EB-2007-0707

ONTARIO ENERGY BOARD

IN THE MATTER OF *sections 25.30 and 25.31 of the Electricity Act*

AND IN THE MATTER OF an Application by Ontario Power Authority for review and approval of its integrated power system plan and approval of its proposed procurement process.

EVIDENCE OF THE INTERVENOR
THE SAUGEEN OJIBWAY NATIONS

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AFFIDAVIT

of

WHITFIELD A. RUSSELL

on behalf of

THE SAUGEEN OJIBWAY NATIONS

Statement of Qualifications

1. My name is Whitfield A. Russell. I am a public utility consultant and principal in Whitfield Russell Associates. I hold a Bachelor of Science degree in Electrical Engineering from the University of Maine, 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 in the United States before State and Federal courts, administrative agencies and other tribunals in approximately 30 States. I have been accepted as an expert in the recently concluded hearings concerning the proposed Bruce-Milton 500 kV double circuit lines in Ontario and in proceedings in two other Canadian provinces (Manitoba and Alberta). My complete resumé and a description of cases on which I have worked are attached as Attachment 1 to this Schedule.

2. I am testifying on behalf of the Saugeen Ojibway Nations. The purpose of my testimony is to review the Integrated Power System Plan ("IPSP") prepared by the Ontario Power Authority ("OPA"), and discuss that Plan as it relates to the concerns of the Saugeen Ojibway Nations ("SON").

Summary of Findings

3. My analysis has focused on two broad areas of concern respecting the analysis and planning decisions made by the OPA in its development of the IPSP.

    A. First, it appears that OPA has based its ranking of large wind sites on inconsistent, faulty and/or or incomplete analyses. These improper analyses have caused the OPA to (i) prefer two large wind sites planned for the Bruce Peninsula and (ii) recommend the development of new 230 kV facilities that will enable the delivery of the output of Bruce Peninsula wind generation to the Ontario grid.

    B. Second, the OPA has relied too heavily on nuclear generation. Over-reliance on nuclear generation will crowd out production of renewable wind and hydro energy during off-peak periods causing Ontario generating resources to produce energy in excess of what Ontario can absorb or export. Excessive off-peak energy production will exacerbate an existing off-peak minimum load problem in Ontario, distort power supply economics, add to costs and cause violations of industry operating standards.

I. OPA'S RANKING OF LARGE WIND SITES IMPROPERLY FAVORS BRUCE AREA WIND GENERATION

OPA's Renewable Goals

4. The Supply Mix Directive sets out two targets respecting the increase of renewable resources within Ontario—one for 2010, and another for 2025. For the most part, the OPA has already arranged to purchase committed resources in amounts sufficient to fulfill the 2010 requirement of an additional 2,700 MW of renewable resources.[1] The IPSP states that the 2003 base amount was 7,702 MW, with another 556 MW added since 2003. The OPA also is counting 1,415 MW of committed resources and the expected 2009 interconnection with Quebec (1,250 MW).[2] The total increase from these resources is 3,318 MW, greater than the 2,700 MW required.[3] Thus, the total existing and committed resources as of 2010, without the Hydro-Quebec interconnection, will total approximately 9,673 MW, or almost 11,000 MW with the Hydro-Quebec interconnection.

5. By 2025, OPA plans to add another 6,400 MW of renewable resources, comprised of approximately 3,000 MW each of hydroelectric and wind, as well as 450 MW of bioenergy.[4] Thus, the total nameplate capacity of renewable resources will increase from approximately 9,700 MW to 16,100. In Exhibit D-5-1, the OPA describes how it ranked various potential renewable resources to determine the location of this potential 6,400 MW in renewable resources. As a means of determining the

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[1] Exh. D-5-1 at pp. 1-4.
[2] However, OPA has not assumed that it will make any firm purchases of power from outside the Province. Negotiations have been held with neighboring jurisdictions regarding possible purchases of hydro power on a firm basis, but no agreements have been reached to date. See Exhibit D-5-1 at p. 13. Yet Hydro-Quebec has substantial hydro resources on its system, and both Hydro Quebec and Labrador are planning substantial new hydro generation. See OPA's response to Interrogatory SEC 18, Exh. I-35-18.
[3] Exh. D-5-1 at pp. 1-2, Table 1.
[4] Exh. D-5-1 at p. 3, Table 2.

locations, the OPA contracted for various studies on hydroelectric and wind potential as a means of determining locations for specific projects.[5]

6. The OPA analysis of the incremental amount of renewable resources necessary to meet the 2025 target employed the following process:
   a. Establish the potential for each resource type without consideration of transmission limitations or policy constraints;
   b. Identify transmission facilities required to achieve the wind or hydro potential;
   c. Establish all-inclusive unit costs for developing the potential resources; and
   d. Determine the resources to be included in the plan, based on potential, timelines and costs, including transmission constraints and hydroelectric policy constraints.[6]

7. The OPA has developed and applied several planning criteria in the development of the IPSP, and specifically, to its decisions respecting the identification and selection of renewable resource projects for development. These criteria are: cost, feasibility, societal acceptance, reliability, and environmental performance.[7] As discussed in detail below, the OPA's principal criterion for selecting among various potential renewable resources projects has been cost. However, the OPA excluded a number of potential wind sites based on considerations other than economic ones. The OPA rejected development of many sites based on its other criteria of societal acceptance, feasibility and environmental performance. For example, some sites were excluded because they were in parklands, in important bird areas, or close to large population centers.[8] Other sites were constrained because of conflicts with commitments to Aboriginal peoples, specifically the Moose River Basin Commitment and the Northern Rivers Commitment. The OPA subsequently included several of these

[5] Exh. D-5-1 at p. 15:22-27 and its Attachments 1-3.
[6] Exh. D-5-1 at p. 15.
[7] Exh. A-2-2 at p. 10, Table 2.
[8] Exh. D-5-1, Attachment 1 at p. 7

constrained sites after receiving comments from stakeholders; however, it acknowledges that "further public review and debate will be required respecting the release of such sites."[9] Potential renewable resource sites remaining after this screening process were analyzed and ranked according to each site's economic effectiveness.

Role of Levelized Unit Energy Cost Analysis in Ranking Wind Sites

8. OPA's principal criterion for ranking renewable generation resources for development is the all-inclusive unit cost, or Levelized Unit Energy Cost ("LUEC") of each resource, including an adjustment for each resource's marginal costs of transmission. "LUEC is the average cost of the energy produced from an electric power generator over its service life, considering all the costs in the lifecycle of the plant, including its construction, operation and fueling, and decommissioning costs."[10]

9. In order to develop a LUEC for each resource, the OPA first calculated a base LUEC, composed of the present worth of lifecycle capital costs and operating costs (fuel and other operations and maintenance expenses – "O&M"). LUEC is composed primarily of fixed costs for hydro and wind resources. This calculation starts with the estimated base construction cost of each generating resource, which is converted into an annuity equal to an annual outlay in dollars that has the same net present value as the initial construction cost.[11] Annual operating costs are then added to each year's costs. The combined total is then divided by the projected annual production of that generating resource in kWh to produce a "real" cost per kWh over the projected life cycle of the

[9] Exh. D-5-1 at p. 12.
[10] D-3-1, Attachment 1 at pp. 2-3. "In the definition that OPA has adopted, LUEC is the price (escalating at the rate of inflation) that would have to be charged for each MWh produced over the lifetime of a generator that would provide the revenue stream with the same present value as the direct costs of construction, operation and decommissioning of the plant."
[11] The construction cost starts with base construction costs which, for wind generation, vary by size of the plant (larger plants have lower per-kilowatt construction costs), as do the operating costs, as shown in Table 14 of Exh. D-5-1 at p. 25

resource (without inflation). A similar process is carried out with respect to the costs of interconnecting and transmitting the output of the generating resource, including the costs of enabler transmission facilities and of network upgrade costs (the costs of upgrades to Ontario's bulk power network attributable to development of the particular generating resource). Finally, an adjustment for transmission losses is added.

10. OPA assigned an all-in LUEC to each potential hydro and wind resource.[12] Of the 9,267 MW of large wind sites, OPA's analysis led it to prefer ten clusters of large wind sites amounting to a total nameplate installed capacity of 5,996 MW "whose development could be facilitated by having the sites share a single connection line to the Ontario transmission network. A single connection line will make all sites in a cluster more economic to develop than they would otherwise be."[13] The remaining 3,300 MW of potential large wind generation is projected to come from "stand-alone" wind sites.

11. Through its LUEC analysis, the OPA identified 10 potential large wind clusters shown on Table 13. Of these ten sites, the OPA selected four clusters in order of their all-inclusive LUECs.[14] These four clusters are the Bruce Peninsula, Goderich, East Lake Superior and Manitoulin.[15] The "Bruce Peninsula" cluster includes two major projects proposed for development, identified as site S46 rated 192 MW and site S5 rated 188 MW.

12. It appears clear from the pre-filed evidence that the cost criterion, and the LUEC analysis on which it is based, has been of utmost importance in determining which resources OPA plans to pursue in the near term. It is on this basis that the OPA has

[12] Exh. D-5-1 at pp. 27-28, Tables 15 and 16.
[13] Exh. D-5-1 at pp. 23-24 of 64 and Table 13.
[14] Exh. D-5-1 at p. 35:9-11.
[15] Exh. D-5-1 at p. 35:12-15.

selected sites within the Bruce Peninsula as preferred sites, and has indicated in Exh. E-3-9 that it cannot recommend the development of other sites which have been determined to be “less economic.” Again, these other potential wind sites are rejected, or not preferred, by the OPA based on its LUEC calculations and the determination that these sites have an LUEC higher than the LUECs of the Bruce Peninsula sites.[16]

13. The OPA’s LUEC analysis is the result of a complex process comprised of many elements and dependent on numerous inputs and assumptions. The LUEC is sensitive to numerous assumptions about cost per kW of a wind farm (which cost depends upon the total MW nameplate capacity of each wind farm to be constructed, the discount rate used in annualizing construction cost of the wind farm, the cost of connecting the farm to the grid and, significantly, the cost of building enabler lines from each project to Ontario’s bulk transmission grid and the cost of upgrades to the grid itself occasioned by interconnecting each wind farm project). Connection, enabler and transmission upgrade costs will vary depending upon the voltage and type of the facilities required, as well as the distances involved.

14. The OPA has refused to provide complete information regarding the inputs and assumptions used in its LUEC analysis. When asked to provide the data that would allow comparisons between the various sites to be reviewed and checked for accuracy, OPA refused. For example, interrogatories from SON as well as from others requested the underlying data, as well as the model used to perform the analysis. In its responses, OPA refused to release the data.[17]

15. The LUEC analysis has been critical in determining which resources to develop, and, in particular, the OPA’s decision to develop particular large wind resources, including

[16] Exh. E-3-9 at pp. 5-7.
[17] Exhibits I-34-11, I-34-21, I-34-11 and I-34-21.

those on the Bruce Peninsula. The evidence to date does not provide sufficient information or data to understand and test OPA's LUEC analysis. Consequently, the evidence has not adequately demonstrated whether OPA has properly chosen the most economical sites for development.

Exclusion of Bulk Transmission Costs for the Bruce Peninsula Projects Skews LUEC Analysis

16. As noted, the OPA has attempted to rank each resource economically based on its all-inclusive LUEC. An important component of each all-in LUEC is the cost of needed transmission upgrades. A critical omission from the economic rankings of wind resources in the Bruce Peninsula and Goderich wind clusters is any cost associated with transmitting their output over the bulk power grid. The OPA includes costs for interconnections and costs for enabling lines, but none for bulk transmission upgrades. This differs from OPA's approach in developing the LUECs associated with other planned renewable developments. As far as I can determine, the OPA did not omit the costs of upgrades to the bulk power grid for those other planned developments.[18] This omission likely has a significant impact on the economic ranking of the Bruce area wind sites.

17. Throughout the IPSP, the OPA acknowledges that enhancements to 500 kV facilities emanating from the Bruce Complex are required if it is to be able to transmit the combined output of eight Bruce Units, approximately 700 MW of committed large wind projects and an additional 1000 MW of planned wind generation projects in the vicinity of the Bruce Complex (including the clusters of wind generation planned for Goderich and the Bruce Peninsula).[19] OPA has proposed the double circuit 500 kV Bruce to Milton transmission project to meet that asserted need. The Bruce-Milton

[18] Exh. D-5-1 at pp. 27-28, Tables 15 and 16 under "Bulk".
[19] Exh. E-2-1 at p. 5.

project is under consideration in a Section 92 leave-to-construct proceeding in which hearings have been concluded and a decision is pending.

18. Specifically, the OPA recognizes that development of the wind sites in Goderich and the Bruce Peninsula are dependent upon the construction of a new Bruce to Milton 500 kV line. The OPA states:

> Furthermore, there are transmission reinforcement needs in the whole Bruce region. The ability to deliver wind energy from the Bruce Peninsula, even with the provision of an enabler line to the area, is premised on the completion of a second 500 kV line from the Bruce Nuclear Generating Station to the Milton transformer station in the west Greater Toronto Area.[20]

19. These statements are consistent with the OPA's position during the recent Bruce-Milton Section 92 application hearing. There, OPA and Hydro One representatives stated that the proposed Bruce-Milton line is needed in part to facilitate the development of 1,000 MW of large wind resources in the Bruce area.[21] This 1,000 MW of potential wind includes 380 MW of wind in the two major projects making up the Bruce Peninsula wind cluster.

20. In spite of the causal relationship between the proposed Bruce-Milton line and the wind generation planned for development at Goderich and on the Bruce Peninsula, the calculation of the all-inclusive LUEC for the Bruce area wind generation

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[20] Exh. E-3-9 at p. 5.

[21] Hydro One's Section 92 Application in EB-2007-0050 at Exhibit B-1-1 at p. 4 and Exhibit B-6-5, Appendix 1 at p. 4, and Attachment 2, which is page 173 of the May 7, 2008, transcript in Docket No. EB-2007-0050:

> MR. MILLAR [Board counsel]: The Bruce-Milton project itself is not being considered as part of the IPSP; is that correct?
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> MR. CHOW [of the OPA]: No. It's included in the discussion paper that forms the basis of the IPSP, as in our letter to Ms. Formusa. We believe that's such an urgency that we cannot await the outcome of the IPSP, so we said it is proceeding as a stand-alone application before the IPSP.

deliberately omits any costs relating to this line. The OPA has excluded the costs of the line or any other upgrades on the basis that (1) the line was the subject of a prior and separate Section 92 application[22] and (2) that the line is considered a network upgrade.

21. The OPA states that the Bruce-Milton Line is a network upgrade that "is paid by all transmission customers because it benefits the entire system and all transmission customers."[23] However, it is clear from the OPA's evidence that, whatever network benefits are derived from the new line, a significant component of its value is to enable the grid to accept delivery of the output of Bruce area wind resources, and that those resources cannot be developed without substantial upgrades. The OPA needs to determine the true relative costs of competing resources based on economic prudence and cost effectiveness. Therefore, all resources need to be analyzed on a level playing field, by attributing transmission upgrade costs to all parties who require the necessary transmission.

22. Despite the unique circumstances that led to the proposed Bruce-Milton line being removed from the IPSP review for approval processes, some costs related to transmission upgrades in the Bruce area must be included in the LUEC analysis to derive a true cost of Bruce area wind. The costs of upgrades to the 500 kV transmission facilities emanating from the Bruce Complex cannot be known until the Board acts on Hydro One's Section 92 leave-to-construct application.[24] If, as and when bulk transmission upgrades are identified, a *pro rata* share of their costs should be included in the LUECs of all wind projects considered for development in the vicinity of the Bruce Complex. It has been the position of Hydro One that such costs

[22] Exh. I-34-5.
[23] Exh. I-34-12.
[24] Substantial evidence was provided in the Bruce-Milton leave-to-construct hearing that a new double-circuit transmission line would not be required if potential large wind resources were removed from consideration. That is, other, less costly transmission upgrades could be implemented to meet the current needs of committed nuclear and wind generation.

could be as high as $635 million. This is a very significant cost and could have significant adverse implications for the economic ranking of the Bruce Peninsula wind generation vis-à-vis the rankings of other major clusters of planned wind generation.

Estimate of Bruce Area Transmission Upgrade LUEC Cost

23. As noted above, the OPA has not provided sufficient information and data to understand its LUEC analysis. However, it is possible to make an estimate of the impact of proposed upgrades in the Bruce area upon the relative economic ranking of the Bruce Peninsula wind projects (in combination with the rankings of wind projects in the Goderich wind cluster).

24. The costs of proposed upgrades to the Bruce area transmission system ranged from a low of approximately $100 million to a high of $635 million for the construction of the proposed Bruce-Milton line. Assuming, hypothetically, that the position of Hydro One and OPA is adopted by the Board, the cost of the proposed Bruce-Milton line should be attributed to the 700 MW nameplate capacity of the wind generation upon which the need for the line was based.[25]

25. Taking the assumptions of Hydro One and the OPA during the Bruce to Milton Section 92 application, the LUECs of the Bruce Peninsula wind projects can be adjusted to include a pro rata share of the $635 million proposed Bruce-Milton transmission project needed to deliver 700 MW nameplate capacity of planned wind. In this case, the LUECs for each of the Bruce Peninsula and Goderich wind sites rise by nearly 1.8 cents/kWh. That is, this adjustment would cause the all-in LUEC to

[25] This estimate cannot consider individual characteristics of the various sites, as that data is unavailable. Instead, the estimate merely spreads the $635 million cost of the proposed Bruce-Milton transmission upgrades over 700 MW of wind. The incremental cost of the 700 MW added by the proposed Bruce-Milton line over the cost of the principal alternative upgrade is $538 million, which has an LUEC impact of 1.5 cents/kWh.

increase by 1.8 cents/kWh for each of these Bruce area wind projects using a 4% discount rate. The LUEC adjustment would be about one-sixth that amount if the lower-cost upgrades were selected.

