPR charges amounted to $13.8 million, and will likely reach similar levels again in 2008, while total Canal LSCPR charges imposed on SEMA loads may exceed $100 million in each of 2007 and 2008. *Id.*

29. MPS (along with a group of non-municipal suppliers) disputed the imposition of these LSCPR charges on them. Following an extensive mediation proceeding, a Settlement was reached. Each of the Complainants is a party to the Settlement Agreement, which was accepted in Docket No. ER07-921-000.

30. The Settlement contains several provisions of direct relevance to the issues raised in this Complaint. First, in terms of relief for past periods, the municipal systems in Upper SEMA received as refunds approximately $3.77 million of their 2006 LSCPR payments. Settlement § 3.1.

31. Second, ISO-NE agreed to issue within sixty days of the execution of the Settlement a report examining the possibility of meeting applicable reliability criteria

through the implementation of either an SPS or a Switching Arrangement instead of relying on the out-of-merit operation of the Canal Units. Section 6.1(b) of the Settlement described the contents of the analyses to be undertaken in this "Short Term Report":

> In the Short Term Report, ISO-NE, consistent with NPCC/NERC criteria and applicable ISO-NE planning criteria and/or operating procedures (collectively, "Applicable Criteria"), shall evaluate and shall state its determinations and recommendations as to whether in accordance with the aforesaid Applicable Criteria the transmission system in the Lower SEMA sub-area (i) can be and (ii) should be operated through either (A) installation of a Special Protection System ("SPS"), or, (B) implementation of Post-First-Contingency Switching (the opening of various circuit breakers following the occurrence of the first contingency), both of which can entail load shedding upon the occurrence of a second contingency.
>
> The ISO-NE analysis in the Short Term Report described in the preceding paragraph will include a list of the potential alternatives considered, the technical feasibility, estimated budgets, the estimated time period required to implement each potential alternative, the degree to which an alternative is expected to reduce the need to run either one or both Canal units out of economic merit order prior to the first contingency, the extent and duration of customer outages that an SPS or Post First-Contingency Switching arrangement would entail, and the anticipated frequency of any such customer outages.

32. Third, the Settlement preserved MPS' rights to initiate litigation. Specifically, and as set forth in Settlement §§ 7.1(a), 7.2 and 10.7, as of January 2, 2008, the MPS are free to: (1) seek relief from LSCPR charges, both prospectively and for a three-month retroactive period; and (2) seek a change in the scope of the SEMA Reliability Region to be effective no earlier than January 1, 2008.

33. On July 17, 2007, ISO-NE issued its Short Term Report,[17] in which it examined whether either SPS or PFCS could be and should be implemented as an alternative to out-of-merit dispatch of the Canal Units, consistent with NPCC/NERC reliability criteria and applicable ISO-NE planning criteria and/or operating procedures (collectively, "Applicable Criteria").[18]

34. **[**BEGIN CEII**]**

[END CEII**]**

35. These findings notwithstanding, **[**BEGIN CEII**]**

36.

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[17] *Short-Term Report of ISO New England Inc. Required Pursuant to Section 6.1(b) of the SEMA Settlement Agreement*, July 17, 2007 ("Short Term Report").

[18] Specifically, the ISO applied ISO-NE Operating Procedure No. 19 (Transmission Operations); NPCC Document A-2 (Basic Criteria for Design and Operation of Interconnected Power Systems); ISO-NE Planning Procedure No. 5-5 (Special Protection Systems Application Guidelines); and NPCC Document A-11 (Special Protection System Criteria) (subsequently superseded by NPCC Reliability Reference Directory No. 7 (Special Protection Systems)). Russell Testimony at 14.

[END CEII**]**

V. STATEMENT OF FACTUAL AND LEGAL BASES FOR REQUESTED RELIEF

37. The Tariff does not allow ISO-NE to assess as LSCPR charges the costs of actions that are not necessary to meet Applicable Criteria. **[**BEGIN CEII**]**

[END CEII**]**

the cost of such operation cannot be allocated to MPS. Alternatively, if the Commission concludes that the Tariff permits the ISO to assess such charges to the MPS, then the Tariff is unjust and unreasonable. The MPS ask that the Tariff be modified to conform to cost-causation principles and ensure that the MPS, which are located in Upper SEMA, do not pay the costs of providing Lower SEMA with more reliability than necessary to meet Applicable Criteria.

A. The Tariff Does Not Permit ISO-NE to Assess LSCPR Charges Incurred to Provide a Level of Reliability Beyond What is Required by Applicable Criteria

38. **[**BEGIN CEII**]**

[END CEII**]** As such, the Tariff makes plain that the out-of-merit

operation of the Units cannot be classified as LSCPR, and the corresponding out of merit costs cannot be imposed on all SEMA loads.

39. As set forth in the Tariff, LSCPR are by definition those resources *necessary* to meet post-first contingency requirements:

> "Local Second Contingency Protection Resources" are those Resources identified by the ISO on a daily basis as **necessary** for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

ISO-NE Tariff § III.6.1 (emphasis added).

1. Post-First Contingency Switching

40. **[**BEGIN CEII**]**

[END CEII**]** is irrelevant to the classification of the Canal Units as LSCPR.[19] By drawing a clear distinction between LSCPR resources that are needed to meet the Applicable Criteria and other resources that may be dispatched at the discretion of ISO or Transmission Owners, the Tariff language does not concern itself with "shoulds" but

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[19] Similarly, the Settlement makes plain the right of MPS to seek relief from Canal LSCPR charges in both "could" and "should" circumstances. Settlement Section 7.1(a) states in relevant part:

> [n]othing in this Settlement is intended to prevent one or more of 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.

rather with what is *necessary* to meet the Applicable Criteria.[20] Because out-of-merit operation of the Canal Units is not *necessary* to fulfill the Applicable Criteria, the costs incurred for that operation cannot be designated as LSCPR charges.

41. **[**BEGIN CEII**]**

[END CEII**]** This statement, however, is based upon an extremely unlikely worst-case scenario, which the ISO is not obligated to assume under the Applicable Criteria. *See* Russell Testimony at 27-28. The miniscule probability of such a worst-case scenario, which would not affect MPS customers were it to occur, does not justify the imposition on MPS customers of purported LSCPR charges approaching (or potentially exceeding) $15 million per year.

42. **[**BEGIN CEII**]**

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[20] Indeed, as previously discussed, the ISO itself initially recognized that LSCPR was not the correct classification for out-of-merit operation of the Canal Units and instead designated the Units as SCRs. The Tariff states that units operated out of merit at the request of a Transmission Owner for any reliability purpose "not reflected in the ISO's systems or Operating Procedures" will be designated as a Special Constraint Resource. Tariff § II, Schedule 19. Moreover, "[w]hen a unit would not be operating above its Economic Minimum Limit (as defined in Market Rule 1) *but for* the request of the Transmission Owner or distribution company, it shall be flagged as SCR." *Id.* (emphasis added).

[21] **[**BEGIN CEII**]**

[END CEII**]**

Existing personnel would presumably perform the switching. Russell Testimony at 29. No new equipment must be installed. *Id.* At most, supervisory controls at the Bourne Substation would have to be installed. *Id.*

[END CEII**]** In fact, ISO-NE has long planned for post-second contingency load shedding in other areas of New England, such as in the Northeast Massachusetts/Boston ("NEMA") region and the Southwest Connecticut ("SWCT") region, and has expressed no doubts as to the safety, effectiveness, or appropriateness of this option. For example, in defending post-second contingency load shedding arrangements for 400 MW of metropolitan Boston load in the Ancillary Services Market Phase Two proceeding (Docket No. ER06-613-000), the ISO pointed out that:

> [p]ursuant to long-standing operational practices, the ISO is authorized to rely on post-second contingency load shedding in its operations planning. The ISO has worked with transmission owners to develop protocols for post-contingency load shedding which ensure that equipment and personnel remain safe after a contingency.

ISO-NE and New Eng. Power Pool, Answer to Motions to Intervene and Motion for Leave to Answer and Answer of ISO New England Inc. to Comments and Protests, Docket No. ER06-613-000, at 27 (Mar. 14, 2006).

43. Later in the same proceeding, ISO-NE elaborated on the use of post-first contingency load shedding in lieu of expensive generation, stating that: "[t]he ISO historically has relied upon load shedding in load pockets . . . where the transmission and generation facilities to cover contingencies may be limited or, in the case of older generation units, inefficient and expensive to operate." *ISO-NE and New Eng. Power Pool*, Compliance Report of ISO New England Inc., Docket No. ER06-613-002, at 6 (Nov. 13, 2006) ("Compliance Report").

44. The ISO went on to explain at length why "involuntary load shedding for post-second contingency response" is a reasonable option:

> [t]he ISO believes that its continued use of involuntary load shedding for post-second contingency response for determining reserve requirements is reasonable from an operational perspective. Because the involuntary load shedding is only utilized following a second contingency resulting from the loss of two transmission lines, there is a low probability of the ISO having to resort to this involuntary load shedding, and the ISO has not had to require involuntary load shedding in the past six years that it has considered this operational option available. The ISO's use of involuntary load shedding is also consistent with the North American Electric Reliability Council ("NERC") and Northeast Power Coordinating Council ("NPCC") requirements: NERC and NPCC allow involuntary load shedding provided time allows the operators to implement these actions, *i.e.*, provided that the load shedding can be implemented in a time frame that supports the necessary second contingency system needs.

Id. MPS assert that the ISO's arguments apply equally to use of post-first contingency load shedding in SEMA instead of running the Canal Units out-of-merit.

45. In the same proceeding, NSTAR likewise defended post-second contingency load shedding as an "acceptable and prudent" approach to second contingency requirements:

> [t]he ISO-NE's proposed reliance on load shedding post second contingency is acceptable and prudent. Indeed, as the ISO-NE notes, it is a long-standing practice in NEPOOL and one that has served the consumers of the NEMA/Boston area well. The ISO-NE is responsible for reliability in NEPOOL. NSTAR and National Grid are directly responsible to customers both in terms of reliability of service and the cost thereof. ISO-NE, NSTAR and National Grid collectively agree that 400 MW of load shedding is the most appropriate reliability response to a second contingency occurring within a narrow window of time. Load shedding would be undertaken only if the second contingency occurred with 30 minutes of the first contingency. In practice, the loss of a major transmission line is an unlikely event. The loss of two major

> transmission lines on the same day is extremely remote. Indeed, controlled load shedding has never had to be implemented since it has been quantified as a potential response. Moreover, 400 MW is similar to the amount of load that could be lost due to the overlapping outage of two transmission lines supplying some areas within the NSTAR service territory, as well as number of other areas within New England. This load would be lost irrespective of the amount of reserve generation available in the region. If this risk is acceptable for these loads, why would it not be acceptable for all loads?

ISO New England Inc. and New England Power Pool, Answer of NSTAR Electric & Gas Corp., Docket No. ER06-613-000, at 4 (Apr. 21, 2006). NSTAR went on to explain that the "collective judgment of the ISO-NE, NSTAR and National Grid" with respect to the use of involuntary load shedding is:

> wholly consistent with Northeast Power Coordinating Council ("NPCC") guidelines. Section 6 of NPCC Document A-2, "Basic Criteria for Design and Operation of Interconnected Power Systems," outlines Transmission Operating Criteria. Section 6.3 thereof addresses post-contingency operation and states that, immediately *after the first contingency*, shedding of firm load is an acceptable action to restore the system to a secure state and prepare for the next contingency. The practice in New England is not to rely on load shedding in response to a first contingency. However, the ISO-NE and the New England transmission owners, who are responsible for system reliability, have deemed it an acceptable risk to rely on a small amount of controlled load shedding in response to a second contingency.

Id. at 5 (emphasis in original).

46. **[**BEGIN CEII**]**

47.

[END CEII**]** — *less* than the 400 MW of load projected to be shed under NEMA's lauded load shedding regime.

48. Indeed, ISO's statements in the Compliance Report **[**BEGIN CEII**]**

[END CEII**]** In the Compliance Report (at 6), the ISO states that:

> when a transmission line is lost, the exposure is generally for only a short finite period because the cause of the transmission fault is quickly investigated and usually repaired soon thereafter. Even though repairs may not be made within 30 minutes, the repaired transmission is likely to be available for the next load-cycle, *i.e.*, within 12-24 hours, and available generation will be dispatched.

49. There is no basis for concluding that the circumstances in SEMA would be substantively different from those in NEMA. Indeed, the disruption of service to Lower SEMA would be comparable to that found acceptable by the ISO in the Compliance Report. In the unlikely event that service to Lower SEMA were disrupted, it would be restored whenever either 345 kV line was restored to service, typically within a matter of minutes according to NSTAR filings, but in no more than 24 hours, even in the unlikely event that both 345 kV lines had experienced permanent forced outages (for example, in the event that an airplane crash took out the towers from which both 345 kV lines are suspended). *See* Russell Testimony at 26-27.[22]

50. Similarly, in supporting the use of the load shedding arrangement described in the Compliance Report, the ISO notes that "involuntary load shedding would only be invoked in the event of a Line-Line contingency, transmission lines are very reliable, and even after a transmission line has been forced out of service, there is a very low probability of losing a second transmission line in good weather." Compliance Report at 6 (footnote omitted). Conversely, when severe weather is forecasted, the Canal Units may be started preemptively.

51. For the same reasons, there is a very low likelihood that load shedding would be implemented if the Switching Arrangement were adopted in SEMA. Mr. Russell explains (at 26):

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[22] Mr. Russell notes that in such a double-contingency event, service to Cape Cod could likely be restored in a matter of minutes or hours through a series of switching, voltage reduction and rotating blackouts, and service to the entirety of Lower SEMA could be restored as soon as Canal generation could be started and synchronized (typically, a matter of 24 hours from a cold start). Russell Testimony at 27.

> This probability of load interruption attributable to use of the PFCS would be well below the 0.1 days per year loss of load probability to which ISO New England designs its entire bulk power system (2.4 hours out of 8,760 annual hours).

In other words, the risk of load loss under the ISO's bulk power design criterion (based on maintaining a loss-of-load-probability that generation will be unable to meet loads in all of New England one-tenth day per year) already exceeds the probability that service to Cape Cod would be severed as a result of implementing the PFCS.

52. **[**BEGIN CEII**]**

[END CEII**]** The price tag for the NSTAR

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[23] **[**BEGIN CEII**]**

[END CEII**]**

upgrades is $50 million. Russell Testimony at 36. Considered against the cost associated with implementing the PFCS — close to zero but certainly less than **[**BEGIN CEII**]**

53.

[END CEII**]** However, we understand that the improvements have been delayed and that current in-service estimate for at least certain of the improvements is no earlier than middle to the third quarter of 2009.

54. **[**BEGIN CEII**]**

[END CEII**]** it would remain the case that that ISO is now charging, and absent an order from the Commission will continue to charge, SEMA customers for the unnecessary expense of operating the Canal Units out-of-merit. The possibility of future relief through transmission construction does not obviate the need for relief between now and then.

55. **[**BEGIN CEII**]**

[END CEII**]** MPS is not here advocating increasing the reliability risks facing the SEMA region. The issue here is who *pays* for the requisite level of reliability. The ISO

Tariff is clear: LSCPR charges are those associated with measures that are *necessary* to meet the Applicable Criteria. Running the Canal Units out-of-merit at load levels below **[**BEGIN CEII**]** **[**END CEII**]** is not *necessary* because there are less expensive choices to meet Applicable Criteria available to the ISO. If the ISO, in its discretion, or at the request of NSTAR or others, decides to implement measures that exceed what is necessary to meet the Applicable Criteria, it may not label the related costs as LSCPR charges that must be borne by all SEMA customers.

2. <u>Special Protection System (SPS)</u>

56. The Settlement also required the ISO to consider whether an SPS could and should be instituted in Lower SEMA in lieu of operating the Canal Units on an out-of-merit basis. **[**BEGIN CEII**]**

[END CEII**]** an SPS not only can be designed to operate in Lower SEMA in accordance with the Applicable Criteria, but it would actually provide more dependable protection against the most serious system risks than is provided by reliance on the out-of-merit operation of the Canal Units.

57. **[**BEGIN CEII**]**

58.

[END CEII**]** However, Lower SEMA is a relatively limited geographic area located entirely within a single state and served by two transmission owners. **[**BEGIN CEII**]**

59.

[END CEII**]** However, ISO's "solution"

makes matters worse, not better. **[**BEGIN CEII**]**

[END CEII**]** in the unlikely event that both 345-kV lines into Cape Cod were to suffer contingencies, it is far more likely that the Canal Units will be unavailable than that an SPS will fail to operate as needed. **[**BEGIN CEII**]**

[END CEII**]** increases the risk of a widespread voltage collapse.

60. **[**BEGIN CEII**]** **[**END CEII**]** implementation of an SPS (including an SPS that deviates to a small degree from the local sensing and local action guidelines of Table I) would provide a major increase in reliability compared to the status quo. Russell Testimony at 54-56. As Mr. Russell explains (at 55):

> [c]urrently, the ISO relies on operation of the Canal generating units to preserve system reliability in the event that both 345 kV lines serving Cape Cod are lost. However, all generating units — particularly very old plants like the Canal Units — must undergo maintenance outages and occasionally do suffer forced outages. . . . Conversely, an SPS could be operational up to 24 hours per day, 365 days per year (subject to disarming when system conditions are such that inadvertent operation could be more detrimental than a failure to operate), and would require only an hour or two per year of testing to ensure continued readiness to serve.

[BEGIN CEII**]**

[END CEII**]** because the outage rates for old generating units such as Canal are much higher than the failure rates for an SPS. This means that reliance on the Canal units provides less dependable protection against a

widespread voltage collapse (*i.e.*, outside of Lower SEMA) than would be provided through the use of an SPS. *Id.* at 56.

61. **[**BEGIN CEII**]**

62.

[END CEII**]** As Mr. Russell explains, the unnecessary opening of the 115-kV lines into Cape Cod should have little impact if one or both 345-kV lines are in service. Russell Testimony at 51-52.

63. **[**BEGIN CEII**]**

[END CEII**]** Specifically, the Applicable Criteria establish "guidelines" that are intended to embody "generally acceptable conditions for the application of SPSs in the New England Control Area," but do not establish absolute rules. Russell Testimony at 53. Instead,

each SPS is evaluated under the guidelines on a case-by-case basis, and exceptions are permitted based on various factors, including the extent of the deviation from the guidelines and the impact of such deviation on any associated reliability or security risk or the complexity of system operations. *Id.* **[**BEGIN CEII**]**

[END CEII**]**

64. Mr. Russell's examination of the Applicable Criteria demonstrates, however, that an SPS in Lower SEMA would be a good candidate for such an exception. Russell Testimony at 54-56. Moreover, any such minimal deviation would have very little negative impact on any associated reliability or security risk or the complexity of system operations. *Id.* MPS's analysis therefore shows that an SPS is a viable option for meeting second-contingency reliability criteria for SEMA and that implementation of an SPS as a means of meeting reliability criteria would be beneficial because an SPS would enable Lower SEMA to meet reliability criteria quickly at all load levels and at a very low cost[25] **[**BEGIN CEII**]**

[END CEII**]** *Id.* at 62.

65. **[**BEGIN CEII**]**

[END CEII**]** in order to permit the development and interconnection of wind generation facilities in Lower SEMA, NSTAR has proposed and ISO has approved the use of an SPS at the Canal substation

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[25] **[**BEGIN CEII**]**

[END CEII**]**

that involves some of the same features that **[**BEGIN CEII**]**

[END CEII**]** Russell Testimony at 41. In evaluating the impact of interconnection of the Cape Wind project to the Lower SEMA grid, the NEPOOL Reliability Committee Transmission and Stability Task Forces found that a Type I SPS would be required to address a related contingency, but that such an SPS would fail to meet all of the Type I SPS conditions. *Id.* at 59-60. The Reliability Committee therefore recommended granting an exception for the proposed SPS. As Mr. Russell notes (at 61),

> the Reliability Committee recommended the installation of a "Type I SPS" that did not meet the "local action" requirements on which the Short Term Report relied in concluding that a Lower SEMA SPS would not meet Applicable Criteria.

ISO-NE approved the proposed plan, including the proposal to install a Type I SPS. *Id.*

[BEGIN CEII**]**

[END CEII**]**

66. As Mr. Russell points out, SPS is a proven and accepted mechanism for dealing with second and third contingency events. Russell Testimony at 41. There are dozens, if not hundreds, of instances of the successful operation of SPSs in the United States. *Id.* For example, the Pacific Northeast-Pacific Southeast Separation Scheme is a well-known SPS that has served with dependability and security — and with a high degree of certainty — since the late 1960's. *Id.* at 61-62. Mr. Russell notes that there is nothing about the electric topography of New England generally, or SEMA specifically, that precludes the use of an SPS. He concludes:

> Any SPS likely to be implemented in Lower SEMA would be far less complex, would operate less frequently, and would affect a far smaller geographic area and magnitude of load than does the [Pacific Northeast-Pacific Southeast] Separation Scheme.

Id. at 62.

67. **[**BEGIN CEII**]**

[END CEII**]**

B. To the Extent that the Tariff Permits ISO-NE to Assess LSCPR Charges for Actions Not Necessary to Meet the Minimum Applicable Criteria, the Tariff is Unjust and Unreasonable

68. Alternatively, if the Commission finds that the Tariff does permit ISO-NE to classify the costs for out-of-merit operation of the Canal Units as LSCPR charges and thus assess them to all SEMA Market Participants, then the Tariff is unjust and unreasonable and should be modified to provide for appropriate allocation of the Canal Units' out-of-merit costs.

69. Under the Tariff, LSCPR charges are spread across the relevant Reliability Region. Tariff § III.F.3.1. All Market Participants within SEMA, however, do not benefit from the designation of the Canal Units as LSCPRs. Indeed, some are paying significant sums (as stated, in the tens of millions of dollars) for actions: (a) to address conditions they did not cause; (b) from which they do not benefit; and (c) they cannot

change. In these circumstances, imposing Canal out-of-merit charges on Upper SEMA customers is unjust and unreasonable because it violates the principles of cost-causation.

70. Out-of-merit operation of the Canal Units in lieu of implementation of an SPS or PFCS benefits only Lower SEMA.[26] As noted previously, all MPS customers are located in Upper SEMA and are not part of the Lower SEMA loads that could be shed under a Switching Arrangement or SPS. That is, Upper SEMA loads would continue to receive electric service irrespective of whether the ISO implements PFCS or SPS, or dispatches Canal generation out-of-merit order. Thus, MPS customers derive no benefit from the ISO's out-of-merit operation of Canal generation in lieu of a PFCS arrangement or an SPS. As stated by Mr. Russell:

> [t]he primary benefit of operating Canal out of merit, when Applicable Criteria could be satisfied through less expensive means, is avoidance of the small probability of an outage that a PFCS arrangement or SPS could entail. But all of the MPS customers are located in Upper SEMA, **[**BEGIN CEII**]**
>
> **[**END CEII**]** The customers that cause Canal to be operated out

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[26] To the extent that the Commission **[**BEGIN CEII**]** **[**END CEII**]** the customers of Upper SEMA would benefit to some extent from such Canal operations — but so would load outside of SEMA. **[**BEGIN CEII**]** **[**END CEII**]** MPS submit that it would be proper to allocate the costs incurred to avoid such consequences throughout New England. However, MPS believe that Canal out-of-merit costs should appropriately be allocated to Lower SEMA rather than spreading them throughout New England. **[**BEGIN CEII**]**

[END CEII**]** which may or may not be available if and when transmission contingencies occur.

> of merit, when Applicable Criteria could be satisfied through PFCS or SPS arrangements, are the Lower SEMA customers.

Russell Testimony at 64.

71. Because the choice between implementation of a Switching Arrangement (or SPS scheme) and out-of-merit operation of the Canal Units impacts only Lower SEMA, the costs of operating the Canal Units out of merit for second contingency purposes when New England load is below 17,000 MW are incurred solely for the benefit of Lower SEMA customers.

72. **[**BEGIN CEII**]**

[END CEII**]** Again, this decision protects and benefits only Market Participants in Lower SEMA.

73. Under cost causation principles well-established by the Commission, charges incurred to benefit a specific group of customers should be borne by only those customers. *See Cal. Indep. Sys. Operator Corp.*, 108 F.E.R.C. ¶ 61,022, P 62 (2004) ("As a general matter, the Commission believes that the entities that cause costs should pay for such costs" (footnote omitted)), *reh'g granted in part*, 109 F.E.R.C. ¶ 61,097 (2004), *reh'g denied*, 110 F.E.R.C. ¶ 61,071 (2005); *Cal. Power Exch. Corp.*, 106 F.E.R.C. ¶ 61,196, P 17 (2004) ("The well-established principle of cost causation requires that costs should be allocated, where possible, to customers based on customer

benefits and cost incurrence"); *N. States Power Co.*, Op. No. 383, 64 F.E.R.C. ¶ 61,324, at 63,379 (1993) ("The fundamental theory of Commission ratemaking is that costs should be recovered in the rates of those customers who utilize the facilities and thus *cause the cost to be incurred.*") (emphasis added), *reh'g denied, clarification granted,* 74 F.E.R.C. ¶ 61,106 (1996); *Ind. & Mich. Mun. Distribs. Ass'n v. Ind. Mich. Power Co.*, 59 F.E.R.C. ¶ 61,260, at 61,956 (1992) (It is a "well-established ratemaking principle that cost recovery should track cost causation."). ISO-NE's misapplication of its Tariff in this instance is contrary to the Commission's cost causation principle, and dampens the price signal that the cost allocation mechanism under the Tariff is supposed to produce.

74. Therefore, assuming *arguendo* that the Tariff allows ISO-NE to classify the Canal Units' out-of-merit operation costs as LPSCR charges which are then allocated only to Market Participants in SEMA (including to those participants who do not benefit from that operation), the Tariff is unjust and unreasonable because it allows costs to be charged to entities that do not benefit from or cause them.

75. In that case, the Tariff would be unjust and unreasonable and would have to be modified to ensure that the charges associated with running the Canal Units out of merit are allocated according to cost causation principles. That is, Canal out-of-merit charges should be allocated only to those who cause or benefit from such charges: the customers of Lower SEMA.[27]

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[27] **[**BEGIN CEII**]**

[END CEII**]** (a benefit could be

76. Another method of remedying the unjust and unreasonable allocation of LSCPR charges to customers outside of Lower SEMA would be to subdivide SEMA into two Reliability Regions: Lower SEMA and Upper SEMA. According to the Tariff, "Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System." Tariff § III.1.3.2. A separation of Lower and Upper SEMA would accurately reflect the different operating characteristics of and transmission constraints on the two areas. Once so divided, if the ISO continues to designate out-of-merit Canal costs as LSCPR charges, the appropriate customers would bear those costs: the members of the Reliability Region affected by those particular post-first contingency reliability concerns.

FAST TRACK PROCESSING REQUESTED

77. Time is of the essence in resolving the issue presented here. The SEMA LPSCR charges are rapidly mounting. Complainants may face charges in excess of $13.5 million this year, in addition to the $24 million already paid. Absent fast track processing, Complainants will continue to incur millions of dollars of unjust LPSCR charges, which constitute a significant financial burden on Complainants. Fast track processing of the instant complaint is therefore warranted to resolve this issue promptly and to avoid the unnecessary and unjust imposition of LPSCR charges on Complainants. Moreover, fast-tracking the Complaint will ensure that the need for retroactive relief, and

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obtained more effectively and at far lower cost through an SPS or PFCS arrangement) — MPS note that such benefits accrue not only to customers in Upper SEMA but to customers outside SEMA as well. **[**BEGIN CEII**]** **[**END CEII**]** the costs incurred to avoid such risks should be allocated throughout New England.

the potential administrative complications that entails, will be minimized. Finally, granting relief on an expedited basis may help to send a timely signal to NSTAR as to the need for it to employ all prudent and diligent means to complete crucial Lower SEMA transmission improvements that would reduce the need to rely on a PFCS arrangement, an SPS, or the out-of-merit operation of the Canal Units. For all of these reasons, fast track processing of this Complaint is warranted.