26. If the $635 million Bruce-Milton line costs were so reflected in the LUEC calculations, the economic ranking of Bruce area wind projects would be adversely altered, reducing their ostensible economic attractiveness and undermining the chance that they would be chosen first for development, if chosen at all. As shown in Table 16 of Exh. D-5-1, the all-in LUEC for various wind generation sites ranges from 7.4 to 11.5 cents/kWh at the 4% discount rate. The LUEC for the Bruce area wind generation sites range from 7.9 – 9.3 cents/kWh. Adding a transmission adjustment of 1.8 cents/kWh to the Bruce area wind generation sites would cause the LUECs for these sites to increase to a range of 9.7-11.1 cents/kWh, close to the high end of the LUECs for a site listed above (which is the 11.5 cents/kWh LUEC for the site located at Alexander in the Northwestern area).

Incremental Cost for 700MW of Wind on the Bruce-Milton Line

	@ 30% CF			
	LUEC		Revenue Reqmts	
Number of yrs = n	38			
Discount Rate = r	0.04			
(1+r)^n	4.44			
r/(1-(1+r)^-n)	0.0516319			
PV	$635,000,000			
Annuity	$32,786,269		$56,000,000	
700 MW wind at 30% CF	1,839,600	MWH	1,839,600	MWH
	17.8225	$/MWH	30.4414	$/MWH
	1.7822	Cents/kWh	3.0441	Cents/kWh

27. Moreover, the LUEC methodology understates the actual impact of an investment in the Bruce-Milton project on ratepayers. The actual incremental revenue requirement of the Bruce-Milton project amounts to about $56 million per year.[26] In order to transmit the 700 MW increment in nameplate wind generation capacity that can be delivered with this increased transfer capacity, this annual revenue requirement for the Bruce-Milton line (about $56 million) equates to 3.0 cents/kWh, far higher than the 1.8 cents/kWh effect of including Bruce-to-Milton transmission line costs in the LUEC methodology. Such an amount would increase the LUEC of the potential wind resources in the Bruce area from the 7.9 – 9.3 cents/kWh range to the 10.9 – 12.3 cents/kWh range, which are at or greater than the highest cost wind resource on Table 16 of Exhibit D-5-1.

28. A more rigorous cost comparison would necessitate refinements to the transmission revenue requirements for each wind site (and not just for the Bruce area sites). Nevertheless, the relative economic ranking of wind generation sites would be substantially altered if OPA were to adjust the LUECs of the Bruce area wind sites to include the cost of the proposed Bruce-Milton transmission upgrades. Indeed, it appears that several other sites would be equally or more attractive than those on the Bruce Peninsula if the LUECs of Bruce area wind generation were to be adjusted to reflect the cost of bulk transmission upgrades.

Effect of Adding Upgrade Costs to LUEC Analysis

29. In its analysis of the potential wind sites on the Bruce Peninsula, the OPA analyzed four other wind sites in comparison to the LUEC of the Bruce Peninsula wind sites, assuming an all-inclusive LUEC of 8.29 cents/kWh with the costs of the preferred

[26] Upon completion of the Bruce-Milton Lines, its estimated $635 million cost would increase annual charges to consumers in amounts ranging between $53.1 million per year (in 2013) to $58.9 million per year (2026). See Exh. B-4-4 at pp. 3-5 of Docket No. EB-2007-0050. The average of these two amounts is used in the calculation above.

Bruce Peninsula "enabler" line included.[27] However, as described above, none of the costs of the proposed Bruce-Milton 500 kV double circuit line are included despite the fact that development of these Bruce Peninsula projects is premised upon completion of the proposed Bruce-Milton transmission line. From the point of interconnection with the grid, these wind projects will need to utilize the transmission system extending from Bruce to the Greater Toronto Area ("GTA").[28] If the LUEC estimate of 1.8 cents/kWh is added to these figures, the costs of the wind power located in the Bruce Peninsula increase to 10.1 cents/kWh.

30. Adding 1.8 cents/kWh to the all-in LUEC of each Bruce Peninsula wind project would cause its LUEC to exceed the LUECs of three specific projects that OPA views as "less economic" alternatives. The three alternative projects (Pembroke, West of London and Parry Sound) have LUECs ranging from 9.59 to 9.81 cents/kWh. Adding 1.8 cents/kWh to the all-in LUEC of the Bruce Peninsula wind cluster would cause its LUEC to exceed the LUECs of three of the four specific projects that OPA views as vying to replace them. The estimated 10.1 cents/kWh of the Bruce Peninsula wind sites would equal the LUEC of the fourth alternate project at North Bay.[29] The proposed Bruce-Milton line is not needed to deliver the output of the alternative wind generation sites at Parry Sound, North Bay or Pembroke, and should make a minor contribution to the deliverability of the alternative wind cluster west of London. Therefore, the cost of the proposed Bruce-Milton line should not logically be attributed to the wind sites that the OPA considers to be alternatives to the Bruce Peninsula wind generation clusters and would not affect their LUECs.

31. Parry Sound wind generation could be even more competitive than is portrayed by OPA in the IPSP because the enabler line component of Parry Sound's cost seems to be overstated. Exhibit C-9-1 at p 45, indicates that OPA estimated the potential wind

[27] Exh. E-3-9 at p. 10.
[28] Exh. E-3-9 at p. 5:4-9 and Exh. E-3-8, p. 6:3-6.
[29] Exh. E-3-9 at p. 6.

generation to be 800 MW in the Parry Sound area. The conceptual design of the enabler lines called for extending two 230 kV lines about 100 km to Parry Sound Substation at an estimated cost of about $130 million. That exhibit states that most of the Parry Sound wind sites are located within 25 km of the 500 kV North-South tie to which they could be interconnected at 500 kV. However, OPA recommends extending a 230 kV radial line to Parry Sound in order to avoid tying up a portion of the constrained transfer capacity of the North-South tie which OPA plans to save for use by renewable resources being developed at locations north and west of Sudbury.[30] It is not entirely clear whether the enabler line design conceptualized in Exhibit C-9-1 was used in developing the LUEC for Parry Sound, but if it was, the all-in LUEC of Parry Sound can be further reduced by removing these costs, thereby making it even more economically advantageous than the Bruce Peninsula wind projects.

32. From the foregoing, it appears that there are various large wind sites identified as “less economic” alternatives to the Bruce Peninsula cluster that will actually be less expensive once the costs associated with the Bruce area transmission upgrades, which OPA insists are required, are reflected in the LUEC analysis.

33. Further, a corrected LUEC analysis respecting Bruce Peninsula wind clusters may have an impact on future decisions respecting the comparative economics of those clusters and other potential renewable resources in the longer term. Examples of other sources include purchases from sources outside Ontario, which OPA has not examined in great detail, and the development of off-shore wind, which has recently been made possible through a change in Ontario government policy.

[30] Exh. C-9-1 at pp. 44-46.

Competitive Issues Arising from Faulty LUEC Analysis

34. The OPA cites the Board's December 27, 2006, IPSP filing guidelines to explain its failure to consider the new Bruce-Milton line in the IPSP.[31] It appears that OPA is referring to the section entitled Pre-IPSP Projects which provides:

> The economic prudence or cost effectiveness of specific generation or conservation projects that were the subject of governmental procurement or OPA procurement prescribed by Ministerial directive issued prior to the date of approval of the IPSP (for example, the OPA's York region demand response process or the existing Standard Offer Program) will not be assessed as part of the IPSP review process, even if these projects are included in the IPSP.
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> To the extent that the need for and costs associated with a transmission project are examined in the course of the review of a transmitter's capital budget in a rate proceeding or in the course of a leave to construct proceeding that is pending prior to approval of the IPSP, these issues will not be assessed a second time as part of the IPSP review process even if the project is included in the IPSP.[32]

35. The Board's policies with respect to the IPSP have numerous provisions addressing concern about maintaining competition. Although we do not know how OPA proposes to arrange procurement for major large wind projects, construction of the proposed Bruce-Milton line does raise significant competitive issues because, if LUECs are not adjusted properly, it would favor procurement and development of wind and nuclear generation in the vicinity of the Bruce Complex (to which no transmission grid costs are allocated) over competing generation projects to which analogous transmission upgrade costs are allocated. Thus, the effect of the Bruce-Milton line on competition should be reviewed in the IPSP consistent with the Board's directive that "[t]o the greatest extent possible, the procurement process must be a competitive process." See Issue 2(b) under Procurement Processes in

[31] Exh. D-5-1 at p. 1.
[32] Exh. A-3-1 at pp. 11-12.

Attachment 3 to this Schedule, which is Appendix A: Issues List to the Board's March 26, 2008, Decisions with Reasons.[33]

36. The OPA's failure to consider the cost of the proposed Bruce-Milton line in the IPSP has altered the competitive positions of potential wind developments and proponents, and may give an unfair advantage to those seeking to develop sites on the Bruce Peninsula. This unfair advantage is evident from OPA's preference to develop those sites, which preference was arrived at pursuant to the flawed processes used in the IPSP.

Transmission Enabling Bruce Peninsula Wind is Uncertain

37. The OPA plans to add several enabler transmission projects necessary to enable it to deliver the output of renewable resources from regions in which the resources are plentiful, to the extra high voltage ("EHV") grid that services the GTA load center. One of these developments is a proposed enabler line for the large wind cluster located on the Bruce Peninsula. The OPA recommends that this transmission project, as well as enabler facilities for the Goderich area, be built in Stage 1 of its transmission development plan, expected to be completed by 2015.[34]

38. Existing electrical infrastructure supplying the Bruce Peninsula consists of a 44 kV line extending from Owen Sound to Tobermary, about 100 km in length with a transfer capability of about 25 MW. This line is not capable of accommodating the

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[33] Also see:

a. Procurement-Related Issues in Developing the IPSP, No. 28, Attachment 3 at p. 5 ("Has the OPA, in developing the IPSP, identified and developed innovative strategies to facilitate competitive market-based responses and options for meeting overall system needs?")

b. Issue 2(a) under Procurement Processes in Attachment 3 at p. 6 ("Procurement processes and selection criteria must be fair and clearly stated and, wherever possible, open and accessible to a broad range of interested bidders.")

c. Issue 2(c) under Procurement Processes in Attachment 3 at p. 6 ("There must be no conflicts of interest or unfair advantages allowed in the selection process.")

[34] Exh. E-2-2 at p. 2:14-27.

380 MW of new large wind generation planned for the Bruce Peninsula.[35] OPA has identified three transmission options to facilitate development of potential wind development along the Bruce Peninsula, and states that development of the necessary enabler line needs to begin as early as 2009.[36] Two of the options identified would enable development of only one wind project. Consequently, the OPA has focused on the first option - the construction of a single 230 kV line extending northwesterly for about 80 km up the peninsula from the existing Owen Sound transformer station to a location south of Cameron Lake via Ferndale. This facility will provide interconnection points for two aggregations of wind generation with a combined nameplate capacity of approximately 380 MW, at an estimated cost of $92 million.[37]

39. Further, the OPA describes three alternatives to the construction of a new 230 kV line in the Bruce Peninsula. Two of the alternatives identified involve purchasing hydro power from Manitoba, Quebec, or Labrador. The OPA dismisses these alternatives as having “significant uncertainties.”[38] The other alternative identified is the development of alternate wind sites in other parts of Ontario. As discussed above, the OPA dismisses this alternative on the basis of its determination that those alternate sites are less economically attractive than the Bruce Peninsula sites.

40. In dismissing the option of developing other wind sites as an alternative to those on the Bruce Peninsula, the OPA indicates that “there are no other reasons (reliability, flexibility, feasibility, environmental performance, societal acceptance) that would make higher cost wind preferable to Bruce Peninsula wind.”[39] These factors are the key non-economic planning criteria that OPA uses as the basis for its development of the IPSP.

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[35] Exh. E-3-9 at pp. 3-4.
[36] Exh. E-3-9 at p 1.
[37] Exh. E-3-9 at pp. 7-8 and Figure 4.
[38] Exh. E-3-9 at p. 5:12 – p. 7:12.
[39] Exh. E-3-9 at p. 7.

41. The OPA commissioned a report by Hardy Stevenson and Associates Limited ("Hardy Stevenson") to perform an environmental analysis of the proposed enabler line. The report indicates a number of critical factors that have a direct impact on the enabler line's feasibility, social acceptance and environmental performance. The report identifies serious concerns surrounding the impact of the proposed project on First Nations interests, and on environmentally, culturally and socially valuable lands and resources.[40]

42. The report notes the following:

> However, significant social, economic and environmental tradeoffs would be required to connect the transmission line to Dorcas Bay. The transmission line would have the potential to affect wetlands, forest resources, and protected areas. Cultural heritage and tourism features in the northern Bruce Peninsula may be affected. The local First Nations communities may have traditional land uses in the area as well as an interest in the transmission line and renewable energy development in the area. Based on the results of this study, the Bruce Peninsula transmission line will not be feasible without the involvement of First Nations.[41]

And:

> The study team identified factors that challenge the feasibility of connecting new wind powered generation in the northern Bruce Peninsula at Dorcas Bay. The landscape of the Bruce Peninsula is characterized by ecological, cultural, heritage and recreation areas including numerous parks, conservation areas, sensitive ecosystems and First Nations hunting grounds. These features will present challenges to the feasibility of potential transmission corridors in the northern Bruce Peninsula.
>
> First Nations associated with the Bruce Peninsula are likely to have a strong interest in matters of land claims and traditional land uses. Early engagement and involvement of these groups in the development of the new transmission line may help overcome some of the challenges identified.[42]

[40] Exh. E-3-9, Attachment 1 at p. 10.
[41] Exh. E-3-9, Attachment 1 at p. 9.
[42] Exh. E-3-9, Attachment 1 at p. 11.

43. The Hardy Stevenson report made the OPA aware of significant issues respecting the feasibility, societal acceptance and environmental performance of its plan to construct new transmission facilities in the Bruce Peninsula, and by implication, its plan to develop Bruce Peninsula wind resources. However, there is no indication that the OPA has given proper consideration to these uncertainties and concerns. Instead, it has relied only on its economic analysis to justify its selection of Bruce Peninsula wind clusters. In doing so, the OPA has failed to apply its own planning criteria properly, creating significant uncertainty respecting the overall feasibility of its planning for the development of wind resources in the Bruce area.

44. The IPSP could accommodate a deferral of any decision on wind generation development on the Bruce Peninsula until the issues and uncertainties raised by the Hardy Stevenson Report can be resolved. The OPA states that "the planned 2025 total of 16,084 MW [of renewable generation] exceeds the 15,700 MW directive requirements by 384 MW, an amount viewed as not significant in the overall context of the IPSP."[43] Separately, the OPA states "the OPA has identified and included approximately 1,100 MW of Small Wind sites and approximately 1,900 MW of Large Wind sites in the IPSP to meet the 2025 target. Of these, 380 MW of the Large Wind sites are located along the Bruce Peninsula."[44] Taken together, these statements make clear that OPA could satisfy the Ministry's directives by eliminating the 380 MW of wind generation planned on Bruce Peninsula, reducing the surplus renewable generation in its plan from 384 MW to 4 MW.

[43] Exh. D-5-1 at p. 11.
[44] Exh. E-3-9 at p. 1.

II OPA'S OVER-RELIANCE ON NUCLEAR AND WIND GENERATION

45. The OPA has planned for 14,000 MW of nuclear power, the maximum permissible under the Supply Mix Directive. It appears from the pre-filed evidence that the OPA has done so without fully considering the stress that such maximum reliance can place on the electric system. Over-reliance on nuclear generation will crowd out production of renewable wind and hydro energy during off-peak periods causing Ontario generating resources to produce energy in excess of what Ontario loads can absorb. Excessive off-peak energy production will exacerbate an existing off-peak minimum load problem in Ontario, distort power supply economics, add to costs and cause violations of industry operating standards.