STATEMENT OF COMPLIANCE WITH SPECIFIC REQUIREMENTS OF RULE 206, 18 C.F.R. § 385.206

78. Rule 206(b)(1): The action alleged to violate statutory standards or regulatory requirements is ISO-NE's classification of the costs of out-of-merit operation of the Canal Units as LSCPR charges, and their subsequent allocation on the basis of day-ahead and real-time load within the SEMA Reliability Region.

79. Rule 206(b)(2): This action violates statutory standards or regulatory requirements by constituting a misapplication of the terms of the ISO Tariff. Alternately, if it is not a misapplication of the ISO Tariff, the Tariff is unjust and unreasonable because it allocates costs to customers who do not cause, or benefit from, the actions creating such costs.

80. Rule 206(b)(3): The allocation of the Canal Units' out-of-merit charges to Complainants mean that the Complainants, and thereby their customers, will continue to make improper, unjustified payments to the ISO.

81. Rule 206(b)(4): Complainants paid approximately $10.2 million in Canal LSCPR charges in 2006 and $13.8 million in 2007 and estimate that, absent relief, they will be required to pay more than $13.5 million in unwarranted charges in 2008.

82. Rule 206(b)(5): Complainants are unaware of any environmental, safety or reliability impacts associated with ISO's misclassification of Canal out-of-merit charges. However, ISO's unnecessary operation of the Canal Units, which emit significant amounts of carbon dioxide and other pollutants, imposes substantial environmental costs. Further, **[**BEGIN CEII**]**

[END CEII**]** than is provided by the ISO's current reliance on the operation of generating units that are more than 30 years old.

83. Rule 206(b)(6): The issues presented in this Complaint are not pending in an existing Commission proceeding or in a proceeding in any other forum in which Complainants or ISO-NE is a party.

84. Rule 206(b)(7): Complainants seek an Order requiring ISO-NE to reclassify the Canal LSCPR charges so that they are no longer assessed to customers outside of lower SEMA when other, lower-cost operations could be instituted to meet the Applicable Criteria. Alternatively, if the Commission finds that the Tariff currently allows ISO-NE to classify Canal out-of-merit charges as LSPCR charges when other, lower-cost measures are available to meet the Applicable Criteria and thereby to allocate such charges across the SEMA Reliability Region, Complainants ask the Commission to find that such provisions are unjust and unreasonable and must be modified. Complainants also request that the Commission order ISO-NE to refunds of improperly-

paid LSCPR charges for the three month period preceding the filing of this Complaint, as permitted by the Settlement.

85. Rule 206(b)(8): Complainants have attached to this Complaint the documents in their possession or obtainable by them to "support the facts in the complaint." Through the Russell Testimony, the Complainants have presented the facts and information in their possession or obtainable by them that go to show that running the Canal Units out of merit is not always "necessary" to meet the Applicable Criteria.

86. Rule 206(b)(9): The instant dispute arose in 2006. Complainants, ISO, and other interested parties participated in an extended informal mediation proceeding under the auspices of then-Deputy Chief Judge Brenner in an effort to resolve their disputes. That informal mediation led to a partial settlement, which narrowed the issues remaining in dispute and expressly preserved the Complainants' rights to litigate the issues raised herein. Based on that 8-month negotiation, Complainants do not believe that further dispute resolution would be effective in resolving any of the matters remaining in dispute and addressed herein.

87. Rule 206(b)(10): A form of Notice is attached to this Complaint.

RELIEF REQUESTED

88. For the reasons set forth above, the Commission should issue an order taking action in accordance with the relief requests presented herein.

Respectfully submitted,

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March 28, 2008

Exhibits

Exhibit No. MPS-1: Direct Testimony of Whitfield A. Russell

Exhibit No. MPS-2: Resume of Whitfield A. Russell and Description of Cases

Exhibit No. MPS-3: Short Term Report of ISO New England, Inc.

Exhibit No. MPS-4: Excerpt from *System Protection Schemes in Power Networks*, Chapter 6: SPS Design Procedure and Reliability Evaluation.

Exhibit No. MPS-5: July 22, 2005 Letter to NEPOOL Reliability Committee Members re: "Proposed Plan Applications for the Cape Wind Generation Project."

Exhibit No. MPS-1

PUBLIC VERSION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Braintree Electric Light Department, Hingham Municipal Lighting Plant, Hull Municipal Lighting Plant, Mansfield Municipal Electric Department, Middleborough Gas & Electric Department, and Taunton Municipal Light Plant, Complainants,	
v.	Docket No. EL08-___
ISO New England Inc. Respondent.	

DIRECT TESTIMONY AND EXHIBITS
OF
WHITFIELD A. RUSSELL

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Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Whitfield A. Russell. I am a public utility consultant and principal in Whitfield Russell Associates. My office is located at 4232 King Street, Alexandria, VA 22302-1507.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS.

A. I hold a Bachelor of Science degree in Electrical Engineering from the University of Maine at Orono, a Master of Science degree in Electrical Engineering from the University of Maryland, and a Juris Doctor degree from Georgetown University Law Center. I have been accepted as an expert on bulk power systems in more than 150 proceedings before State and Federal courts, administrative agencies and other tribunals in more than 30 States and in two Canadian provinces. My complete resume and a description of cases on which I have worked are attached as Exhibit No. MPS-2.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of individual municipally-owned power systems serving the Massachusetts communities of Hull, Mansfield, Middleborough, Taunton, Braintree and Hingham. I will refer to these complainants collectively as "Massachusetts Public Systems" or "MPS." All of the MPS systems are located in the portion of the New England grid known as the Southeast Massachusetts or "SEMA" reliability region. More specifically, the individual MPS systems are located in the more northwestern portion of SEMA, known (and referred to in this testimony) as "Upper SEMA."

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The main purpose of my testimony is to provide technical support for the MPS complaint, which seeks relief from the continued imposition upon Upper SEMA customers of Local Second Contingency Protection Resource ("LSCPR") charges

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associated with the out-of-merit operation of the Canal generating units. My analysis relies in part on the *Short-Term Report of ISO New England Inc. Required Pursuant to Section 6.1(b) of the SEMA Settlement Agreement*, dated July 17, 2007 ("Short Term Report"). For convenience, the Short Term Report is Exhibit No. MPS-3.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Since January 2006, ISO New England ("ISO-NE" or "ISO") has operated Canal Units 1 and 2, two old and relatively inefficient steam turbine units located in Sandwich, Massachusetts, out of economic merit order to meet system operating requirements in the highly unlikely event of the concurrent failure of the two extra high voltage (345 kV) transmission lines serving Cape Cod. Using these generators in this fashion imposes unnecessary costs on SEMA consumers of approximately $100 million per year.

ISO-NE's FERC-approved Tariff ("Tariff" or "TMST")[1] authorizes the imposition of the kind of charges ISO-NE imposes for operating the Canal Units out of merit only where "*necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria*" (ISO-NE Tariff § III.6.1, emphasis added).[2] Given other options available to the ISO, operating the Canal Units out of merit is not "necessary for . . . adherence to . . . reliability criteria," and the costs of such operation are therefore not properly charged under the ISO Tariff to SEMA consumers.[3]

---

[1] *Available at* http://www.iso-ne.com/regulatory/tariff/index.html.

[2] ISO Tariff Sections III.F.3.1 and III.6.4 allocate out-of-merit LSCPR costs to Day-Ahead or Real-Time Load Obligation within a Reliability Zone (in this case, SEMA).

[3] In this testimony, I refer to the relevant "NERC, NPCC and ISO reliability criteria" collectively as "Applicable Criteria," which is the same term used in Section 6.1(b) of the May 2007 settlement regarding the allocation of out-of-merit Canal charges (FERC Docket No. ER07-921-000, accession no. 20070523-0023) (hereafter, "Settlement").

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Q. WHAT ARE THE MAJOR FINDINGS THAT YOU HAVE REACHED THAT UNDERLIE YOUR CONCLUSION THAT ISO-NE IS IMPOSING CHARGES THAT ARE NOT IN ACCORDANCE WITH ITS TARIFF?

A. My major findings are:

1. The ISO claims to operate one of the Canal units as an LSCPR in order to guard against a double contingency involving the loss of two 345 kV transmission lines, which is an extremely low probability event. At other times, the ISO operates both of the Canal units out of merit, and includes loss of one of the Canal units as one of the contingencies to be protected against. **[**BEGIN CEII****]**

[END CEII**]** Specifically, Applicable Criteria permit firm loads to be shed in response to a second contingency event, so long as steps are taken to ensure that loads are shed in a controlled fashion. Moreover, ISO-NE's FERC-approved Tariff authorizes the imposition of the kind of charges ISO-NE imposes for operating the Canal Units out of merit only where "*necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria*" (ISO-NE Tariff § III.6.1, emphasis added). Because operating the Canal Units is not "necessary for . . . adherence to . . . reliability criteria," the ISO's imposition of LSCPR charges is in this instance inconsistent with the ISO's own Tariff.

2. In the Short Term Report, the ISO considered whether the Applicable Criteria could and should be satisfied through either of two actions, each of which would be considerably less costly (and much more environmentally-friendly) than continued out-of-merit operation of the

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Canal units: the implementation of Post-First Contingency Switching ("PFCS") or the installation of a Special Protection System ("SPS").

3. **[**BEGIN CEII****]**

[END CEII**]** The imposition of these charges in the face of this finding is impermissible under the ISO Tariff.

4. A substantial portion of Canal uplift costs probably is incurred in such hours because there is a substantial number of hours during which New England control area load levels can be expected to remain below 17,000 MW when the Canal Units are called upon to operate out of merit.[5] In any case, ISO data show that New England actual daily peak loads remained below 17,000 MW during 151 days in 2006 and 138 days in 2007.[6] Day

[4] **[**BEGIN CEII**]**

[END CEII**]**

[5] The Canal Units have a 24-hour cold start-up time, but can start up more quickly under other conditions and can be operated so as to permit more rapid start-up when necessary. In many cases in which one or more Canal unit(s) might be called upon because New England load levels are projected to exceed 17,000 MW, the unit(s) will not be "cold," and would therefore not require the full 24-hour startup period. Indeed, utilities have developed procedures under which they can keep boilers hot but not pass steam through the turbine, a procedure sometimes called "banking the boiler." This procedure requires less fuel than does operating at minimum load and less time to start up than would be the case after a full shutdown. The generator would presumably be paid for any incremental costs of banking its boilers.

[6] *See* ISO New England, Inc., Daily Summary of Load, LMP & Weather Data, Column D (PkDEMD) (Mar. 7, 2008) (*available at* http://www.iso-ne.com/markets/hstdata/znl_info/daily/smd_daily.xls).

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ahead forecast of daily peak loads indicated that loads were expected to remain below 17,000 MW during 126 days in 2006 and 111 days in 2007.[7]

5. **[**BEGIN CEII****]**

[END CEII**]** SPS is an effective, low-cost, environmentally-sound alternative which, if implemented, would enable the ISO to avoid out-of-merit operation of Canal generation for all load levels. Furthermore, use of an SPS would be more reliable than operating the Canal Units.

6. This case is not about exposing customers to potential blackouts. It is about deciding which customers should pay the cost of avoiding such risks through the out-of-merit operation of Canal. Although Applicable Criteria would permit use of PFCS or an SPS, I am not suggesting that ISO must implement either option. However, whether or not either option is implemented, their existence and viability means that the additional cost of operating Canal out of merit cannot reasonably be imposed as LSCPR charges. The ISO Tariff only permits the ISO to impose as LSCPR charges those costs that are necessary to satisfy Applicable Criteria. It does not permit the ISO to collect as LSCPR charges additional costs associated with purchasing greater reliability than is required by those criteria. To the extent that reliability levels beyond those required by Applicable Criteria are desired, then the costs of those reliability

[7] *See* ISO New England, Inc., Daily Capacity Status, Columns Q and R (Peak Load Forecast) (downloaded Jan. 29, 2008) (*available at* http://www.iso-ne.com/sys_ops/mornrpt/daily_capacity_status.xls).

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enhancements should be borne by the customers who cause the need for them. In this case, the customers who, apparently, want to lessen the risk of load shedding that a PFCS or an SPS could entail, and thereby cause additional reliability costs to be incurred, are those located in Lower SEMA, and not the customers served by MPS, who are located in Upper SEMA.

7. The concurrent failure of both 345 kV lines, in the unlikely event it were to happen, would affect service to the customers of NSTAR Electric Corp. (formerly known as Boston Edison Co.) on Cape Cod. Such a failure would not affect NSTAR customers located nearer to Boston (*e.g.*, Braintree or Hull), and it would not affect customers served by the National Grid transmission system (Mansfield, Middleborough or Taunton). Yet the customers who derive no benefit from ISO-NE's abundance-of-caution approach to this risk are charged with the same costs as are those NSTAR customers on Cape Cod who arguably do derive some measure of additional protection from this wasteful operating practice. As the non-Cape Cod customers do not benefit from ISO-NE's operation of the Canal Units in this way, did not cause the transmission condition which ISO-NE claims causes the need for their operation, and cannot do anything to mitigate or resolve the claimed problems with the NSTAR transmission system, it is not appropriate to impose these charges on them.

8. The ISO is classifying Canal out-of-merit costs as LSCPR charges which are allocated to all SEMA loads. This allocation is either over- or under-inclusive, depending on which of the risks that operating Canal generation out of merit is thought to avoid. If the risk avoided is loss of Lower SEMA loads, then Lower SEMA loads should pay the costs incurred to avoid those risks. Conversely, if the risk avoided by running Canal out of

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merit is a system-wide voltage collapse, then it is unreasonable to charge only SEMA loads for the costs incurred to avoid those region-wide risks.

9. The ISO's improper designation of out-of-merit Canal costs as LSCPR charges has imposed, and may continue to impose, hundreds of millions of dollars in unnecessary costs. This unnecessary charge amounts to about $6.5/MWH (0.65 cents per kWh) based on $100 million per year divided by 15,387,675 MWH of non-PTF Demand in SEMA in 2006 (15,602,116 MWH in 2007). Unless corrected by the Commission or obviated by fuel-price changes that cause Canal to be dispatched in merit order, this situation is likely to persist. Although the ISO and NSTAR have belatedly planned certain transmission upgrades that are expected to improve the situation, those upgrades will not be a panacea. **[**BEGIN CEII**]**

[END CEII**].**[8] ISO apparently expects to continue operating one or both Canal generating units out-of-merit, and to continue to bill all SEMA customers under the LSCPR provisions of the ISO Tariff, even after the NSTAR transmission upgrades are completed. I understand that the upgrades are not expected to be completed until the third quarter of 2009 at the earliest.

Q. WHAT ACTIONS DO YOU RECOMMEND THAT THE COMMISSION TAKE IN THIS PROCEEDING?

[8] In Lower SEMA, the difference is only 70 MW. A 17,000 MW ISO load is equivalent to a 594 MW Lower SEMA load. A 19,000 MW ISO load is equivalent to a 664 MW Lower SEMA load. The equivalence was obtained by multiplying the ISO-wide load by the ratio of (a) the 1000 MW peak demand in Lower SEMA to (b) the ISO's 28,600 MW peak demand (*e.g.*, 17,000*1,000/28,600 = 594).

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A. Given my views on SPS viability, I recommend that the Commission prohibit the ISO from treating as LSCPR charges any costs related to operating Canal out-of-merit order.

[BEGIN CEII**]**

[END CEII**]** with respect to PFCS, the Commission should prohibit the ISO from treating as LSCPR charges any costs related to such operation during periods when the ISO load level is projected to remain at or below 17,000 MW during the applicable start-up period for the Canal units.

For purposes of setting forth here the minimum relief that should be provided, I accept **[**BEGIN CEII**]**

[END CEII**]** As I discuss below, however, such an arrangement likely could be implemented consistent with Applicable Criteria at even higher system-wide load levels.

In accordance with these findings, the Commission should require the ISO to refund all such charges billed as LSCPR since December 28, 2007. Alternatively, the ISO should be directed to refund all charges billed as LSCPR since December 28, 2007 for costs incurred when load levels were forecast a day ahead to remain at or below 17,000 MW during the applicable start-up period for the Canal units (or whatever load level the ISO is able to support). LSCPR charges imposed on SEMA when load levels were forecast to remain at or below 17,000 MW amounted to $63 million during 2006 and 2007.

The ISO should also be directed to file a refund report setting forth its calculation of such refunds on a monthly basis.

PROCEDURAL BACKGROUND

Q. PLEASE DESCRIBE THE CANAL GENERATING UNITS.

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A. The Canal Units are two steam reheat generating units presently owned by Mirant. Each of the two units has a summer capacity rating of 559 MW, while the winter capacity rating for each of them is approximately 562-564 MW. Both of these units were owned originally by Canal Electric/Commonwealth/Cambridge Electric (now part of NSTAR). The units were sold to Mirant as part of the move to deregulate electricity markets in Massachusetts. Both of the Canal units run on No. 6 fuel oil, although one of the units has the capability of running (at least partially) on natural gas. Before deregulation, the two units were considered the primary source of generation in the Lower Southeastern Massachusetts ("Lower SEMA") portion of the SEMA region. The Units entered commercial service more than thirty years ago.

Q. ARE THE MASSACHUSETTS PUBLIC SYSTEMS LOCATED IN LOWER SEMA?

A. No. The MPS are located in Upper SEMA. Lower SEMA consists primarily of Cape Cod and nearby eastern portions of the Massachusetts mainland (referred to as the "Plymouth" and "New Bedford" Districts of the NSTAR system **[**BEGIN CEII**]**
[END CEII**]** Load in Lower SEMA constitutes approximately 28% of the SEMA area load and from 3.0% to 3.5% of the New England load, reaching a maximum of approximately 1,000 MW.

Upper SEMA is located on the Massachusetts mainland well northerly and westerly of the Cape Cod Canal, outside the Plymouth and New Bedford Districts of the NSTAR system. In electrical terms, Upper SEMA loads are served from circuits and substations that are "upstream" of the circuits and substations serving Lower SEMA loads.

The following map provides details on the transmission system in Upper and Lower SEMA. As indicated, there is significant transmission infrastructure "upstream" of the rather limited circuits and substations serving Lower SEMA

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loads. The location of each of the six MPS members is indicated by a red arrow. Note that each MPS member is located outside Lower SEMA.

Figure 1

Q. ARE THE CANAL UNITS RELATIVELY EFFICIENT?

A. No, they are not. The efficiency of the Canal steam units (heat rates of approximately 10,000 BTU/kWh) is well below the efficiency of modern gas-fired combined cycle generating units (heat rates of approximately 7,000 BTU/kWh). Nonetheless, when oil prices are low compared to natural gas prices, the Canal units may then be dispatched in merit order despite their relative inefficiency. As oil prices approach or exceed natural gas prices, however, the Canal units are unable to produce energy at competitive prices and would not be

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selected by the ISO to operate within merit order under many load conditions. The ability of one Canal unit to operate on natural gas does not materially affect the economics because, when operating on natural gas, that unit's heat rate remains higher than those of the gas-fired combined cycle generating units.

Q. PLEASE SUMMARIZE THE PROCEDURAL HISTORY OF THE DISPUTE OVER THE CLASSIFICATION OF CANAL OUT-OF-MERIT OPERATION AND RELATED COSTS.

A. Historically, the Canal units tended to be dispatched either in economic merit order or, when not economically competitive, out-of-merit in order to provide reactive power (volt-amperes reactive or "VARs"), which helped the ISO maintain proper voltage levels (the incremental costs for which have historically been allocated to all load in New England). However, starting around January 2006, NSTAR began operating reactive power compensation devices that eliminated the need to run Canal for reactive power purposes. Also, according to the ISO, as the historic relationship between fuel prices for No. 6 fuel oil and natural gas changed, with oil becoming a fuel that is as expensive, or more expensive, than gas, the oil-fired Canal Units increasingly fell out of merit order.

Q. HOW DID THE ISO RESPOND TO THIS CHANGE IN THE DISPATCH OF THE CANAL UNITS?

A. Initially, the ISO did not dispatch Canal out-of-merit order to meet reliability requirements. However, the local area transmission owner (NSTAR) apparently believed the Canal units were needed to ensure reliable service to its Lower SEMA loads, especially Cape Cod, and requested that the ISO run the Units. Under Schedule 19 of the ISO's Tariff, running Canal in response to NSTAR's requests meant that the units would be treated as "Special Constraint Resources" ("SCR"), the costs of which were allocated to NSTAR's retail load. The treatment of the Canal out-of-merit generation costs as SCR charges continued for the period from January 27 through April 14, 2006.

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Q. WHAT HAPPENED NEXT?

A. In response to a challenge from NSTAR, the ISO subsequently reclassified Canal out-of-merit charges from "SCR" to "LSCPR" retroactively for the period January 27 to April 14, 2006. Going forward after April 14, 2006, Canal out-of-merit costs were classified by the ISO as LSCPR charges.

Q. WHAT DOES THE ISO TARIFF STATE WITH RESPECT TO THE DEFINITIONS AND ALLOCATION OF LSCPR AND SCR CHARGES?

A. The following provisions of the ISO's Tariff address the matter of LSCPR:

> **III.6 Local Second Contingency Protection Resources**
>
> **III.6.1 Definition.** "Local Second Contingency Protection Resources" are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.
>
> **III.6.2 Day-Ahead and Real-Time Energy Market.** When establishing operating schedules, the ISO will select and identify Local Second Contingency Protection Resources on a not unduly discriminatory basis in accordance with the procedures defined in the ISO New England Manuals. ***Appendix A*** will determine which, if any, Supply Offers will be adjusted. The ISO will also record, in an auditable log, the reason the Resource was selected.

LSCPR charges are paid by all load within the reliability region in which such resources are required, as provided in Section III.6.4.4 of the TMST.

Q. THE QUOTED TARIFF LANGUAGE REGARDING LSCPR REFERS TO "NERC, NPCC, AND ISO RELIABILITY CRITERIA." WHAT DOES THAT LANGUAGE ENCOMPASS IN THIS CONTEXT?

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A. Section 6.1(b) of the Settlement required the ISO to assess whether certain alternatives to operating Canal out of merit order would satisfy "NPCC/NERC criteria and applicable ISO-NE planning criteria and/or operating procedures (collectively, 'Applicable Criteria')." In responding to this requirement in the Short Term Report, the ISO applied ISO-NE Operating Procedure No. 19 (Transmission Operations); NPCC Document A-2 (Basic Criteria for Design and Operation of Interconnected Power Systems); ISO-NE Planning Procedure No. 5-5 (Special Protection Systems Application Guidelines); and NPCC Document A-11 (Special Protection System Criteria) (subsequently superseded by NPCC Reliability Reference Directory No. 7 (Special Protection Systems)).

Q. WHAT ARE THE TARIFF PROVISIONS REGARDING SPECIAL CONSTRAINT RESOURCES?

A. In contrast to an LSCPR, which is designated by the ISO, a Special Constraint Resource ("SCR") is requested specifically by a Transmission Owner, and its costs are then charged to that Transmission Owner, as found in Section III.6.2.1 and Schedule 19 of Section II of the TMST. Schedule 19 states as follows:

SCHEDULE 19

SPECIAL CONSTRAINT RESOURCE SERVICE

> In order to maintain area reliability, Transmission Owners or distribution companies may request the ISO to change the commitment of a generating Resource or the incremental loading on a previously committed generating Resource *to provide relief for constraints not reflected in the ISO's systems for operating the New England Transmission System or adhering to the ISO's Operating Procedures.* Requests will normally be made to the ISO via the appropriate Local Control Center unless emergency conditions justify immediate communications with the Resources.

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> *Such out of merit operation of units for any reliability purposes to provide relief for constraints (thermal, voltage or stability) not reflected in the ISO's systems or Operating Procedures will result in the Resource(s) being designated as a Special Constraint Resource* (SCR) and administered in accordance with the provisions of this Schedule. However, in the event a SCR is requested by a Transmission Owner or distribution company and the ISO also requires that unit to be on-line in accordance with the ISO's systems and procedures, the ISO will apply the appropriate flag to reflect the ISO's need for the unit and will only flag the unit as SCR when the ISO does not require the Resource (or when changed dispatch of the unit is requested by the Market Participant)....
>
> **I. DETERMINING THE AMOUNT TO BE PAID FOR SERVICE UNDER THIS SCHEDULE**
>
> Service under this Schedule is to be provided through the ISO. *The Transmission Owner or distribution company making a request or on whose behalf a Local Control Center makes a request to change the commitment of a generating Resource or the incremental loading on a previously committed generating Resource must purchase such service through the ISO. The Transmission Owner or distribution company shall be charged an amount equal to the NCPC Credit (as calculated pursuant to Market Rule 1) associated with the Real-Time operation of the Special Constraint Resource.*

Emphasis Added.

Q. WHAT WAS THE MAGNITUDE OF THE CANAL UNIT OUT-OF-MERIT CHARGES DURING 2006 AND 2007?

A. During 2006, Canal LSCPR charges to the SEMA region exceeded $80 million, of which the Massachusetts Public Systems and their customers paid approximately $10.2 million. During 2007, total Canal LSCPR charges for SEMA ran in excess of $100 million, and these charges are expected to reach this level again in 2008. MPS customers paid approximately $13.8 million in 2007 for these charges, and will likely be charged similar amounts in 2008.

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Q. HOW DID ADVERSELY AFFECTED SEMA ENTITIES RESPOND TO THE ISO'S RETROACTIVE RE-CLASSIFICATION OF THE CANAL SCR CHARGES AS LSCPR?

A. The MPS systems (and others) objected to the imposition of Canal LSCPR charges on them, contending that the reliability issues in SEMA involve the NSTAR system (located in Lower SEMA), and not the Municipal systems (located in Upper SEMA). The parties subsequently entered into FERC-supervised mediation sessions, and reached a settlement that was filed with the Commission in May 2007 in Docket No. ER07-921-000. The settlement was accepted by the Commission in a letter order issued on June 21, 2007.

The Settlement acknowledges that the MPS may raise certain claims against the ISO and/or the Transmission Owners as of January 2, 2008, and in so doing may seek relief both prospectively and for a three-month retroactive period. In addition, the Settlement acknowledges the rights of MPS to seek a change in the configuration of the SEMA reliability region, which would be another way to correct the mis-allocation of Lower SEMA Canal LSCPR charges to Upper SEMA loads.

ELECTRICAL TOPOGRAPHY OF SEMA AND THE NATURE OF THE RELEVANT RELIABILITY NEEDS

Q. WHAT ARE THE MAJOR CIRCUITS SERVING LOWER SEMA?

A. As indicated on the diagram below, loads on the Lower SEMA 115 kV system are served by local generators (primarily Canal) and four transmission lines into the area -- two 115 kV circuits and two key 345 kV transmission lines. In the diagram, the 115 kV system is shown inside the dotted line forming the boundary of Lower SEMA; for simplicity, details of the 115 kV lines inside the dotted line boundary are not shown. Each 345 kV circuit and each 115 kV line crossing the boundary is labeled with its circuit number and the names of the substations at its

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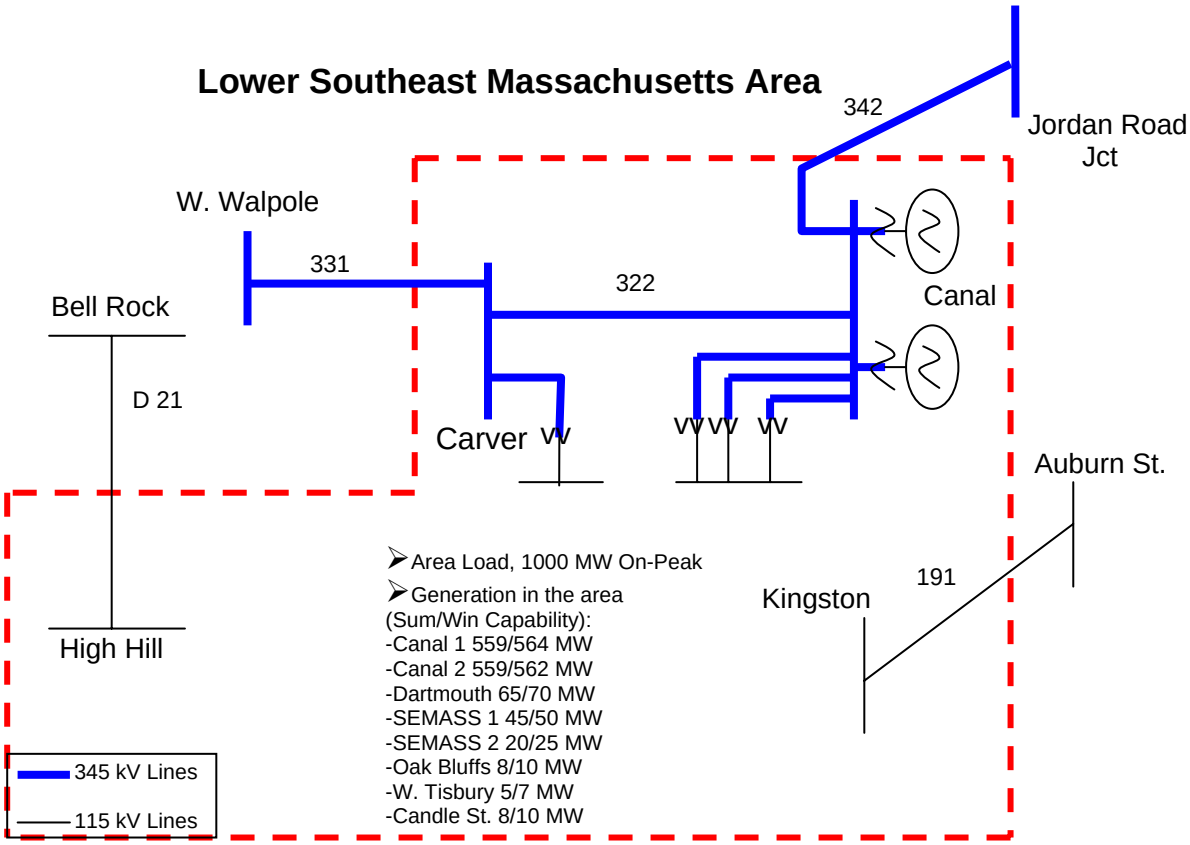
terminals, with heavier bold lines representing 345 kV lines and thinner lines representing 115 kV lines. I have prepared the tabulation that appears just below the diagram, which provides relevant statistics on loads and generation within Lower SEMA during annual peak demand periods.



Total Generation	1269 / 1298 MW
New England Peak Load	29,000 MW
Lower SEMA Area Load	1000 MW
SEMA N-2 Import Limit (eliminating 2-345 kV lines)	225-350 MW Range
Generation Needed in Lower SEMA	775-650 MW
Lower SEMA Generation (other than Canal)	151 MW
Deficiency	624-499 MW

Figure 2

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Q. PLEASE EXPLAIN WHAT THE DIAGRAM SHOWS WITH RESPECT TO THE IMPACT OF OUTAGES ON THE KEY 345 KV LINES.

A. The diagram shows that only four transmission lines serve the loads of Lower SEMA. Two of these lines operate at 345 kV and two operate at 115 kV:

1. West Walpole-Carver 345 kV line (331 line)
2. Jordan Road - Canal 345 kV line (342-2 line section)
3. Auburn – Kingston 115 kV line (191-1 line section)
4. Bell Rock – High Hill 115 kV line (D21 line)

In essence, there are six supplies to the 115 kV network in Lower SEMA: the two 115 kV lines listed above (the 191 line and the D21 line), a 345/115 kV stepdown transformer at Carver Substation and three 345/115 kV stepdown transformers at Canal Substation. Four of the six supplies to the 115 kV network originate at the two 345 kV substations (Canal and Carver), which are supplied by the two Canal generators and the two 345 kV lines (Nos. 331 and 342). (The Canal generating units are interconnected to the 345 kV bus at the Canal substation.)

This configuration means that, if the Canal Units were not operating and at the same time the ISO experienced the very rare loss of both key 345 kV lines to Lower SEMA (*i.e.*, both the 331 and 342 lines), then four of the six supplies to the 115 kV network would be eliminated, and only two 115 kV supplies would remain. Under these conditions, the two remaining 115 kV lines would be severely overloaded. **[**BEGIN CEII**]**

[END CEII**]**

Q. HOW CAN THIS CONCERN BE ADDRESSED?

A. The 115 kV network in Lower SEMA can be protected against the impact of the loss of both of the 345 kV lines by a number of means. One would be upgrading the transmission system to allow for the introduction of additional 345 kV

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supplies to the 115 kV network (east of the Cape Cod canal), but such upgrades involve long lead times and do nothing to address the problem in the meantime. NSTAR is working on certain less ambitious transmission upgrades that are expected to improve the situation, but my understanding is that recent forecasts indicate that those upgrades are not expected to be in place until mid-2009 at the earliest. Until (and even after) those upgrades are in place, there are essentially still three options. The most expensive option, and the one being implemented currently by the ISO, is to operate the Canal Units out of merit. The second, and least expensive option (in terms of out-of-pocket costs, which would be negligible) is to implement a Post-First-Contingency Switching arrangement. The third option, involving slightly greater out-of-pocket costs than the Switching Arrangement, is to install a Special Protection System. A PFCS arrangement or an SPS would make it possible to shed load before thermal damage or voltage collapse occurred upon the loss of the second 345 kV path into Lower SEMA. **[**BEGIN CEII**]**

[END CEII**]**

Q. WHAT HAS THE ISO CONCLUDED CONCERNING THE NEED FOR THE CANAL UNITS?

A. **[**BEGIN CEII**]**

[END CEII**]** This very expensive mode of operation exceeds Applicable Criteria.

Q. YOU REFERRED TO PLANNED TRANSMISSION UPGRADES. DOES THE ISO'S SHORT TERM REPORT CONTAIN A DESCRIPTION OF PLANNED UPGRADES THAT WILL ADDRESS THE SECOND CONTINGENCY ISSUES IN LOWER SEMA?

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A. **[**BEGIN CEII**]**

[END CEII**]** Therefore, completion of those upgrades will not fully resolve nor moot the issues raised by MPS in this proceeding.

Q. ARE THERE MORE COMPREHENSIVE TRANSMISSION UPGRADES THAT COULD MORE FULLY ADDRESS LOWER SEMA RELIABILITY NEEDS?

A. Yes, but it is likely to be several years or longer before such upgrades are planned and put in place (assuming they are put in place at all). Section 6.1(c) of the Settlement requires the ISO to follow up its Short Term Report with a more comprehensive Long Term Report within 18 months, or by January 2009. The Long Term Report is to identify and evaluate projects that would "achieve or maintain the reliability of the Lower SEMA sub-area in compliance with Applicable Criteria" without relying at all upon the out-of-merit operation of the Canal Units. *Id.* In the Long Term Report, the ISO is to identify separately and evaluate (a) projects that would permit compliance with Applicable Criteria without relying on either of the Canal Units, PFCS, or an SPS and (b) projects that would permit compliance in conjunction with PFCS or an SPS. *Id.*

Q. ARE THE LONGER TERM UPGRADES NEEDED IN ORDER TO ELIMINATE FULLY THE NEED TO RELY ON THE CANAL UNITS?

A. No. At sufficiently high New England daily load levels, the Canal Units can be expected to be dispatched in merit. **[**BEGIN CEII**]**

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[**END CEII**]

Q. DO YOU HAVE LOAD SHAPE DATA FOR NEW ENGLAND AS A WHOLE?

A. Yes. These data are presented in the graph appearing immediately below.[9]

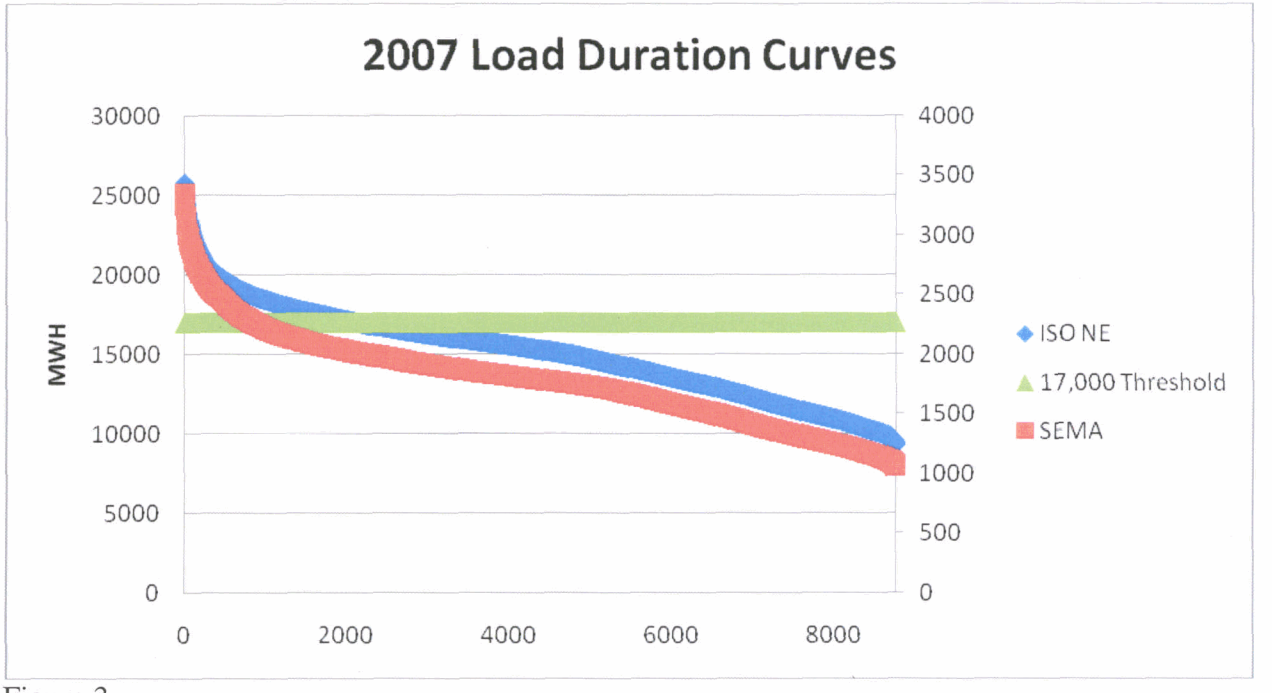

Figure 3

Q. WHAT DO THESE DATA SHOW?

A. They show the number of hours during the year that the New England-wide load is less than 17,000 MW. In these hours, using a PFCS arrangement, neither of the Canal Units would need to be run out-of-merit. The data also show that the shape

[9] Data *available at* http://www.isonewengland.com/markets/hstdata/znl_info/hourly/2007_smd_hourly.xls.

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of the SEMA load duration curve is similar to that of the New England-wide load duration curve.

Q. ARE YOU SUGGESTING THAT ISO AND NSTAR SHOULD BE REQUIRED TO IMPLEMENT PFCS OR AN SPS?

A. No. I am not insisting that either PFCS or an SPS be implemented. I am saying that, because Applicable Criteria can be met through either of two relatively inexpensive options — PFCS or an SPS — the much more expensive cost of operating Canal out of merit cannot be characterized *as necessary* to meet those criteria and, hence, cannot be considered LSCPR charges under the ISO's tariff.

Q. WHY IS THAT DISTINCTION IMPORTANT?

A. The distinction is important because it highlights that MPS do not propose to deny National Grid or NSTAR the discretion to call for out-of-merit operation of Canal generation to lessen the minimal risk of shedding load, and MPS are not advocating that other customers must be exposed to an added risk of load shedding. By the same token, however, customers that wish to avoid load-shedding risks that are *permitted by Applicable Criteria* should bear the costs of avoiding those risks. That is the result embodied in the ISO Tariff, which correctly allows the ISO to collect as LSCPR charges only those costs that are *necessary* to satisfy Applicable Criteria and allocates the costs of other reliability-based dispatch to those who request that such steps be taken. The purpose of the Complaint is to ensure that MPS pay only those reliability charges that are properly imposed upon them and their customers under the applicable provisions of the ISO Tariff, in return for reliability levels that are consistent with all Applicable Criteria. If the relief sought here is granted, the ISO can of course continue to operate the Canal Units on an out-of-merit basis. What the ISO cannot do, however, is to recover as LSCPR charges, costs that are not *necessary* to satisfy the Applicable Criteria.

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ISO ANALYSIS OF POST-FIRST-CONTINGENCY SWITCHING ARRANGEMENT

Q. WHAT IS POST-FIRST CONTINGENCY SWITCHING?

A. Switching is a routine utility practice by which the configuration of the network is changed either by workers at the site of the switchgear or from a control center through supervisory control. As used in this context, post-first contingency switching involves a pre-planned set of procedures that would be initiated after a first contingency outage event in order to position the system to shed load automatically upon the occurrence of the second contingency. Criteria require that such actions be taken within a short time following the occurrence of a contingency, and a PFCS meets this requirement

Q. WHAT SWITCHING ARRANGEMENT HAS BEEN EVALUATED BY THE ISO FOR USE IN LOWER SEMA?

A. **[**BEGIN CEII**]**

[END CEII**]**

Q. IS THE 594 MW FIGURE DEVELOPED IN THE SHORT TERM REPORT?

A. No. I calculated that figure.

Q. WHAT IS THE BASIS FOR THE 594 MW LOAD LIMITATION?

A. This 594 MW level is the Lower SEMA load associated with an ISO load level of 17,000 MW. It was determined by scaling down **[**BEGIN CEII**]** **[**END CEII**]** to

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the equivalent Lower SEMA load level. The 594 MW Lower SEMA load was calculated by multiplying the 17,000 MW ISO load by the ratio of (a) the 1000 MW peak demand in Lower SEMA to (b) the ISO's 28,600 MW peak demand (17,000*1,000/28,600).

Q. PLEASE CONTINUE EXPLAINING HOW THE PFCS ARRANGEMENT WOULD WORK IN THIS CIRCUMSTANCE.

A. On each occasion that the ISO operators determined that it would be appropriate to shut down the Canal generation, they would do so and then be on the lookout for an outage of either of the two 345 kV lines serving the Canal 345 kV bus. Immediately upon the loss of either of those 345 kV lines supplying the Canal Substation (which is located on Cape Cod), the ISO would implement a PFCS arrangement that isolates all 115 kV service to Cape Cod onto the three 345/115 kV transformers served from the Canal 345 kV bus (leaving no 115 kV service connected to Cape Cod from the mainland). **[**BEGIN CEII**]**

[END CEII**]**

This sequence of procedures has been given the name Post-First-Contingency Switching or "PFCS" because it would be initiated immediately after the occurrence of the first 345 kV contingency. **[**BEGIN CEII**]**

[END CEII**]** even in this situation, service could be quickly restored to Cape Cod loads up to the N-1 thermal/voltage capability of the

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remaining usable lines. Thus, even where 100% load shedding is needed, service could be quickly restored to some Cape Cod load before Canal generation could be started up and synchronized.

Q. IF PFCS WERE ACTUALLY IMPLEMENTED, WHAT IS THE PROBABILITY THAT SERVICE TO CAPE COD WOULD BE SEVERED?

A. If the PFCS arrangement described above were implemented, service interruptions resulting from a loss of both 345 kV lines would remain extremely rare. The forced outage rates of high-voltage transmission lines are negligible. Assuming that the forced outage rate of each 345 kV line is about 0.3 events per year and a typical outage will have a duration of about three hours, each line will experience an average of about 0.9 hours of forced outage time each year. The resulting probability of a line being on forced outage at any given time is thus 0.0001 (*i.e.*, 0.9/8760) or 0.01%. The probability of an overlapping outage of two similar lines in a given year is thus 0.000001% (i.e., 100*0.0001*0.0001).[10] The probability of a double 345 kV line outage occurring during load conditions that require operation of Canal but do not cause it to operate in merit would be even smaller. Further, the exposure to the second outage would be limited to a maximum of 24 hours, the time required for a cold start of a Canal unit. There may be a higher risk of an overlapping outage of the two lines as a result of storms, longer outage duration assumptions, substation problems or taking into account the few common towers these two lines share. However, the probability would remain extremely low: either negligible or bordering on negligible.

Q. HOW DOES THIS RISK OF LOAD INTERRUPTION COMPARE TO OTHER, RELATED RISK TOLERANCES?

[10] These estimates are based on the assumption that routine maintenance of these important transmission lines would not be done during high-load hours when an outage would be troublesome. Thus only forced outages are considered.

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A. This probability of load interruption attributable to use of the PFCS would be well below the 0.1 days per year loss of load probability to which ISO New England designs its entire bulk power system (2.4 hours out of 8,760 annual hours).

Q. DOES THE SHORT TERM REPORT ESTIMATE [BEGIN CEII**]**

A.

[END CEII**]**

Q. ASSUMING THAT A PFCS ARRANGEMENT WERE IMPLEMENTED AND THAT THE VERY LOW PROBABILITY INTERRUPTION OF SERVICE TO CAPE COD WERE TO OCCUR, HOW LONG WOULD YOU EXPECT THE INTERRUPTION TO LAST?

A. If the PFCS arrangement were to be implemented and the very unlikely interruption discussed above were to occur, service to Cape Cod would be restored upon the earlier of: (a) the startup and loading of a Canal Unit (which the ISO would begin upon the occurrence of the first contingency), or (b) the restoration of either 345 kV line to service. Filings by NSTAR at the Commission indicate that such lines are typically restored to service within a matter of minutes or less after a forced outage. In the even less likely event that both 345 kV lines were to experience *permanent* forced outages (for example, in the event that an airplane crash took out towers from which both 345 kV lines are suspended), partial service to Cape Cod could likely be restored in a matter of minutes or hours through a series of switching, voltage reduction and rotating blackouts. Service to the entirety of Lower SEMA could be restored as soon as Canal generation could be started and synchronized (typically, a matter of 24

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hours from a cold start). The 24-hour period required for a startup could be reduced substantially by banking the boilers at Canal.

Q. WHAT DID THE ISO'S SHORT TERM REPORT CONCLUDE [BEGIN CEII**]**

A.

[END CEII**]**

Q. PLEASE COMMENT ON THE ISO'S ANALYSIS.

A. No. **[**BEGIN CEII**]**

[END CEII**]** However, estimating the outage frequency and refining the exposure to such outages is straightforward, as I demonstrated previously.

Q. ARE YOU AWARE OF ANY OBLIGATION ON THE PART OF THE ISO TO [BEGIN CEII**]**

A.

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[END CEII**]** As I noted, a long-duration outage is possible if a large aircraft takes out a double circuit tower (or several such suspension towers), but such an aircraft could also take out an entire right-of-way. Proper planning calls for examination of such "maximum credible" outages, but the bulk electric system need not be designed to withstand them. The probability of a 24-hour 345 kV line outage accompanied by a second outage during that period is very slight, perhaps as low as 1 in a million in any given year.

Q. ARE YOU DISAGREEING WITH [BEGIN CEII**]**

[END CEII**]**

A. No. **[**BEGIN CEII**]**

[END CEII**]** In fact, it not only meets criteria, but *can* be implemented with almost no impact on the reliability of power supply.

Q. THEN THE ISO SHOULD USE A PFCS?

A. At this time, I am not taking a position on that question one way or the other. **[**BEGIN CEII**]**

[END CEII**]** In accordance with the ISO's Tariff, that choice is one NSTAR and National Grid must make and pay for on behalf of their Lower SEMA customers. If NSTAR and National Grid are willing to pay Canal uplift charges in order to avoid the low probability and likely short duration of an outage that PFCS would entail, they are free to make that decision and to ask that the Canal Units be operated as Special Constraint Resources.

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However, the ISO may not impose LSCPR charges on all SEMA load for costs that were not *necessary* to satisfy Applicable Criteria.

Q. WHAT ARE THE COSTS ASSOCIATED WITH IMPLEMENTING A SWITCHING ARRANGEMENT IN SEMA?

A. **[**BEGIN CEII**]**

[END CEII**]** Existing personnel would presumably perform the switching. No new equipment must be installed. At most, supervisory controls at the Bourne Substation would have to be installed.

Q. WHAT IS THE BOTTOM LINE OF THE ISO FINDINGS AS REGARDS PFCS?

A. **[**BEGIN CEII**]**

[END CEII**]**

Q. WHAT ELSE DOES THE ISO SHORT TERM REPORT STATE [BEGIN CEII**]**

[END CEII**]**

A. Presumably because of the unpopularity of service curtailments, **[**BEGIN CEII**]**

[END CEII**]** This consideration is not relevant to a determination of whether either a PFCS arrangement or an SPS *could* be implemented in accordance with Applicable Criteria.

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Q. WHAT IS THE EFFECT OF THE SHORT TERM REPORT'S FINDINGS [BEGIN CEII**]**

A.

[END CEII**]**

Q. WHAT COSTS ARE IMPOSED AS A RESULT OF OPERATING CANAL OUT OF MERIT RATHER THAN RELYING ON PFCS?

A. The out-of-merit costs associated with Canal's operation were as much as $87 million in 2006 alone and exceeded or are expected to exceed $100 million annually in 2007 and 2008. **[**BEGIN CEII**]**

[END CEII**]** Using data available on the ISO's website, it is possible to estimate the Canal uplift charges that were incurred on days when New England peak load was forecasted to remain below 17,000 MW. Based on that data, I estimate that approximately $31 million per year in unnecessary Canal uplift charges could have been avoided in 2006 and 2007 by implementing a PFCS arrangement on such days. In fact, that is a conservative estimate because it counts as "avoidable" only the uplift charges incurred on calendar days when the New England peak load was projected to remain below 17,000 MW. In effect, that is similar to assuming a 24-hour (*i.e.*, cold) start time for the Canal Units in all cases. But the 24-hour start time is a maximum amount

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that applies only under certain conditions. There would be other situations in which the Canal Units could be started more quickly (*e.g.*, when a boiler was banked or when a Canal Unit had been only recently been shut down). Thus, even on days when the New England peak was expected to exceed 17,000 MW, there should be some hours during which a PFCS would have allowed the ISO to avoid operating the Canal Units out of merit. I estimate that implementation of PFCS would have saved SEMA customers more than (and perhaps substantially more than) $63 million in unnecessary Canal uplift costs in 2006 and 2007.

Q. HOW DID YOU CALCULATE THE COSTS THAT COULD HAVE BEEN AVOIDED USING A PFCS ARRANGEMENT USING THE 17,000-MW THRESHOLD?

A. Using data available on the ISO's website,[11] I identified the days for which the ISO forecasted peak loads below 17,000 MW during 2006 and 2007. There were 126 such days in 2006 and 111 such days in 2007. Using other data available on the ISO website, I found that the RMR NCPC charges incurred in SEMA on those days (all or virtually all of which would have constituted Canal LSCPR charges) totaled $31,001,846 in 2006 and $32,287,734 in 2007. For the period between June 1, 2006 and December 31, 2007, I determined the RMR NCPC charges incurred using data queried from the ISO's "Transmission Related Commitment and NCPC Reporting" page.[12] However, data was not available on that page for the period prior to June 1, 2006. Therefore, for the period between January 1, 2006 and June 1, 2006, I used data from ISO's "NCPC Credits Summary" page.[13]

Q. WHAT DO YOU CONCLUDE REGARDING THE COSTS THAT COULD HAVE BEEN OR COULD BE AVOIDED BY IMPLEMENTING PFCS?

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[11] Available at http://www.iso-ne.com/sys_ops/mornrpt/daily_capacity_status.xls.

[12] *Available at* http://www.iso-ne.com/othrmkts/opsres/tcorc_rpt/ncpc.do.

[13] *Available at* http://www.iso-ne.com/markets/othrmkts_data/ncpc/ncpc_sum/2006/index.html.

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A. Those out-of-merit costs either should not have been incurred at all or, if incurred, should not have been treated as LSCPR and allocated to all SEMA loads. Instead, costs incurred through the out-of-merit operation of the Canal Units, at times when Applicable Criteria could have been satisfied through PFCS, should have been allocated to NSTAR and National Grid. Allocating such costs to NSTAR and National Grid is appropriate because NSTAR's and Grid's customers are the ones who benefit from the above-tariff-levels of reliability, by avoiding the (exceedingly small) risk of load-shedding that Applicable Criteria permit and that a PFCS would entail. In any case, such costs cannot be collected as LSCPR charges under the ISO's tariff, because the out-of-merit operation of the Canal Units at those times was not "*necessary*" to satisfy Applicable Criteria.

Q. DO YOU AGREE WITH THE SHORT TERM REPORT'S CONCLUSION [BEGIN CEII**]**

A.

[END CEII**]**

Q. PLEASE EXPLAIN.

A. **[**BEGIN CEII**]**

[END CEII**]** I drew upon other ISO sources. As discussed below, those sources indicate that, when only one 345 kV line is out of service, between 500 MW and 900 MW of Lower SEMA load can be met without operating the Canal generating units.

Q. WHAT DO THESE MATERIALS SHOW?

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A. An August 2006, ISO PowerPoint presentation labeled "Lower Southeast Massachusetts Area Transmission Interface" authored by Mr. Michael Taniwha, Manager, Operations indicates that only 225-350 MW of power can be imported under N-2 conditions, apparently depending upon generation dispatch.[14] The specific generation dispatches are not identified. This lower SEMA N-2 import limit represents only 22.5% to 35% of the 1,000 MW peak demand in Lower SEMA. When both 345 kV lines are out of service (referred to as the most limiting N-2 contingency), only two 115 kV lines (plus local generation) remain as supplies for Lower SEMA with combined import limits ranging from 225 MW to 350 MW. That is, unless some generation located in Lower SEMA is operating, the load that can be served within Lower SEMA after the outage of both 345 kV lines would be limited to 225 MW to 350 MW. Without citing these or any other import limits, the ISO concludes in its Short Term Report that under N-2 conditions, the Lower SEMA load cannot be met under most load conditions unless one or both of the Canal Generating units are operating. Short Term Report at 7-8, 13-14.

Q. WHAT IS THE SIGNIFICANCE OF THESE DATA POINTS?

A. These data indicate that the PFCS may be workable for load levels in excess of those associated with an ISO load level of 17,000 MW and that only one Canal generating unit would need to operate under most conditions as protection against the putative threat of voltage collapse.

Q. PLEASE EXPLAIN.

A. **[**BEGIN CEII**]**

[END CEII**]** As I described above,

[14] *Available at* http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2006/aug792006/a10_iso_presentation_08_09_06.ppt

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the 28,600 MW New England peak load corresponds to a Lower SEMA peak load of 1,000 MW. **[**BEGIN CEII**]**

[END CEII**]** I determined from ISO power flows that PFCS would isolate and shed the Lower SEMA load on Cape Cod which represents about 60% of the Lower SEMA demand, leaving only about 40% of Lower SEMA load to be served after implementation of PFCS. Accordingly, the import capability needed to serve 40% of 60% of Lower SEMA's peak demand would be 240 MW. This is approximately equal to the import capability of the two 115 kV supplies to Lower SEMA that would remain after a loss of both 345 kV lines.

Q. WHAT IS WRONG WITH THIS [BEGIN CEII**]**

A.

[END CEII**]** If, on the other hand, 151 MW of non-Canal generation could be added to the 225 MW of import capability of the two 115 kV lines serving Lower SEMA, the ISO could serve nearly 400 MW of Lower SEMA load after the PFCS shed 600 MW of load on Cape Cod. Arithmetically, this 400 MW of mainland load post-PFCS-shedding of load

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equates to a 1,000 MW Lower SEMA load before implementing PFCS. In essence, it appears that the PFCS would enable both Canal generating units to be shut down in all but a few hours of the year. If PFCS were not implemented, it appears that, for most load conditions, only one Canal generating unit would need to operate in combination with the 400 MW of import capability plus non-Canal local generation to meet loads. However, absent a PFCS arrangement, the limited ramping capability of the Canal generation units may necessitate the operation of that single Canal generating unit at a fairly high level of output

Q. WHAT IS THE SIGNIFICANCE OF THE SHORT TERM REPORT'S [BEGIN CEII**]**

A.