46. Inclusion of excessive amounts of base load nuclear generation in the supply mix can be expected to lead to two major problems:

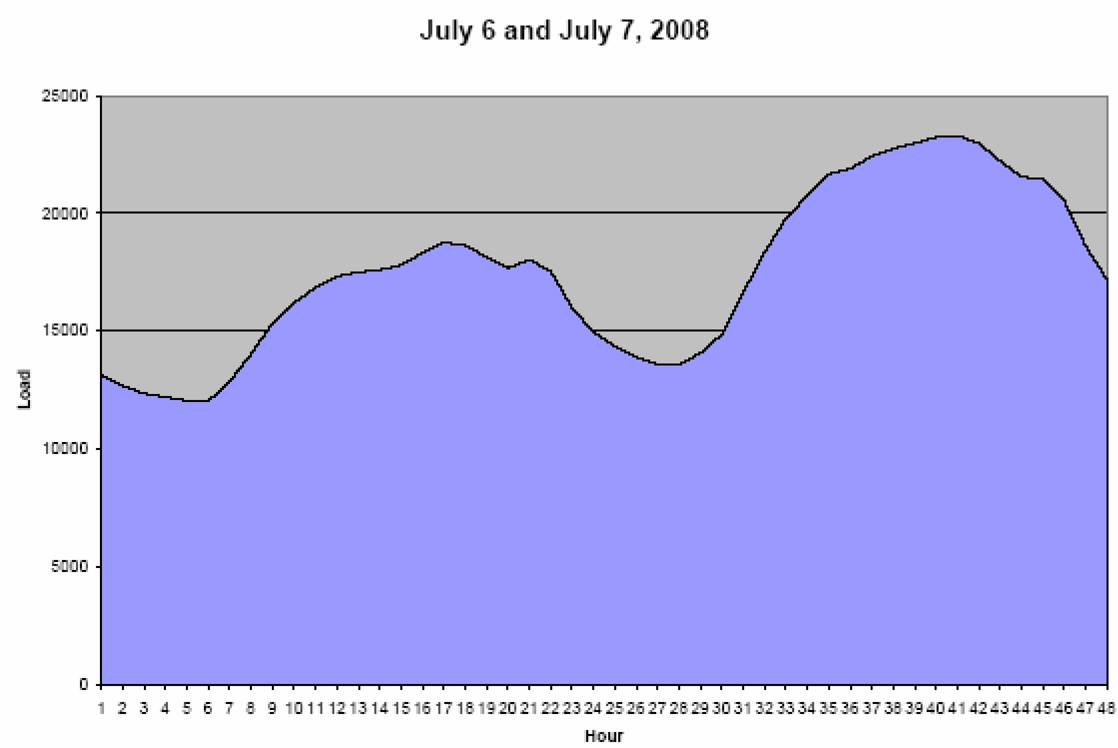
    A. The Ontario bulk power system will become inflexible and inoperable, constrained to produce more energy during off-peak periods than can be absorbed by consumers either inside or outside the Province. The need for operability constitutes a binding constraint that must be satisfied without regard to economics. Off-peak constraints caused by excessive nuclear generation threaten to necessitate costly shutdowns of nuclear generation or violations of industry operating criteria. An Independent Electricity System Operator ("IESO") analysis discussed below has indicated that Ontario can expect to face nearly insuperable off-peak operating problems if it constructs the full 14,000 MW of nuclear generation proposed by the OPA.

    B. The all-in LUEC of classes of wind and hydro generating resources will be understated. The LUEC of each resource type is based on an assumed level of kWh output. However, the IESO study indicates that the combined amounts of wind, hydro, base load nuclear and other must-run generation planned in the IPSP cannot all be accommodated during minimum load conditions, necessitating curtailments of renewable wind and/or hydro generation for nearly 900 hours in some years. Reflecting these curtailments in the LUEC calculations would drive up the cost of wind and hydro generation.

Ontario's Minimum Load Problem

47. Minimum load conditions occur on all electric utility systems as a result of the need for base load generators to "get under" low demands during off-peak periods. Most North American electric utilities have a daily load pattern in which the sequence of hourly demands goes from a minimum during the night hours (11 p.m.- 6 a.m.), followed by a morning ramp up, hitting maximum demands in the 3 p.m. to 5 p.m. period in the summer and at about 7 p.m. in the winter. The daily load pattern for Ontario on July 6 and 7, 2008, is shown below.[45] Ontario demand hit a minimum of 12,035 MW at 6 a.m. on Sunday July 6 and rose to a peak of 23,309 at 5 p.m. on Monday, July 7, a difference of 12,274 MW within one 36-hour period. On July 7, the load ranged from a low of 13,579 to 23,309, a range of 9,730 MW.

[45] Data from: http://www.ieso.ca/imoweb/pubs/marketReports/download/HourlyDemands_20080725.csv



48. It is clear that the IESO would have difficulty getting under an off-peak minimum load of 12,274 MW if all 14,000 MW of planned nuclear and 5,000 MW of planned wind energy were operating. This difficulty would be compounded if, in addition, Ontario hydro reservoirs were full, inhibiting hydro generation from being backed down. Backing down hydro under those conditions would cause a very undesirable spill of water from reservoirs. Thus, this condition would pit excess nuclear generation against both renewable wind and renewable hydro generation. The IESO would very likely be required either to (a) find an off-system wholesale buyer to take the surplus power away or (b) shut down wind and/or hydro and/or nuclear generation.

49. Ontario's minimum generation is expected to exceed its annual hourly minimum load by amounts ranging from 272 MW to 3,555 MW in the years through 2027.[46] The excess of minimum generation over minimum load is projected to be about 3,000 MW in all years after 2012 except in the 2015-2021 period, possibly as a result of Bruce B Nuclear Units being taken out of service for refurbishment. Data from that OPA interrogatory response shows the following:

Year	Min Load	Min Gen	Delta
2008	11590	13025	1435
2009	11673	12829	1156
2010	11756	13007	1251
2011	11849	13620	1771
2012	11943	13325	1382
2013	12036	14802	2766
2014	12133	15001	2868
2015	12229	14146	1917
2016	12351	12955	604
2017	12474	13032	558
2018	12599	13283	684
2019	12724	12996	272
2020	12851	14113	1262
2021	13008	14664	1656
2022	13167	15926	2759
2023	13328	16795	3467
2024	13491	16775	3284
2025	13655	16926	3271
2026	13822	17377	3555
2027	13991	16917	2926

50. The daily load cycle requires that cycling generation be turned off during the off-peak hours and that even base load units be backed down. When the daily ramp up of load occurs, base load units come off their minimum loadings (or whatever lower level was needed to get under the off-peak load). In addition, a series of non-base load

[46] Exh. I-22-119, OPA's response to GEC-Pembina-OSEA Interrogatory 119.

generation is started up and synchronized in a sequence called "unit commitment" and then ramped up, preferably in the order of the incremental costs of the non-base load units. Some additional generation must be synchronized and operated at partial output - less than its rated capability - in order to provide load following and operating reserves. Unit commitment often begins at midnight. Keeping up with the morning ramp often requires operators to call upon all the power that on-line units can produce as rapidly as those units can respond.

51. If a utility is required to shut down a base load unit because it cannot get under the minimum load, there will be a deficit in low-cost base load generation during the next daily peak period if that unit cannot be restarted, necessitating the startup and operation of more costly generation. In competitive markets, the owners of base load generation prefer not to be shut down. A shutdown would cause them to lose sales at high on-peak prices during the next peak period, and they will sometimes take drastic measures in order to induce other generators to shut down instead. For example, those generators will sometimes bid negative prices during off-peak periods, meaning that they will cause other base load units to pay for the privilege of dumping their energy onto the system and would theoretically pay consumers to take the energy away.

52. In Ontario, power is transacted based on the Hourly Ontario Energy Price ("HOEP"). Only one negative hour of HOEP occurred in 2007, during September. Negative HOEP was more prevalent in 2008. The IESO "Weekly Market Report" for July 2 – July 8, 2008 indicates that the five-minute clearing price was negative for one period on July 2, two periods on July 4, for 57 periods on July 5 (pushing the HOEP into negative territory in hours 3 to 7 and in hour 24) and for 78 five-minute periods on Sunday, July 6 (pushing the HOEP negative in hours 1 to 7). The five minute market clearing price hit an all-time low of -$20.00 on Sunday, July 6 and resulted in an all-time low HOEP of -$14.59 in hour 6. See Attachment 4 to this Schedule.

53. Following closely in time on the minimum load problems of July 5-6, 2008, Ontario experienced its Highest Hourly Market Demand of 27,477 MW on Tuesday, July 8 in hour 16, superseding the previous high of 27,375 MW that occurred on August 1, 2006, in hour 14.[47]

54. This diurnal swing in prices and demands can impose stresses on base load generators and impose cost burdens on consumers because OPA is obligated to pay some wind and nuclear generators a fixed price per kWh irrespective of whether the HOEP drops below the contract price.

OPA's Plan for Nuclear Exacerbates the Problem

Inflexible and Nondispatchable Generation

55. A major problem inherent in the supply mix proposed by the OPA in the IPSP is that it fails to take account of the adverse effects that planned base load resource developments are projected to have upon minimum load conditions within Ontario. The IPSP calls for the development of conservation and distributed generation resources that will diminish the Province's minimum loads by reducing off-peak loads generally.[48] Problematically, the OPA has also elected to plan for the maximum permissible levels of nuclear generation, whose high level of off-peak operation will increase the amounts of energy that cannot be absorbed by the Province's off-peak loads. The problem is further magnified by the OPA's plan for significant increases in nondispatchable wind generation (which produces two-thirds of its energy output during off-peak periods), given its commitment to nuclear power.

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[47] Attachment 4, IESO "Weekly Market Report" for July 2 – July 8, 2008 at p. 4.
[48] The attached article describes the substantial conservation achieved by Dow Chemical whose processes have historically represented a base load on the adjacent utility. See Attachment 5, "Why we never need to build another polluting power plant" by Joseph Romm from Salon, found at http://www.salon.com/news/feature/2008/07/28/energy_efficiency/print.html

56. In general, base load generators are relatively inflexible in that they are designed for continuous operation. Typically, base load generation cannot be shut down and restarted in the course of a daily load cycle, a process referred to as "daily cycling." Nuclear generators are even less flexible than coal-fired and gas-fired base load generators in that they cannot be backed down nearly as much (only about 50 MW per unit) as compared to coal-fired units (which can be backed down by 40% to 60% of their rated capability or even more with sliding pressure control and removal of burners) and gas-fired units (which often can be cycled but have a minimum down time).[49] Nuclear generators cannot be cycled on-and-off during a daily cycle. Energy production from wind generators, on the other hand, is delivered when the wind blows in sufficient velocities to cause them to generate. Thus, wind energy production is not dispatchable and cannot be scheduled to operate only when needed. Approximately two-thirds of the energy produced by wind generators occurs during off-peak periods. Wind can be spilled from the blades of wind generators, enabling part of the available wind production to be curtailed if necessary, or wind generators can be constrained off (or not started up). Similarly, even hydro generation with storage reservoirs cannot defer production of energy once their reservoirs fill, as is often the case during high stream flow conditions in springtime and early summer.

Load Following Problems

57. Other problems that OPA, and ultimately the IESO, must confront when coal-fired generation is shut down will be the loss of load following, operating reserves and regulating capability now provided by its 6,000 MW of coal-fired generation. The response to OEB interrogatory #17 indicates that Ontario will have increased load

[49] The IESO Operability Review of OPA's Integrated Power System Plan ("Operability Review"), April 21, 2008, IESO_REP_0411 (Attachment 6 to this schedule) indicates that reducing a nuclear unit's output can lead to its being unavailable for up to three days. The IESO's analysis assumed the worst case for a reduction of a nuclear unit, i.e., the reduction resulted in the unit's "poisoning out," leaving it entirely unavailable for 72 hours. The term "poisoning out" refers to the situation in which a nuclear unit reduces reactor power to a level where it can no longer sustain the chain reaction and must shut down. This occurs when its normal reactor regulating devices cannot overcome the build-up of neutron absorbing isotopes that takes place after a significant power reduction. Operability Review at pp. 21-22.

following requirements during the IPSP period attributable to the addition of wind and other non-dispatchable resources. The OPA does not seem to have planned for this requirement, stating that “specific resources were not added in the IPSP to provide load following capability.”[50]

58. Load following is an attribute of generation that enables an electric system to maintain the match of load and generation as system load ramps up during the morning hours and ramps back down during the evening. The need for load following capability on July 7, 2008 was 9,730, about 42% of the daily peak demand (when the load ramped from a minimum of 13,579 to 23,309). This 42% need for load following is to be contrasted to operating reserves which tend to range from 5% to 7% of hourly and daily demands. Operating reserves include interruptible loads, quick-start (non-spinning reserve) and synchronized but unloaded generation (spinning reserve) carried continuously in order to provide backup for unscheduled loss of a generator, transmission line or wholesale purchase.

59. The diurnal pattern of wind generation exacerbates the load following problem. Wind generation production generally peaks at night and drops off coincident with the morning load ramp up, which is the worst possible time for generation to drop off because every other load following generating unit on line is usually at its limits in the chase to keep up with the morning load ramp.

The IESO’s Analysis of Operability

60. In its recent report, “Operability Review of OPA’s Integrated Power System Plan”, the IESO reviewed how the operability of the Ontario bulk power system would be affected by the IPSP and offered its analysis of the IESO’s ability to function under the IPSP in real time.[51] The IESO stated that “[o]perability is a measure of whether

[50] Exh. I-1-17.
[51] See Attachment 6 to this Schedule, the Operability Review.

the proposed supply mix from the ISPS can be reasonably coordinated through unit commitment decisions and real-time dispatch to follow the ever-varying load profile through both high and low demand conditions, while meeting all operating standards."[52] The report identifies a number of serious concerns respecting the OPA's heavy reliance on nuclear power and other non-dispatchable resources.

61. The Operability Review noted two key issues relating to the operability of the IPSP. The first of these is the reduced amount of dispatchable generation, which can follow the minute-by-minute fluctuations in demand (or load). Second, the IESO noted that the proposed IPSP will increase the number of hours each year of surplus baseload generation ("SBG"). SBG is measure of minimum load constraints. The IESO noted that currently, SBG occurred only a few times each year. Under the IPSP, the hours in which SBG occur are projected to increase to over 800 hours in some years (nearly 10% of the annual hours) despite the fact that all 6,000 MW of existing base load coal-fired generation will be retired. For example, the IESO projects that Ontario's base load generation cannot be absorbed by Ontario loads for up to 891 hours per year in 2024 (and will continue not to be absorbable for 193 hours even if wind generation is curtailed).[53]

62. The IESO found that the SBG and load following problems are created as a result of OPA's decision to have approximately 14,000 MW of nuclear generation as base load resources and 5,000 MW of wind generation (which produces over half its energy during off-peak hours). The IESO stated:

> The IPSP includes increases in conservation, which will have a lowering affect on the demand for electricity across the day, and increases in intermittent and embedded generation, both of which can increase the supply even at low demand periods. For these reasons, the frequency, magnitude, and duration of surplus baseload conditions is likely to increase in the future.

[52] Operability Review at p. 9.
[53] Operability Review at pp. 20-21.

> Analysis of the OPA data indicated that management of surplus baseload generation in the simulated schedules relied on significant amounts of exports. If these exports failed to materialize in real-time, the IESO would have to take other control actions to maintain reliability.[54]

63. The IESO also commented upon the problems associated with load following service. The IESO identified 12.5% of days in 2010-2014 and 20.8% of days in 2016-2026 as having load following and/or peak demand problems, mostly in the summer. The IESO stated: "Given the shrinking portion of manoeuvrable generation in Ontario's fleet of generators, load following capability will be a generating commodity that will increase in value to the market."[55]

64. Although the IESO summary indicates that the Ontario bulk power system will be operable after implementation of the IPSP, the IESO's detailed comments indicate that many serious problems remain unresolved and require further study.

Critique of Possible Solutions Proposed by the IESO

65. The IESO's solution for the operability problems arising from the IPSP is a combination of steps including market scheduling and commitment of fossil units and "not scheduling exports and/or dispatchable load,"[56] which signals the IESO's intent to lean on neighboring control areas by recalling exports and by dropping interruptible loads. Ontario has limits to the amount of power it can export and import, and must stay within these limits. It is also contrary to industry operating criteria to push surplus energy out onto the grid without warning or prescheduling.

66. The IESO assumes that some excess production during minimum load conditions can be sold to interconnected utilities. However, most other utilities experience minimum

[54] Operability Review at p. 20.
[55] Operability Review at p. 26.
[56] Operability Review at p. 16

load conditions at the same times that Ontario does and will pay very little (or even impose a charge caused by negative locational marginal costs) for energy absorbed during minimum load conditions. The IESO also mentions "additional measures to satisfy reserve requirement (i.e., additional imports, management of scheduled outages)."[57] Managing scheduled outages probably means planned maintenance, which is difficult and expensive to shift at the last minute. The IESO also places considerable emphasis on "current market mechanisms" and evolving market incentives to retain operability[58] -- especially for load-following, much of which includes changing schedules on synchronous tie lines.

67. The IESO also expressed concern over "intra-hour operability"[59] and a need to "improve transparency and efficiency."[60] As a solution, the IESO suggests that interchange schedules with adjacent control areas be changed at half-hour intervals (instead of on the clock hour as is the general industry standard) in order to address the reduction in Ontario's load following and ramping ability that will follow the planned shutdown of coal generation.[61] Half-hour schedule changes will lessen the amount by which Ontario and its neighboring utilities will be required to ramp generation during a change in interchange schedules, enabling both parties to an interconnection to achieve a 1,000 MW change in net interchange in two half-hour ramps instead of in a single ramp across the clock hour.

68. This proposal represents a substantial change from historical industry practice and will necessitate agreement from neighboring utilities (and perhaps approval from NPCC). This proposal reflects the extremity of the adverse impacts that the IPSP is expected to have upon the operability of Ontario's bulk power system.

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[57] Ibid.
[58] Operability Review at pp. 26-27.
[59] Operability Review at pp. 18-19.
[60] Operability Review at p. 8.
[61] Operability Review at p. 27.

69. Therefore, in spite of the IESO's attempt to reassure readers that the IPSP "provides sufficient flexibility to meet future system needs," the IESO's proposed solutions raise concerns about the feasibility of depending upon the market and operational changes.