[END CEII**]**

Q. ACCORDING TO THE SHORT TERM REPORT, [BEGIN CEII**]**

[END CEII**] PLEASE DISCUSS THE EFFECT OF THOSE UPGRADES VIS-À-VIS PFCS.**

A. First, my understanding is that the short term transmission upgrades are unlikely to be in service before mid-2009. Assuming the near-term transmission improvements proposed by NSTAR are completed, the ISO will be able to shut down all Canal generation and still meet Applicable Criteria for ISO-wide load levels up to 19,000 MW. **[**BEGIN CEII**]**

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[**END CEII**] As noted above, that increase corresponds to a 70 MW increase in SEMA load levels. However, PFCS could be implemented very quickly and at very low cost (if ISO were to decide to do so). In contrast, in order to achieve this additional coverage up to 19,000 MW, upgrades costing $50 million are planned to be constructed.

SPECIAL PROTECTION SYSTEM

Q. ARE THERE MECHANISMS OTHER THAN THE PFCS BY WHICH THE ISO COULD MEET APPLICABLE CRITERIA WITHOUT OPERATING THE CANAL UNITS OUT OF MERIT?

A. Yes, there are. The ISO can meet all Applicable Criteria through the installation of a "Special Protection System" or "SPS," which could be implemented and operated at a fraction of the cost of operating the Canal Units out-of-merit.

Q. WHAT IS A SPECIAL PROTECTION SYSTEM?

A. The NPCC Glossary (Document A-07 at 22)[15] defines an SPS as:

> **Special Protection System (SPS)** – A **protection system** designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted **elements**. Such action may include changes in **load**, **generation**, or system configuration to maintain system **stability**, acceptable voltages or **power** flows. Automatic underfrequency **load shedding** as defined in the *Emergency Operation Criteria* A-3, is not considered an SPS. Conventionally switched, locally controlled shunt devices are not SPSs.

In other words, a special protection system or "SPS" is a set of relays and telecommunication devices that trigger "special" protective actions, meaning actions that go beyond the customary protective actions triggered by a fault on a

[15] *Available at* http://www.npcc.org/viewDoc.aspx?name=A-7.pdf&cat=regStandCriteria.

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single transmission line or transformer and that are designed to isolate only that faulted element. Electrical systems around the country frequently make use of Special Protection Systems to safeguard equipment and protect against cascading outages in various circumstances

Q. HAS THE ISO EVALUATED THE USE OF AN SPS IN LOWER SEMA?

A. **[**BEGIN CEII**]** **[**END CEII**]** The Settlement in Docket No. ER07-921 required the ISO to determine whether an SPS could be employed in Lower SEMA consistent with Applicable Criteria and, if so, whether it should be employed. **[**BEGIN CEII**]**

[END CEII**]**

Q. WHAT DID THE ISO'S SHORT TERM REPORT CONCLUDE AS TO SPS?

A. **[**BEGIN CEII**]**

[END CEII**]**

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Q. PLEASE SUMMARIZE [BEGIN CEII**]**

A.

[END CEII**]**

Q. DO YOU AGREE WITH THE ISO'S CONCLUSIONS CONCERNING SPS?

A. **[**BEGIN CEII**]**

[END CEII**]** Special

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Protection Systems are commonly-used, important, and reliable tools for maintaining system reliability. Indeed, as I explain below, an SPS is almost certainly a more dependable means of protecting the New England electric system against potential voltage collapse upon loss of the 345 kV lines serving Cape Cod than is the current reliance on operation of the Canal generating units. That is, while the ISO can rely upon either Canal generation or an SPS in order to deal with the impacts upon Lower SEMA of the loss of two 345 kV lines, it is more probable that the SPS will be there when needed than that the Canal generation will be available.

Q. WHAT ARE THE GENERAL CRITERIA FOR USE OF AN SPS?

A. Section 2.1 of NPCC Document A-2, *Basic Criteria for Design and Operation of Interconnected Power Systems*,[16] states:

> A **special protection system (SPS)** shall be used judiciously and when employed, shall be installed, consistent with good system design and operating policy.
>
> A SPS may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. An **SPS** may also be applied to preserve system integrity in the event of **severe facility outages** and extreme **contingencies**. The decision to employ an SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.
>
> The requirements of **special protection systems** are defined in the NPCC *Bulk Power System Protection Criteria*, (Document A-5), and the *Special Protection System Criteria*, (Document A-11).

Emphasis in original.

[16] Last revised May 6, 2004, *available at* http://www.npcc.org/viewDoc.aspx?name=A-02.pdf&cat=regStandCriteria.

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A SPS in Lower SEMA lends itself to this Document A-2 prescription in that (1) as demonstrated in the prior discussion of PFCS, forced outages of both 345 kV lines are very "infrequent contingencies" and (2) the purported risk of voltage collapse is "temporary" in that the risk for about two-thirds of peak demands will be eliminated upon the completion of the NSTAR short-term upgrades. Likewise, Canal can be expected to be operated in merit during at least some portion of the highest one-third of peak demand days, further reducing reliance on the SPS.

Q. WHAT DO THE APPLICABLE CRITERIA REQUIRE WITH RESPECT TO LOCAL SECOND CONTINGENCY PROTECTION IN LOWER SEMA?

A. ISO-NE Operating Procedure No. 19 ("OP 19") sets out the applicable reliability criteria, which dictate that operating reserves be available so that following a transmission contingency:

- Post-contingency facility loadings are within equipment emergency ratings;
- All facilities can be brought to below the Long-Time Emergency ("LTE") rating within applicable time frames; and
- Coverage (i.e., protection of the transmission system) for the next contingency is restored within 30 minutes (referred to herein as the "30-minute second contingency protection criteria").

In Lower SEMA, these requirements can be met in one of two ways: operation of the Canal generation units or controlled load shedding upon the occurrence of a permanent outage of one 345 kV transmission line and the trip of a second 345 kV transmission before a Canal unit can be put into service. Without the operation of either of the Canal generating units (or other Lower SEMA generation) or

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controlled load shedding, loadings on many 115 kV lines would vastly exceed their normal and emergency ratings after loss of the second 345 kV line.

Q. HOW WOULD AN SPS HELP TO SATISFY THESE REQUIREMENTS?

A. An SPS would enable the ISO to shed automatically some Lower SEMA loads and delivery facilities almost instantaneously after the loss of the second 345 kV transmission line. This load shedding would prevent voltage collapse and meet the requirement to bring loadings on the remaining Lower SEMA facilities within their appropriate ratings within 30 minutes.

Q. WHY IS AN SPS BENEFICIAL AS A SOLUTION TO THE LOWER SEMA SECOND CONTINGENCY RISK?

A. Implementation of an SPS as a means of meeting reliability criteria is beneficial because an SPS would enable Lower SEMA to meet reliability criteria quickly at all load levels and at a very low cost. **[**BEGIN CEII**]**

[END CEII**]** in contrast to the $100 million per year cost of operating Canal generation out of economic merit. SPS is a proven and accepted mechanism for dealing with second and third contingency events, and in certain circumstances has been used for dealing with first contingencies. There are literally dozens of instances in which SPS has been used to great advantage in the United States, including a number of existing SPS installations operating in New England under the control of the ISO. In fact, in order to permit the development and interconnection of wind generation facilities in Lower SEMA, NSTAR has proposed and ISO has approved the use of an SPS at the Canal substation **[**BEGIN CEII**]**

[END CEII**]**

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Q. IN GENERAL, WHAT SORTS OF OPERATIONAL ISSUES ARE ADDRESSED USING A TYPICAL PROTECTIVE SCHEME, AND HOW IS AN SPS DIFFERENT?

A. A typical protective scheme deals with system contingencies such as a short circuit or overload on a line or transformer. Ordinarily, a fault or overload is detected at the terminals of that line or transformer by sensing devices and is dealt with through communications between those two sensing devices and the tripping of circuit breakers adjacent to each of them. Additionally, such equipment is always made reliable through redundancy. Once an unacceptable condition is detected by one of the redundant sensing devices (*e.g.*, a phase impedance relay that detects a level of line impedance that is characteristic of a short circuit or fault), relays automatically (*i.e.*, without any human intervention) send a signal to the circuit breakers at each terminal of the line or transformer that is overloaded or short circuited and directs those circuit breakers to open. Completion of these actions removes the associated line or transformer from service and isolates the faulted or overloaded element from the remainder of the electric system.

In contrast to this protective scheme, an SPS detects a "system" problem and sends a signal to operate circuit breakers to alleviate that problem. For instance, an overload on several transmission lines might best be addressed by opening circuit breakers on transformers that serve load at some remote location. Likewise, if tripping of transmission lines leaves a system subject to possible voltage collapse, those tripping events may trigger the operation of some remote circuit breakers to drop load and thereby alleviate the risk. Even generators can be tripped by an SPS when that is the best way to alleviate an overload on one or more transmission lines. The circuit breakers that are opened by an SPS may be located either in the same substation or in a substation remote from the location of the sensing devices and their associated logic. With the exception of the case where it operates remote circuit breakers, an SPS is little different from the

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protection applied to every transmission line and transformer in the system. Such SPS applications are very common in the electric utility industry.

To ensure reliability, SPSs use the same redundancy as do fault protection. Redundant sensing devices and redundant communication channels are applied. Additional logic is applied to ensure freedom from unnecessary operation

Q. WHAT SORT OF SPS SHOULD BE CONSIDERED IN LOWER SEMA?

A. Generally, an SPS should detect that both 345 kV lines are out of service and take remedial action to remove loads in Lower SEMA to a level commensurate with the limited capability of the remaining Lower SEMA 115 kV transmission system. The SPS could monitor the loading on the two 345 kV lines and use that information to determine the amount of load to drop, thereby avoiding excess load shedding. Monitoring the two important 345 kV transmission lines would provide a very clear signal on which an SPS could act.

Q. PLEASE EXPLAIN WHY THE SHORT TERM REPORT CONCLUDES [BEGIN CEII**]**

A.

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9 **[**END CEII**]**
10
11 According to PP 5-5 (at 2):

12 NPCC defines Type I SPSs to be those that are associated with conditions
13 resulting from design and operating contingencies for which failure or
14 misoperation has the potential for significant adverse impact outside of the
15 local area.

16 **Q. WHAT DOES "LOCAL AREA" MEAN IN THIS CONTEXT?**

17 A. Note 1 to PP 5-5 states in part that:

18 For the purpose of these SPS Application Guidelines, "local area" refers to
19 an area comprising no more than 10% of the total New England Control
20 Area load. Other influencing factors to be considered in determining
21 whether or not an event is confined to a "local area" are the size of the
22 geographic area, number of states, and number of customers affected.

23 **Q. SHOULD LOWER SEMA BE CONSIDERED A "LOCAL AREA" IN THIS**
24 **CONTEXT?**

25 A. Yes, Lower SEMA should be considered a local area. **[**BEGIN CEII**]**
26
27 **[**END CEII**]** the

[17] NPCC Document A-11 was subsequently retired and replaced by NPCC Regional Reliability Reference Directory # 7 Special Protection Systems (Dec. 27, 2007, *available at* http://www.npcc.org/viewDoc.aspx?name=NPCC+Directory+7+-+Special+Protection+System+RCC+Endorsed+Nov+28+2007rev5.pdf&cat=regStandDir).

[18] Special Protection Systems Application Guidelines (effective Apr. 13, 2007), *available at* http://www.iso-ne.com/rules_proceds/isone_plan/PP5-5R2.doc.

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Lower SEMA load affected by the 345 kV transmission line contingencies would be, at most, less than 1,000 MW out of a total ISO peak of 28,600, or less than 3.5% of total ISO load. That falls well below the 10% threshold for determining whether an electrically-confined area constitutes a "local area."

Q. WHY DOES THE SHORT TERM REPORT CONCLUDE [BEGIN CEII**]**

A.

[**END CEII**] However, Lower SEMA is a relatively limited geographic area located entirely within a single state and served by two transmission owners. **[**BEGIN CEII**]**

[END CEII**]**

Q. WHAT IS THE SIGNIFICANCE OF THE ISO'S INSISTENCE [BEGIN CEII**]**

A.

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[END CEII**]**

Q. WHAT WOULD IT MEAN IF THERE WERE LITTLE OR NO RISK OF VOLTAGE COLLAPSE OR WIDE AREA IMPACT ASSOCIATED WITH THE LOSS OF BOTH 345 KV LINES WHEN THE CANAL UNITS WERE NOT OPERATING?

A. If there is no wide area impact, then an NPCC Type I SPS would not be necessary, and another type of SPS (*e.g.*, NPCC Type III) could be installed without the restrictions as to monitoring and triggering actions within the same substation. **[**BEGIN CEII**]**

[END CEII**]**

Q. DO YOU AGREE WITH THE SHORT TERM REPORT'S CONCLUSION [BEGIN CEII**]**

A.

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1
2
3
4
5 **[**END CEII**]**

6 Finally, I note that the current reliance on out-of-merit operation of Canal is not
7 only more expensive but is also *less dependable* than an SPS (including an SPS
8 that departs in some respects from the Type I requirements) as a means of
9 protecting against voltage collapse outside Lower SEMA upon the loss of both
10 345 kV lines serving Cape Cod. It violates the ISO Tariff — and, in any case,
11 would be unjust and unreasonable — to charge Upper SEMA customers (or
12 customers in other reliability regions) Canal out-of-merit costs when an SPS
13 could afford them substantially greater protection at much lower cost.

14 **Q. PLEASE EXPLAIN YOUR CONTENTION THAT [**BEGIN CEII**]**
15
16

17 A.
18
19
20
21
22
23 **[**END CEII**]**
24 considering that major additional static capacitors (devices designed expressly to
25 support voltage) were planned for installation in Lower SEMA during the summer
26 of 2007 (*see* the NSTAR report entitled *NSTAR South 115 kV Shunt Capacitor*
27 *Installation and Uprate Project, Transmission Facilities Proposed Plan Steady*

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State Analysis)[19] and that the ISO has implemented a program of changing transformer taps on a seasonal basis to support voltage in Lower SEMA. Further voltage support will be provided to SEMA by the 2008 planned addition of the Barnstable Statcom. Moreover, as I discuss later, the ISO's report on the December 2003 outage of both 345 kV lines and both Canal generators did not indicate that voltage collapse occurred. Finally, while the risk of voltage collapse and easily implemented solutions such as undervoltage load shedding could be demonstrated through dynamic simulations of an outage of both 345 kV lines serving Lower SEMA, **[**BEGIN CEII**]**

Q.

[END CEII**]**

A. If the loss of both 345 kV lines into Lower SEMA and failure or mis-operation of an SPS would not create significant adverse impacts outside of Lower SEMA, then a Type I SPS would not be required. At most, the load affected in such a case would be less than 1,000 MW out of a total ISO peak of about 29,000 MW, or about 3.4-3.5% of total load. As I mentioned earlier, that is well below the 10% threshold for determining whether an electrically-confined area constitutes a "local area." An SPS whose failure or mis-operation significantly affects only a local area is not required to meet Type I requirements.

Q. [BEGIN CEII**]**

[END CEII**] DO THE APPLICABLE CRITERIA PRECLUDE USE OF AN SPS IN LOWER SEMA?**

[19] *Available at* http://www.isonewengland.com/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2007/may152007/Zip%203%20NSTAR%20Study.zip.

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A. No, they do not. **[**BEGIN CEII**]**

[END CEII**]**

Q. PLEASE EXPLAIN WHAT YOU MEAN BY "DEPENDABILITY" AND "SECURITY."

A. **[**BEGIN CEII**]**

[END CEII**]**

Q. WHAT DO THE APPLICABLE CRITERIA SAY ABOUT DEPENDABILITY AND SECURITY?

A. NPCC Reliability Reference Directory No. 7, the successor to NPCC Document A-11 (referenced in the Short Term Report), provides that in designing an SPS "[d]ue consideration" shall be given to dependability and security. NPCC Reliability Reference Directory #7 § 3.3.1. This means that design parameters should reflect "[t]he relative effect on the bulk power system of a failure of an SPS to operate when desired versus an unintended operation." *Id.* (emphasis removed). Appendix A reiterates these requirements, explaining that the "general objective for any SPS is to perform its intended function (generator rejection, load rejection, etc.) in a dependable and secure manner," while the selection of design

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parameters requires consideration of the "relative effects" of unintended operation versus failure to operate when needed. *Id.*, Appendix A at 15.

Q. WHAT DOES PP 5-5 SAY ABOUT DEPENDABILITY AND SECURITY?

A. Table I of PP 5-5 contains guidelines for acceptable Type I SPS application in New England. Under the heading "Security & dependability," Table I of PP 5-5 refers back to NPCC Document A-11, the predecessor to NPCC Reliability Reference Directory No. 7.

Q. DOES PP 5-5 SAY ANYTHING ELSE ABOUT DEPENDABILITY AND SECURITY?

A. Not explicitly, but other guidelines set forth in Table I implicitly address these considerations. For example, the Table sets forth guidelines regarding the number of detection triggers per SPS, the number of actions per SPS, and the locations for monitoring and for actions taken by each SPS, among other things. **[**BEGIN CEII**]**

[END CEII**]**

Q. PLEASE EXPLAIN.

A. **[**BEGIN CEII**]**

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[END CEII**]**

Q. DO YOU AGREE WITH THAT ASSESSMENT?

A. **[**BEGIN CEII**]**

[END CEII**]**

Q. WHAT DOES THE SHORT TERM REPORT SAY ABOUT [BEGIN CEII**]**

A.

[END CEII**]**

Q. DO YOU AGREE WITH THOSE ASSESSMENTS?

A. **[**BEGIN CEII**]**

[END CEII**]** Also, given the small amount of generation in Lower SEMA when the Canal units are off-line, transient power swings will be minimal or nonexistent. **[**BEGIN CEII**]**

[END CEII**]** Moreover, I would not expect that a false positive signal to

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open two 115 kV lines (if that is part of the remedial action of an SPS) would have any substantial adverse effect on service in Lower SEMA if one or both 345 kV lines were in service.

Q. WHAT DOES THE SHORT TERM REPORT SAY [BEGIN CEII**]**

A.

[END CEII**]**

Q. DO YOU AGREE WITH THAT CONCLUSION?

A. **[**BEGIN CEII**]**

[END CEII**]** First, with respect to monitoring, Table I in PP 5-5 states that "[r]emote monitoring is permissible when used to determine if a remote terminal of a line has been opened." Such monitoring would be useful in this case in that the trigger for remedial action by an SPS would be loss of both 345 kV lines. Second, with respect to the location of action relative to the SPS, Table I permits either local action or action at the end of a radial connection. Thus, the Table I guidelines incorporate a degree of flexibility that could be employed to design a Lower SEMA SPS that complies with the local-monitoring and local-action requirements.

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Even more fundamentally, the Table I guidelines do not purport to be set in stone. On its face, PP 5-5 establishes "guidelines" that are intended to embody "generally acceptable conditions for the application of SPSs in the New England Control Area," but does not establish absolute rules. *See* PP 5-5 at 2. Instead, "[e]ach SPS will be evaluated based on these guidelines *and* consideration of the potential impacts on system operations and reliability." *Id.* (emphasis added). Moreover, "[e]xceptions to these guidelines may be permitted in limited circumstances, based on an assessment of such factors as the extent of the deviation from the guidelines and the impact of such deviation on any associated reliability or security risk or the complexity of system operations." *Id.* At the same time, "consideration of such factors and alternatives, including upgrading the transmission system, may result in an SPS being judged unacceptable even though it adheres to the guidelines." *Id.*

Q. DID THE SHORT TERM REPORT ASSESS WHETHER [BEGIN CEII**]**

A.

[END CEII**]**

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Q. HOW MUCH WOULD AN SPS IN LOWER SEMA NEED TO DEVIATE FROM THE GUIDELINES?

A. The required deviations would appear to be minimal. For example, distances over which signals would need to be transmitted in Lower SEMA are relatively short. The SPS would not need to be armed under all conditions. For example, there would be no need to arm the SPS when Canal is operating in dispatch merit or when Lower SEMA loads are low. Additionally, the SPS security called for in the guidelines could be provided by undervoltage supervision.[20] Only with signals that both 345 kV transmission lines have opened and confirmation that a major event has occurred would the SPS send a signal to substations within 30 miles directing circuit breakers to open the two remaining supplies to Lower SEMA: the two 115 kV lines shown on Figure 2 in terms of system protection and the sophistication of existing SPS schemes, these attributes do not represent a complex SPS or a substantial deviation from an NPCC Type I SPS. Additionally, redundant communications paths could be used to assure the use of communications does not measurably increase risk of a failure to operate when required.

Q. WHAT WOULD BE THE IMPACT OF SUCH A DEVIATION ON ASSOCIATED RELIABILITY OR SECURITY RISK OR COMPLEXITY OF SYSTEM OPERATIONS?

A. Again, the impact would be minimal.

Even more important, implementation of an SPS (including an SPS that deviates to a small degree from the local sensing and local action guidelines of Table I from PP 5-5) would provide a major increase in reliability compared to the status

[20] The drop in voltage would be used to confirm the need to shed load but not to trigger load shedding on its own. As such, the voltage sensor hypothesized here would be set to detect a modest drop in voltage so as to ensure that the voltage sensor only confirms that a major event has occurred and does not inhibit immediate operation of the SPS.

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quo. Currently, the ISO relies on operation of the Canal generating units to preserve system reliability in the event that both 345 kV lines serving Cape Cod are lost. However, all generating units — particularly very old plants like the Canal Units — must undergo maintenance outages and occasionally do suffer forced outages. The Canal units are oil- and gas-fired steam turbines. These units generally have a forced outage rate of approximately 5%, and forced outage rates can often be higher. In the ISO, the average fossil-fired steam units with an installed capacity in the range of 400-599 MW had an equivalent forced outage rate ("EFORd") of .0471 for the period March 2003 through October 2007.[21] In addition, large steam generators such as those at Canal are typically scheduled out of service for two to four weeks per year for planned maintenance. Each week of planned maintenance represents an additional unavailability of approximately 2% (scheduling maintenance for 1 week out of the 52 weeks per year represents an outage rate of 1.923%). Conversely, an SPS could be operational up to 24 hours per day, 365 days per year (subject to disarming when system conditions are such that inadvertent operation could be more detrimental than a failure to operate), and would require only an hour or two per year of testing to ensure continued readiness to serve.

The risk in relying on the Canal generating units to preserve system reliability is demonstrated by the outage that occurred in 2003. On December 1, 2003, when both Canal Unit 1 and one 115 kV line were out for maintenance, a fire on the right of way caused the outage of one 345 kV line, a switching error took out the remaining 345 kV line, and a fire started by a fuel oil leak caused Canal Unit 2 to shut down. *See Joint Report of ISO New England, National Grid and NSTAR Electric on the Cape Cod Outage of December 1, 2003.*[22]

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[21] *See* http://www.iso-ne.com/genrtion_resrcs/gads/class_averages_2-29-08.pdf.

[22] *Available at* http://www.iso-ne.com/pubs/spcl_rpts/2003/joint_report_cape_cod_outage.pdf.

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[BEGIN CEII**]**

[END CEII**]** This point is significant because the outage rates for old generating units such as Canal are much higher than the failure rates for an SPS. In other words, reliance on the Canal units provides less dependable protection to customers outside Lower SEMA than would be provided through the use of an SPS.

Q. PLEASE DISCUSS IN MORE DETAIL HOW THE FAILURE RATE OF AN SPS COMPARES TO THE FORCED OUTAGE RATES OF THE CANAL UNITS.

A. Again, in talking about SPS failure rates, one must distinguish between failure-to-operate and inadvertent operation. Use of an SPS involves a small risk of inadvertent operation (unnecessary remedial action which might involve load loss in SEMA), which is not presented by operation of the Canal units. However, the likelihood of inadvertent operation is very low; the consequences of inadvertent operation would be limited to Cape Cod; and service could be restored very quickly as demonstrated in the earlier discussion of Post-First Contingency Switching. These drawbacks pale in comparison to the fact that an SPS would have far greater dependability than would reliance on Canal as a means to guard against broader system impacts in the event that both 345 kV lines serving Cape Cod are lost.

The loss of one or both Canal Units is very possible upon loss of the 345 kV lines. That is, it is not unusual for generators to trip in response to the voltage and angle excursions that accompany a fault and line trip.

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Q. DOES THE SHORT TERM REPORT DISCUSS [BEGIN CEII**]**

A.

[END CEII**]** However, an SPS is typically composed of relays and telecommunications. Ordinarily, a protection engineer trusts his relays and telecommunications. Such trust is implicit in the widespread use of relays and telecommunications in everything from run-of-the-mill protection designs to elaborate systems. Moreover, an SPS combines these relays and telecommunications redundantly to assure reliability and security. That is, an SPS is designed to respond reliably when needed and to be free from unnecessary operation. **[**BEGIN CEII**]**

[END CEII**]**

Q. WHAT HAS BEEN INDUSTRY EXPERIENCE WITH INADVERTENT OPERATION?

A. Experience in North America indicates that there is a very low probability of inadvertent operation of an SPS. Indeed, of the 429 disturbances reported to NERC for the United States and Canada during the 13 years from 1986 through 1998 (those that caused loss of customers above the MW reporting threshold), only 30 involved an SPS and only 9 of the 30 involved operational failures. Of the 9 operational failures of an SPS that occurred throughout the U.S. and Canada during those 13 years, 2 involved human error (failure to arm or set correctly), 4 involved design failures, and 3 involved hardware failures. *See generally* NERC's "DAWG Database" of "Disturbances, Load Reductions, and Unusual

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Occurrences."[23] These reports do not include statistics on the many correct SPS operations that did not involve loss of customers. Moreover, much has been learned since 1998 about proper procedures for auditing the design and operation of an SPS, so it would be reasonable to expect still lower failure rates for a newly designed and implemented SPS. *See* Exhibit No. MPS-4, an excerpt from *System Protection Schemes in Power Networks*, chapter 6 ("SPS Design Procedure and Reliability Evaluation").

Also, as I discussed above, it is important to recognize that a Lower SEMA SPS need not be armed in all hours. When the Canal generation is operating or when loads are low, there would be a reduced need to shed load upon loss of the 345 kV lines, and the SPS could be disarmed to prevent inadvertent operation. Furthermore, completion of the short-term NSTAR transmission upgrades (by the middle of 2009 at the earliest) should increase the load level below which the SPS could be disarmed to prevent inadvertent operation.

Finally, as I noted, the inadvertent opening of one or two 115 kV lines would not be expected to have a significant impact on service to loads in Lower SEMA if both 345 kV lines are in service.

Q. YOU CRITICIZED THE SHORT TERM REPORT [BEGIN CEII**]**

[END CEII**] PLEASE COMMENT ON THE USE OF SPS SYSTEMS IN NEW ENGLAND.**

A. I have reviewed numerous documents indicating that the use of SPS is an accepted practice in New England.

[23] *Available at* http://www.nerc.com/~dawg/database.html.

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Q. ARE YOU AWARE OF ANY LOAD SHEDDING SCHEMES ALREADY IN PLACE IN NEW ENGLAND?

A. Yes. I am aware of several, including one in the Boston area that prepares the system to drop a significant amount of load as well as similar schemes in Connecticut.

Q. YOU MENTIONED EARLIER THAT, IN CONNECTION WITH A PROPOSED OFF-SHORE WIND GENERATION DEVELOPMENT, NSTAR HAD PROPOSED, AND THE ISO HAD APPROVED, AN SPS FOR USE AT THE CANAL SUBSTATION. PLEASE ELABORATE.

A. Exhibit No. MPS-5 is a recommendation to the NEPOOL Reliability Committee by the Transmission and Stability Task Forces of that Committee, commenting on the "Proposed Plan Applications for the Cape Wind Generation Project" ("Transmission Task Force Report"). As explained in that document, thermal analysis of the system before interconnection of the proposed project showed a preexisting condition following the simultaneous loss of the 342 and 322 Lines when both Canal 1 and Canal 2 units are on line. With both Canal units in service, "loss of the 342 and 322 Lines…can result in overloading the Bourne – Tremont 115 kV 108 and 113 Lines beyond their STE ratings of 291 MVA." *Id.* at 1. The report noted that this was "an existing problem that requires the tripping of a Canal unit to avoid this overload," which could be addressed through an NPCC Type III SPS. *Id.* However, the Task Forces concluded that with the wind generation project on line as well, a Type I SPS would be required to address this contingency. The proposed SPS, referred to as the Canal 345 kV SPS, would trip any on-line Cape Wind generation as well as the Canal 2 generator whenever (a) both Canal 1 and Canal 2 were on-line and (b) the two 345 kV lines were lost.