Operability Issues Affect Economic Ranking of Resources

70. In addition to causing adverse effects on day-to-day operation, minimum load constraints can be expected to have an adverse effect upon long-term planning and procurement. Long-term economic comparisons of generation alternatives have been distorted by the OPA's failure to account for the unwanted and unneeded production of nuclear generation and wind generation during minimum load conditions. That is, OPA's analysis unduly favors nuclear and wind generation because it assumes that their fixed costs will be spread across megawatthours of off-peak energy production from those resources when in fact some of that off-peak energy production cannot be absorbed by Ontario loads or by neighboring utility loads. Ignoring production lost to minimum load constraints produces an unrealistically low LUEC. Instead, some of this energy from nuclear and wind generation may need to be curtailed (if wind), or sold off at a loss to neighboring systems, if possible. The adverse economic and environmental effects of these relationships have not been considered by OPA in the IPSP.

71. Minimum load curtailments are likely to have an especially severe impact upon the LUEC of wind generation because about two-thirds of wind generation occurs in the approximately 4500 off-peak hours of the year. By contrast, the LUEC of most gas-fired resources would not be affected because they typically can be and are shut down during off-peak periods and would not lose any of their assumed production. The LUEC of hydro peaking resources that can store water (non-run-of-the-river hydro) would be less affected than the LUEC of wind generation because such hydro resources are designed to produce most of their energy during on-peak periods.

Unless their reservoirs are full, they can be shut down or backed down during off-peak periods and store water for release through their turbine-generators in later on-peak periods.

72. Once the facts of Ontario's minimum load conditions become known to developers, those facts can be expected to have adverse impacts on prices for wind and hydro energy that will be forced to back down or shut down during minimum load conditions in order to allow Ontario to continue to take delivery of uncurtailable nuclear energy. Because of deemed energy protection and fixed prices for energy, at least one part of the Bruce Nuclear complex is unlikely to be at economic risk, but the developers of wind and hydro generation can be expected to raise their prices in order to recoup any revenue they expect to lose as a result of backdowns and shutdowns necessitated by minimum load conditions. This will affect the LUECs and bids of wind generators and possibly their rankings relative to rankings of other wind generators and other generation types. There is no indication in the IPSP application that OPA or its consultants took proper account of minimum load conditions in developing forecasts of potential energy production from individual wind sites.

Failure to Adequately Plan for Operability Concerns

73. The OPA has planned insufficient amounts of other, more flexible generating resources that can respond to load following needs and minimum load problems. It has instead concentrated on planning for the upper limit of nuclear generation allowed by Ministry Directives, as well as planning wind generation. Neither of these resources provides the flexibility that coal generation currently is now providing. Without coal generation, the primary sources of flexible generation are gas-fired generation, including cogeneration resources in some instances, and non-run-of-the river hydro resources, including pumped storage hydro, but the OPA has de-emphasized development of gas-fired cogeneration and pumped storage hydro.

Pumped Storage Hydro

74. One way in which to mitigate the operability problems of minimum load and load following constraints is to install pumped storage hydro or compressed air storage. OPA ignored the potential of pumped storage hydro ("PSH"), stating that "further certainty in load forecast and baseload resource projection is required."[62]

75. In its responses to interrogatories, OPA stated that:

> [s]torage resources would provide additional capacity (MW) but no additional (net) energy (in fact, they would tend to reduce energy production because of losses). The value of storage relative to other resources would therefore depend on overall system needs for capacity and energy, which in turn depend upon forecast load and baseload resources, as well as other resources such as Conservation. The future needs for capacity relative to energy are judged insufficient to warrant the inclusion of storage in this IPSP.[63]

76. The dismissal of PSH in this response is questionable in terms of power supply economics and appears to have been written without appreciation of the significant operability concerns identified by the IESO. OPA's dismissal of PSH is not accompanied by any analyses of its power supply economics and minimum load conditions. PSH will absorb surplus baseload generation that is expected to be forced upon Ontario by the IPSP supply mix, converting it into peaking energy. PSH can be cost-effective despite the fact that it returns only 64% of the energy used in pumping provided that the value of pumping energy is less than 64% of the value of the energy returned plus the value of the firm peaking capacity PSH provides.[64] Moreover, PSH is a flexible resource that can be switched off as a load and turned on as a generator within minutes. It can provide spinning reserve because of its ability to ramp quickly from zero to full load in a matter of a minute or two, far less than the ten minutes

[62] Exh. D-5-1 at p. 12:7-9.
[63] Exh. I-22-61.
[64] As a rule of thumb, pumped storage hydro is approximately 80% efficient in the pumping mode and 80% efficient in the generating mode, with the result that 64% of the energy used to pump is returned to the system in the generating mode.

needed to qualify as spinning reserves. Its output can respond to a control signal to provide system regulation to help the IESO maintain the minute-to-minute match between generation and constantly varying loads.[65]

Cogeneration or CHP Resources Not Explored

77. The OPA has failed to emphasize base load generation alternatives to nuclear generation such as efficient and cost-effective gas-fired large-scale cogeneration. This appears to be a policy deficiency and not just an absence of information in the IPSP. Large-scale cogeneration conserves gas used to produce steam (as compared to gas used to produce steam with conventional boilers). That is, wherever large amounts of gas or oil are used to produce steam, steam can be produced more efficiently by first producing power with that gas or oil and capturing the waste heat to produce steam in a heat recovery steam generator ("HRSG"). Cogeneration is more flexible operationally than nuclear generation and can achieve efficiencies (heat rates) in the vicinity of 5,000 BTU/kWh (called fuel charged to power) versus 7,000 BTU/kWh achievable with combined cycle gas turbine generation. Industrial cogeneration, which tends to operate 24 hours per day, seven days a week whenever its industrial steam host needs steam, can nevertheless be shut down. Such shutdowns are possible because, typically, large industrial users maintain standby boilers to provide steam when the electric generating equipment or its associated heat recovery steam generator is out of service. With a sufficient economic incentive, through a special rate or otherwise, it is likely that an industrial cogenerator could be induced to shut down in off-peak periods when minimum load constraints become severe.

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[65] Even conventional hydro generators with storage reservoirs can convert intermittent off-peak wind energy into firm on-peak capacity. This is accomplished by backing off hydro production during off-peak hours in order to allow the bulk power system loads to absorb intermittent wind energy. This backing off causes streamflows to accumulate and be stored in hydroelectric reservoirs, thereby "shaping" non-firm, off-peak intermittent wind energy into a firm on-peak resource. The Bonneville Power Administration has offered a "shaping" service for wind energy (and other off-peak energy) for a number of years.

78. The OPA projects that base load gas-fired cogeneration capacity (also known as combined heat and power ("CHP")) will fall from 1658 MW in 2007 to 471 MW while only 586 MW of new CHP is to be added.[66] By allowing existing cogeneration to wither away, OPA has bolstered its ostensible justification for base-load nuclear generation.

79. In summary, solutions to the operability problems include reconsidering the amount of nuclear generation (backing off the 14,000 MW target level in the supply mix), substituting non-run-of-the river hydro for wind generation, installing energy storage technologies such as pumped storage hydro and compressed air storage, and emphasizing development of cogeneration resources.

80. This concludes my affidavit.

[66] Exh. D-8-1 at p. 5, Figure 1.

IN THE MATTER OF *sections 25.30 and 25.31 of the Electricity Act*

AND IN THE MATTER OF an Application by the Ontario Power Authority for review and approval of its integrated power system plan and approval of its proposed procurement process.

AFFIDAVIT

of

WHITFIELD A. RUSSELL

on behalf of

THE SAUGEEN OJIBWAY NATIONS

I, Whitfield A. Russell, certify that the attached Affidavit and Exhibits on behalf of the Saugeen Ojibway Nations, which bears my name, were prepared by me or under my direct supervision and are true and accurate to the best of my knowledge and belief formed after a reasonable inquiry.

Whitfield A. Russell

Whitfield A. Russell

Subscribed and sworn to before me on this 1st day of August, 2008, by Whitfield A. Russell.

City of Alexandria
Commonwealth of Virginia

Notary Public: Tara K. Parker-Johnson

Notary Registration Number: 333663

My Commission Expires: November 30, 2011

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

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 Ontario, 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 1982.

19. In re: Pacific Gas and Electric Company, FERC Project Nos. 2735 and 1988, concerning the Helms Project, a pumped storage generating unit; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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, Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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"); Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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, Filed 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; Filed 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; Filed 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."; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed May 7, 1997.

99. In re: City of College Station, FERC Docket No. TX 96-2-000, concerning transmission rates; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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, Filed 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"); Filed 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; Filed 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; Filed 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; Filed October 1998.

112. In re: Tri-State Generation and Transmission Assoc., Inc., in Arbitration No. 77 Y 181 0023097 before the American Arbitration Association; Filed 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; Filed 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; Filed 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; Filed 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; Filed July 22, 1999, August 3, 1999, August 18, 1999 and September 9, 1999.

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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; Filed 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; Filed 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; Filed June 19, 2000.

119A. In re: Mobil Oil Corporation vs. Southern California Edison, Oral Testimony in a jury trial before the Superior Court of the State of California for the County of Los Angeles in Docket No. BC 175784, on behalf of Mobil Oil Corporation. The purpose of the testimony was to explain how Southern California Edison's actions contributed to substantial damage to equipment at Mobil's Torrance, California refinery during the cascading blackout on August 10, 1996; Testimony on July 17, 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; Filed 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; Filed 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"); Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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"); Filed 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"); Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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"); Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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, Filed 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; Filed 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; Filed 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; Filed 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;" Filed 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; Filed 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.; Filed 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.; Filed 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.; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed 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; Filed March 17, 2008.

165. In re: Braintree Electric Light Department, Hingham Municipal Lighting Plant, Hull Municipal Lighting Plant, Mansfield Municipal Electric Department, Middleborough Gas and Electric Department and Taunton Municipal Light Plant v. ISO New England Inc.: Direct Testimony and Exhibits before the Federal Energy Regulatory Commission in Docket No. EL08-48-000, on behalf of the individually municipally-owned power systems serving the Massachusetts communities of Hull, Mansfield, Middleborough, Taunton, Braintree and Hingham. The purpose of this testimony is to provide technical support for the MPS complaint; Filed March 28, 2008.

166. In re: Entergy Nuclear Operations Inc. and Entergy Nuclear Palisades, Inc. (Palisades Nuclear Plant), Entergy Nuclear Operations Inc. and Entergy Nuclear Fitzpatrick, Inc. (James A. Fitzpatrick Nuclear Power Plant), Entergy Nuclear Operations Inc. and Entergy Nuclear Generation Company (Pilgrim Nuclear Power Station), Entergy Nuclear Operations Inc. and Entergy Nuclear Vermont Yankee, Inc. (Vermont Yankee Nuclear Power Station), Entergy Nuclear Operations Inc.; Entergy Nuclear Indian Point 2, LLC; and Energy Nuclear Indian Point 3, LLC (Indian Point Nuclear Generating Unites Nos. 1, 2, and 3), and Entergy Nuclear Operations Inc. and Entergy Nuclear Palisades, LLC. (Big Rock Point): Affidavit before the Nuclear Regulatory Commission in Docket Nos. 50-255-LT and 72-7-LT, 50-333-LT and 72-12-LT, 50-293-LT, 50-271-LT, 50-003-LT, 50-247-LT and 50-286-LT and 50-155-LT and 72-43-LT, on behalf of the Locals 369 and 590, Utility Workers Union of America, AFL-CIO. The purpose of this affidavit is to provide support for the April 15, 2008 Reply of Locals 369 and 590, Utility Workers Union of America, AFL-CIO to Answer of Energy Nuclear Operations, Inc. Opposing Petitions for Leave to Intervene, Request for Hearing, and Related Requests for Relief; Filed April 15, 2008.

167. In re: ISO New England, Inc.: Affidavit before the Federal Energy Regulatory Commission in Docket No. ER08-633-000, on behalf of The Connecticut Department of Public Utility Control. The purpose of this affidavit is to review the reliability analyses performed by the ISONE on the need to retain NRG's Norwalk Harbor Units 1 and 2 as listed Capacity Resources in the Forward Capacity Market for the 2010/2011 Capacity Year; Filed April 17, 2008.

168. In re: In the Matter of the Ontario Energy Board Act, 1998, S.O. 1998, C.15 (Sched. B); In the Matter of an Application by Hydro One Networks Inc. pursuant to section 92 of the Act, for an Order or Orders granting leave to construct a transmission reinforcement project between the Bruce Power Facility and Milton Switching Station, all in the Province of Ontario: Affidavit and Exhibits before the Ontario Energy Board in Docket No. EB-2007-0050, on behalf of the Saugeen Ojibway Nations. The purpose of this affidavit is to review the analyses performed by the Ontario Power Authority, Hydro One and the Independent Electric System Operator of Ontario in support of the application to construct a proposed Bruce-to-Milton double circuit 500 kV transmission line project; Filed April 18, 2008.

169. In re: Braintree Electric Light Department, Hingham Municipal Lighting Plant, Hull Municipal Lighting Plant, Mansfield Municipal Electric Department, Middleborough Gas and Electric Department and Taunton Municipal Light Plant v. ISO New England Inc.: Second Affidavit before the Federal Energy Regulatory Commission in Docket No. EL08-48-000, on behalf of the individually municipally-owned power systems serving the Massachusetts communities of Hull, Mansfield, Middleborough, Taunton, Braintree and Hingham. The purpose of this affidavit is to responds to the testimony of Messrs. Peter Brandien and Gregory Sullivan, which are part of the respective responses to the Complaint submitted by Independent System Operator New England, Inc and NSTAR Energy Company; Filed May 23, 2008.

VT INCEPIT FIDELIS SIC PERMANET
Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2007-0050**

VOLUME:	**5**	
DATE:	**May 7, 2008**	
BEFORE:	**Pamela Nowina**	**Presiding Member and Vice Chair**
	Cynthia Chaplin	**Member**
	Ken Quesnelle	**Member**

on that, essentially, and your response is:

> "Hydro One agrees with the IESO's assessment concerning the operational challenges associated with the Milton-Claireville corridor. These matters are being investigated further and are likely to be considered as part of the IPSP process."

So I take it your view is that this is a matter for consideration not in this proceeding, but in the IPSP?

MR. FALVO: Um..., yes, I think with all of the power funnelling into Milton, the work that is required there has been included in this project, but as load grows and the system continues to develop in that area, there will need to be a target of further investigation.

MR. MILLAR: The Bruce-Milton project itself is not being considered as part of the IPSP; is that correct?

MR. CHOW: No. It's included in the discussion paper that forms the basis of the IPSP, as in our letter to Ms. Formusa. We believe that's such an urgency that we cannot await the outcome of the IPSP, so we said it is proceeding as a stand-alone application before the IPSP.

MR. MILLAR: Thank you.

Is it fair to say that the issues that the IESO highlights with regard to the Milton-to-Claireville corridor that I have just referenced are either caused by or exacerbated by the Bruce-to-Milton transmission line? I assume that's the case, because the system-impact assessment is about the Bruce-to-Milton transmission line;

Ontario Energy Board | **Commission de l'énergie de l'Ontario**

EB-2007-0707

IN THE MATTER OF AN APPLICATION BY THE ONTARIO POWER AUTHORITY

INTEGRATED POWER SYSTEM PLAN ISSUES

BEFORE: Pamela Nowina
Vice Chair, Presiding Member

Ken Quesnelle
Member

David Balsille
Member

DECISION WITH REASONS

March 26, 2008

APPENDIX A: ISSUES LIST

A. The Integrated Power System Plan ("IPSP")

The Electricity Act, section 25.30(4):
The Board shall review each integrated power system plan submitted by the OPA to ensure it:

- **complies with any directions issued by the Minister and**
- **is economically prudent and cost effective.**

Issues:

Conservation (including conservation vehicles and load reduction initiatives as listed in the Supply Mix Directive)

1. Does the IPSP define programs and actions which aim to reduce projected peak demand by 1,350 MW by 2010, and by an additional 3,600 MW by 2025?

2. Has the OPA, in developing the IPSP, identified and developed innovative strategies to accelerate the implementation of conservation, energy efficiency and demand management measures?

3. Is the mix of conservation types and program types included in the Plan to meet the 2010 and 2025 goals economically prudent and cost effective?

4. Would it be more economically prudent and cost effective to seek to exceed the 2010 and 2025 goals?

5. Is the implementation schedule for conservation initiatives economically prudent and cost effective?

Renewable Supply (including sources of renewable energy as listed in the Supply Mix Directive)

6. Does the IPSP assist the government in meeting its target for 2010 of increasing the installed capacity of new renewable energy sources by 2,700 MW from the 2003 base, and increase the total capacity of renewable energy sources used in Ontario to 15,700 MW by 2025?

7. Is the mix of renewable resources included in the Plan to meet the 2010 and 2025 targets economically prudent and cost effective?

8. Would it be more economically prudent and cost effective to seek to exceed the 2010 and 2025 targets?

9. Is the implementation schedule for the renewable resources in light of lead times for supply and transmission economically prudent and cost effective?

Nuclear for Base-load

10. Does the IPSP plan for nuclear capacity to meet base-load requirements and limit the installed in-service capacity of nuclear power over the life of the Plan to 14,000 MW?

11. What is the base-load requirement after the contribution of existing and committed projects and planned conservation and renewable supply?

12. Is the IPSP's plan to use nuclear power to meet the remaining base-load requirements economically prudent and cost effective?

13. In the context of the determination of economic prudence and cost effectiveness, is the IPSP sufficiently flexible to accommodate building new nuclear plants or refurbishing existing plants or both?

14. Is the schedule for implementing base-load resources in light of lead times for supply and transmission economically prudent and cost effective?

Natural Gas

15. Does the IPSP maintain the ability to use natural gas capacity at peak times and pursue applications that allow high efficiency and high value use of the fuel?

16. Has the OPA, in developing the IPSP, identified opportunities to use natural gas in high efficiency and high value applications in electricity generation?

17. How can gas be used for peaking, high value and high efficiency purposes?

18. How can gas-fired generation contribute to meeting transmission capacity constraints?

19. Is the IPSP's plan for additional gas resources for peaking, high value and high efficiency purposes and for contributing to transmission capacity constraints economically prudent and cost effective?

Replacement for Coal-Fired Generation

20. Does the IPSP plan for coal-fired generation in Ontario to be replaced by cleaner sources in the earliest practical time frame that ensures adequate generating capacity and electricity system reliability in Ontario?

21. How do existing, committed and planned conservation initiatives, renewable resources and nuclear power contribute to meeting the contribution that coal-fired generation currently provides to meeting Ontario's electricity needs with respect to capacity (6,434 MW), energy production (24.7 TWh) and reliability (flexibility, dispatchability, and the ability to respond to unforeseen supply availability)?

22. What are the remaining requirements in all of these areas?

23. Will the IPSP's combination of gas and transmission resources meet these remaining requirements in the earliest practical timeframe and in a manner that is economically prudent and cost effective?

Transmission

24. Does the IPSP plan to strengthen the transmission system to:

(a) Enable the achievement of the supply mix goals set out in the Supply Mix Directive?

(b)Facilitate the development and use of renewable energy resources such as wind power, hydroelectric power and biomass in parts of the province where the most significant development opportunities exist?

(c) Promote system efficiency and congestion reduction and facilitate the integration of new supply, all in a manner consistent with the need to cost effectively maintain system reliability?

25. What is the effect, if any, on the IPSP of the results of the OEB consultation *Review of Cost Responsibility Policies for Connection to Electricity Transmission Systems?*

26. Is the IPSP strategy for transmission economically prudent and cost effective?

Consultation with non-Aboriginal Interests in Developing the IPSP

27. Has the OPA, in developing the IPSP, consulted with consumers, distributors, generators, transmitters and other persons who have an interest in the electricity industry in order to ensure that their priorities and views are considered in the development of the Plan?

Procurement-Related Issues in Developing the IPSP

28. Has the OPA, in developing the IPSP, identified and developed innovative strategies to encourage and facilitate competitive market-based responses and options for meeting overall system needs?

29. Has the OPA, in developing the IPSP, identified measures that will reduce reliance on procurement under section 25.32(1) of the Act?

30. Has the OPA, in developing the IPSP, identified factors that it must consider in determining that it is advisable to enter into procurement contracts under subsection 25.32 of the Act?

Environmental Issues in Developing the IPSP

31. Has the OPA, in developing the IPSP, ensured that safety, environmental protection and environmental sustainability are considered?

32. Has the OPA, in developing the IPSP, ensured that for each electricity project recommended in the Plan that meets the criteria set out in subsection 2(2) of Regulation 424/04, the Plan contains a sound rationale including:

(a) an analysis of the impact on the environment of the electricity project; and

(b) an analysis of the impact on the environment of a reasonable range of alternatives to the electricity project?

IPSP in General

33. Do the forecasts relied upon by the OPA in developing the IPSP, and the uncertainties attributed to them, present a reasonable range of future outcomes for planning purposes?

34. Does the IPSP meet its obligation to provide adequate electricity system reliability in all regions of Ontario?

B. Procurement Processes

1. Do the OPA’s procurement processes provide for simpler procurement processes for electricity supply or capacity to be generated using alternative energy sources or renewable energy sources, or both, where the supply or the capacity or the generation facility or unit satisfies the prescribed conditions?

2. In developing its procurement processes, has the OPA complied with the following principles:

(a) Procurement processes and selection criteria must be fair and clearly stated and, wherever possible, open and accessible to a broad range of interested bidders;

(b) To the greatest extent possible, the procurement process must be a competitive process;

(c) There must be no conflicts of interest or unfair advantage allowed in the selection process; and

(d) To the greatest extent possible, the procurement process must not have an adverse impact outside of the OPA procurement process on investment in electricity supply or capacity or in measures that will manage electricity demand as described in subsection 25.32(1) of the Electricity Act.

3. Should the Board approve the OPA's proposed procurement processes as being appropriate for managing electricity supply, capacity and demand in accordance with the IPSP?

C. Aboriginal Peoples Consultation for both the IPSP and the Procurement Processes

1. Have all Aboriginal Peoples whose existing or asserted Aboriginal or treaty rights may be affected by the IPSP or the procurement processes been identified, have appropriate consultations been conducted with these groups, and if necessary, have appropriate accommodations been made with these groups?

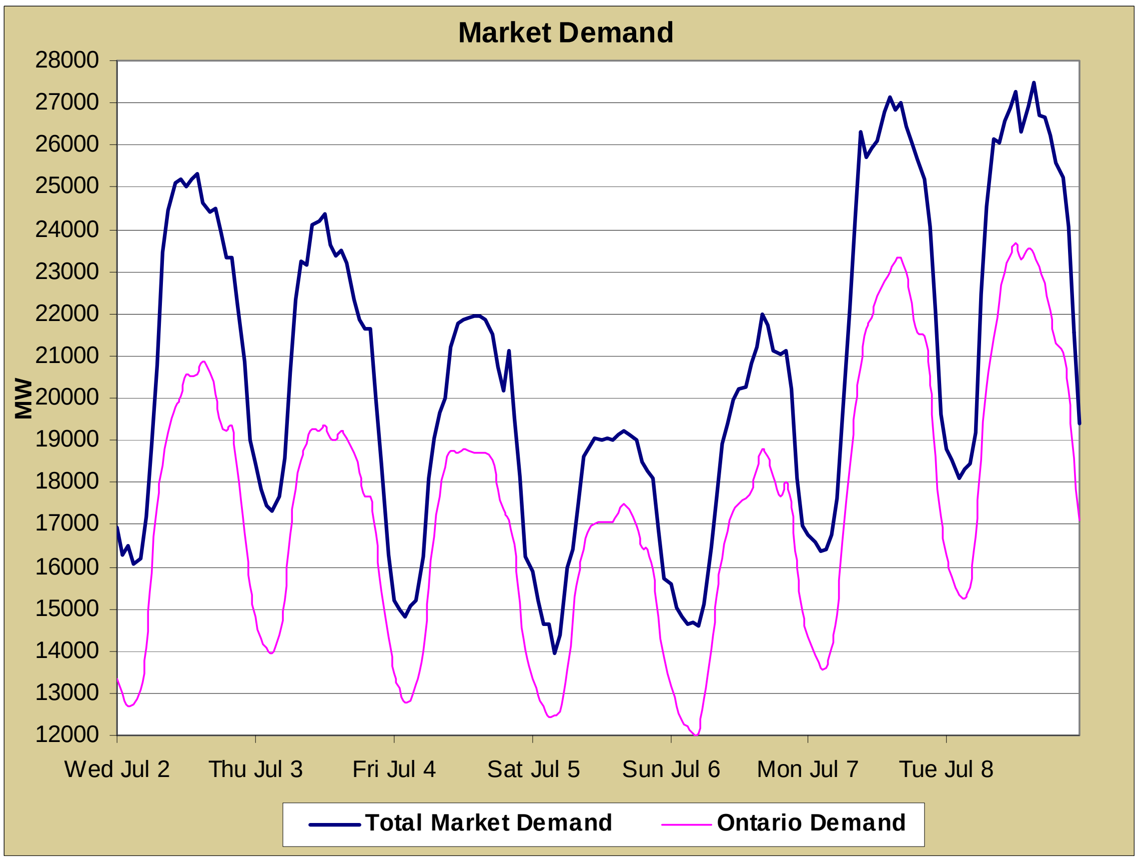
Weekly Market Report

July 2 - July 8, 2008

ieso Power to Ontario. On Demand.

This report provides a summary of key market data from the IESO-administered markets. It is intended to provide a quick reference for all market stakeholders. It is composed of two sections: Section 1 provides graphical summaries of key market data, and will be repeated in each report. In all cases, the data used to produce all graphs in this report, are available for download from the Market Summaries page of the IESO Web site. Any data used in this report is provided for information purposes only, and should not be used for settlement purposes. Section 2 provides additional comments on any specific events, which occurred during the reporting week. Finally, an Appendix is included, which contains a description of all terms used in this report.

Section 1: Market Data Graphs



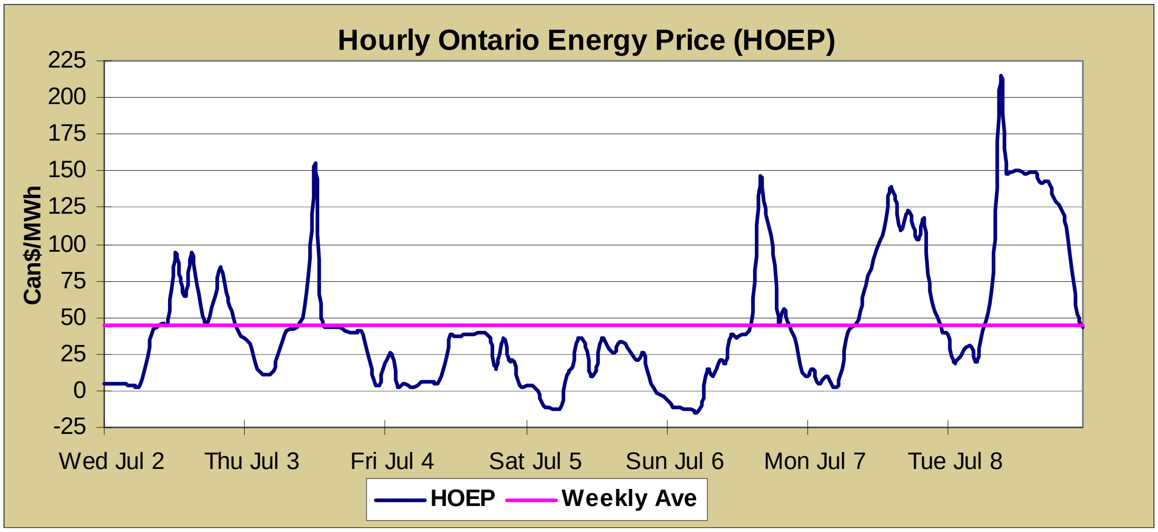
	Total Market Demand (MW)	Ontario Demand (MW)
Average hourly values for the week:	20,564	17,389
Maximum hourly values for the week:	27,477	23,680
Minimum hourly values for the week:	13,965	12,035

For a description of Total Market Demand and Ontario Demand, please see Section 1 of the Appendix.

ieso Power to Ontario. On Demand.

Weekly Market Report

July 2 - July 8, 2008

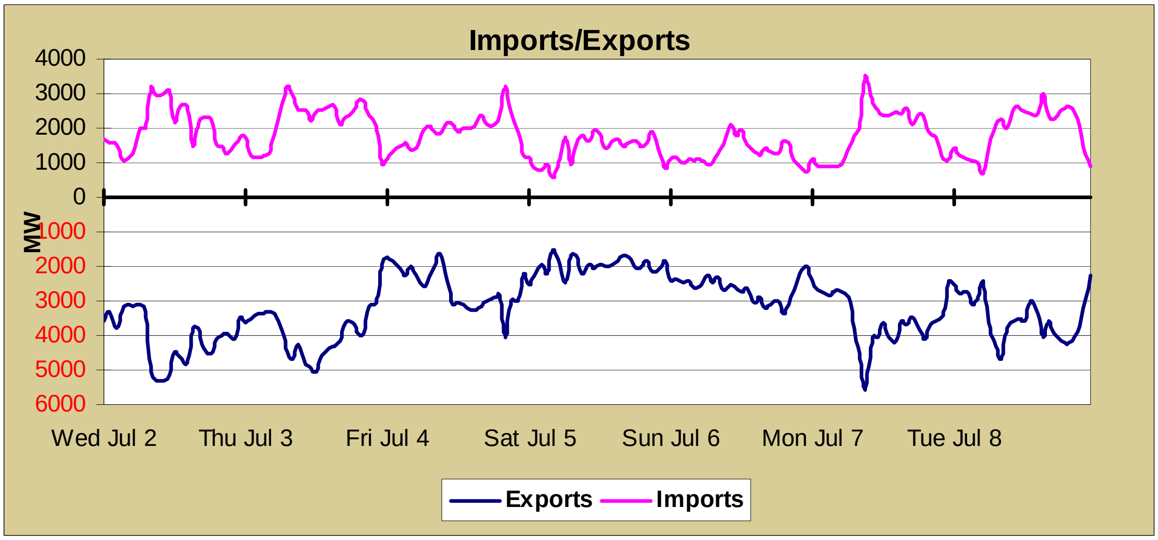


Hourly Ontario Energy Price $/MWh			
	Weekly	On-Peak	Off-Peak
Average	44.21	71.34	19.55
Maximum	215.21	215.21	144.95
Minimum	-14.59	4.32	-14.59

Weekly Weighted Average based on Ontario Demand: $51.15 /MWh or 5.12 ¢/kWh
Weighted Average based on Ontario Demand since Jan 1, 2008: $50.93 /MWh or 5.09 ¢/kWh

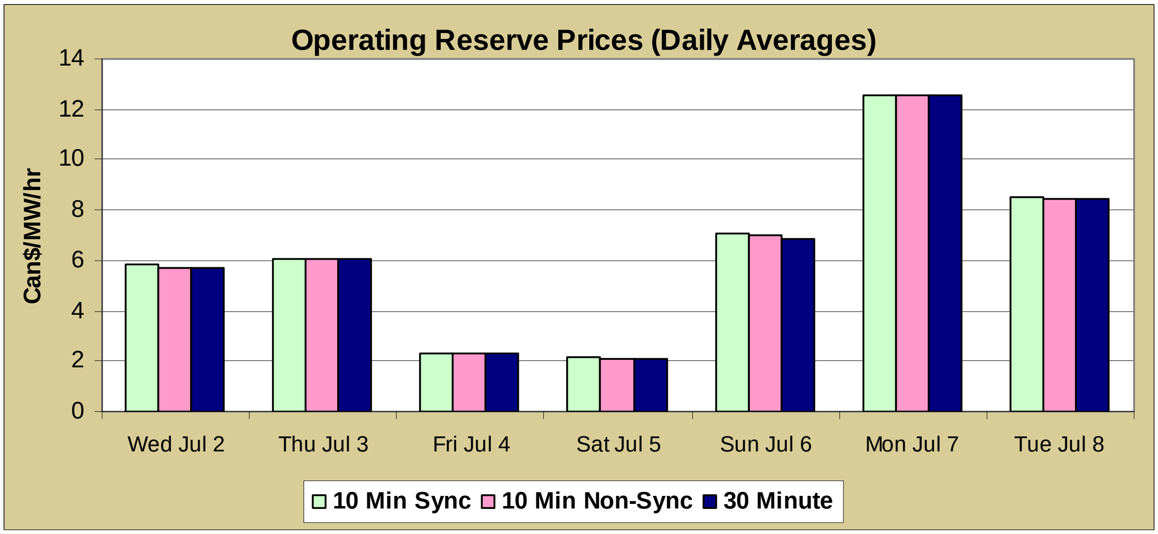
For a description of Hourly Ontario Energy Price, please see Section 2 of the attached Appendix.

NOTE: At the request of market participants, the IESO has shifted the On Peak definition by one hour (from 7 to 22, to 8 to 23) as of December 2004, to better reflect the industry practice.



Average export schedule for the week: 3,174 MW
Average import schedule for the week: 1,795 MW
Average net intertie schedule: 1,379 MW net export

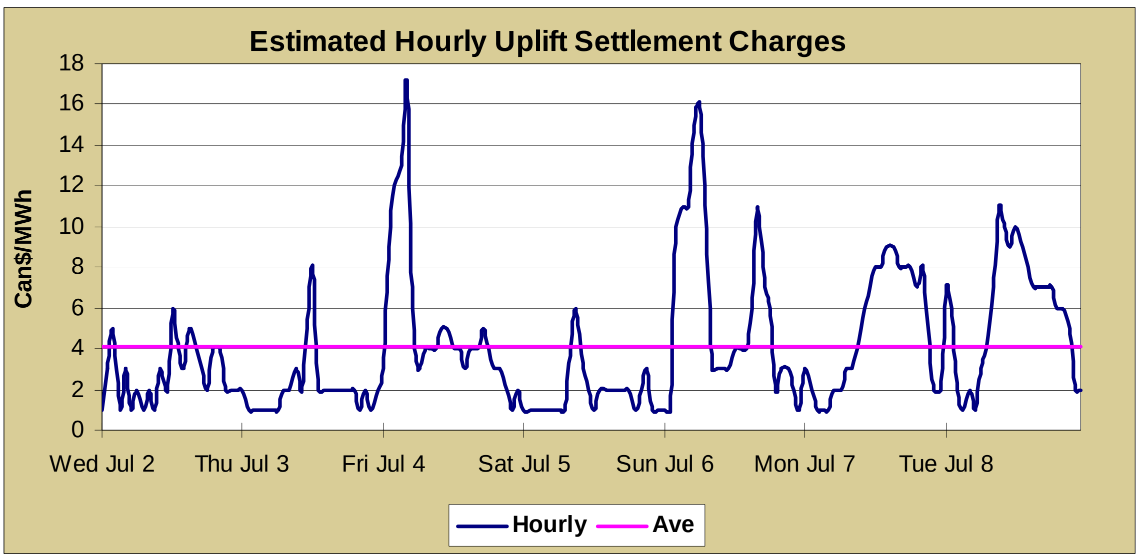
For a description of Imports/Exports, please see Section 3 of the attached Appendix



Average Operating Reserve Prices for the week were:

10 minute synchronized reserve:	$6.36 /MWh
10 minute non-synchronized reserve:	$6.31 /MWh
30 minute reserve:	$6.28 /MWh

For a description of Operating Reserve, please see Section 4 of the Appendix.