Q. DID THE PROPOSED CANAL 345 KV SPS MEET ALL OF THE TYPE I SPS GUIDELINES?

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A. No. The report acknowledged that "the Canal 345 kV SPS fails to meet all of the conditions for a Type I SPS" as specified in PP5-5. Transmission Task Force Report at 2. Specifically, the report noted that "an NPCC Type I SPS is required to have local action relative to the SPS" but "[t]ripping of Cape Wind as specified above is a remote action." *Id.*

Q. WHAT DID THE TASK FORCE RECOMMEND?

A. The Transmission Task Force recommended "that the Reliability Committee should consider granting an exception to requiring the proposed Canal 345 kV SPS to meet the condition of the SPS Guidelines that Type I SPS only employ local action" and it agreed that the addition of the SPS was otherwise acceptable. Transmission Task Force Report at 2. Both the Transmission Task Force and the Stability Task Force "agreed that the analyses subject to their review sufficiently support[ed] the required applications for implementation of the Project under Section I.3.9 of the ISO Tariff, subject to further consideration of the appropriateness of the proposed Canal 345 kV SPS not meeting the SPS Guidelines. . . ." *Id.* Both Task Forces agreed that with the addition of the proposed 345 kV SPS, "the interconnection of the Project will not have a significant adverse effect upon the stability, reliability or operating characteristics of the New England Transmission system or the system of a Market Participant," and they recommended that the Reliability Committee approve the forthcoming Generation Proposed Plan Application for the Project. *Id.*

Q. WHAT DID THE RELIABILITY COMMITTEE DO?

A. The Reliability Committee recommended approval of the Cape Wind application, on grounds that it would "not have a significant adverse effect upon the reliability or operating characteristics of the NSTAR Gas & Electric Corporation (NSTAR) transmission facilities, the transmission facilities of another Transmission Owner, or the system of a Market Participant," provided that an "a NPCC Type I SPS" is installed at the Canal 345 kV Substation that will "trip Cape Wind generation and

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1 the Canal 2 generator following the simultaneous trip of the 342 and 322 Lines for
2 the condition when the Canal 1 and Canal 2 generators are both on line."[24]
3 **[**BEGIN CEII**]**
4
5
6 **[**END CEII**]**

7 **Q. WHAT DID THE ISO DO?**

8 A. ISO approved the proposed plan, including the proposal to install a Type I SPS
9 whose attributes were not confined to local action, on October 6, 2005.[25]

10 **Q. ARE YOU FAMILIAR WITH ANY OTHER SPS?**

11 A. Yes, I have encountered numerous SPS installations over the 40-year course of
12 my engineering career. A well-known SPS, some of whose attributes are similar
13 to an SPS that I expect would be acceptable for Cape Cod, is the Pacific
14 Northeast-Pacific Southeast Separation Scheme ("PNE-PSE Separation
15 Scheme"). That SPS has served with dependability and security (that I would
16 characterize as providing "a high degree of certainty") since the late 1960s. It
17 incorporates logic that accepts a signal to dump thousands of megawatts of
18 generation, to shed and add load and to open breakers on numerous transmission
19 lines hundreds of miles away from the events which give rise to activation of the
20 SPS. Activation occurs only if at least "two-out-of-three" totally independent and
21 redundant communication schemes indicate that action is necessary. And these
22 transfer tripping signals are transmitted over great distances to facilities up to
23 1000 miles apart. Interestingly, the PNE-PSE Separation Scheme was thought to

[24] Memorandum from Richard W. Burke, Secretary, Reliability Committee to the Participants Committee (August 1, 2005) at 4-5, *available at* http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/actions/2005/rc_actions_050728_29.pdf

[25] Memorandum from Richard W. Burke, Secretary, Reliability Committee to the Participants Committee (October 6, 2006)at 6, *available at* http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/actions/2005/rc_actions_051004.pdf

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be no longer needed when a third 500 kV AC line was extended from California to Oregon in the early 1990s, and the scheme was taken out of service. It was quickly put back into service (following an August 1996 blackout) when it became evident that it would have prevented the August 1996 blackout and prior cascading failures had it been left in service. Any SPS likely to be implemented in Lower SEMA would be far less complex, would operate less frequently, and would affect a far smaller geographic area and magnitude of load than does the PNE-PSE Separation Scheme.

Q. BASED ON YOUR REVIEW OF [BEGIN CEII**]**

[END CEII**]**

A. No, I do not agree. With a comparatively small expenditure on engineering analysis, and minimal expenditures on capital equipment, the ISO could design and implement an SPS that would provide reliable service in compliance with Applicable Criteria. **[**BEGIN CEII**]**

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9 **[**END CEII**]**

10 **Q. IS THERE ANYTHING ELSE YOU WOULD LIKE TO ADD AS TO ISO'S**
11 **[**BEGIN CEII**]**
12

13 A.
14
15 **[**END CEII**]**

16 However, the ISO is characterizing those costs as Local Second Contingency
17 Protection Resource charges, which are allocated to all SEMA loads. This
18 allocation is either over- or under-inclusive depending on which of the risks that
19 operating Canal generation is thought to avoid. If the risk avoided is loss of
20 Lower SEMA loads, then Lower SEMA loads should pay the costs incurred to
21 avoid those risks. As explained above, it is unreasonable to charge Upper SEMA
22 customers for the costs of avoided Lower SEMA load-shedding. **[**BEGIN**
23 **CEII**]**
24
25 **[**END CEII**]**

26 Conversely, if the risk avoided by running Canal out of merit is a system-wide
27 voltage collapse, then it is unreasonable to charge only SEMA loads for the costs
28 incurred to avoid those region-wide risks.

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Q. WHAT IS THE SIGNIFICANCE OF CONCLUDING THAT [BEGIN CEII**]**

A.

[END CEII**]**

Q. YOU HAVE STATED THAT THE ISO TARIFF PROHIBITS THE RECOVERY AS LSCPR CHARGES OF COSTS THAT COULD HAVE BEEN AVOIDED THROUGH IMPLEMENTATION OF A PFCS ARRANGEMENT OR AN SPS. IF THE COMMISSION REJECTS YOUR INTERPRETATION OF THE ISO TARIFF LANGUAGE, WHAT DO YOU SUGGEST BE DONE?

A. In that case, the ISO Tariff is inconsistent with cost-causation principles and should be revised. The primary benefit of operating Canal out of merit, when Applicable Criteria could be satisfied through less expensive means, is avoidance of the small probability of an outage that a PFCS arrangement or SPS could entail. But all of the MPS customers are located in Upper SEMA, **[**BEGIN CEII**]**

[END CEII**]** The customers that cause Canal to be operated out of merit, when Applicable Criteria could be satisfied through PFCS or SPS arrangements, are the Lower SEMA customers. Allowing the ISO to classify the Canal Units as LSCPR and therefore allocate their out-of-merit charges to all of SEMA conflicts with the principles of cost-

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1 causation because it forces Upper SEMA customers to bear the costs of actions
2 they do not benefit from and have no power to change. If the Tariff is
3 inconsistent with the cost-causation principles, it is unjust, unreasonable and
4 unduly discriminatory and therefore must be revised.

5 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

6 A. Yes, at this time.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Braintree Electric Light Department, Hingham Municipal Lighting Plant, Hull Municipal Lighting Plant, Mansfield Municipal Electric Department, Middleborough Gas & Electric Department, and Taunton Municipal Light Plant Complainants, v. ISO New England Inc. Respondent.	Docket No. EL08-___

AFFIDAVIT

DISTRICT OF COLUMBIA

Whitfield A. Russell, being first duly sworn, deposes and says:

that he is the same Whitfield A. Russell whose testimony on behalf of Braintree Electric Light Department, Hingham Municipal Lighting Plant, Hull Municipal Lighting Plant, Mansfield Municipal Electric Department, Middleborough Gas & Electric Department, and Taunton Municipal Light Plant accompanies this Affidavit; that he has read the foregoing questions and answers constituting that testimony, and that if asked such questions his answers in response would be as shown; that the facts set forth therein are true and correct to the best of

his knowledge, information and belief; and that he does adopt the same as his sworn testimony in this proceeding.

Whitfield A. Russell

Subscribed and sworn to before me this 19th day of March 2008, by Whitfield A. Russell.

Tara K. Parker-Johnson
Notary Public

My Commission expires: NOV. 30, 2007

Notary registration Number: 333663

TARA K. PARKER-JOHNSON
Notary Public
Commonwealth of Virginia
333663
My Commission Expires Nov 30, 2011

Exhibit No. MPS-2

WHITFIELD A. RUSSELL

Whitfield A. Russell is an electrical engineer, attorney and President of Whitfield A. Russell and Associates, P.C., a corporate Partner of Whitfield Russell Associates. He holds a Bachelor of Science degree in Electrical Engineering from the University of Maine at Orono, a Master of Science in Electrical Engineering from the University of Maryland, and a Juris Doctor degree from Georgetown University Law Center.

Mr. Russell is experienced in electric utility system planning (transmission and generation), ratemaking and bulk power contracts. He has been qualified as an expert witness in 27 states (as well as in the Provinces of Alberta and Manitoba and the District of Columbia) and has been accepted as an expert in approximately 150 proceedings before state and federal courts, arbitration panels, public service commissions, the Federal Energy Regulatory Commission and numerous other administrative agencies. Mr. Russell's clients have included public power utilities, state and federal power marketing agencies, investor-owned utilities, independent power producers, and state regulatory bodies and their staffs. He has written and spoken extensively on matters relating to regulated electric utilities.

Mr. Russell founded Whitfield Russell Associates in 1976.[1] Prior to that, from 1972 to 1976, he served as Engineer and eventually Chief Engineer for the Securities and Exchange Commission's Division of Corporate Regulation. That Division, in administering the Public Utility Holding Company Act of 1935, regulated registered pubic utility holding company systems representing approximately 20% of the gas and electric industries in the United States.

From 1971 to 1972, Mr. Russell was on the staff of the Federal Power Commission. He served as a consultant to staff attorneys in proceedings, and as an expert witness in an administrative proceeding before the Atomic Energy Commission.

From 1969 to 1971, Mr. Russell served as an Associate Engineer in the System Planning Division of the Potomac Electric Power Company. At PEPCO, he conducted system studies of load flows and stability. He was also a member of numerous study groups concerned with planning and operation of the Pennsylvania-New Jersey-Maryland Interconnection.

[1] Whitfield Russell Associates is located at 4232 King Street Alexandria, VA 22302. (703) 894-2200

PROCEEDINGS IN WHICH
WHITFIELD A. RUSSELL
HAS TESTIFIED

1. Anaheim v. Kleppe, U.S. District Court, Arizona (Civil No. 74-542 PHX-WEC), concerning the availability of transmission capacity in the Pacific Southwest.

2. In re: Potomac Electric Power Company, before the Maryland Public Service Commission, Case No. 7004, concerning the need for proposed 500 kV transmission lines in the Washington, D.C. area.

3. In re: Baltimore Gas and Electric Company, and Potomac Electric Power Company, before the Maryland Public Service Commission, Case No. 6984, involving the same transmission lines mentioned in the preceding case.

4. Perry v. The City of Monroe, Louisiana (State of Louisiana, Parish of Ouachita, Fourth District Court; Nos. 111145, 111146, 111147) regarding the necessity of Monroe's disposing of its municipal utility system; August 16, 1977.

5. In re: Potomac Electric Power Company, before the District of Columbia Public Service Commission, in Case No. 685, concerning the system planning of the Potomac Electric Power Company and the PJM Pool.

6. In re: Generic Hearings on Rate Structure, before the Colorado Public Utilities Commission, Case No. 5693, regarding the engineering aspects of marginal cost pricing and power pooling in Colorado; October 1980.

7. In re: Pacific Gas and Electric Company, FERC Docket No. ER76-532, regarding the proper level of rates to be charged by PG&E to the Central Valley Project for transmission service; April 1978, revised January 1979.

8. In re: Pacific Power and Light Company, FERC Docket No. E-7796, regarding the Seven Party Agreement and related matters; May 1978.

9. In re: Pacific Gas and Electric Company, FERC Docket No. E-7777 (II), concerning the provisions of numerous bulk power arrangements governing electric utilities in California; October 1978.

10. In re: Potomac Edison Company, before the Maryland Public Service Commission, Case No. 7055, concerning the need for a 230 kV transmission line in Montgomery County, Maryland.

11. In re: Delmarva Power and Light Company, before the Maryland Public Service Commission, Case Nos. 7239F, 7239G, 7239H, 7239I, 7239J, 7239K, 7239L,

7239M and 7239N concerning fuel rate adjustments; June 17, 1980, March 17, 1981, August 19, 1981 and November 20, 1981.

12. In re: Baltimore Gas and Electric Company, before the Maryland Public Service Commission, Case Nos. 7238G, 7238H, 7238I, 7238J, 7238L and combined dockets 7238P, Q, R and S, concerning fuel rates; June 20, 1980, November 2, 1980, April 14, 1981, July 17, 1981 and September 14, 1981.

13. In re: Potomac Electric Power Company, before the Maryland Public Service Commission, Case Nos. 7240A, 7240B, 7240C, 7240D, 7240E, 7240F and 7240G, concerning fuel rate adjustments; October 1980.

14. In re: Florida Power & Light Company, FERC Docket No. E-9574, concerning system planning for the City of Vero Beach, Florida. FP&L withdrew its application to acquire the Vero Beach system.

15. In re: Oklahoma Gas and Electric Company, FERC Docket No. ER77-465, concerning rates for energy banking and transmission services rendered to the Western Farmers Electric Cooperative; October 20, 1978.

16. In re: Idaho Power Company, before the Idaho Public Utility Commission, Case No. U-1006-158, concerning the value of interruptible industrial loads and Idaho Power Companies entitlement to Federal secondary energy; March 1980.

17. In re: Potomac Electric Power Company, before the District of Columbia Public Service Commission, Case No. 737, concerning the Company's construction program; October 27, 1980.

18. In re: Virginia Electric and Power Company, before the Virginia State Corporation Commission, Case No. PUE 800006, concerning construction of transmission lines in the Charlottesville, Virginia area; 1982.

19. In re: Pacific Gas and Electric Company, FERC Project Nos. 2735 and 1988, concerning the Helms Project, a pumped storage generating unit; August 24, 1979.

20. Southeastern Power Administration v. Kentucky Utilities Company, FERC Docket No. EL 80-7, concerning SEPA's attempt to obtain a FERC wheeling order under the Public Utility Regulatory Policies Act of 1978; October 6, 1980.

21. In re: Sierra Pacific Power Company, before the Public Service Commission of Nevada, Docket No. 81-105, concerning construction and transmission planning; June 29, 1981.

22. In re: Virginia Electric and Power Company, before the North Carolina Utilities Commission, Docket No. E-22, Sub 257, concerning production cost simulation and normalized fuel adjustment clause formula; June 9, 1981.

23. In re: the Investigation of the Capital Expansion For Electric Generation, before the New Mexico Public Service Commission, Case No. 1577, concerning construction programs of the Public Service Company of New Mexico and El Paso Electric Company; July 2, 1981.

24. In re: Potomac Edison Company, before the Maryland Public Service Commission, Case Nos. 7241A, 7241B, 7241C and 7241D, concerning fuel rate adjustments and productivity of generating units; March 13, 1981.

25. In re: Potomac Edison Company, before the Maryland Public Service Commission, Case No. 7528, concerning the method of calculating Potomac Edison's fuel rate.

26. In re: Delmarva Power & Light Company, before the Maryland Public Service Commission, Docket No. 7570, concerning transmission loss allocation methodology; October 30, 1981.

27. In re: Nebraska Public Power District, before the South Dakota Public Utilities Commission, Docket No. F-3371, concerning proposed construction and operation of the 500 kV MANDAN Transmission Facility; September 29, 1981.

28. In re: Sierra Pacific Power Company, before the Public Service Commission of Nevada, Docket No. 81-660, concerning construction and transmission planning; January 4, 1981.

29. In re: Kentucky Utilities Company, FERC Docket Nos. ER-81-341-000 and ER81-267-000, concerning construction planning and the market for short term power; February 26, 1982 and May 7, 1982.

30. In re: Kentucky Power Company et al., before the Kentucky Public Service Commission, Case No. 8566, concerning cogeneration and avoided costs; September 16, 1982.

31. In re: Appalachian Power Company, before the West Virginia Public Service Commission, Case No. 82-162-42T, concerning the wholesale market and short-term power sales; October 19, 1982.

32. In re: Central Maine Power Company, before the Maine Public Utility Commission, Docket No. 82-137, concerning the application of Central Maine Power Company to reorganize in the form of a holding company; October 25, 1982.

33. In re: Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 4712, concerning rates to be paid to cogenerators and small power producers; February 28, 1983.

34. In re: Dow Chemical Company, before the Public Utility Commission of Texas, Docket Nos. 4802, 5050 and 5062, concerning rates for interruptible service; September 26, 1983.

35. In re: Nevada Power Company, before the Nevada Public Service Commission, Docket No. 83-707, concerning the Reid Gardner No. 4 Participation Agreement, October 11, 1983.

36. Dow Chemical Company vs. Houston Lighting & Power Company, before the District Court of Brazoria County, Texas, 149th Judicial District, No. 79-F-2620, regarding the custom and usage of contract terms in the electric utility industry. Live direct testimony in a jury trial. No transcript available.

37. In re: The Montana Power Company and the Confederated Salish and Kootenai Tribes of the Flathead Reservation, Project Nos. 5-004 and 2776-000, concerning the Tribes' intention and ability to sell its output to one or more entities in the Western states, if obtaining the license to the Kerr Project; July 15, 1983.

38. In re: the Dow Chemical Company vs. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-16038, concerning cogeneration and small power production; October 28, 1984.

39. In re: Petition of the Dow Chemical Company, before the Public Utility Commission of Texas, Docket No. 5651, for an order compelling Houston Lighting & Power Company to comply with the Commission Order concerning cogeneration and small power production; December 10, 1984.

40. In re: Oklahoma Gas and Electric Company, before the Oklahoma Corporation Commission, Cause No. 29017, concerning priority for recognition of capacity costs to Qualifying Facilities; January 1985.

41. In re: Kansas City Power & Light Company of Kansas City, Missouri, before the Missouri Public Service Commission, Case Nos. ER-85-128 and EO-85-185, regarding rate design and allocation of production-related costs for the Company's Wolf Creek Generating Station on behalf of the United States Department of Energy; May 3, 1985.

42. In re: Kansas City Power and Light Company, before the State Corporation Commission of the state of Kansas, Docket Nos. 142,099-U and 120,924-U, concerning operating problems caused by excess capacity, mitigation measures and regulatory requirements, on behalf of Johnson County Joint Intervenors; May 6, 1985.

43. In re: Duke Power Company, before the North Carolina Utilities Commission, Docket No. E-7, Sub 391, concerning the Company's use of an Extended Cold Shutdown program to mitigate its excess capacity situation resulting from the

Catawba Units, on behalf of the Department of Justice for the State of North Carolina; June 26, 1985.

44. Sierra Pacific Power Company, before the Public Service Commission of the State of Nevada, Docket No. 85-430, on behalf of the State of Nevada Attorney General's Office of Advocate for Customers of Public Utilities, concerning the effects upon retail rates of placing Valmy Unit No. 2 in service; August 26, 1985.

45. United States of America Department of Energy, before the Bonneville Power Administration, on behalf of the City of Vernon, California, concerning the 1985 Proposed Firm Displacement Power Rate; November 8, 1985.

46. In re: City of Anaheim, et al., v. Southern California Edison, Docket No. 78-0810, on behalf of five partial requirements wholesale customers of Southern California Edison Company, making claims under Federal antitrust laws for access to the Pacific Northwest-Pacific Southwest Intertie.

47. In the Matter of the Application of Sierra Pacific Power Company for Approval of its 1986-2006 Electric Resource Plan, Docket No. 86-701, on behalf of the State of Nevada Attorney General's Office of Advocate for Customers of Public Utilities, concerning efforts of Sierra Pacific Power Company to develop a new interconnection (the SMUD Tie) with the Sacramento Municipal Utility District; September 8, 1986.

48. The Federal Executive Agencies, Complainant v. Public Service Company of Colorado, before the Public Utilities Commission of the State of Colorado, Case No. 6551, on behalf of the Federal Executive Agencies concerning the feasibility of wheeling federal preference power to the Government's facilities at Rocky Flats, the Lowry Air Force Base, the Rocky Flats Technical Center and the Denver Federal Center; December 15, 1986 and February 10, 1987.

49. Commonwealth Edison Company, before the State of Illinois, Illinois Commerce Commission, Docket Nos. 87-0043, 87-0044 and 87-0057 Consolidated, on behalf of Intervenor, Citizen's Utility Board of Illinois, concerning Edison's proposal to form a generating subsidiary.

50. Nevada Power Company, before the Nevada Public Service Commission, Docket No. 87-750, concerning a 345 kV transmission line proposed to connect Nevada Power Company to Utah Power and Light Company; September 28, 1987, October 8, 1987 and October 24, 1987.

51. Utah Power & Light Company, PacifiCorp, PC/UP&L Merging Corporation, FERC Docket No. EC88-2-000, establishing conditions for the proposed merger; also challenging PP&L's/UP&L's assertion that the claimed coordination benefits would not be attainable through power pooling or by contract; February 12, 1988.

52. Rosemount Cogeneration Joint Venture, Biosyn Chemical Corporation and Oxbow Power Corporation vs. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E-002/GG-88-491, on behalf of Petitioners, Rosemount Cogeneration Joint Venture, Biosyn Chemical Corporation and Oxbow Power Corporation, concerning a contract between Northern States Power and Biosyn Chemical Corporation covering the 50 MW output of a yet-to-be-constructed power plant based on the forecast costs of Sherburne County Unit #3 ("Sherco Unit 3"); October 24, 1988.

53. In re: Potomac Electric Power Company, before the District of Columbia Public Service Commission, Case No. 869, on behalf of the District of Columbia Office of the People's Counsel, concerning the prudence of off-system purchases; June 6, 1988.

54. In re: Wisconsin Public Power Inc. System, Advance Plan 5, before the Public Service Commission of the state of Wisconsin, on behalf of the Wisconsin Public Power System, Inc., concerning transmission planning in the state of Wisconsin; August 15, 1988.

55. In re: Nevada Power Company, before the Public Service Commission of Nevada, Docket No. 88-701, on behalf of the Attorney General's Office of Advocate for Customers of Public Utilities, concerning NPC's 1988 Resource Plan; August 29, 1988.

56. In re: Commonwealth Edison Company, before the Illinois Commerce Commission, Docket Nos. 87-0427, 87-0169, 88-0189 and 88-0219, on behalf of the Citizens Utility Board, concerning rejection of an unfair, Staff-proposed rate order; September 12, 1988.

57. In re: Dow Chemical Company vs. Houston Lighting & Power Company, before the Texas Public Utilities Commission, Docket No. 8425, 8431, on behalf of The Dow Chemical Company, concerning application of Houston Lighting & Power Company for authority to change rates; Fuel Reconciliation, Revenue Requirements and Rate Design; March 15, 1989.

58. Dow Chemical Company vs. Houston Lighting & Power Company, before the Texas Public Utilities Commission, Docket No. 8555, on behalf of The Dow Chemical Company, concerning rate discrimination, cost to serve and class load characteristics; August 7, 1989.

59. In re: Sierra Pacific Power Company, before the Public Service Commission of Nevada, Docket No. 89-676, on behalf of the Attorney General's Office of Advocate for Customers of Public Utilities, concerning Sierra's system planning; August 18, 1989.

60. In re: Northern California Power Agency vs. Pacific Gas and Electric Company, before the Federal Energy Regulatory Commission, Docket No. EL89-4-000, on behalf of the Northern California Power Agency ("NCPA"), concerning the Interconnection Agreement between Pacific Gas & Electric Company and NCPA; October 3, 1989.

61. In re: M-S-R Public Power Agency vs. Tucson Electric Power Company, before the United States District Court of Arizona, No. CIV-86-521-TUC-ACM, on behalf of M-S-R, concerning TEP's breach of contract.

62. In re: Southern California Edison Company and San Diego Gas & Electric Company, before the Federal Energy Regulatory Commission, Docket No. EC89-5-000, on behalf of the City of Vernon, California concerning expected effects of the proposed merger on competition, system operation and transmission access; January 3, 1990 and March 12, 1990.

63. In re: Farmers Electrical Cooperative Corporation and City Water & Light Plant of the City of Jonesboro, Arkansas, v. Arkansas Power & Light Company, No. LR-C-86-118. Presented deposition testimony on AP&L's liability and assisted in settlement negotiations of treble damage claims for transmission line foreclosure made by plaintiffs, City Water and Light Department of Jonesboro, Arkansas and the Farmers Electric Cooperative.

64. In re: Southern California Edison Company and San Diego Gas & Electric Company, before the California Public Utilities Commission, Docket No. 88-12-035, on behalf of the City of Vernon, California concerning expected effects of the proposed merger on competition, system operation and transmission access; April 1990.

65. In re: Northeast Utilities Service Company and Public Service Company of New Hampshire, before the Federal Energy Regulatory Commission, Docket Nos. EC90-10-000, ER90-143-000, ER90-144-000, ER90-145-000 and EL90-9-000, on behalf of Massachusetts Municipal Wholesale Electric Company, concerning the effect of a proposed merger on competition and transmission access; May 25, 1990.

66. Report to the Public Utilities Board of Manitoba concerning 1990 Manitoba Hydro Capital Projects Review: Generation and Transmission Requirements. Whitfield Russell Associates was appointed to report to The Public Utilities Board on matters regarding the economic consequences to the domestic customers of the Manitoba Hydro capital program; August 28, 1990.

67. In re: Northeast Utilities Service Company, before the Federal Energy Regulatory Commission, Docket Nos. ER90-373-000, et al., on behalf of the Massachusetts Municipal Wholesale Electric Company, evaluating the Preferred Transmission Service Agreement between MMWEC and Northeast Utilities Service Company,

for the transmission of MMWEC's power purchase from the New York Power Authority; November 27, 1990.

68. In re: New Hampshire Electric Cooperative Rate Plan Proposal, before the New Hampshire Public Utilities Commission, Docket No. DR90-078, on behalf of the New Hampshire Electric Cooperative, concerning contract valuation; December 11, 1990.

69. Tampa Electric Company v. Zeigler Coal Company. This was an arbitration held in August 1991, concerning provisions of a coal contract in which Mr. Russell offered testimony for Zeigler to the effect that Tampa Electric was not suffering a hardship by measures commonly used in the electric utility industry.

70. In re: The Long Range Forecast of Ohio Power Company, before the Ohio Public Utilities Commission, Docket No. 90-660-EL-FOR (Phase II). Mr. Russell presented and defended testimony on behalf of Ormet Aluminum Corporation concerning Ormet's right to allowances to emit sulfur dioxide from the Kammer Power Plant of Ohio Power Company under the Clean Air Act Amendments of 1990 and the propriety of Ohio Power's Compliance Plan; July 17, 1991.

71. In re: Application of Tex-La Electric Cooperative to Increase Rates. Mr. Russell presented testimony in 1991, demonstrating that Tex-La was prudent in selling its entitlement in a nuclear plant and in settling its 1988 claims against Texas Utilities concerning Texas Utilities' fraud and imprudence in the construction of the Comanche Peak Nuclear Plant; June 1991.

72. In re: Southern California Edison Company, before the Federal Energy Regulatory Commission, Docket No. ER88-83, on behalf of the City of Vernon, California concerning expected effects of Edison's administration of its transmission network on competition, system operation and transmission access; June 1991.

73. In the Matter of the Application of the Public Service Company of New Mexico for Approval to Construct, Own, Operate and Maintain the Ojo Line Extension and for Related Approvals before the New Mexico Public Service Commission, Case No. 2382, on behalf of the United States Department of Energy, concerning transmission line construction programs of the Public Service Company of New Mexico; November 8, 1991.

74. In re: Wisconsin Public Power Inc. System et al., Advance Plan 6, before the Public Service Commission of the state of Wisconsin, Docket No. 05-EP-6, concerning Eastern Wisconsin Utility Joint Transmission System and Interface Study; December 31, 1991.

75. In re: MidAtlantic Energy v. Monongahela Power Company and the Potomac Edison Company, before the Public Service Commission of West Virginia, Case No. 89-783-E-C, on behalf of MidAtlantic Energy, concerning need for capacity

and the appropriate avoided cost; January 6, 1992, June 8, 1992 and February 13, 1992..

76. In re: Northeast Utilities Service Company, before the Federal Energy Regulatory Commission, Docket No. EL91-36-000, on behalf of the Massachusetts Municipal Wholesale Electric Company evaluating the tie-line adjustment charge borne by MMWEC that arose under a Transmission Service Agreement between New England Power Company and Northeast Utilities; May 1, 1992 and August 24, 1992.

77. In re: Application of Houston Lighting & Power Company for a Certificate of Convenience and Necessity for the DuPont Project, before the Public Utility Commission of Texas, Docket No. 11000, on behalf of Destec Energy, Inc; September 28, 1992, June 24, 1993 and June 29, 1993.

78. In re: Investigation on the Commission's Own Motion into Barriers to Contracts Between Electric Utilities and Nonutility Cogenerators and Certain Related Policy Issues, before the Public Service Commission of the state of Wisconsin, Docket No. 05-EI-112, on behalf of JOINT PARTIES: DESTEC Energy, Inc., EnerTran Technology Company, LS Power Corporation, The AES Corporation, LG&E Development Corporation, National Independent Energy Producers, and Citizens' Utility Board, concerning appropriate QF contract provision; November 23, 1992.

79. In re: Application of Cap Rock Electric Cooperative, Inc. for a Certificate of Convenience and Necessity, before the Public Utility Commission of Texas, Docket No. 11248, on behalf of Cap Rock Electric Cooperative, Inc., concerning its proposed transmission system improvements; December 30, 1992.

80. In re: Application of Texas Utilities for Authority to Change Rates, before the Public Utility Commission of Texas, Docket No. 11735, on behalf of Cap Rock Electric Cooperative, Inc., concerning standby rates, wholesale rate contracts and terms and conditions of the Power Sales Agreement, May 18, 1993.

81. In re: Determination of Houston Lighting & Power Company's Standard Avoided Cost Calculation for the Purchase of Firm Energy and Capacity from Qualifying Facilities Pursuant to P.U.C. Subst. R. 23.66(H)(3), before the Public Utility Commission of Texas, Docket No. 10832, on behalf of Destec Energy, Inc; August 11, 1993.

82. In re: Complaint of Phibro Refining, Inc. v. HL&P, Docket No. 11989, before the Public Utility Commission of Texas, on behalf of Phibro Energy, USA, Inc., concerning electric service contracts and terms and conditions of HL&P's industrial rate schedule; August 3, 1993.

83. In re: Application of Texas Utilities Electric Company for Authority to Implement Economic Development Service, General Service Competitive Pricing, Wholesale

Power Competitive Pricing, and Environmental Technology Service, Docket No. 13100, before the Public Utility Commission of Texas, on behalf of Rayburn Country Electric Cooperative, Inc., concerning TU Electric's so-called "competitive rates."; August 8, 1994

84. In re: Complaint of Kenneth D. Williams v. HL&P, Docket No. 12065, on behalf of Destec before the Public Utility Commission of Texas; January 10, 1995.

85. In re: Rebuttal testimony in a Complaint of Tex-La v. TUEC, Docket No. 12362, on behalf of Rayburn County Electric Coop. before the Public Utilities Commission of Texas; March 6, 1995.

86. In re: Application for Authorization and Approval of Merger Between Wisconsin Electric Power Company, Northern States Power Company (Minnesota), Northern States Power Company (Wisconsin), and Cenergy, Inc., in Docket No. EC-95-16-000, before the Federal Energy Regulatory Commission (on behalf of Certain Intervenors, including Madison Gas & Electric Company, Wisconsin Public Service Corporation, Minnesota Power & Light Company, Otter Tail Power Company and the Lincoln Electric System), in Docket Nos. 6630-UM-100 and 4220-UM-101, before the Wisconsin Public Service Commission and Docket No. 6-2500-10601-2 before the Minnesota Office of Administrative Hearings for the Minnesota Public Utilities Commission (both on behalf of Madison Gas & Electric, Wisconsin Industrial Energy Group, Wisconsin Federation of Cooperatives and the Citizen's Utility Board), concerning the effect upon transmission access of the merger of NSP and WEPCO into Primergy; May 10, 1996.

87. In re: Merger of The Washington Water Power Company and Sierra Pacific Power Company, Docket Nos. EC94-23-000 and ER95-808-000, before the Federal Energy Regulatory Commission, on behalf of Truckee Donner Public Utility District, concerning ancillary services and single system transmission rates; May 22, 1996.

88. In re: Alberta Electric Utilities 1996 Tariff Application before the Alberta Energy And Utilities Board, on behalf of the Industrial Power Consumers Association of Alberta concerning calculation of charges for ancillary services; June 3, 1996.

89. In re: Surrebuttal Testimony in Docket Nos. EC95-16-000, ER95-1357-000 and ER95-1358-000, on behalf of Madison Gas & Electric Company, Citizens Utility Board and Wisconsin Electric Cooperative Association; June 10, 1996.

90. In re: City Public Service Board of San Antonio Filing in Compliance with Subst. Rule 23.67, Docket No. 15613, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; September 5, 1996.

91. In re: City of Austin Filing in Compliance with Subst. Rule 23.67, Docket No. 15645, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; September 5, 1996.

92. In re: Central Power and Light and West Texas Utilities Filing in Compliance with Subst. Rule 23.67, Docket No. 15643, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; September 5, 1996.

93. In re: Texas Utilities Electric Company, Filing in Compliance with Subst. Rule 23.67, Docket No. 15638, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; September 18, 1996.

94. In re: Docket No. 15840, Regional Transmission Proceeding to Establish Postage Stamp Rate and Statewide Load Flow Pursuant to P.U.C. Subst. Rule. 23.67 on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; August 30, 1996.

95. In re: Application of Wisconsin Energy Corporation, Wisconsin Electric Power Company, Northern, States Power Company, and Northern States Power Company-Wisconsin for Approval of a Series of Transactions by Which Northern States Power Company-Wisconsin is merged into Wisconsin Electric Power Company, Northern States Power Company becomes a Subsidiary of Wisconsin Energy Corporation, and Wisconsin Energy Corporation is Renamed Primergy Corporation: Direct Testimony, Rebuttal Testimony and Surrebuttal Testimony on behalf of The Wisconsin Industrial Energy Group ("WIEG"), The Citizens' Utility Board ("CUB"), The Wisconsin Federation of Cooperatives ("WFC") and Madison Gas and Electric ("MG&E") in Docket Nos. 6630-UM-100 and 4220-UM-101 before the Public Service Commission of Wisconsin. The purpose of the direct testimony was to address Certain Intervenors' Transmission System Control Agreement and ISO Bylaws; October 8, 1996. The purpose of the rebuttal testimony was to address Applicants' Unilateral Settlement Offer which was submitted to FERC in their FERC merger proceeding; October 24, 1996. The purpose of the surrebuttal testimony was to address two sets of Rebuttal testimony of Jose Delgado and the Rebuttal Testimonies of Malcolm Bertsch of the Applicants and Don Carlson of Minnesota Power and Light; November 5, 1996.

95a. In re: In the Matter of Northern States Power Company's Petition for Approval to Merge with Wisconsin Energy Corporation; OAH Docket No. 6-2500-10601-2: Direct Testimony and Exhibits and Rebuttal Testimony and Exhibits on behalf of

Madison Gas and Electric ("MG&E"), The Wisconsin Federation of Cooperatives ("WFC"), and The Citizens' Utility Board ("CUB") in Docket No. E,G-002 and PA-95-500 before the Minnesota Office of Administrative Hearings for the Minnesota Public Utilities Commission. The purpose of the direct testimony is to remedy a Wisconsin Energy Corporation merger, in order to prevent anti-competitive effects with an Independent System Operation which actually operates the transmission system and which is truly independent of the proposed Primergy; October 21, 1996. The purpose of the rebuttal testimony is to address the direct testimony of Dr. Eilon Amit of Minnesota Department of Public Service and Dan Carlson of Minnesota Power and Light; November 8, 1996.

95b. In re: Joint Application of WPL Holdings, Inc. and Wisconsin Power & Light Company for all Requisite Approvals in Connection with a Series of Related Transactions by which Interstate Power Company Becomes a Subsidiary of WPL Holdings, Inc., IES Industries, Inc. is Merged into WPL Holdings, Inc. and is Renamed Interstate Power Corporation and for Certain Related Transactions and Matters: Direct Testimony and two Surrebuttal Testimonies on behalf of Badger Cooperative Group ("BCG"), The Citizens' Utility Board ("CUB"), Madison Gas and Electric ("MG&E"), The Wisconsin Federation of Cooperatives ("WFC"), Wisconsin Industrial Energy Group ("WIEG") and Municipal Wholesale Power Group ("MWPG") in Docket No. 6680-UM-100 before the Public Service Commission of Wisconsin. The purpose of the direct testimony was to discuss the characteristics of an appropriate ISO and present the ISO recommended by Certain Intervenors; May 7, 1997. The purpose of surrebuttal testimony #1 was to answer the rebuttal testimony of WP&L's witness Rodney Frame, Arnold Kehrli and Scott Wallace; May 30, 1997. The purpose of surrebuttal testimony #2 was to address the rebuttal testimony of WP&L's witness Arnold Kehrli; May 30, 1997.

96. In re: Houston Lighting & Power Company Filing in Compliance with Subst. Rule 23.67, Docket No. 15639, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas; September 30, 1996.

97. In re: IES Utilities, Inc., Interstate Power Company, Wisconsin Power & Light Company, South Beloit Water, Gas & Electric Company, Heartland Energy Services, and Industrial Energy Applications, Inc., Docket Nos. EC96-13-000, ER96-1236-000, and ER96-2560-000, before the Federal Energy Regulatory Commission, on behalf of Wisconsin Intervenors ("WI"). Mr. Russell simultaneously filed 2 sets of testimony; the first, sponsored by the intervenors listed above as well as by Wisconsin Public Service Corporation ("Pub Service"), and Dairyland Power Cooperative. ("Dairyland") analyzed engineering and operating problems created by the merger of WP&L, IPW and IES. The second set of testimony discusses how the IEC Independent System Operator ("ISO") fails in general to meet the rigorous and comprehensive ISO standards promulgated by the Wisconsin Public Service Commission (WPSC). Both sets of testimony

(Engineering and ISO) were filed before the Federal Energy Commission; March 27, 1997.

98. In re: Joint Application of WPL Holdings, Inc. and Wisconsin Power & Light Company for all Requisite Approvals in Connection with a Series of Related Transactions by which Interstate Power Company Becomes a Subsidiary of WPL Holdings, Inc., IES Industries, Inc. is Merged into WPL Holdings, Inc. and is Renamed Interstate Power Corporation and for Certain Related Transactions and Matters, in Docket No. 6680-UM-100, before the Public Service Commission of Wisconsin; May 7, 1997.

99. In re: City of College Station, FERC Docket No. TX 96-2-000, concerning transmission rates; November 7, 1997.

100. In re: Application for Approval of Restructuring Plan Under Section 2806 of the Public Utility Code, in Docket No. R-00973981 on behalf of Mid-Atlantic Power Supply Association, before the Pennsylvania Public Utility Commission; November 7, 1997.

101. In re: Application for Approval of Restructuring Plan Under Section 2806 of the Public Utility Code, in Docket No. R-00974104 on behalf of Mid-Atlantic Power Supply Association, before the Pennsylvania Public Utility Commission; November 7, 1997.

102. In re: New England Power Company, FERC Docket No. OA96-74-000, concerning proposed formula rates for Tariffs No. 9 and 4, on behalf of the Massachusetts Municipals; December 12, 1997.

103. In re: Sierra Pacific Power Company before the Federal Energy Regulatory Commission in Docket Nos. ER97-3593-000, ER97-3779-000, ER97-4462-000 on behalf of Truckee Donner Public Utility District, addressing lack of comparable access to transmission systems; February 23, 1998.

104. In re: Application for Approval of Restructuring Plan Under Section 2806 of the Public Utility Code, on behalf of Newmont Gold Company and Barrick Goldstrike Mines, in Docket Nos. 97-11018 and 97-11028, before the Public Service Commission of Nevada; February 1, 1998.

105. In re: Southern California Edison Company before the Federal Energy Regulatory Commission in Docket No. ER97-2355-000 on behalf of Department of Water Resources of the State of California, regarding lower pricing for off-peak transmission services; April 1998.

106. In re: Response to Procedural Order Number Three Load Pockets, on behalf of Newmont Gold Company and Barrick Goldstrike Mines, Docket Number 97-8001, before the Public Utilities Commission of Nevada; May 15, 1998.

107. In re: Supplemental Testimony in an Application for Approval of Restructuring Plan Under Section 2806 of the Public Utility Code, on behalf of Newmont Gold Company and Barrick Goldstrike Mines, Docket Numbers 97-11018 and 97-11028, before the Public Utilities Commission of Nevada, May 22, 1998.

108. In re: Southern California Edison Company, on behalf of The Department of Water Resources of The State of California, Docket No. ER97-2355, before FERC in reference to Transmission Revenue Balancing Account Adjustment ("TRBAA"); November 16, 1998.

109. In re: Ormet Primary Aluminum Corporation, on behalf of Ormet Primary Aluminum Corporation, Arbitration Number 55-199-0051-94, before the American Arbitration Association, concerning the relationship between AEP and other power systems within NERC and ECAR; July 14 1998.

110. In re: Rebuttal Testimony in response to Mr., Walter R. Kelley and Mr. Thomas Kennedy, on behalf of Ormet Primary Aluminum Corporation, Arbitration Number 55-199-0051-94, before the American Arbitration Association; September 2, 1998.

111. In re: Application No. RE95081 – TransAlta Utilities Corp., on behalf of Albchem Industries Ltd., CXY Chemicals and Dow Chemicals Canada Ltd., before the Alberta Energy & Utilities Board addressing ACD's interest in providing interruptible service; October 1998.

112. In re: Tri-State Generation and Transmission Assoc., Inc., in Arbitration No. 77 Y 181 0023097 before the American Arbitration Association; September 14, 1998.

113. In re: Joint Application for Approval of Merger, Docket No. 98-7023 on behalf of The Staff of the Public Utilities Commission, before the Public Utilities Commission of Nevada; November 9, 1998.

114. In re: Independent System Administrator, Docket No. 97-8001 on behalf of The Staff of the Public Utilities Commission, before the Public Utilities Commission of Nevada; December 11, 1998.

115. In re: Petition for Order Concerning Delineation of Transmission and Local Distribution Facilities, Docket No. 98-0894 on behalf of The City of Chicago, before the Illinois Commission in reference to re-functionalization; April 2, 1999.

116. In re: Consolidated Edison Company, Docket No. EL99-58-000 on behalf of The Village of Freeport, New York, before FERC in reference to remedies for the breach of contract to provide firm service on a non-discriminatory basis; July 22, 1999, August 3, 1999, August 18, 1999 and September 9, 1999.

117. In re: Wisconsin Public Power, Inc. Docket No. 05-EI-119 on behalf of Wisconsin Transmission Customer Group (WTCG"), before the Public Service Commission of Wisconsin to address the concerns of municipally-owned utilities within Wisconsin; March 6, 2000.

118. In re: Joint Application of Utilicorp United Inc. & St. Joseph Light & Power Co., Docket No. EM-2000-292 on behalf of Springfield (MO) City Utilities before the PSC of the State of Missouri to address why the merger between the two is detrimental to the public interest; May 1, 2000.

119. In re: Utilicorp United Inc, and Empire District Electric Co. Docket No. EM-2000-369 on behalf of Springfield (MO) City Utilities before the Public Service Commission of the State of Missouri to explain why the merger between the two is detrimental to the public interest; June 19, 2000.

120. In re: Arrowhead - Westin Transmission Line Project, Docket No. 05-CE-113 on behalf of the Wisconsin Public Service Corporation ("WPSC"), before the Public Service Commission of the State of Wisconsin to provide support for the transmission project as proposed by WPSC and Minnesota Power; November 22, 2000.

121. In re: Kansas Municipal Energy Agency ("KMEA"), Docket No. ER00-2644-000 on behalf of the Kansas Municipal Energy Agency ("Kansas Municipal"), before the Federal Energy Regulatory Commission ("FERC") to review, assess and comment on the actions taken by the Southwest Power Pool in connection with two transmission service requests made by the Kansas Municipal Energy Agency aggregating 39 MW of contract demand; December 8, 2000.

122. In re: Arrowhead - Weston 345 kV Transmission Line, Rebuttal testimony in Docket No. 05-CE-113 on behalf of the Wisconsin Public Service Corporation ("WPSC"), before the Public Service Commission of the State of Wisconsin to address matters set forth in the direct testimony of Dr. Richard A. Rosen on behalf of Save Our Unique Lands ("SOUL"), Mr. David Schoengold on behalf of Wisconsin's Environmental Decade, and Mr. George R. Edgar on behalf of the Citizens' Utility Board ("CUB"); December 18, 2000.

123. In re: Ethyl Corporation verses Gulf States Utilities Company, Civil Docket No. M, live direct testimony in a dispute over direct assignment of substation facilities; April 2001.

124. In re: Joint Application of Entergy Louisiana, Inc. and Entergy Gulf States, Inc., Docket No. U-25533 on behalf of Occidental Chemical Corporation ("OxyChem"), before the Louisiana Public Service Commission for authorization to participate in contracts for the purchase of capacity and electric power for the Summer of 2001; May 3, 2001.

125. In re: Petitioners' Joint Proposal for Merger & Rate Plan, testimony in Case No. 01-M-0075 on behalf of Alliance for Municipal Power before the New York State Public Service Commission. The purpose of this testimony is explain (1) the inappropriateness of Rule 52 in the post merger competitive energy markets; (2) to have stranded transmission cost and distribution costs expunged; and (3) to show how merged Companies exacerbates the incentive to abuse Rule 52 against newly formed municipal utilities; November 5, 2001.

126. In re: Northeast Utilities Service Company Transmission Line Project, direct testimony in Docket No, 217 before the Connecticut Siting Council of the State of Connecticut on behalf of the Attorney General, State of Connecticut for the purpose of (1) Whether there is a need for the 345 f transmission line from Plum-tree to Norwalk; (2) whether the proposed transmission system design is the best option based on current transmission design and (3) whether any approval of the project by the Siting Council should be conditioned upon CL&P and NU's agreement; March 12, 2002.

127. In re: Alliance Companies, et al., Affidavit in Docket Nos. RM01-12-000, RT01-87-000 and RT01-88-000, before the Federal Energy Regulatory Commission on behalf of the Ormet Primary Aluminum Corporation, for the purpose of providing relevant engineering fundamentals related to the proper design of methodology for quantifying transmission losses and for allocating such losses to the customers of regional transmission organizations; March 12, 2002.

128. In re Cannon Power Corporation:, Affidavit in Docket No. ER02-2189-000, before the Federal Energy Regulatory Commission on behalf of Whitewater Hill Wind Partners, LLC developing a 66 MW wind power project to be interconnected to Southern California Edison Company; July 29, 2002.

129. In re Cannon Power Corporation:, Affidavit in Docket No. ER02-1764, before the Federal Energy Regulatory Commission on behalf of Cabazon Wind Partners, LLC developing a 66 MW wind power project to be interconnected to Southern California Edison Company; August 2, 2002.

130. In re: Response to Pacificorp's Motion: Affidavit in Response to Pacificorp's Daubert Motion Regarding Richard Slaughter and Supplemental Expert Report on behalf of Snake River Valley Electric Association; September 10, 2002.

131. In re: Pacific Gas & Electric Company : Direct Testimony in Docket No. ER01-2998, before the Federal Energy Regulatory Commission on behalf of Northern California Power Agency to explain what level of firmness is required of transmission service under the Stanislaus Commitments; December 20, 2002.

132. In re: American Electric Power Corp.: Affidavit in Docket No. ER03-242, before the Federal Energy Regulatory Commission on behalf of Ormet Primary Aluminum Corp. to respond to AEP's proposed electric transmission rates to be included in the OATT of the PJM Interconnection; December 24, 2002.

133. In re: Application of the CT Light & Power Company: Supplemental Direct Testimony in Docket No. 217, before the State of CT Siting Council on behalf of The Attorney General, State of CT as a follow-up to the direct testimony filed on March 12, 2002 and to address various studies and reports that have been filed since that original testimony; January 14, 2003.

134. In re: Pacific Gas & Electric: Rebuttal Testimony before the Federal Energy Regulatory Commission in Docket No. ER01-2998 on behalf of Northern California Power Agency ("NCPA") to respond to testimony from witnesses Judi K. Mosley, Kevin J. Dasso, Dr. Roy Shanker and Linda Patterson; April 1, 2003.

135. In re: Order Instituting Investigation into implementation of Assembly Bill 970 regarding the identification of electric transmission and distribution constraints, actions to resolve those constraints, and related matters affecting the reliability of electric supply: Direct testimony before the Public Utilities Commission of California on behalf of Oak Creek Energy Systems. The purpose of the testimony is to provide comments on and recommendations with respect to the Tehachapi Transmission Conceptual Facility Study ("Tehachapi CFS" or "TCFS"), performed by Southern California Edison ("SCE" or "Edison"); April 22, 2003.

136. In re: Order Instituting Investigation into implementation of Assembly Bill 970 regarding the identification of electric transmission and distribution constraints, actions to resolve those constraints, and related matters affecting the reliability of electric supply: Rebuttal testimony before the Public Utilities Commission of California on behalf of Oak Creek Energy Systems. The purpose of the testimony is to rebut the testimony of Mr. Jorge Chacon and Mr. Melvin Stark on behalf of Southern California Edison Company, taking into account the testimony of Mr. Robert Sparks filed on behalf of the California Independent System Operator ("CA ISO" or "ISO"); May 13, 2003.

137. In re: California Independent System Operator Corporation: Direct testimony before the Federal Energy Regulatory Commission in Docket No. ER00-2019 on behalf of State Water Contractors and the Metropolitan Water District of Southern California. The purpose of the testimony is to provide a critical analysis of ISO's proposed Transmission Access Charge; June 2, 2003.

138. In re: Ameren Services Company, et al.: Affidavit in Docket No. EL03-212-000, before the Federal Energy Regulatory Commission on behalf of Ormet Primary Aluminum Corp. to respond to AEP's Submission in Response to the Commission's Section 206 Investigation; September 2, 2003.

139. In re: Pacific Gas and Electric Company: Direct Testimony in Phase I before the Federal Energy Regulatory Commission in Docket Nos. ER00-565-000, ER00-565-003, and ER00-565-007 on behalf of the Northern California Power Agency. The purpose of the testimony is to explain the nature of the costs for which Pacific Gas

and Electric Company seeks recovery through its Scheduling Coordinator Service Tariff; September 15, 2003.

140. In re: California Independent System Operator Corporation: Surrebuttal Testimony before the Federal Energy Regulatory Commission in Docket Nos. ER00-2019-006, ER01-819-002, and ER03-608-000 on behalf of State Water Contractors and the Metropolitan Water District of Southern California. The purpose of the testimony is to respond to the Prepared Rebuttal Testimony of Mr. Johannes P. Pfeifenberger on behalf of the ISO; October 20, 2003.

141. In re: Midwest Independent Transmission System Operator, Inc. and Public Utilities With Grandfathered Agreements in the Midwest ISO Region: Prepared Testimony before the Federal Energy Regulatory Commission in Docket Nos. ER04-691-000 and EL04-104-000 on behalf of Marshfield Electric & Water District. The purpose of the testimony is to review Marshfield Electric & Water District's transmission arrangements in order to respond to the Commission's May 26, 2004 Order in this proceeding; June 25, 2004.

142. In re: Pacific Gas and Electric Company: Direct Testimony in Phase II before the Federal Energy Regulatory Commission in Docket Nos. ER00-565-000 and ER00-565-003 on behalf of the Northern California Power Agency ("NCPA"). The purpose of the testimony is to discuss PG&E's propriety in passing through ISO Charge Type costs as Scheduling Coordinator Service charges to NCPA under the terms of the NCPA-PG&E Interconnection Agreement; September 13, 2004.

143. In re: Southern California Edison Company: Prepared Direct Testimony before the Federal Energy Regulatory Commission in Docket No. ER02-2189-003 on behalf of Whitewater Wind Hill Partners. The purpose of the testimony is to provide support for Whitewater's request that the Commission revise the Interconnection Facilities Agreement ("IFA") between Whitewater and Southern California Edison Company ("SCE or Edison"); September 14, 2004.

144. In re: Cabazon Wind Partners, LLC Complainant vs. Southern California Edison Company Respondent: Affidavit in Docket No. EL04-137 before the Federal Energy Regulatory Commission on behalf of Cabazon Wind Partners, LLC ("Cabazon"). This Affidavit provides support for Cabazon's request that Southern California Edison Company ("SCE") grant Cabazon reimbursement, in the form of a transmission credit or otherwise, for the cost of certain upgrades Cabazon has borne to interconnect its generation to SCE; September 27, 2004.

145. In re: Southern California Edison Company: Cross Answering Testimony before the Federal Energy Regulatory Commission in Docket No. ER02-2189-003 on behalf of Whitewater Hill Wind Partners. The purpose of the testimony is to respond to testimony filed on October 28, 2004, in this proceeding by Commission Staff witnesses, Ms. Tania Martinez Navedo and Mr. Edward W.

Mills. As discussed in my prior testimony, the issue in this case involve the designation of disputed upgrades contained in the IFA between Whitewater and Southern California Edison Company; November 22, 2004.

146. In re: Pacific Gas and Electric Company: Direct and Answering Testimony before the Federal Energy Regulatory Commission in Docket No. ER01-1639-006 on behalf of Northern California Power Agency. The purpose of this testimony is to explain 1) PG&E's failure to justify the pass-through of Reliability Service charges to Western and PG&E's additional failure to "unbundle the rates in its ETCs and provide a full cost of service analysis supporting the unbundled rates," 2) PG&E's attempt to pass-through Scheduling Coordinator Service Charges to Western, and 3) The inappropriateness of PG&E's imposition of interest charges; November 23, 2004.

147. In re: Petition for a Declaratory Order or Advisory Opinion as to the Applicability of the Commission's Decision in Docket No. 03-10003, Plant Project in Orange County, California: Affidavit in Docket No. 04-10023, before the Public Utilities Commission of Nevada on behalf of Ridgewood Renewable Power, LLC ("Ridgewood") with respect to a landfill methane gas powered electric generating project located at the Olinda/ Alpha landfill in Orange County, California; December 30, 2004.

148. In re: Southern California Edison Company and Cabazon Wind Partners, LLC: Prepared Direct Testimony before the Federal Energy Regulatory Commission in Docket No. EL04-137, on behalf of Cabazon Wind Partners, LLC. The purpose of this testimony is to provide support for Cabazon's request that Southern California Edison ("SCE") grant Cabazon reimbursement, in the form of transmission credit or otherwise, for the cost of certain upgrades Cabazon has borne to interconnect generation to SCE; February 4, 2005.

149. In re: Pacific Gas and Electric Company: Phase II Answering Testimony to PG&E's Supplemental Testimony; Cross Answering Testimony; and Errata of Whitfield A. Russell before the Federal Energy Regulatory Commission in Docket No. ER00-565-000, et al and ER04-1233-000, on behalf of Northern California Power Agency. The purpose of this testimony is to respond to Mr. Bray's contention that the SCS Tariff is a formula rate, to respond to aspects of the Prepared Direct and Answering Testimony of Ms. Linda M. Patterson on behalf of the Federal Energy Regulatory Commission Staff and to provide updates to my previously filed testimony, March 8, 2005.

150. In re: Southern California Edison Company: Affidavit before the Federal Energy Regulatory Commission in Docket No. EL05-80-000, on behalf of the California Wind Energy Association ("CalWEA"). The purpose of this affidavit is to explain how and why the proposed Antelope-Tehachapi 230 kV line will be integrated into the regional transmission grid and thereby constitute a network upgrade facility; April 14, 2005.