Average Hourly Uplift Settlement Charges since Jan 1, 2008:	$2.58 /MWh or 0.26 ¢/kWh
Weighted Average Hourly Uplift Settlement Charges since Jan 1, 2008:	$2.71 /MWh or 0.27 ¢/kWh

For a description of Hourly Uplift Settlement Charges, please see Section 5 of the Appendix.

Section 2: Comments about the Week

On Wednesday, July 2, 2008, the five-minute market clearing price was negative in one hour, as follows:

Hour	HOEP ($/MWh)	MCP ($/MWh) 1	2	3	4	5	6	7	8	9	10	11	12
7	2.71	-3.99	1.55	1.94	2.14	2.33	3.01	3.5	4	4.2	4.5	4.6	4.7

On Friday, July 4, 2008, the five-minute market clearing price was negative in one hour, as follows:

Hour	HOEP ($/MWh)	MCP ($/MWh) 1	2	3	4	5	6	7	8	9	10	11	12
6	2.54	-4.13	-4.08	2.5	3.01	3.42	3.5	4	4.1	4.2	4.4	4.7	4.8

On Saturday, July 5, 2008, the five-minute market clearing price was negative in several hours, as follows:

Hour	HOEP ($/MWh)	MCP ($/MWh) 1	2	3	4	5	6	7	8	9	10	11	12
3	-0.58	3.30	3.20	3.10	2.45	3.10	3.10	2.30	0.50	2.30	-9.90	-10.19	-10.19
4	-10.39	-10.46	-10.29	-10.29	-10.39	-10.39	-10.39	-10.39	-10.29	-10.29	-10.49	-10.46	-10.49
5	-11.71	-10.97	-10.97	-10.97	-11.35	-11.74	-11.44	-11.65	-13.20	-11.74	-13.20	-11.74	-11.56
6	-12.53	-13.85	-13.50	-13.30	-13.30	-13.30	-13.20	-13.30	-11.74	-11.44	-11.44	-11.07	-10.97
7	-9.77	-11.44	-11.44	-11.07	-10.97	-10.87	-10.78	-10.78	-10.64	-10.49	-10.29	-9.90	1.46
23	1.44	4.03	4.03	3.95	3.80	3.90	3.70	3.60	3.50	3.40	2.60	-9.63	-9.63
24	-2.32	3.70	3.60	3.40	3.40	3.40	2.60	2.60	-9.54	-9.90	-10.09	-10.49	-10.49

On Sunday, July 6, 2008, the five-minute market clearing price was negative in several hours, as follows:

Hour	HOEP ($/MWh)	MCP ($/MWh) 1	2	3	4	5	6	7	8	9	10	11	12
1	-6.40	1.40	1.40	2.40	-1.10	-9.54	-9.81	-9.82	-9.81	-10.18	-10.49	-10.49	-10.78
2	-10.92	-10.58	-10.58	-10.68	-10.68	-10.87	-10.78	-11.17	-11.17	-10.87	-11.17	-11.26	-11.17
3	-11.27	-11.17	-11.17	-11.17	-11.26	-11.26	-11.36	-11.26	-11.46	-11.46	-10.78	-11.36	-11.55
4	-13.03	-11.55	-11.65	-13.20	-13.31	-13.20	-13.30	-13.30	-13.31	-13.30	-13.39	-13.40	-13.40
5	-12.68	-11.55	-11.46	-11.36	-11.55	-11.55	-11.65	-11.55	-11.65	-13.20	-13.30	-13.30	-20.00
6	-14.59	-15.00	-20.00	-15.00	-15.00	-15.00	-13.59	-13.59	-13.46	-14.04	-13.50	-13.46	-13.40
7	-10.67	-11.65	-11.36	-11.26	-11.17	-10.78	-10.58	-10.49	-10.49	-10.49	-10.00	-9.90	-9.81
8	14.19	-9.90	-9.81	2.70	2.70	3.40	3.60	3.70	3.80	39.90	40.76	46.95	42.47

The market clearing price hit an all-time low of -$20.00 / MWh on Sunday, July 6, 2008, hour 5, interval 12, and hour 6, interval 2. This also resulted in an all-time low HOEP of -$14.59 / MWh in hour 6.

This week also saw the Highest Hourly Market Demand: 27,477 MW on Tuesday, July 8, 2008, hour 16 (the previous record of 27,375 MW was on August 1, 2006, hour 14).

Appendix: Additional Background Information

1. Market Demand

Total Market Demand represents the total energy that was supplied from the IESO-Administered Market.

The IESO calculates Total Market Demand by summing all output from generators registered in the Market plus all scheduled imports to the province. It is also equal to the sum of all load supplied from the Market plus exports from the province, plus all line losses incurred on the IESO-controlled grid.

Ontario Demand represents the total energy that was supplied from the IESO-Administered Market for the sake of supplying load within Ontario.

The IESO calculates Ontario Demand by subtracting exports from the Total Market Demand quantity. It is also equal to the sum of all load within Ontario which is supplied from the Market, plus all line losses incurred on the IESO-controlled grid.

2. Hourly Ontario Energy Price (HOEP)

HOEP is the hourly price that is charged to Local Distributing Companies and other non-dispatchable loads. HOEP is also paid to self-scheduling generators.

HOEP is defined as the hourly arithmetic average of the uniform Ontario energy price determined for each of the 12, 5-minute dispatch intervals in a particular hour.

On Peak average price is the straight arithmetic average of HOEP in hours 8 to 23 EST, Monday to Friday (5 x 16). Off Peak average price is the straight arithmetic average of HOEP for all remaining hours in the week.
Weeks with statutory holidays will cause the on-peak average to be calculated using 4 weekdays (4 x 16). The wholesale market does not use a formal definition of on and off-peak hours. The IESO is providing this calculation purely for information purposes, and will continue to use this definition throughout the year.

NOTE: At the request of market participants, the IESO has shifted the On Peak definition by one hour (from 7 to 22, to 8 to 23) as of December 2004, to better reflect the industry practice.

3. Import and Export Quantities

Economic **imports** and **exports** are scheduled into/out of Ontario on an hourly basis, up to the physical capabilities of the Grid and the interconnections between the systems. The import and export quantities are measured in MWh. The units for the graphed hourly quantities are MWh/hour, and are therefore labeled as MW on the graph.

4. Operating Reserve

Operating Reserve is generation capacity or load reduction capacity that the IESO can call upon on short notice to restore a balance between supply and demand, in the event of an unexpected load increase or generator outage. The IESO purchases defined amounts of Operating Reserve from Participants via three real-time markets.

5. Estimated Hourly Uplift Settlement Charges

Hourly Uplift Settlement Charges are applied to all customers in the physical market. The IESO uses funds collected under these charges to pay for such items as the three types of Operating Reserve, any Congestion Management Settlement Credits owed to dispatchable resources, Intertie Offer Guarantee payments (IOG), and other incurred hourly costs such as energy losses on the IESO-controlled grid.

The Hourly Uplift Settlement Charges appear on settlement statements along with other charges such as energy charges, non-hourly settlement amounts, and transmission charges.

The Estimated Hourly Uplift Settlement Charges presents estimates of this charge for the current week. This eliminates a two-week lag in the data presented, compared to the rest of the data in the report.

6. Administrative Prices

The Market Rules recognize that there are occasions where it may be appropriate or necessary to apply administrative prices and schedules to replace those calculated by the market dispatch algorithm or when a price can not be calculated by the dispatch algorithm. These occasions include forced or planned outages to market software, hardware, or communications systems, market suspensions, and data losses due to operational metering or market software failures.

7. Relating Wholesale Charges to Retail Bills

The IESO has released "A Guide to Electricity Charges in Ontario's Competitive Marketplace". This guide describes the various wholesale charges more fully, and also explains how the wholesale charges are reflected in Retail settlements.

Questions on any information contained in this report should be directed to:

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1-888-448-7777
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salon.com

Why we never need to build another polluting power plant

Coal? Natural gas? Nuke? We can wipe them all off the drawing board by using current energy more efficiently. Are you listening, Washington?

By Joseph Romm

Jul. 28, 2008 | Suppose I paid you for every pound of pollution you generated and punished you for every pound you reduced. You would probably spend most of your time trying to figure out how to generate more pollution. And suppose that if you generated enough pollution, I had to pay you to build a new plant, no matter what the cost, and no matter how much cheaper it might be to not pollute in the first place.

Well, that's pretty much how we have run the U.S. electric grid for nearly a century. The more electricity a utility sells, the more money it makes. If it's able to boost electricity demand enough, the utility is allowed to build a new power plant with a guaranteed profit. The only way a typical utility can lose money is if demand drops. So the last thing most utilities want to do is seriously push strategies that save energy, strategies that do not pollute in the first place.

America is the Saudi Arabia of energy waste. A 2007 report from the international consulting firm McKinsey and Co. found that improving energy efficiency in buildings, appliances and factories could offset almost all of the projected demand for electricity in 2030 and largely negate the need for new coal-fired power plants. McKinsey estimates that one-third of the U.S. greenhouse gas reductions by 2030 could come from electricity efficiency and be achieved at negative marginal costs. In short, the cost of the efficient equipment would quickly pay for itself in energy savings.

While a few states have energy-efficiency strategies, none matches what California has done. In the past three decades, electricity consumption per capita grew 60 percent in the rest of the nation, while it stayed flat in high-tech, fast-growing California. If all Americans had the same per capita electricity demand as Californians currently do, we would cut electricity consumption 40 percent. If the entire nation had California's much cleaner electric grid, we would cut total U.S. global-warming pollution by more than a quarter without raising American electric bills. And if all of America adopted the same energy-efficiency policies that California is now putting in place, the country would never have to build another polluting power plant.

How did California do it? In part, a smart California Energy Commission has promoted strong building standards and the aggressive deployment of energy-efficient technologies and strategies -- and has done so with support of both Democratic and Republican leadership over three decades.

Many of the strategies are obvious: better insulation, energy-efficient lighting, heating and cooling. But some of the strategies were unexpected. The state found that the average residential air duct leaked 20 to 30 percent of the heated and cooled air it carried. It then required leakage rates below 6 percent, and every seventh new house is inspected. The state found that in outdoor lighting for parking lots and streets, about 15 percent of the light was directed up, illuminating nothing but the sky. The state required new outdoor lighting to cut that to below 6 percent. Flat roofs on commercial buildings must be white, which reflects the sunlight and keeps the buildings cooler, reducing air-conditioning energy demands. The state subsidized high-efficiency LED traffic lights for cities that lacked the money, ultimately converting the entire state.

Significantly, California adopted regulations so that utility company profits are not tied to how much electricity they sell. This is called "decoupling." It also allowed utilities to take a share of any energy savings they help consumers and businesses achieve. The bottom line is that California utilities can make money when their customers save money. That puts energy-efficiency investments on the same competitive playing field as

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generation from new power plants.

The cost of efficiency programs has averaged 2 to 3 cents per avoided kilowatt hour, which is about one-fifth the cost of electricity generated from new nuclear, coal and natural gas-fired plants. And, of course, energy efficiency does not require new power lines and does not generate greenhouse-gas emissions or long-lived radioactive waste. While California is far more efficient than the rest of the country, the state still thinks that with an even more aggressive effort, it can achieve as much additional electricity savings by 2020 as it has in the past three decades.

Serious energy efficiency is not a one-shot resource, where you pick the low-hanging fruit and you're done. In fact, the fruit grows back. The efficiency resource never gets exhausted because technology keeps improving and knowledge spreads to more people.

The best corporate example is Dow Chemical's Louisiana division, consisting of more than 20 plants. In 1982, the division's energy manager, Ken Nelson, began a yearly contest to identify and fund energy-saving projects. Some of the projects were simple, like more efficient compressors and motors, or better insulation for steam lines. Some involved more sophisticated thermodynamic "pinch" analysis, which allows engineers to figure out where to place heat exchangers to capture heat emitted in one part of a chemical process and transfer it to a different part of the process where heat is needed. His success was nothing short of astonishing.

The first year of the contest had 27 winners requiring a total capital investment of $1.7 million with an average annual return on investment of 173 percent. Many at Dow felt that there couldn't be others with such high returns. The skeptics were wrong. The 1983 contest had 32 winners requiring a total capital investment of $2.2 million and a 340 percent return -- a savings of $7.5 million in the first year and every year after that. Even as fuel prices declined in the mid-1980s, the savings kept growing. The average return to the 1989 contest was the highest ever, an astounding 470 percent in 1989 -- a payback of 11 weeks that saved the company $37 million a year.

You might think that after 10 years, and nearly 700 projects, the 2,000 Dow employees would be tapped out of ideas. Yet the contest in 1991, 1992 and 1993 each had in excess of 120 winners with an average return on investment of 300 percent. Total savings to Dow from just those projects exceeded $75 million a year.

When I worked at the Department of Energy in the mid-1990s, we hired Nelson, who had recently retired from Dow, to run a "return on investment" contest to reduce DOE's pollution. As they were at Dow, many DOE employees were skeptical such opportunities existed. Yet the first two contest rounds identified and funded 18 projects that cost $4.6 million and provided the department $10 million in savings every year, while avoiding more than 100 tons of low-level radioactive pollution and other kinds of waste. The DOE's regional operating officers ended up funding 260 projects costing $20 million that have been estimated to achieve annual savings of $90 million a year.

Economic models greatly overestimate the cost of carbon mitigation because economists simply don't believe that the economy has lots of high-return energy-efficiency opportunities. In their theory, the economy is always operating near efficiency. Reality is very different than economic models.

In my five years at DOE, working with companies to develop and deploy efficient and renewable technologies, and then in nearly a decade of consulting with companies in the private sector, I never saw a building or factory that couldn't cut electricity consumption or greenhouse-gas emissions 25 percent to 50 percent with rapid payback (under four years). My 1999 book, "Cool Companies," detailed some 100 case studies of companies that have done just that and made a great deal of money.

There are many reasons that most companies don't match what the best companies do. Until recently, saving energy has been a low priority for most of them. Most utilities, as noted, have little or no incentive to help companies save energy. Funding for government programs to help companies adopt energy-saving strategies has been cut under the Bush administration.

Government has a very important role in enabling energy savings. The office of Energy Efficiency and

Renewable Energy at the U.S. Department of Energy has lots of (underfunded) programs that deliver savings every day. Consider, for instance, Chrysler's St. Louis complex, which recently received a DOE Save Energy Now energy assessment. Using DOE software, Chrysler identified a variety of energy-saving measures and saved the company $627,000 a year in energy costs -- for an upfront implementation cost of only $125,000.

The key point for policymakers now is that we have more than two decades of experience with successful state and federal energy-efficiency programs. We know what works. As California energy commissioner Art Rosenfeld -- a former DOE colleague and the godfather of energy efficiency -- put it in a recent conversation, "A lot of technology and strategies that are tried and true in California are waiting to be adopted by the rest of country."

So how do we overcome barriers and tap our nearly limitless efficiency resource? Obviously, the first thing would be to get all the states to embrace smarter utility regulations, which is a core strategy of Barack Obama's plan to reduce greenhouse gases. But how does the federal government get all the states to embrace efficiency?

We should establish a federal matching program to co-fund state-based efficiency programs, with a special incentive to encourage states without an efficiency program to start one. This was a key recommendation of the End-Use Efficiency Working Group to the Energy Future Coalition, a bipartisan effort to develop consensus policies, in which I participated. The first year should offer $1 billion in federal matching funds, then $2 billion, $3 billion, $4 billion, and finally stabilizing at $5 billion. This will give every state time to change their regulations and establish a learning curve for energy efficiency.

This program would cost $15 billion in the first five years, but save several times that amount in lower energy bills and reduced pollution. Since the next president will put in place a cap-and-trade system for greenhouse gases, the revenues from auctioning the emissions permits can ultimately be used to pay for the program.

We should restore a federal focus on the energy-intensive industries, such as pulp and paper, steel, aluminum, petroleum refining and chemicals. They account for 80 percent of energy consumed by U.S. manufacturers and 90 percent of the hazardous waste. They represent the best chance for increasing efficiency while cutting pollution. Many are major emitters of greenhouse gases other than carbon dioxide. A 1993 analysis for the DOE found that a 10 to 20 percent reduction in waste by American industry would generate a cumulative increase of $2 trillion in the gross domestic product from 1996 to 2010. By 2010, the improvements would be generating 2 million new jobs.

For these reasons, in the 1990s, the Energy Department began forming partnerships with energy-intensive industries to develop clean technologies. We worked with scientists and engineers to identify areas of joint research into technologies that would simultaneously save energy, reduce pollution and increase productivity. The Bush administration slashed funding for this program by 50 percent -- and keeps trying to shut it down entirely.

Indeed, conservatives in general have cut the funding or shut down entirely almost all federal programs aimed at deploying energy-efficient technologies. Conservatives simply have a blind spot when it comes to energy efficiency and conservation, seeing them as inconsequential "Jimmy Carter programs."

I recently testified at a Senate Environment and Public Works Committee hearing on nuclear power and spoke about how alternative technologies, particularly energy efficiency, were a much better bet for the country. Senator George Voinovich (R-Ohio) said this was "poppycock," and then asked all the pro-nuclear witnesses to address the question, "If nuclear power is so uncompetitive, why are so many utilities building reactors?"

Voinovich apparently has forgotten about the massive subsidies he himself voted to give the nuclear industry in 2005. He seems to be unaware that states like Florida allow utilities to sharply raise electric rates years in advance of a nuclear plant delivering even a single electron to customers. If you could do that same forward-pricing with energy efficiency, we would never need to build another polluting plant.

Although he is a senior member of the Senate and a powerful voice on energy and climate issues, Voinovich doesn't seem to know the first thing about the electricity business; namely, that a great many utilities have a huge profit incentive to build even the most expensive power plants, since they can pass all costs on to consumers while retaining a guaranteed profit. But they have a strong disincentive from investing in much less costly efforts to reduce electricity demand, since that would eat into their profits.

The next president must challenge the public service commission in every state to allow utilities to receive the same return on energy efficiency as they are allowed to receive on generation. That single step could lead the country the furthest in solving our ever-worsening climate and energy problems.

-- By Joseph Romm

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REPORT

IESO Operability Review of OPA's Integrated Power System Plan

Issue 2.0

Advice to Reader

The study results in this report are based on information made available to the IESO at the time the assessment was carried out and the assumptions set out in the report. The IESO assumes no responsibility for the accuracy or completeness of such information or the conformity of actual events to the assumptions. Furthermore, the results and conclusions are subject to further consideration due to changes to this information or assumptions, or to additional information that may become available in the future.

The performance expectations of power system facilities were determined based on typical assumptions used in power system planning studies. The actual performance of these facilities during real-time operations will depend on actual system conditions, including ambient temperature, wind speed and facilities loading, and may be higher or lower than those stated in this study.

The IESO assumes no responsibility to any third party for any use it makes of this report.

Document ID	IESO_REP_0411
Document Name	IESO Operability Assessment of the OPA's Integrated Power System Plan
Issue	Issue 2.0
Reason for Issue	Second Issue
Effective Date	April 21, 2008

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Table of Changes

Reference (Paragraph and Section)	Description of Change
Section 3	Clarified assumptions in response to questions received from market participants.

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Executive Summary

The electricity infrastructure of the future as envisioned by the Integrated Power System Plan represents the most significant transformation of Ontario's electricity sector since the incorporation of nuclear generation. Many of the proposed supply options have significantly different operating characteristics from the current generation fleet – and some of the proposed projects, such as intermittent and embedded generation are outside the IESO's traditional dispatch authority and monitoring. Also, increased conservation and demand management programs will create new daily, weekly and annual load patterns. These much needed initiatives must be incorporated into the routine operation of the system such that reliability is maintained throughout their implementation.

The IESO is accountable for managing the operation of the electricity system so that supply is reliably and efficiently delivered to the people of Ontario, and has carried out this task since its inception. Drawing on its experience and expertise, the IESO is well positioned to assess any operability issues and to develop any new or evolved operational and market processes needed to support the changing infrastructure going forward.

Operability is a measure of whether the proposed supply mix from the IPSP can be reasonably coordinated through unit commitment decisions and real-time dispatch to follow the ever-varying load profile through both high and low demand conditions, while constantly meeting all operating standards, such as operating with sufficient operating reserves.

The IESO has assessed the operability of the IPSP and concluded that it provides sufficient flexibility to meet future system needs. Current market mechanisms and control actions will allow the IESO to reliably operate the system described in the IPSP.

This report represents just the first step in addressing future operability. Assessments will be on-going for two reasons:

- System operability is directly related to the infrastructure of the day. This operability assessment involved many assumptions about in-service dates for new generators, implementation timetables and results for conservation and demand response programs. The IESO will update this assessment for material changes to any assumptions, particularly in-service milestones, which can have an impact on operability.

- The currently available information provides a reasonable representation of hourly outcomes in the future. However, like other system operators, to date Ontario has limited actual experience with the combined impacts of significant amounts of wind generation, embedded generation and demand management. As the future is realized greater detail will be incorporated to examine intra-hour operability, local area impacts, and to achieve minute-to-minute coordination. The IESO expects that these more detailed operational requirements will be addressed through mechanisms such as the connection assessment process as each

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project moves from the proposal stage to reality, and with the benefit of actual experience. As their penetration increases, future operations planning will capture their impact.

The IESO's operability assessment also reinforced a number of opportunities to improve transparency and efficiency in the operation of the power system and electricity market as the province moves forward with the IPSP. The IESO and its stakeholders should continue to evolve current operating processes and market incentives to capture these benefits, and the IESO has started initiatives to address these opportunities on several fronts. These efforts include a stakeholder initiative to address market design issues related to operability, and a new industry-wide examination of smart grid technologies and other non-traditional solutions to facilitate greater consumer involvement in solving future operational challenges.

– End of Section –

1. Introduction and Purpose

The IESO directs the operation of Ontario's bulk electricity system, balancing demand and supply of electricity on a second-to second basis to meet the electricity needs of over 12 million Ontarians. It does this by administering the competitive wholesale electricity market, which involves, among other things, collecting offers from suppliers and bids from purchasers to determine the market price of electricity that reflects current conditions across the province. This price, in turn, helps to drive market efficiencies and participant behaviour to assist in solving reliability issues.

The IESO is also involved in planning and assessment of future conditions of the electricity system. Through various assessments, the IESO ensures that sufficient generation and transmission resources are available to satisfy the needs of Ontario's consumers and respond to unforeseen contingencies, both now and in the future. These assessments include:

- Near-term and mid-term adequacy assessments of generating resources and transmission system status
- Contingency planning for major outages or disruptions to power supply;
- The need for market evolution initiatives to enhance the efficiency of the market and encourage market-based solutions to managing reliability.

Given the IESO's role in overseeing the reliable operation of Ontario's electricity market and power system, it assisted the OPA in several areas of IPSP study. Support was given in the form of several system impact assessments, preliminary assessments, and planning study reports based on the forecast transmission and resource expansions contained in the IPSP.

This report is an independent assessment of the IPSP's operability. Operability is a measure of whether the proposed supply mix from the IPSP can be reasonably coordinated through unit commitment decisions and real-time dispatch to follow the ever-varying load profile through both high and low demand conditions, while meeting all operating standards.

The analysis is based on preliminary IPSP hourly data submitted to the IESO by the OPA, which includes Ontario demand, conservation[1] , scheduled intertie imports and exports, generator availability, and generation schedules. The simulated data was compiled by the OPA using cost-based dispatch as an approximation of market outcomes to determine generation output, costs and economic transactions between interconnected areas for each hour in the simulation period (2010 - 2026).

[1] OPA conservation programs include demand management, demand response, customer generation, fuel switching and efficiency programs.

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The criteria used to determine the operability of the IPSP includes the ability of the future supply mix to:

- Provide sufficient load following capability
- Manage surplus baseload generation conditions
- Serve Ontario demand during high demand conditions
- Meet operating reserve requirements

The IESO will continuously monitor IPSP implementation and update the assessment for material changes to any assumptions, particularly in-service milestones, which can have an impact on operability.

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2. Generation and Supply Mix Summary

This section provides a summary of Ontario's forecasted generating capacity, its evolving composition, based on fuel type, and an overview of the proposed supply mix changes. The generation summary is based on simulated schedules provided by OPA for every year between 2010 and 2014, and every second year between 2016 and 2026.

The OPA simulations produced an hourly available capacity value for each major generating station/resource in Ontario. The highest hourly value for the year for each resource was summed to produce the annual totals. Results are lower than could be achieved by summing the nameplate capacity of the affected resources as the capacity maximums used by the simulations reflect operational capacity limits.

2.1 Generation

Table 1 shows the simulated hourly maximum capability of each resource in each year, grouped by fuel type. These values do not represent either coincident peak-hour production quantities or installed capacity values, as they are simulations of actual hourly outputs which are subject to normal outages and de-ratings. As such, they provide practical maximum production levels for the various sources in any year.

	2010	2011	2012	2013	2014	2016	2018	2020	2022	2024	2026
Nuclear	11,379	11,379	12,919	12,403	12,403	10,242	10,572	10,941	12,923	13,804	13,804
Gas/Oil	9,338	9,690	10,696	11,576	12,112	11,986	11,540	11,012	10,350	10,352	10,349
Renewables	8,689	9,307	9,347	9,713	10,181	10,868	11,369	12,922	13,473	13,477	13,683
Conservation	2,911	3,342	3,762	4,170	4,570	5,153	5,658	6,040	6,453	6,849	7,329
Coal	6,343	4,893	3,928	3,443	3,232	-	-	-	-	-	-
Interconnections	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
Other	88	88	149	189	229	457	483	525	525	525	525
TOTAL	39,999	39,949	42,051	42,744	43,977	39,955	40,872	42,690	44,973	46,255	46,940

Table 1: Annual Generation Capacity Based on Preliminary IPSP Data Provided by OPA

2.2 Supply Mix Changes

The changes in the proposed supply mix from 2010 through to 2026 are:

- Phase-out of all coal-fired generation by the end of 2014
- A significant increase in reliance on conservation and demand management with the implementation of the OPA's conservation programs
- Growth of wind generation in Ontario's generation portfolio
- Increase in biomass and gas-fuelled generation
- Refurbishment of 16 nuclear units as well as addition of two new units
- Production from contracted non-utility generation (NUG) units that is consistent with the IPSP assumptions
- General reduction in the proportion of manoeuvrable generation in Ontario's generating fleet

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3. Assumptions

The IESO's analysis was performed using production data provided by the OPA. As such, the data reflects the many assumptions used in the IPSP. The IESO did not modify any IPSP assumptions. Hence, the analysis is based on the following:

- New resources and the transmission capability necessary to support the OPA's simulated hourly schedules were assumed in service, as indicated in the IPSP.
- Non-utility generator (NUG) outputs were consistent with IPSP assumptions and were provided to the IESO in the OPA's simulated hourly schedules.
- The energy and capacity schedules provided by the OPA respected normal operational limitations on the associated resources. These limitations include forced and planned outages, daily energy limits, and the need for hydroelectric units to run during periods of freshet.

The IESO was required to make certain assumptions to accurately interpret the simulated data and produce meaningful operating conditions:

- Existing generation resources were assumed to have ramping and operating characteristics similar to those they currently exhibit in the IESO-administered markets.
- Generation resources not yet in service were assumed to have ramping and operating characteristics similar to existing resources of the same technology type. Some operating parameters such as minimum load point were adjusted in proportion to nameplate capacity.
- It was assumed that ramping and operating characteristics did not appreciably degrade over the life of the plant and were held constant for the entire study period.
- Ontario's operating reserve requirement was assumed to be constant throughout the entire study period as no new generating unit in the OPA simulated schedules exceeded the size of today's largest resource. Any future increase in operating reserve requirements will be addressed within the IESO's Connection Assessment and Approval processes.
- Using voluntary regional reserve sharing programs, which can reduce operating reserve requirements, was not considered for this analysis.
- The operability benefits of currently registered dispatchable loads or NUGs that have elected to operate as dispatchable generation in today's IESO-administered markets were not considered in the simulated schedules. However, they were used in the analysis as a viable control action.

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4. Hourly Load Following

Load following capability is a measure of the dispatchable resources' ability to be effectively dispatched to follow the fluctuations of consumer demand and overall system needs. The OPA submitted hourly data to the IESO for its analysis. The study of inter-hour load following capability used these hourly schedules by employing a methodology developed through the IESO's Stakeholder Engagement Program[2] that analyzed historical load following requirements. The hourly schedules include generation, Ontario demand, imports and exports, and the results of conservation programs.

The IESO assessment focused on the most critical days - the days with the highest hourly peak demand and highest hourly positive load following requirement (LFR)[3] of each season for each year of study. Where shortfalls were observed during these critical days, the analysis evaluated existing market mechanisms and control actions to determine whether a more optimized dispatch than provided by the OPA schedules could have resolved the shortfall. The assessment revealed that all the identified load following shortfalls could be successfully addressed through the current dispatch methodology. Table 2 summarizes the results of this analysis.

4.1 Hourly Load Following Analysis (2010-2016)

The first five years of the analysis, from 2010-2016, are the critical period, during which there is a profound transformation of the resource mix. During this period all of the coal-fired plants will be replaced with gas-fired units, hydroelectric, wind and conservation programs. In addition, a number of nuclear units are expected to be removed from operation for refurbishment. Over the 2010-2014 period, five of 40 days studied (12.5%) showed load following shortfalls, though all were successfully resolved by applying the unit commitment, curtailing exports and constraining-off dispatchable loads.

4.2 Hourly Load Following Analysis (2017-2026)

The second interval of the analysis was limited to every second year. This period saw the completion of all planned nuclear refurbishments, as well as the commissioning of two new nuclear units. Additionally there was continued growth in conservation programs, wind generation and several new hydroelectric units. The only reduction in the resource capacity over the period was due to an assumed further retirement of NUGs.

2 "Stakeholder Engagement #38 – Load Following Standard", http://www.ieso.ca/imoweb/consult/consult_se38.asp

3 The hourly load following requirement is the calculated change in demand requirement between one hour and the next.

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As shown in Table 2, during the later interval of study, the frequency of critical days with seemingly insufficient load following increased to 10 of 48 days (20.8%). With the increase, several days required more actions then were needed in the previous period to overcome shortfalls.

In addition to such actions as unit commitment, curtailment of exports, and constraining off of dispatchable loads, further imports and outage management were needed to resolve shortfalls.

Year	2010	2011	2012	2013	2014	2016	2018	2020	2022	2024	2026
Winter Max LFR	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Spring Max LFR	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Summer Max LFR	🔴[1,2]	🔴[1,2]	🟢	🔴[1,2]	🟢	🔴[1,2,3]	🔴[1,2,3]	🔴[1,2]	🔴[1,2,3]	🟢	🟢
Fall Max LFR	🟢	🟢	🟢	🟢	🟢	🟢	🔴[1,2,3]	🟢	🟢	🟢	🟢
Winter Peak Demand	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Spring Peak Demand	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Summer Peak Demand	🟢	🔴[1]	🟢	🟢	🟢	🔴[1,2]	🔴[1,2]	🔴[1,2]	🟢	🟢	🔴[1,2,3]
Fall Peak Demand	🔴[1]	🟢	🟢	🟢	🟢	🔴[1,2]	🟢	🟢	🟢	🟢	🟢

1 - Resolved through market scheduling and commitment of fossil units
2 - Resolved through market not scheduling exports and/or dispatchable load
3 – Requires additional measures to satisfy reserve requirement (i.e. additional imports, management of scheduled outages)

🟢 - Sufficient Load Following Capability (73 of 88)

🔴 - Insufficient Load Following Capability that would be managed through dispatch of the market (15 of 88)

Table 2: Results of Critical Days (2010-2026)

4.3 Unit Commitment

In today's operation, the market utilizes two programs to commit generation units:

- The Day-Ahead Commitment Process (DACP) provides a generator with day-ahead certainty in covering their start up costs, including the incremental operating and maintenance costs associated with the start up.
- The Spare Generation On Line (SGOL) program allows generators to commit to a start three hours out of real-time operation and covers the fuel costs associated with the start up.

Both programs schedule units to their minimum load points and allow them to meet the technical characteristics of the unit through a minimum runtime. This positions the units so they will be able to ramp to meet market dispatch.

In the OPA simulated schedules, hourly load following capability shortfalls often occurred when internal generation resources were scheduled at low energy output so they would be available to provide operating reserve. This positioning of the units at low output, left them operating in a range of poor ramping capability. In these cases, the future potential of a load following shortfall is not a concern, as it will be mitigated by using of one of the unit commitment processes discussed above.

4.4 Dispatchable Load

In today's IESO-administered markets, dispatchable loads provide ramping services on the same basis as generators. In the analysis, shortfalls in hourly load following capability were significantly mitigated by dispatching these resources, particularly during summer periods. This is consistent with experience in the summer of 2005, when the dispatch of dispatchable load allowed for more effective use of energy-limited hydroelectric resources during challenging operating conditions. The analysis shows the continued value of dispatchable demand in the market.

4.5 Other Market Actions

Where unit commitment and dispatch of dispatchable loads was unlikely to resolve hourly shortfalls in load following capability, other actions were evaluated for effectiveness. Generally these events occurred in the summer, during periods of high demand and challenging operating conditions which typically included periods of operating reserve shortfalls. These types of conditions send market price signals that cause market participants to reschedule planned outages and elect not to export.

All shortfalls in hourly load following that remained after using the unit commitment process and the dispatch of dispatchable loads could be resolved through a combination of outage management (provided to the IESO through the OPA's hourly availability schedules) and curtailment of exports (provided through the hourly export schedules). It is expected that should such shortfalls actually develop, normal market price signals would be sufficient to drive these outcomes without intervention by the IESO.

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5. Intra-Hour Load Following and Dispatch Issues

The IESO balances supply and demand through its direction of dispatchable resources, which will continue throughout the on-going evolution of Ontario's generating fleet. Although this report indicates, at least on an hourly basis, that there is sufficient flexibility to successfully operate using the proposed resources mix, challenges remain. Load following capability on a more granular level than hourly blocks of time is required if the proposed resource mix is to achieve true operability.

Figure 1 shows the gradual increase in the proportion of generation outside the dispatch control of the IESO or normally unavailable for dispatch and a corresponding decrease in dispatchable generation able to respond to 5-minute dispatch.