151. In re: American Electric Power Service Corporation: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER05-751-000, on behalf of Ormet Primary Aluminum Corporation. The purpose of this affidavit is to respond to American Electric Power Corporation's (AEP's) request (a) to increase its annual Network Integration Transmission Service (NTS) revenue requirements to $486 million per year and (b) to increase the NTS rates; April 29, 2005.

152. In re: Southern California Edison Company and Cabazon Wind Partners, LLC: Prepared Rebuttal Testimony before the Federal Energy Regulatory Commission in Docket No. EL04-137, on behalf of Cabazon Wind Partners, LLC. The purpose of this testimony is to respond to direct testimony filed on March 14, 2005 and cross answering testimony filed on May 3, 2005 by Mr. Daniel J. Allstun, the witness of Southern California Edison and to respond to testimony filed on April 14, 2005 by Commission Staff witness, Ms. Emily White; May 20, 2005.

153. In re: In the Matter of the Arbitrations between PG&E Energy Trading-Power, LP Claimant, Counter-Respondent and Southaven Power, LLC, and Caledonia Generating, LLC, Respondents, Counter-Claimants: Expert Report and litigation before the American Arbitration Association in AAA Nos. 16-198-00206-03 & 16-198-00207-03, on behalf of Williams & Connolly LLP (counsel of Southaven Power, LLC) and Bingham McCutchen LLP (counsel for Caledonia Generating, LLC). The purpose of this expert report was to provide my opinion on certain elements of the matters in dispute between PG&E Energy Trading-Power, L.P., on the one hand, and each of Southaven and Caledonia, on the other hand. These disputes have arisen in connection with two similar tolling agreements, each titled "Dependable Capacity and Conversion Services Agreement;" September 8, 2005.

154. In re: Midwest Independent Transmission System Operator, Inc: Pre-Filed Answering Testimony before the Federal Energy Regulatory Commission in Docket No. ER05-6-001, et al, on behalf of Ormet Primary Aluminum Corporation. The purpose of this testimony is to analyze the proposed SECA rate design as it relates to Ormet; October 24, 2005.

155. In re: Berkshire Power Company, LLC: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER05-1179-001, on behalf of Massachusetts Municipal Wholesale Electric Company, Chicopee Municipal Lighting Plant, and South Hadley Electric Light Department. The purpose of this affidavit is to review the engineering analysis performed by ISO New England in support of its determination of the system reliability for the Springfield, Massachusetts area in Western Massachusetts and, more specifically, the ISO's analysis of the reliability need for two units in that area: (1) the 245 MW Berkshire facility operated by Berkshire Power Company; and (2) the 107 MW West Springfield Unit 3 operated by Consolidated Edison Energy Massachusetts, Inc.; November 7, 2005.

156. In re: Consolidated Edison Energy Massachusetts, Inc.: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER05-903-002, on behalf of Massachusetts Municipal Wholesale Electric Company, Chicopee Municipal Lighting Plant, and South Hadley Electric Light Department. The purpose of this affidavit is to review the engineering analysis performed by ISO New England in support of its determination of the system reliability for the Springfield, Massachusetts area in Western Massachusetts and, more specifically, the ISO's analysis of the reliability need for two units in that area: (1) the 245 MW Berkshire facility operated by Berkshire Power Company; and (2) the 107 MW West Springfield Unit 3 operated by Consolidated Edison Energy Massachusetts, Inc.; November 10, 2005.

157. In re: Pittsfield Generating Company, LP: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER06-262-000, on behalf of Massachusetts Municipal Wholesale Electric Company, Chicopee Municipal Lighting Plant, and South Hadley Electric Light Department. The purpose of this affidavit is to review the engineering analysis performed by ISO New England in support of its evaluation of the system reliability for the Pittsfield, Massachusetts area of Western Massachusetts and, more specifically, the ISO's analysis of the reliability need for the 160 MW facility operated by Pittsfield Generating Company, L.P.; December 21, 2005.

158. In re: Mystic Development LLC: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER06-427-000, on behalf of Massachusetts Municipal Wholesale Electric Company, Wellesley Municipal Light Plant, Reading Municipal Light Department and Concord Municipal Light Plant. The purpose of this affidavit is to (a) respond to portions of the testimony offered by Mystic witnesses Messrs. Theodore Horton, Robert B. Stoddard, and Alan C. Heintz; and (b) review the engineering analysis of the December 7, 2004, "Need for Mystic Units 7, 8 and 9 for System Reliability," performed by ISO New England ("ISO") and included by Mystic in its filing as support for the assertion that Mystic Units 8 and 9 are needed to ensure system reliability in the Northeast Massachusetts/Boston Area load pocket; January 19, 2006.

159. In re: In the Matter of the Application of Ohio Power Company for Approval of a Special Contract Arrangement with Ormet Primary Aluminum Corporation, In the Matter of the Joint Petition of Ohio Power Company and South Central Power Company for Reallocation of Territory, In the Matter of: Ormet Primary Aluminum Corporation and Ormet Primary Mill Products Corporation v.South Central Power Company and Ohio Power Company: Pre-Filed Testimony before the Public Utilities Commission of Ohio in Docket Nos. 96-999-EL-AEC, 96-1000-EL-PEB and 05-1057-EL-CSS, on behalf of Ormet Primary Aluminum Corporation. The purpose of this testimony is to analyze: (a) the effect upon the ratepayers of South Central and Buckeye of requiring South Central to serve Ormet and (b) the effect upon the ratepayers and stockholders of Ohio Power

Company ("OPCO") of requiring OPCO to serve Ormet's full requirements under OPCo's retail GS-4 rate schedule; September 8, 2006.

160. In re: Mystic Development, LLC: Direct Testimony before the Federal Energy Regulatory Commission in Docket No. ER06-427-000, on behalf of Massachusetts Municipal Wholesale Electric Company, Reading Municipal Light Department Wellesley Municipal Light Plant and Concord Municipal Light Plant. The purpose of this testimony is to assess whether a cost-of-service ("COS"), Reliability Must-Run ("RMR") Agreement is needed in order to keep Mystic Development LLC's ("Mystic's") Units 8 and 9 available to provide reliability service and if, contrary to my testimony, the Commission finds that a COS RMR agreement is needed to keep Mystic Units 8 and 9 available to provide reliability service, the Commission would be required to determine a just and reasonable COS rate to be imposed on customers under the RMR agreement. I testify regarding adjustments that need to be made to Mystic's proposed COS rates in order to render them just and reasonable; November 9, 2006.

161. In re: Hydroelectric Production Rates and Rate Modification Plan-2007 and 2008 Rate Years: Direct Testimony and Supporting Exhibits before the New York Power Authority, on behalf of the New York Association of Public Power. The purpose of this testimony is to address the understatement of capacity at the Niagara and St. Lawrence Projects of the New York Power Authority ("NYPA") and how that understatement of capacity improperly reduces the amount of capacity made available to preference customers of the Niagara Project and improperly increases the rates applicable to capacity sold to those customers; April 9, 2007.

162. In re: ISO New England Inc: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER08-190-000, on behalf of Massachusetts Municipal Wholesale Electric Company ("MMWEC"). The purpose of this testimony is to review the engineering analysis performed by ISO New England Inc. in support of its determination that MMWEC's Phase II Stony Brook Unit is not qualified to participate in the first Forward Capacity Market auction, scheduled to be held in February 2008; November 21, 2007.

163. In re: Columbus Southern Power Company and Ohio Power Company: Affidavit before the Public Utilities Commission of Ohio in Case Nos. 07-1132-EL-UNC, 07-1191-EL-UNC, 07-1278-EL-UNC, and 07-1156-EL-UNC, on behalf of Ormet Primary Aluminum Company. The purpose of this affidavit is in the matter of the Application of Columbus Southern Power Company and Ohio Power Company for approval of an additional generation service rate increase pursuant to their post-market development period rate stabilization plans and to update each company's transmission cost recovery rider; February 28, 2008.

164. In re: Niagara Mohawk Power Corporation: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER08-552-000, on behalf of the New York Association of Public Power and several of its members which include

Green Island Power Authority, Jamestown Board of Public Utilities, City of Salamanca Board of Public Utilities, City of Sherrill Power & Light and Oneida-Madison Electric Cooperative, Inc. The purpose of this affidavit is review the filing by NMPC for Amendments to its Wholesale Transmission Service Charge for Point-to-Point Transmission service and Network Integration Transmission Service; March 17, 2008.

Exhibit No. MPS-3

ISO new england

Short-Term Report of ISO New England Inc. Required Pursuant to Section 6.1(b) of the SEMA Settlement Agreement

ISO New England Inc.
July 17, 2007

This Report Contains
Critical Energy Infrastructure
Information

Remainder of Exhibit No. MPS-3 removed as containing CEII.

Exhibit No. MPS-4

SYSTEM PROTECTION SCHEMES IN POWER NETWORKS

TASK FORCE 38.02.19

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System Protection Schemes in Power Networks

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Chapter 6

SPS Design Procedure and Reliability Evaluation

SPS is often perceived to be highly reliable because significant redundancy is typically considered in the design of an SPS. Diagnostic and self-check features to detect and alarm when essential components fail or critical functions are not operational are often used. In the U.S., standards exist to require that each SPS owner has an SPS maintenance and testing program and that the design of SPS both in terms of circuitry and physical arrangement should facilitate periodic testing and maintenance [6.1].

More specific requirements for SPS reliability can be found in [6.2-6.9]. For example, WSCC *Reliability Criteria for Transmission System Planning* [6.3] requires that systems which rely on SPS to meet the performance levels specified by these criteria must ensure that the SPS are highly reliable. System studies shall be conducted to assess the consequence of SPS failure unless it has been satisfactorily demonstrated the SPS failure is not credible. Therefore, failure of planned or existing SPS will only be studied if the SPS failure is considered credible or if the credibility of SPS failure has not been established. The credibility of failure of an existing SPS may be demonstrated by actual operating performance.

Most of today's requirements are qualitative, rather than quantitative. This is as it should be, since reliability criteria must be broad enough to capture a wide range of situations. However, there is presently little guidance in the industry to develop, study and assess, and maintain SPS reliability. For example, there are formal methods for identifying failure modes in SPS, and for quantifying their reliability, yet very few utilities use them as indicated by industry survey results summarised in [6.10]. In fact, in [6.10], over 70 percent of utilities indicated that they had no reliability model and made no reliability computations. A majority of the responses indicated that verification of reliability was done via system monitoring with subsequent adjustments. Yet, in this approach, dependability assessment requires an operation, and since SPS are normally dormant systems, this approach is not very effective in ensuring dependability. Therefore, it is important to develop and use formal methods to model, assess and study SPS reliability. Our objective in this chapter is to further motivate the need for SPS reliability analysis and to provide a structured framework for doing it. A secondary objective is to identify some specific analysis techniques that can be used within this framework.

In the next section, the classification of SPS failures is provided and some specific instances of SPS failure are described. Section 6.2 describes a number of technical standards useful in developing SPS design procedures. In Section 6.3, a framework for SPS design, adapted from these standards, is provided and some techniques useful in SPS reliability assessment are summarised. An illustration is provided in the Appendix.

6.1 Examples of SPS Failure

An SPS event can be classified into one of the following categories:

- desirable operation,
- undesirable operation, or
- failure to operate.

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An SPS operation may be desirable or undesirable, depending on the consequence of the operation relative to the consequence had the SPS not operated. If the consequence of the operation is less severe than the consequence had the SPS not operated, the operation is desirable. This is case, for example, when the action of a generation rejection scheme trips one out of three units following a disturbance when otherwise, all three units would have lost synchronism.

If the consequence of the operation is more severe than the consequence had the SPS not operated, the operation is undesirable. Undesirable operation may either be unintended, due to a hardware, software, or human error, or it can be intended (according to the design), but still undesirable due to a fault in the design logic. A nuisance operation, when an SPS takes unnecessary action when there is no disturbance in the system, is an example of an undesirable, unintended operation. An example of an undesirable, intended operation is when a generator rejection scheme operates and trips a unit following a disturbance for which it was designed to operate, but had the SPS not operated, the plant would have been stable. This situation can occur if the disturbance is single phase to ground fault and the design criteria is based only on three phase faults.

An SPS failure to operate occurs when the SPS fails to respond as designed to conditions for which the SPS is supposed to operate. An SPS may fail to operate as expected for several reasons, among which are:

- hardware failure,
- faulty design logic,
- software failure, or
- human error.

Hardware failure occurs when some physical stress exceeds the capability of one or more installed components. Faulty design logic may occur as a result of inappropriate or incomplete study procedure during the design. Software failure results from errors in vendor written and user written embedded, application, and utility software. The vendor software typically includes the operating system, I/O routines, diagnostics, application oriented functions and programming languages. User written software failure results from errors in the application program, diagnostics, and user interface routines. Human errors can be classified according to whether they are associated with construction, operation, or maintenance.

When correctly operating, SPS significantly improve system response following a contingency. However, the failure of SPS to accurately detect the defined conditions, or the failure to carry out the required pre-planned remedial action, can lead to serious and costly consequences. The survey by IEEE-CIGRE [6.10] in 1992 suggests that the cost of SPS failure can be very high as most of the respondents selected the highest cost category when asked to estimate the cost of an operational failure of SPS.

Here, the U.S. NERC *System Disturbance Reports* from 1986-1998 [6.11] have been reviewed. Of the 30 cases that involved the operation of SPS, 21 were reported as successful operation of SPS, while 9 involved operational failures[1]. The reasons for these failure cases include flaw in logic design, software failure, hardware failure, incorrect setting, and inadvertent failure to arm. The following are brief descriptions of these failure cases:

[1] In the U.S., all disturbances which result in significant loss of load must be reported to the U.S. Department of Energy's (DOE) Emergency Operation Center (EOC) (See Appendix A of the 1995 NERC Report on System Disturbances). However, only a selected few of these disturbances are described in the reports. Therefore, 9 failures out of 30 occurrences should not be interpreted as a statistic representing SPS reliability in the U.S., as it is likely that there were more occurrences and more failures during the time period of interest.

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WSCC - Northeast/Southeast Separation Scheme - April 4, 1988:

Scheme: System separation.
Reason: Flaw in design (the scheme was susceptible to misoperation due to short bursts of communications circuit noise).
Consequence: 1902 MW of generation was lost and 253 MW of load was interrupted.
Lessons learned: Faulty design logic.

NPCC - Hydro-Québec - April 18-19, 1988:

Scheme: Load rejection.
Reason: Hardware failure.
Consequence: Systemwide blackout.
Lessons learned: Hardware failure.

NPCC - Hydro-Québec - November 15, 1988:

Scheme: Load rejection.
Reason: Hardware failure.
Consequence: 3950 MW of load was interrupted.
Lessons learned: Hardware failure.

WSCC-British Columbia Hydro/TransAlta Separation - January 7, 1990:

Scheme: Controlled opening of lines.
Reason: Not armed (inadvertently).
Consequence: It caused 230 kV Cranbrook-Nelway circuit to trip on the subsequent swing and resulted in separation (islanding) of the eastern part of the BCHA/TAUC system from the Interconnection.
Lessons learned: Human error.

WSCC-Garrison - Taft 500 kV No.1 and 2 outages - January 8, 1990:

Scheme: Var Compensation (trip two 500 kV bus reactors).
Reason: Flaw in the logic design.
Consequence: It caused the unnecessary dropping of generation at Hauser, Morony, and Ryan (119 MW) as well as the loss of customer load (25 MW) in Helena.
Lessons learned: Faulty design logic.

WSCC-SE Idaho/SW Wyoming Outage - September 12, 1991:

Scheme: Generator rejection.
Reason: Hardware failure (telemetry that automatically arms this scheme was out of calibration).
Consequence: It caused the loss of a second 345 kV line which led to further loss of transmission by overload and out of step conditions.
Lessons learned: Hardware failure.

WSCC-Pacific AC Intertie Separation - November 17, 1991:

Scheme: System separation.
Reason: Software failure in PG&E SPS programmable logic controller caused the delay in initiating remedial actions (also maybe hardware failure).

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Consequence: Fail to separate WSCC system into two islands, but did not produce any severe problems (it was expected that there would be load lost and out-of-step conditions).
Lessons learned: Software failure and/or hardware failure.

WSCC-Minnesota - Wisconsin Interface 69 kV conductor burn down - October 13, 1992:
Scheme: Controlled opening of lines.
Reason: Incorrect setting.
Consequence: Two 69 kV lines in the Northern States Power and Dairyland Power Cooperative service burned open causing the lines to fall to ground and trip out.
Lessons learned: Human error.

MAPP & MAIN - Eastern MAPP-Western MAIN Interface Separation -November 6, 1997:
Scheme: Controlled opening of lines.
Reason: Flaw in design (opened the circuit at an ampere level below its setting, possibly due to an unbalanced load.).
Consequence: Resulted in low voltages in the south-western Wisconsin, eastern Iowa and western Illinois (Cordova), heavy loading of parallel, lower voltage transmission systems, and a large phase angle across the open tie at Arpin.
Lessons learned: Faulty design logic.

6.2 Existing ISA and IEC Standards

It is likely that individual companies have documented procedures for performing SPS design, installation, and start-up. However, the effort fails to identify documentation of these procedures in the literature or in publicly available documentation, available on the Internet and elsewhere, with just a few exceptions, including [6.4-6.8]. Yet, most of these are quite general and tend more towards «criteria» rather than «procedures». Indeed, the 1993 IEEE/CIGRE survey conducted by Anderson and LeReverend [6.10] found that most often utility criteria for SPS contained at most general requirements for equipment redundancy.

It is found, however, that the other industries have confronted quite similar problems. One of them in particular is the process control industry. This industry is comprised of companies in the petroleum, pharmaceutical, power, chemical, pulp and paper, and textile, and supporting areas. Often, the failure consequence of the various processes implemented can be very high, and so a great deal of attention is paid to standardising procedures for designing, installing, and maintaining safety instrumented systems (SIS). These are systems that are comprised of sensors, relays, breakers, communication equipment, and logic solvers that «take the process to a safe state when predetermined conditions are violated» [6.12]. The SIS equipment and function are quite similar to the equipment and function of SPS in power systems.

The procedures described in this document to be utilised in the design stage of SPS are borrowed heavily from three SIS standards. These standards include ISA SA84.01-1996 (including ISA dTR84.02), IEC 61508, and IEC 61511. ISA SA84.01-1996 [6.12] addresses the application of SIS for the process industries, including integrity levels for electrical (E), electronic (E), and programmable electronic (PE) systems. These systems include electromechanical relays, solid state logic, programmable electronic systems, motor-driven timers, solid state relays and timers, hard-wired logic, and combinations of the above. ISA-

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dTR84.02 [6.13] is a supporting document for ISA SA84.01 that provides evaluation approaches for SIS reliability. The focus of this document is on modelling and calculation. IEC 61508 [6.14] provides definitions, requirements, and methods of assessing functional safety integrity levels of E/E/PE safety-related systems. It is generally based and applicable to all E/E/PE safety-related systems irrespective of the application. IEC draft 61511 [6.15] is a process industry sector implementation of IEC61508. It is primarily concerned with safety instrumented systems for the process industry sector. It provides general framework, definitions and requirements, and guidelines on the application of hazard and risk analysis.

There are three basic ideas on which these ISA and IEC materials depend. One is that the potential harm or danger can be measured by *risk*, which is the combination (usually the product of) the probability of occurrence of the harm and the severity of the harm. A second basic idea is that the safety instrumented functions, which mitigate or prevent the harm and are therefore much like SPS, can be characterised by their *safety integrity*. This is the probability of a safety instrumented function satisfactorily performing the required functions under all the stated conditions within a stated period of time. In the cited standards, safety integrity is quantified by a *safety integrity level* (SIL). The SIL is a discrete number, 1, 2, 3, or 4, which specifies the requirements of the safety instrumented functions to be allocated to the safety instrumented systems. SIL 4 has the highest level of safety integrity, and SIL 1 has the lowest level. Each SIL has associated target failure measures, according to whether the mode of operation is low demand operation where frequency of demand for operation is not more than once per year or high demand operation where this frequency is greater than once per year. For low demand operation, the average probability of failure to perform the design function on demand should lie in the range: 10^{-4} to 10^{-5} (SIL 4), 10^{-3} to 10^{-4} (SIL 3), 10^{-2} to 10^{-3} (SIL 2), and 10^{-1} to 10^{-2} (SIL 1). For high demand operation, the probability of a dangerous failure per hour should lie in the range: 10^{-8} to 10^{-9} (SIL 4), 10^{-7} to 10^{-8} (SIL 3), 10^{-6} to 10^{-7} (SIL 2), and 10^{-5} to 10^{-6} (SIL 1). The third basic idea embedded in these documents is that risk and SIL are keys in showing how the establishment and maintenance of safety-instrumented system integrity involves many activities over the lifetime of the equipment. This idea is captured via use of the term *safety life cycle*, the necessary activities involved in the implementation of safety instrumented function(s) occurring during a period of time that starts at the concept phase of a project and finishes when all of the safety instrumented functions are no longer available for use.

6.3 SPS Step-by-Step Development

Some procedures recommended in the documents described above for use in guiding SPS development are adapted. The adapted procedure consists of six main steps:

1) Identify specifications and logic design.
2) Perform SPS hardware and software design
3) Perform SPS installation, commissioning, and pre-start-up tests.
4) Establish operating and maintenance procedures.
5) Perform pre-start-up safety review.
6) Perform SPS review and modification.

Some guidelines for each of these steps are provided in the following subsections.

This procedure and the guidelines provided for the various steps should not be used as a self-contained guide for SPS development nor should it be viewed as comprehensive and complete. Rather, it serves to outline in broad and general terms some of the basic issues associated with SPS development with the emphasis on reliability. Individual designers might

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use this as a basis for which to write their own SPS development guidelines. In doing this, it is strongly recommended reviewing the above described standards.

6.3.1 SPS specifications and logic design

The objective of this step is to design the logic and identify the specifications for the SPS. This step should result in the following information:

- SPS specification:
  - Type of SPS to be employed and its intended function.
  - Location within the system where the SPS will be installed.
  - System reliability criteria necessitating employment of the SPS.
  - SPS performance requirements for which the SPS is required to meet.
- Logic design:
  - Events and conditions for which the SPS will operate.
  - Events and conditions for which the SPS will not operate.
  - The consequence resulting from a failure of the SPS.

SPS specification:

For most SPS operating today, SPS specification was accomplished via studies carried out by an experienced engineer familiar with the network. Typically, the engineer becomes aware of a particular disturbance for which the power system does not meet the reliability criteria, either for some expected conditions, or for conditions that would be economically attractive if the disturbance-performance criteria could be satisfied. Most often, this awareness comes about as a result of simulation studies. One approach, suggested in [6.16], is to automate contingency analysis in a way that randomly simulates a large number of credible disturbances under various operating conditions and flags contingencies that do not satisfy disturbance-performance criteria. These contingencies are then candidates for further study by the engineer.

Subsequent to identification of a contingency in violation of disturbance-performance criteria, the engineer begins to study the problem, probing different solution strategies until one or more feasible ones become apparent. It is assumed that at least one of the identified feasible strategies include adoption of an SPS. At this stage, the engineer normally performs some rough economic analysis to determine which of the solution strategies are most economic. If this analysis identifies the strategy including SPS adoption as most economic, then a document describing all of the information prescribed in the SPS specification should be prepared. The information pertaining to the first three items in the SPS specification is normally available at this point from the studies already completed. In addition, the engineer should identify any specific performance requirements associated with the type of SPS under consideration.

Initial logic design:

The logic design may be interpreted as a search for a rule. A high-level statement of this rule is:

- IF{armed $\cap$ activated} THEN{actions}, or IF{A $\cap$ B} THEN {C }.

There are three information requirements regarding the rule:

- determination of the arming condition, A;
- determination of the activation conditions, B; and
- identification of the actions to take, C.

The *arming* conditions are typically specified based on one or more operational parameters in the network, e.g., load, generation, flow, or voltage level. The *activation* conditions are

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typically specified based on detection of one or more events or responses in the network. Detection of a circuit outage is the most common event-based activation. Response-based detection may include underfrequency, generator over-speed, and others. *Actions* are typically specified in terms of network changes such as generator tripping, load rejection, capacitor insertion, etc., but they may as well take the form of controller setting changes as in the case of excitation boosting.

The rule may be quite simple, e.g., IF$\{A \cap B\}$ THEN $\{C\}$, or it may be more complex, e.g., IF$\{A \cap B1\}$ THEN $\{C1\}$ OR IF $\{A \cap B2\}$ THEN $\{C2\}$. More complex rules are clearly possible. The designer should understand that increased rule complexity usually comes at the expense of an increased number of SPS failure modes, not only in the logic itself, but also in the interaction of the logic with the logic of other SPS logic, and in the hardware and software necessary to implement the rule. Increased rule complexity almost always results in decreased reliability performance level and therefore, if necessary, provides incentive to consider other solution strategies.

The study work associated with SPS specification, described above, typically provides enough information so that the engineer can provide the initial logic design. However, the integrity of the rule is paramount. Past efforts at validating SPS rules have relied on engineering experience and judgement, coupled with tedious trial and error testing involving manual computer simulations. This is still the case, and the essential contribution of human judgement in this process should be fully embraced. Yet, today, there is both motive and method to improve upon this approach. The *motive* is that there exist greater risk in the use of SPS due to: their proliferation; the increased variability of network conditions and associated uncertainty in SPS logic integrity; and the increased number of network participants resulting in increased financial exposure to an SPS owner should an SPS fail. The *method* lies in the power of the computer and its ability to perform large numbers of simulations of system conditions so as to test and refine the integrity of the rule. Additional insight into this method is provided next.

Logic validation and refinement:

It is desired to probe the integrity of a specified SPS rule using computer simulation and refine the rule when problems are observed. The following is a procedure for doing this:

1) *Simulation tool and network model*: Identify the appropriate simulation tool and the corresponding model. The simulation tool could be a power flow program, or, more likely, it could be a short-term time domain simulation program, or a mid- to long-term time domain simulation package, or some other analysis tool. The model should include:
   - the network of interest;
   - the ability to simulate the activating event;
   - the model of the SPS: its proposed arming, activating, and action logic; and
   - models of all components necessary to the study of the SPS logic integrity: this might include other protection and control equipment and especially other SPS that could be activated as a result of the identified initiating event.
2) *Simulation*: Use computer automation to test the integrity of the rule over a large number of operating conditions, and for a defined number of events. This step should create a large database, with each record providing the operating conditions, the events, and the performance measures characterising the acceptability of the system response.
3) *Analysis*: Analyse the resulting database; modify and refine the rule as needed.
4) *Stopping*: If the rule has been modified, repeat steps 2 and 3. Otherwise, stop.

Steps 2 and 3 require some further elaboration, provided in what follows. Additional information about SPS simulation and analysis can be found in Chapter 5.

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Simulation:

The simulation procedure should provide that the SPS logic is tested for a wide range of conditions and events, including those that result in SPS activation and those that do not. This procedure should include intelligence for updating or modifying the operating conditions and the events for each successive simulation. This can be done in a variety of ways, but some randomisation in the selection is typically appropriate. The simulation procedure should also include the ability to store various parameters characterising the operating conditions and various performance measures characterising the acceptability of each simulation. One approach to security assessment automation, described in [6.17], is based on Latin Hypercube sampling, also called *structured Monte Carlo sampling*. Here, the operating range of interest, as defined by n-operational parameters, forms an n-dimensional hyperspace. This hyperspace is segregated into hypercubes. The simulation procedure then steps through each hypercube and performs a simulation for each one. The specific operating condition to be used in the simulation is chosen at random within the designated hypercube. The granularity (i.e. the number) of the hypercubes determines how many simulations are done for each automated security assessment run. The hypercube step-through procedure results in a uniform sampling of operating conditions throughout the operating range. The random selection within each hypercube maximises the number of different values chosen for each operating parameter over the entire simulation run.

Analysis:

The analysis of the database resulting from the automatic security assessment run is done with appropriate software. A minimal analysis would pick out the simulations that result in unacceptable system response. More advanced software would provide the ability to learn from the database. A statistical approach has been proposed in [6.18, 6.19]. Machine learning techniques using decision trees have been suggested for similar purposes [6.20, 6.21]; these techniques are attractive as they are also capable of automatically deriving and refining the rule.