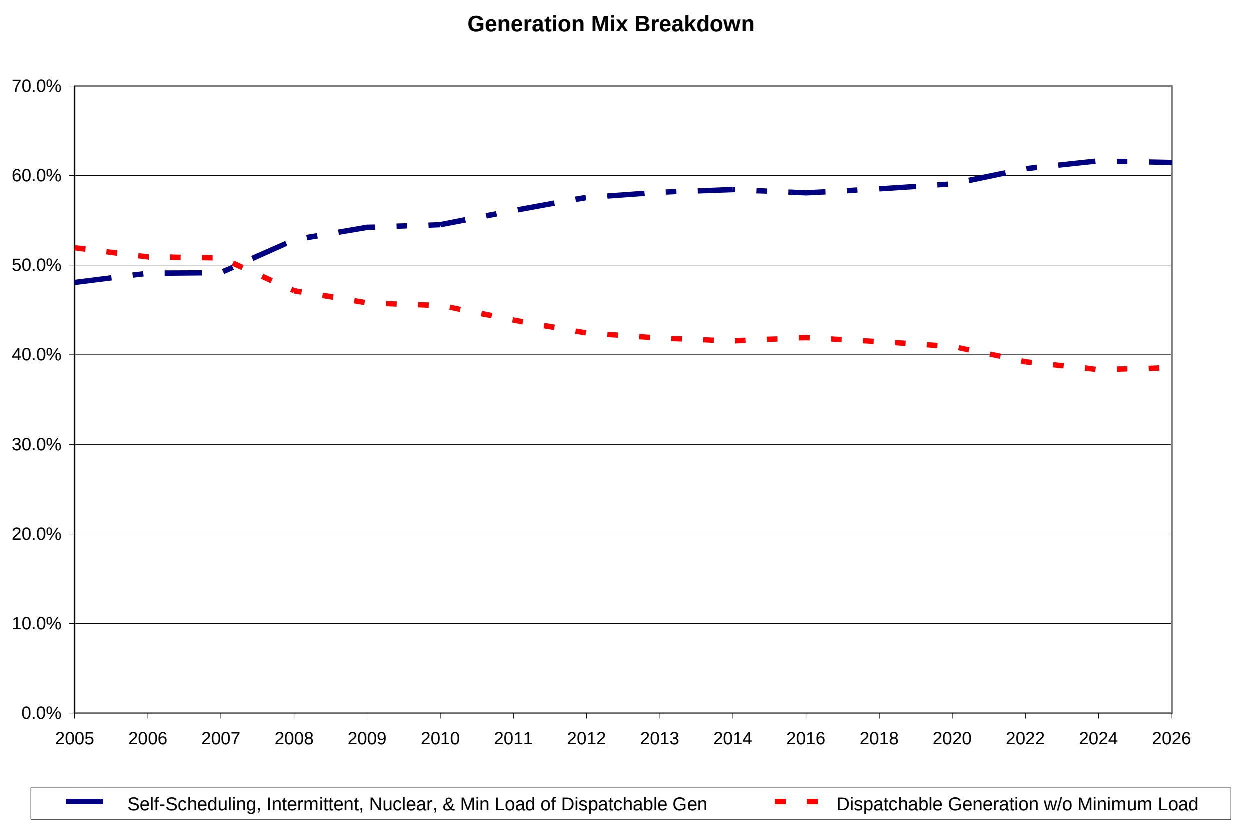

Figure 1: Generation Availability for Dispatch

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5.1 Wind Generation

In 2006 the IESO participated in a study of the impact of wind power penetration on the operation of the IESO- controlled grid and the IESO-administered markets. This GE Truewind study[16] was sponsored by CANWEA, the Ontario Power Authority and the IESO. The study indicated that there is a 16% probability that the output of wind generation will change over the next ten-minute interval by more than 10%. The probability of a 20% change over 10 minutes was predicted to be negligible. The IESO has been monitoring wind production since the fall of 2006 and has found that this study value is consistent with operational experience. There is approximately 500 MW of currently installed wind capacity. As the size of the wind fleet increases as shown by the data in the IPSP, the IESO will have to consider its impact on flexible generation and the need for additional intra-hour load following services.

5.2 Dispatch Issues

The hourly data provided by the OPA did not allow an explicit analysis of the 5-minute dispatch effect on the future flexible generation pool. It is reasonable to assume that dispatch volatility is unlikely to reduce from current levels, in the absence of any further mitigation. For example, throughout the study period, in 20% of the hours, hydroelectric generation volumes changed by more than 500 MW. As slower moving thermal and gas units try to respond to these changes, other fast-moving resources must ramp to make up the difference, exposing them to significant dispatch volatility.

The IESO recognizes stakeholder concerns in this area and has implemented various programs to mitigate the dispatch volatility of load following units, but concerns remain. In order to maintain the availability rate of the dispatchable resources presented in the IPSP, the IESO and its stakeholders must continue to address the impact of dispatch issues on flexible generation. These efforts will ensure that the market maintains sufficient drivers to guarantee reliable and efficient load following and dispatch capability.

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6. Surplus Baseload Generation

Surplus baseload generation (SBG) is an over-generation condition that occurs when Ontario's electricity production from baseload facilities such as nuclear and must-run hydroelectric units is greater than market demand.

Surplus baseload generation periods are typically the result of low demand and can be exacerbated by:

- Spring freshet, when hydroelectric stations cannot lower generation output
- The inability of neighbouring jurisdictions to absorb surplus energy in the form of exports
- High production from intermittent resources such as wind generation

Often these events can be foreseen in the planning timeframe. However, sometimes events such as unexpectedly high production of intermittent resources (i.e. under-forecasting from participants) or low export levels to adjacent areas can lead to surplus generation conditions in real-time.

Currently, surplus baseload generation occurs only a few times a year. In the planning timeframe, the IESO's reliability publications send signals to the market to take actions such as rescheduling outages to take advantage of these conditions. Closer to real-time operation, participants may respond to forecast surplus baseload generation by increasing the Ontario demand for electricity or scheduling additional exports during times of very low price signals.

The IPSP includes increases in conservation, which will have a lowering affect on the demand for electricity across the day, and increases in intermittent and embedded generation, both of which can increase the supply even at low demand periods. For these reasons, the frequency, magnitude, and duration of surplus baseload conditions is likely to increase in the future.

Analysis of the OPA data indicated that management of surplus baseload generation in the simulated schedules relied on significant amounts of exports. If these exports failed to materialize in real-time, the IESO would have to take other control actions to maintain reliability. In order to mimic operational conditions, a number of assumptions were made with respect to the schedules provided by the OPA:

- The maximum export schedule considered was capped at 1000 MW**.** This is based on the historical export volumes seen during overnight operation, and during the infrequent surplus baseload generation conditions seen over the last few years. This is consistent with current IESO practice (limited reliance on intertie transactions for reliability planning).

- All thermal generation, gas fired generation, and dispatchable hydroelectric resources were dispatched-off to mitigate surplus conditions, which reflects current practice
- An allowance of 100 MW of surplus baseload generation was considered acceptable in the analysis, as this amount can realistically be managed by generation under contract to provide Automatic Generation Control

6.1 Results of Surplus Baseload Generation Analysis

Surplus baseload generation can be managed through actual operation of the market and its attendant price signals. For example, recent experiences with surplus baseload generation due to export failures resulted in negative Ontario energy market prices, with a significant increase in exports in response. Such prices can be expected during the surplus events seen in the study period. This should encourage domestic consumer response and attract exports beyond the level assumed in the study.

Under existing market rules, the IESO only considers the curtailment of wind resources when all market mechanisms are exhausted, including the reduction in output of nuclear units. The significant amount of surplus baseload generation hours left after dispatching down all thermal, gas and dispatchable hydroelectric units during the periods from 2012-2014 and 2022-2026, led the IESO to analyze the effectiveness of curtailing wind resources. Curtailment of wind and other intermittent resources can be an effective approach when the dispatch down (or complete shut down) of a nuclear unit can lead to reliability concerns in future hours. The effectiveness of wind generation curtailment can be seen by comparing the number of hours of surplus baseload generation under the two columns of Table 3.

Year	Number of hours of Surplus Baseload Generation (no gas, thermal or dispatchable hydroelectric generation in service)	Hours remaining after further action of curtailing wind resources
2010	59 of 8760 Hours	25 of 8760 Hours
2011	115 of 8760 Hours	64 of 8760 Hours
2012	781 of 8784 Hours	435 of 8784 Hours
2013	754 of 8760 Hours	343 of 8760 Hours
2014	788 of 8760 Hours	282 of 8760 Hours
2016	88 of 8784 Hours	3 of 8784 Hours
2018	116 of 8760 Hours	14 of 8760 Hours
2020	140 of 8784 Hours	6 of 8784 Hours
2022	580 of 8760 Hours	114 of 8760 Hours
2024	891 of 8784 Hours	193 of 8784 Hours
2026	857 of 8760 Hours	236 of 8760 Hours

Table 3: Surplus Baseload Generation Results

Reducing a nuclear unit's output can lead to it being unavailable to generate for up to three days. The analysis assumed the worst case for a reduction of a nuclear unit, i.e. the reduction resulted in the unit poisoning out[4], leaving it entirely unavailable for 72 hours. Therefore, before a unit was shut down in the analysis to resolve surplus baseload generation concerns, a verification step was taken to ensure that the remaining available generation could meet Ontario's peak demand over the period required to return the nuclear generator to service.

Given the flexibility of thermal and gas units, any resulting generation shortfalls during the peak hours were resolved by increasing these generators' schedules. Recognizing the possibility of thermal and gas units being on maintenance outage during the extended periods of low demand expected with surplus baseload conditions, a limitation was imposed on the increase to thermal and gas schedules. This limit was set to the larger of the maximum amount scheduled in the previous 24-hour period or 2,000 MW (conservative value based on estimates of fossil and gas availability). Where replacement energy was not available, Table 4 reported these as unresolved hours of surplus baseload generation.

Year	# of Nuclear Unit Shutdowns	# of SBG periods resolved by nuclear shutdown	Remaining SBG Hours
2010	5	4	0
2011	9	7	6
2012	77	36	47
2013	52	31	1
2014	39	25	6
2016	2	1	0
2018	4	4	3
2020	2	1	4
2022	23	16	2
2024	36	26	16
2026	42	25	28

Table 4: Nuclear Unit Shutdowns to Resolve SBG Events

Table 4 lists the results of the analysis that used nuclear generation to reduce unresolved hours of surplus baseload generation. The table includes:

- The number of unit-shutdowns that were required over the entire year,
- The number of surplus periods, lasting 3 days or more, where nuclear unit shutdowns were used to resolve the condition
- The remaining number of surplus condition hours, which could not be resolved through nuclear shutdown, due to insufficient replacement generation for upcoming demand.

Although not considered, the number of surplus baseload generation hours could be further reduced through the use of shallow manoeuvres of nuclear units. Shallow manoeuvres allow

[4] Term "poisoning out" refers to the situation where a nuclear unit reduces reactor power to a level where it can no longer sustain the chain reaction and must shutdown. This occurs when its normal reactor regulating devices cannot overcome the build-up of neutron absorbing isotopes that takes place after a significant power reduction.

nuclear units to partially reduce, without poisoning out and result in a limited restriction on their total subsequent output. Such manoeuvres could limit the impacts to the market by reducing the need for complete shutdown of a nuclear unit and the associated cost of replacement energy.

6.2 Other SBG Management Requirements

With a shrinking proportion of dispatchable generation for load following purposes, fossil and gas generation will be called on to provide energy as a result of peaking demand and fluctuations created by intermittent generators. Non-quick start units will need to be efficiently committed to address load following and operating reserve requirements, and must also be able to shut down during anticipated surplus baseload generation conditions. Committed generators need to respect the technical requirements of units such as minimum load, minimum run-time, maximum number of starts per day, and minimum turnaround time, which could require some generators to continue to operate through the night, potentially adding to the SBG likelihood. The IESO and stakeholders will have to continue their efforts to improve unit commitment processes and to create the market signals and incentives to encourage flexibility in these generators.

The IPSP indicates a forecasted growth of embedded/distributed generation. Embedded generators are generators that are connected to a distribution system or are connected "behind the meter" of an industrial facility. When located close to distribution load centres, these resources can provide benefits to the electricity system by reducing losses, and can often contribute to reduced load on transmission facilities. These generators are not currently monitored by IESO, nor under its dispatch control. This could result in less than optimal management of surplus baseload generation conditions. With the appropriate procedural and technological changes, embedded generation has the potential to enhance operability during periods of surplus baseload generation as well during normal conditions. These changes could include real-time monitoring, availability for dispatch (under specific conditions), appropriate communication protocols, and exposure to effective market signals.

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7. Adequacy Overview

The OPA data was also analyzed for adequacy to assess periods where energy was not served or there were operating reserve shortfalls.

7.1 Periods of Energy Not Served

Energy not served refers to an under-generation condition that occurs when there is insufficient generation to meet Ontario demand. In determining whether an energy not served condition existed for the analysis, a shortfall of 100 MW was considered acceptable, as this amount can realistically be managed by generation under contract to provide Automatic Generation Control. There were no instances of insufficient energy to meet Ontario demand over the entire study period of 2008 to 2026.

7.2 Shortfalls in Operating Reserve

The IESO's operating reserve requirement is based on Northeast Power Coordinating Council Operating Reserve criteria and is roughly equal to one and one-half times the largest single contingency loss. This amount would increase if larger capacity generation units or single-element based contingencies than those presently in service were to materialize. The IPSP preliminary data provided to the IESO does not currently include larger generators or single contingencies than currently exist.

The OPA simulation results did not specifically model all options available to the IESO in meeting operating reserve requirements, and hence at times generated more exports than would actually occur. As a result, when analysing the ability of the Plan to provide sufficient operating reserve, the simulation data resulted in occasional periods of operating reserve shortfalls. During actual operation of the IESO-administered markets, such exports would not be scheduled in the pre-dispatch timeframe, or would be made recallable if the shortfall developed in real-time. In addition, the IESO- administered markets currently have over 600 MW of dispatchable load, which provides a significant amount of operating reserve to the market.

The incidence of operating reserve shortfalls becomes negligible when the market-driven export behaviour and the availability of dispatchable load to provide operating reserve is considered, as shown in Table 5.

Year	IPSP Simulated Schedule After considering Non-Scheduled Exports & Dispatchable Loads
2010	0 of 8760 Hours
2011	0 of 8760 Hours
2012	0 of 8784 Hours
2013	0 of 8760 Hours
2014	0 of 8760 Hours
2016	2 of 8784 Hours
2018	3 of 8760 Hours
2020	1 of 8784 Hours
2022	0 of 8760 Hours
2024	0 of 8784 Hours
2026	1 of 8760 Hours

Table 5: Frequency of Insufficient Operating Reserve

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8. Conclusions and Recommendations for Future Action

The IESO has assessed the operability of the IPSP and concluded that it provides sufficient flexibility to meet future system needs. Current market mechanisms and control actions will allow the IESO to reliably operate the system described in the IPSP.

8.1 Recommendations for Future Action

The assessment identified several opportunities, and in many instances reinforced current IESO initiatives to improve transparency and efficiency in the operation of the power system and electricity market. The IESO and its stakeholders should continue to evolve current operating processes and market incentives to capture these benefits. The IESO has begun initiatives to address these opportunities on several fronts, and will ensure the following are addressed:

Reliability Starts and Unit Commitment – Efficient scheduling of thermal units has been shown to facilitate optimal load following capability. With future reductions in fleet load following capability and the likelihood of increased surplus baseload generation conditions, current commitment programs should be maintained and evolved to meet the needs of the proposed supply mix.

Dispatch Volatility and Load Following - In order to maintain the availability rate of the dispatchable resources presented in the IPSP, the IESO and its stakeholders must continue to address the impact of dispatch volatility on flexible generation. These efforts will ensure that the market maintains sufficient drivers to guarantee reliable and efficient load following and dispatch capability.

Load Following Service (incentives for capability) – Given the shrinking portion of manoeuvrable generation in Ontario's fleet of generators, load following capability will be a generating commodity that will increase in value to the market. Market incentives should be investigated to determine if additional drivers are needed for new generators and loads to provide load following services.

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Mid-Hour Intertie Scheduling – In order to implement the growing magnitude of intertie activity seen in the IPSP simulation data, the IESO should develop an intertie protocol that allows for more frequent scheduling that the current hourly practice. This would serve two purposes: to limit the load following required to accommodate changing intertie schedules, and to allow intertie scheduling to be used as a source of load following in a manner more granular nature than currently available.

Conservation and Demand Management Measures –The continuation and expansion of dispatchable load programs and smart grid technologies should be encouraged as these measures improve operability under all conditions.

Visibility and Control of Embedded Generation – The IESO should work with stakeholders to investigate incorporating increased visibility and control of embedded generation to enhance operability during periods of surplus baseload generation and assist in load following.

Generation Curtailment Options to Manage Surplus Baseload Generation – The future holds an increased likelihood of surplus baseload generation. The current practice of shutting down nuclear units to manage extreme surpluses carries significant risk. As a result, the IESO should perform a review of the prioritization and impact of current generation manoeuvring/shutdowns to manage surplus baseload generation conditions.

Regional Reserve Sharing – The IESO should continue to participate in reserve sharing programs that allow for portions of operating reserve to be shared between neighbouring jurisdictions. These programs reduce the associated costs and effectively free-up manoeuvrable generation for other services such as load following.

– End of Section –

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