6.3.2 Hardware and software design

The objective of this step is to perform the SPS hardware and software design based on the rule obtained from the procedures described in the introduction to this chapter. Some guidelines useful in performing this design are provided in what follows. These guidelines are focused on enhancing reliability and are intended to complement those provided in Chapter 4. First, some good practices for general use in hardware and software design are presented. Then, a design refinement that can be used to enhance SPS reliability is described. Finally, the issues about software and human reliability assessment are addressed.

SPS components - good practices:

The following «good practices» are oriented towards enhancing SPS reliability and should be used together with the design criteria provided in Chapter 4. These were extracted from industry references [6.4-6.6].

Logic solver: The logic solver is that portion of an SPS that performs one or more logic functions used to execute the SPS application logic and initiate protective actions. Although it may be electrical or electronic, it is assumed in what follows that it is a programmable electronic (PE) system such as a microprocessor [6.22], micro-controller, programmable logic controller (PLC), or application-specific integrated circuit (ASIC). If the logic solver is purchased externally, the supplier should provide an integrated design including input module(s), output module(s), maintenance interface device(s), communication(s), and utility software. The logic solver should have a published mean time to failure (MTTF), unsafe

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failure mode listing, and frequency of unsafe failure mode. It should have a method (internal and/or external) to protect against covert faults (such as a "watchdog" timer). The logic solver should be designed to ensure the process will not restart automatically when power is restored, unless it is required to do so. Detected failure of the logic solver should not result in an unsafe system condition, if the appropriate, documented, response action is undertaken.

Logic solver software: In developing software necessary for the logic solver, good software development practices should be followed. For example, a software requirements specification and a software design document should be developed. These documents should specify the functionality of the design using functional blocks so that the programmer does not need to make any assumptions about the functionality of each software module. Software architecture should be clearly identified including specification of the operating system, databases, input/output subsystems, communication subsystems, programming and diagnostic tools, and programming languages used. Coding standards should specify good programming practices (e.g., readability, traceability, checkability, and analysability), proscribe unsafe language features, and specify procedures for source code documentation. Testing plans should be able to show that each individual software module, each software subsystem, and the entire software system performs their intended functions and does not perform any unintended functions.

Sensors: The sensors are devices that measure the power system condition. Generally, they include relays and breaker/switch status detectors. Relays may be current, voltage, power, frequency, rate of change of each of these, out-of-step, generator power output level, line loading power level, etc. Neither loss of current nor loss of power can be used alone to determine that a line is open, because they both go through zero as power flow reverses direction on the line. Caution must be taken in determining settings required to distinguish between local faults or system problems by using rate of change of current, voltage, power, or frequency. Out-of-step relays may be used in some cases for detecting pending instabilities. However, these are usually applied only where it is acceptable to wait until the swing is "coming out of" the swing setting of the relay before taking corrective action. Studies must be performed to determine the proper setting to prevent out-of-step tripping on recoverable swings.

Communication equipment: This equipment communicates the power system conditions as measured by the sensors to the logic solver and the logic solver output to the final or actuating elements. When using communication channels to provide remote logic indication, the design logic should be such that loss of a signal, channel noise, or failure of the communication channel does not give wrong logic information at the receiving end. It should be designed to ensure correct and adequate signal transmission during large system disturbances. Channel equipment used in SPS should be dual channel, shift up/shift down type. All communication equipment and channel equipment should be monitored and alarmed to the appropriate dispatch or maintenance centre so that appropriate action may take place upon failure. Communication channels should be well labelled or identified in some manner such that personnel working on a channel can readily identify the proper circuit.

Power supplies: No single battery or DC power supply failure should prevent the SPS from performing its intended function. Each battery should be provided with its own charger. The regulation of the dc voltage should be such that, under all possible charging and loading conditions, voltage within acceptable limits is supplied to all devices. DC systems should be monitored to detect abnormal voltage levels, DC grounds, and loss of AC supply to the battery chargers.

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Monitoring devices: Each SPS should have instrumentation to monitor and analyse the SPS operations. For example, data logging with sequence of events timing can be designed into the SPS at many points. Such data logging assists in the accurate analysis of any operation in the overall scheme, either correct or incorrect.

Design refinement for enhancing reliability:

This section draws on the material provided in the ISA and IEC standards [6.12-6.15], particularly IEC 61508 [6.14]. It is assumed that, based on identification of the rule, an initial SPS design has been completed. The purpose of the design refinement procedure is to enhance the SPS reliability. This procedure consists of repeating the following basic steps until the desired performance level is reached: 1) evaluate the design, 2) assess the evaluation, and 3) modify the design.

1) *Evaluate the design*: This is a two-step procedure. The first step is to perform a failure analysis of the design in order to identify the possible failure modes, their initiating events, and the possible consequences of these failures if they should occur. This step is generally qualitative but may also include quantitative analysis if desired. Different methods are available for performing it, and a few of them are summarised below [6.14]. Additional information regarding these and other methods can be found in [6.14] and the references contained therein. Often, the best results are achieved by applying more than one method.

- Hazard and Operability (HAZOP): Here, a team of engineers performs a structured examination of a design. A leader drives the procedure by presenting each part of the system in connection with several guide words. Every applied condition or failure mode is considered for its feasibility, how it could arise, the possible consequences, and how it could be avoided.
- Failure Modes and Effects Analysis (FMEA): This is a «bottom-up» method that starts with a detailed list of all components in the system. An entire system can be analysed one component at a time. Alternatively, the system can be hierarchically divided into subsystems and modules as required. The FMEA technique is generally poor at identifying combinations of failures that cause critical problems. Since each component is reviewed individually, failures due to combination of components are not addressed. Common cause failures are rarely identified since they require more than one component failure. An extension of this method, called Failure Modes, Effects, and Criticality Analysis (FMECA), results in a criticality ranking of all components.
- Common Cause Failure Analysis: This method determines the potential failures in multiple systems/sub-systems that would undermine the benefits of redundancy, because of the appearance of the same failures in the multiple parts at the same time. For example, if a system is installed in a single room, an air-conditioner failure might reduce the benefits of redundancy.
- Event Tree Analysis: This method is a «bottom-up» approach. It begins with the determination of a «bottom event», which is a basic or initiating event and aims to determine the possible consequences of the event. Possible consequences of this event are described in a tree fashion using logical operators. Intermediate consequences are similarly analysed, and so on, until a terminal event is reached. A terminal event is one that has no other immediate consequences.
- Fault Tree Analysis: Fault tree analysis is a «top-down» approach. It begins with the determination of a «top event», which is the immediate cause of a serious consequence. Combinations of causes for this top event are described in a tree fashion using logical operators. Intermediate causes are similarly analysed, and so on, back to «basic» or initiating events, where the analysis is then repeated for other «top events». The method is good at finding combinations of failures that may cause problems.

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- Cause-Consequence Analysis: This technique can be regarded as a combination of fault tree and event tree analysis. Starting from a critical event, a cause consequence graph is traced backwards using fault tree construction techniques and forwards using event tree construction techniques.

Recognising that HAZOP and FMEA are inductive methods, and common cause, event tree, fault tree, and cause-consequence are deductive methods, it is often effective to use at least one of each to gain complementary benefits. A simple illustration of hardware reliability assessment using FMEA and corresponding Markov modelling for a Generation Rejection Scheme (GRS) is presented in the Appendix.

The second step in the design evaluation is to perform quantitative failure analysis. This step may not be required for low complexity SPS, but it should always at least be considered. The deductive methods of failure mode identification are amenable to quantitative analysis, but these methods are not capable of modelling time varying effects of failures throughout the system life cycle. Therefore, Markov models are usually considered more rigorous. In Markov modelling [6.23], the status of the system with regard to its identified failure states, modelled as nodes, and the failure or repair events, modelled as node interconnects weighted by failure or repair rates, is represented as a graph. With time modelled in discrete increments (for example, once per hour), calculations can be made showing the probability of being in each state for each time interval. Markov modelling is applicable for systems for which at any given time the subsequent system state only depends on the state at the given time and is not affected by the state at any preceding time. It can be assumed that an SPS has this characteristic. Markov modelling is well suited for use in SPS reliability modelling because its flexibility provides that it can account for the variety of features that are common in SPS. Specifically, Markov modelling can incorporate independent and common cause failures, partial and full repairs, maintenance, and diagnostic coverage. Most importantly, it provides that all of these features can be modelled as a function of time. This is in contrast to probability methods that provide steady state results and are accurate only for short repair times and low failure rates. When there is a large number of states, methods of state reduction can be applied to obtain state probabilities. In very complex models, the graph can be computer simulated to obtain state probabilities. This technique is suitable for modelling systems in which the level of redundancy varies with time due to component failure and repair.

2) *Assess the evaluation*: The result from the design evaluation should be assessed to determine whether the design is satisfactory or not. In this step, the result of the design evaluation is compared to a standard. As indicated at the beginning of Section 6.2, existing SPS design standards are too general to make this step very meaningful. More specific standards existing within individual companies could be identified and used for this purpose, if available. Alternatively, recommended approaches published in the ISA/IEC documents [6.12-6.15] could be adopted. One such approach is based on identification of four risk classes: I (intolerable), II (undesirable, and tolerable only if the cost of risk reduction grossly exceeds the improvement gained), III (tolerable if the cost of risk reduction exceeds the improvement gained), and IV (negligible). These risk classes are identified according to the combination of frequency (or probability) and consequence, as illustrated in Table 6.1.

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Frequency	Consequence			
	Catastrophic	**Critical**	**Marginal**	**Negligible**
Frequent	I	I	I	II
Probable	I	I	II	III
Occasional	I	II	III	III
Remote	II	III	III	IV
Improbable	III	III	IV	IV
Incredible	IV	IV	IV	IV

Table 6.1. Identification of risk classes.

Numerical designations for the various levels of frequency and consequence would normally be used. If the result of the design evaluation indicates the SPS design falls into classes I, II, or III, then risk reduction is necessary, as described in below. Another attractive approach utilises a so-called risk graph [6.15-part 3]. A risk graph is a method of making decisions on a complex issue by breaking down the overall problem into a number of relevant issues which can then be considered on an individual basis. This approach results in a specified safety integrity level (SIL) appropriate to the situation under study, and then the design evaluation results can be compared against the performance measures corresponding to the specified SIL (see Section 6.2) to determine if further risk reduction is necessary.

3) *Modify the design*: Design modification is necessary if design evaluation described above results in an indication that risk reduction is required. Here, the first step is to identify the critical elements. These are components, subsystems, and/or parameters within the design that are responsible for unacceptable risk. The second step is to identify improvements corresponding to each identified critical element. These are typically measures to control failures and could include:

- Using more reliable components.
- Implementing additional defences against common mode failures.
- Increasing diagnostic coverage using, for example, comparison checks between parallel signals, designs which fail to a detectable state for specific failure modes (using normally energised modes), and test and/or cut-out switches at the initiating points, logic receiver or monitoring locations, and at sites where devices are to be operated or tripped.
- Increasing redundancy.
- Reducing proof of test interval.

Following selection of one or more design improvements, the design evaluation should be repeated.

Software and human reliability assessment:

The SPS design refinement approach described in the previous section is broad and inclusive. In particular, it is applicable to reliability problems introduced by software problems and also human errors. However, these are not familiar areas to many engineers, therefore additional comments about them are provided here.

Software Reliability: Most of the software typically used in SPS is not very complicated. But as shown in Section 6.1, software is one of the factors that cause SPS to fail. Software reliability concerns itself with how well the software functions meet the design requirements. Defined precisely, software reliability is the probability of failure-free operation of a computer program for a specified period of time in a specified environment. Software reliability can be improved by flawless design and error-free coding [6.24]. Studies have

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shown that most software errors are introduced during specification development. Adopting formal methods to develop specifications may reduce this sort of errors.

A software reliability model (SRM) specifies the general form of the dependence of the failure process on the principle factors that affect it, namely fault introduction, fault removal, and the environment. A good SRM is simple, gives good predictions of future failure behaviour, and computes useful quantities. SRMs are mathematical models that represent failures as a random process that is characterised by either times of failures or number of failures at fixed times, which can be classified into four categories: *times between failures models*, *failure count models*, *fault seeding models*, and *input domain based models* [6.24, 6.25], described further in what follows:

- *Times between failures models* include models that provide an estimate of the times between failures in a software. The key assumptions of these models are
  a) independent time between successive failures,
  b) equal probability of exposure of each fault,
  c) embedded faults are independent of each other, and
  d) no new faults introduced during corrective actions.
  The most common approach is to assume that the time between, say, the $(i\text{-}1)^{th}$ and the ith failures, follows a distribution whose parameters depend on the number of faults remaining in the program during the interval. Estimation of the parameters are obtained from observed values of times between failures and estimates of software reliability, mean time to next failure, etc., are then obtained from the fitted model.
- *Failure count models* include models that estimate the number of faults or failures experienced in a specific time. The key assumptions are
  a) test intervals are independent of each other,
  b) testing intervals are homogeneous distributed, and
  c) number of faults detected during different intervals are independent of each other.
  Parameters of failure rate can be estimated from observed values of failure counts or from failure times. Estimates of the software reliability, mean time to next failure, etc., can again be obtained from the relevant equations.
- *Fault seeding models* include models that assess the number of faults in the software at time zero via seeding extraneous faults. The key assumptions are
  a) seed faults are randomly distributed in the software, and
  b) indigenous and seeded faults have equal probabilities of being detected.
  The basic approach taken here is to "seed" a known number of faults in a program which is assumed to have an unknown number of indigenous faults. The program is tested and the observed number of seeded and indigenous faults are counted. From these, an estimate of the fault content of the program prior to seeding is obtained and used to assess software reliability and other relevant measures.
- *Input domain based models* include models that assess the reliability of software when the test cases are sampled randomly from a well known operational distribution of software inputs. The key assumptions are
  a) input profile distribution is known,
  b) random testing is used (inputs are selected randomly), and
  c) input domain can be partitioned into equivalence classes.
  The basic approach taken here is to generate a set of test cases from an input distribution that is assumed to be representative of the operational usage of the program. Because of the difficulty in obtaining this distribution, the input domain is partitioned into a set of equivalence classes, each of which is usually associated with a program path. An estimate

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of program reliability is obtained from failures observed during physical or symbolic execution of the test cases sampled from the input domain.

Human Reliability: Human errors are an important factor to be considered in SPS reliability. Of the 8 SPS failures described in Section 6.1, at least 3 of them were partly due to human errors (No.1, 4, 8). Human error must be taken into account in order to obtain a precise and accurate measure of SPS reliability. Human errors can be categorised into several types as operating, design, construction, and maintenance [6.24, 6.26]. Operating error results from humans operating the equipment incorrectly such as motivational error, use of wrong procedures, failure to follow procedures, etc. Design error results from inadequate design. Construction error results from poor workmanship such as the use of an incorrect component or failure to follow the design. Maintenance errors result generally from wrong repair or installation. Sometimes design, construction, and maintenance errors are also the cause of operating error. Normally, quality assurance programs are designed and implemented to minimise the occurrence of these types of human error [6.24]. Several human reliability models have been developed [6.24, 6.26, 6.27], including simulation methods, expert judgement methods, and analytical methods.

6.3.3 Installation, commissioning, and pre-start-up test

The objective of this step is to install the SPS and to ensure it is installed in accordance with the design and performs in accordance with the SPS reliability requirements. The commissioning step should include confirmation of proper equipment and wiring, operational energy sources, calibrated instruments, and operational logic solver. The pre-startup test should include confirmation that the SPS communication system (where required) is operational, that relays, logic and final control elements perform correctly in accordance with the design, that the SPS provides the proper operation display, and that manual shutdown systems operate properly.

6.3.4 Operating and maintenance procedures

The objective of this step is to ensure that the SPS functions are in accordance with SPS reliability requirements developed throughout the SPS operational life. The SPS operating and maintenance procedures should be available to the technicians and engineers responsible for the operation and maintenance of the SPS facilities. Improving the familiarity of these well-written procedures for these individuals is an effective means to avoid human error and prevent subsequent degradation of reliability.

The SPS operating procedures should be written to explain the operating criteria of the SPS. These procedures are typically part of the bulk system operating procedures and should include:

- when and how the SPS is to be armed or disarmed,
- when the SPS will take action, and
- how the system operator is to respond to an SPS operation.

A maintenance program should be established which includes written procedures for maintaining, testing, and repairing the SPS. SPS maintenance should include:

- periodic functional testing,
- periodic preventive maintenance, and
- repair procedures for detected faults, with appropriate testing after repair.

The following items can be considered when developing a maintenance program:

- How often can the scheme be taken out of service without degrading the system?

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- What schedule or power flow changes must be made in order to test the scheme?
- What is the length of time to test the scheme?
- What number of times is the scheme expected to operate during a given time interval?
- What is the potential exposure to a false or inadvertent operation caused by personnel during testing?

6.3.5 Pre-start-up safety review

The objective of this step is to provide the last safety review before the start-up of SPS. It should verify that:

- SPS was constructed and installed in accordance with the SPS reliability specification.
- Operating, maintenance and emergency procedures pertaining to the SPS are in place and are adequate.
- Adequate employee training has been completed.

6.3.6 Review and modification

The objective of this step is to ensure adequate management of SPS verification and modification. A review process should be conducted periodically or whenever there are major changes in operating practices or physical changes to the power system. The review should include review of:

- the suitability of the scheme by comparing the system conditions that motivated the original need for the scheme with the system conditions expected to be encountered in the near future; and
- the consequence resulting from a failure of the scheme.

If it is found during the review process that the SPS is no longer needed, the scheme should be disabled or removed. If it is found that some modifications of the existing scheme are necessary due to changes in expected operating conditions, then a full design evaluation should be considered.

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Exhibit No. MPS-5

ISO new england

Jim Helton, Chairman STF

Kevin E. Mankouski, Chairman TTF

July 22, 2005

NEPOOL Reliability Committee Members:

Re: Proposed Plan Applications for the Cape Wind Generation Project

NSTAR Electric and Gas Company ("NSTAR") and Energy Management, Inc. (EMI) propose the installation of the Cape Wind Generation Project (the "Project"). The Project will consist of 130 wind turbines, each consisting of a 4.1 MVA 3.7[1] MW +/- 0.90 pf doubly-fed wound-rotor induction generator, and a 115 kV Electric Service Platform (the "ESP") Substation. The Substation will be located offshore in the Nantucket Sound in the vicinity of Cape Cod, MA. Two 115 kV 18.1-mile long transmission lines, each comprised of two submarine/underground 800 MCM cables, will interconnect the ESP Substation to NSTAR's 115 kV Barnstable Substation. The wind turbines will be connected to the ESP Substation via a collector system that will be comprised of fourteen (14) 33 kV submarine cables. The Project's first installed turbines are expected to be in service in June 2007 and its last installed turbines are expected to be in service in November 2008.

The Transmission Task Force (the "TTF") reviewed the thermal and voltage analyses of the Project. The Stability Task Force (the "STF") reviewed the stability and short-circuit analyses of the Project.

The thermal analysis for the system before the addition of the Project shows a preexisting condition following the simultaneous loss of the 342 and 322 Lines when both Canal 1 and Canal 2 units are on line. The 342 and 322 Lines are on common towers ("double circuit tower" or "DCT") for one span for their crossing of the Cape Cod Canal and their simultaneous loss is therefore considered a normal contingency. The 342 /322 DCT contingency can result in overloading the Bourne – Tremont 115 kV 108 and 113 Lines beyond their STE ratings of 291 MVA when both Canal units are in-service. This is an existing problem that requires the tripping of a Canal unit to avoid this overload. A Northeast Power Coordinating Council ("NPCC") Type III Special Protection System ("SPS") at Canal 345 kV, for the existing system, armed to trip the Canal 2 generation when both Canal 1 and Canal 2 units are in-service for the 342/322 DCT contingency could resolve this preexisting condition.

The analysis of the Project identified that for the Project on line, an NPCC Type I SPS, referred to as the Canal 345 kV SPS, to trip any on-line Cape Wind generation and the Canal 2 generator whenever Canal 1 and Canal 2 are on line for the 342/322 DCT contingency to avoid the overload of the 108 and 113 Lines beyond their DAL ratings.

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[1] Each wind turbine will have an individual transformer to provide output power at 33 kV and will have a manufacturer guaranteed maximum net output of 3.6 MW at its 33 kV terminals.

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The TTF notes that the Canal 345 kV SPS fails to meet all of the conditions for a Type I SPS as specified in the "ISO New England Planning Procedure No. 5-5 Special Protection Systems Application Guidelines" or (the "SPS Guidelines"). Under the SPS Guidelines, an NPCC Type I SPS is required to have local action relative to the SPS. Tripping of Cape Wind as specified above is a remote action. The TTF agreed that the Reliability Committee should consider granting an exception to requiring the proposed Canal 345kV SPS to meet the condition of the SPS Guidelines that Type I SPS only employ local action and that the addition of the SPS is otherwise acceptable in regard to the ISO New England "Reliability Standards for the New England Area Bulk Power Supply System".

The STF notes that the stability analysis for the proposed Canal 345 kV SPS with the Project on line was performed with a power system stabilizer assumed active for the excitation system of the Canal 1 generator for just the testing of 342/322 DCT contingency. Inadequate system damping resulted for that contingency without the stabilizer. The STF therefore agreed that the interconnection of the Project requires the addition of an active power system stabilizer on the Canal 1 generator. Additionally the STF agreed that the stability analysis performed was not sufficient (it was not performed on enough cases to ascertain that its control settings were acceptable) to support the required Proposed Plan Application for the addition and activation of a power system stabilizer on the Canal 1 generator and therefore recommends that the approval of the interconnection of the Project be subject to the completion of such analysis.

Both the STF and the TTF agreed that the analyses subject to their review sufficiently supports the required applications for implementation of the Project under Section I.3.9 of the ISO Tariff, subject to further consideration of the appropriateness of the proposed Canal 345 kV SPS not meeting the SPS Guidelines and additional stability analysis being conducted for the installation of an active power system stabilizer on the Canal 1 generator.

The TTF and STF agreed that the interconnection of the Project will not have a significant adverse effect upon the stability, reliability or operating characteristics of the New England Transmission system or the system of a Market Participant and recommends that the Reliability Committee recommend ISO New England Inc. approve the forthcoming Generation Proposed Plan Application for the Project subject to the following conditions:

1. The Project having a maximum combined net capability of 462 MW at its point of interconnection at the Barnstable 115 kV Substation under all seasonal/temperature conditions.

2. Expansion of the Barnstable 115 kV Substation to include a fifth bay with two circuit breakers and the addition of a third circuit breaker in the planned fourth bay.

3. Construction of a 115/33 kV GIS Electric Service Platform (the "ESP") Substation located in Nantucket Sound that shall consist of six 115 kV circuit breakers and four 33/115 kV 96/128/160 MVA transformers each having an impedance of 12% on a 96 MVA base.

4. Installation of two 115 kV lines with each consisting of two (2) 800 MCM solid dielectric cables, each having a length of 18.1 miles, with 12.2 miles being submarine and 5.9 being underground, that shall connect the ESP Substation to the Barnstable 115 kV Substation.

5. Installation two 35 MVAR shunt reactors at the Barnstable 115 kV Substation and two 35 MVAR shunt reactors at the ESP Substation to compensate for the cable charging of the new 115 kV transmission lines and the Project's 33 kV collector system. Each shunt reactor shall have a dedicated synchronous closing circuit breaker in order to avoid any transient over-voltages during switching.

6. Replacement of the 1200-ampere Brook Street 115 kV EW42 circuit breaker and ancillary equipment with 2000-ampere equipment.

7. Reconductoring the Brook Street-Kingston 117 Line with 954 MCM ACSS conductor.

8. Reconductoring the Kingston-Auburn 191 Line with 795 MCM ACSR conductor.

9. Installation of a redundant circuit breaker in series with the existing #312 circuit breaker at the Canal 345 kV Substation.

10. Replacement of the Canal 345 kV #112, #512 and Auburn 345 kV #2130 and Bourne 115 kV #12272 circuit breakers with breakers having independent pole tripping capability.

11. Installation of two independent high-speed protection systems on the Falmouth to Barnstable 115 Line.

12. Reduction of the backup clearing time for the Canal #412 circuit breaker to10 cycles.

13. Installation of differential insulation and additional grounding at each tower that is common for the 342 and 322 Lines. This common tower construction is used for the Cape Cod Canal crossing of these lines.

14. Modification the SPS at the Barnstable 115 kV Substation, planned to be installed for the 2nd Nantucket interconnection project, to ramp down the Cape Wind generation output to 300 MW for system conditions where the simultaneous loss of the 122 and 120 Lines, which share common towers, would overload the Barnstable to Falmouth 115 Line over its LTE rating of 246 MVA. This modification will result in this SPS continuing to be classified as a NPCC Type III SPS.

15. Addition of a NPCC Type I SPS (the "Canal 345 kV SPS") at the Canal 345 kV Substation that shall trip any on-line Cape Wind generation and the Canal 2 generator following the simultaneous trip of the 342 and 322 Lines for the condition when the Canal 1 and Canal 2 generators are simultaneously on line.

16. Installation and activation of a power system stabilizer on the excitation system of the Canal 1 generator.

17. Completion of further analysis and its documentation as required to support the STF recommending approval of the required Proposed Plan Application for the installation and activation of a power system stabilizer on the excitation system of the Canal 1 generator.

The TTF and STF also recommend that the Reliability Committee recommend that ISO New England approve the Transmission Facilities Proposed Plan Applications for the Project subject to the Reliability

Committee further considering the appropriateness of the proposed Canal 345 kV SPS not meeting the SPS Guidelines.

Sincerely,

/s/ Jim Helton

Jim Helton, Chair
Stability Task Force

/s/ Kevin Mankouski

Kevin Mankouski, Chair
Transmission Task Force

cc: Transmission Task Force
Stability Task Force
C. Bryan, CBX Energy Engineering
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CERTIFICATE OF SERVICE

CERTIFICATE OF SERVICE

In accordance with Commission Rule 206(c), 18 C.F.R. § 385.206(c), I hereby certify that I have on this 28th day of March, 2008, caused a redacted version of the foregoing complaint to be served on all parties on the list complied by the Secretary of the Commission in FERC Docket No. ER07-921, and the complete complaint to be served electronically upon the following:

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FORM OF NOTICE

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Braintree Electric Light Department, Hingham Municipal Lighting Plant, Hull Municipal Lighting Plant, Mansfield Municipal Electric Department, Middleborough Gas & Electric Department, and Taunton Municipal Light Plant, Complainants,	
v.	Docket No. EL08-___
ISO New England Inc. Respondent.	

NOTICE OF COMPLAINT

([DATE] **)**

Take notice that on March 28, 2008, Braintree Electric Light Department, Hingham Municipal Lighting Plant, Hull Municipal Lighting Plant, Mansfield Municipal Electric Department, Middleborough Gas & Electric Department, and Taunton Municipal Light Plant, ("Massachusetts Public Systems") filed a formal complaint against ISO New England Inc. ("ISO") pursuant to sections 206 and 306 of the Federal Power Act, 16 U.S.C. §§ 824e, 825e, and Rule 206 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.206, alleging (*inter alia*) that ISO has violated its tariff by assessing certain out-of-merit generation costs as Local Second Contingency Protection Resource charges to be allocated among all load in Southeast Massachusetts.

Massachusetts Public Systems note that the complaint and accompanying testimony include information designated by the ISO to constitute "Critical Energy Infrastructure Information" ("CEII"), and have therefore redacted the public version of the complaint and accompanying materials. Massachusetts Public Systems disagree with the CEII designation and ask the Commission to remove that designation and release the unredacted copy of the complaint.

Massachusetts Public Systems seek consideration of the complaint in accordance with the Commission's "Fast Track" procedures.

Massachusetts Public Systems certify that an unredacted copy of the complaint was served on the ISO, and that redacted copies have been served on all persons designated on the official service list in *ISO New England, Inc.*, Docket No. ER07-921-000.

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

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

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

Comment Date: 5:00 pm Eastern Time on [DATE]