**ONTARIO ENERGY BOARD**

**EB-2016-0152**

**IN THE MATTER OF** the *Ontario Energy Board Act*, 1998, S. O. 1998, c. 15, Schedule B;

**AND IN THE MATTER OF** an application by Ontario Power Generation (OPG) pursuant to section 78.1 of the *Ontario Energy Board Act*, 1998 for payment amounts for the period from January 1, 2017 to December 31, 2021.

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# COMPENDIUM

**(Environmental Defence Motion For Full and Adequate Interrogatory Responses)**

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Note: The documents in tabs 2, 7, 9, 12-15, and 17 are excerpts of the relevant document.

**ONTARIO ENERGY BOARD**

**EB-2016-0160**

**IN THE MATTER OF** the *Ontario Energy Board Act*, 1998, S. O. 1998, c. 15, Schedule B;

**AND IN THE MATTER OF** an application by Ontario Power Generation (OPG) pursuant to section 78.1 of the *Ontario Energy Board Act*, 1998 for for payment amounts for the period from January 1, 2017 to December 31, 2021.

# NOTICE OF MOTION

Environmental Defence will make a motion to the Ontario Energy Board ("Board") on December 16, 2016, at the offices of the Board, 2300 Yonge Street, 25th Floor, Toronto, Ontario.

**PROPOSED METHOD OF HEARING:** This motion is to be heard orally.

**THE MOTION IS FOR:**

1. An order that OPG provide full and adequate responses to Environmental Defence interrogatories 27-30, 33, 35, and 39 and undertakings JT1.17 (parts G, I, and J) and JT2.05.

**THE GROUNDS FOR THE MOTION ARE:**

***Overview and Relevance***

2. This motion concerns the costs that OPG seeks to recover from consumers for the Pickering Nuclear Generating Station ("Pickering"). Those costs are extremely high, amounting to approximately **$7.5 billion** over the test period.[1] Pickering's non-fuel operating costs per kWh are the highest of all nuclear stations in North America and its forced loss rate is 6.5 times the North American average and 13.3 times the top

[1] JT2.2.

quartile.[2] All of Environmental Defence's questions relate to whether the costs sought by OPG to operate Pickering are just and reasonable.

3. Although there are many ways to assess the reasonableness of Pickering's costs, Environmental Defence is focusing on reasonableness vis-à-vis a proxy for a "market price," namely the least-cost generation alternative to Pickering. Rate setting often strives to be a surrogate for a competitive market. Based on that principle, Pickering should not receive costs on a per MWh basis that are higher than the least-cost alternative. In the very least, this proxy for a "market price" should be considered when approving the rates relating to Pickering. To make that argument, Environmental Defence seeks to test the evidence that has been filed by OPG in this proceeding relating to the purported net benefit of Pickering vis-à-vis alternatives.

4. This "market price" argument applies after August, 2018, at which point the Clarington Transformer Station will be completed. Pickering is currently needed in order to keep the lights on in the Eastern GTA. But after the Clarington Transformer Station is built, Pickering is just one of the potential options to meet demand. At that point, Environmental Defence believes Pickering's costs should be capped at the level of the least expensive alternative.

5. Environmental Defence is *not* asking this Board to decide system planning issues or to decide whether Pickering should continue operate. OPG has mistakenly assumed that this is what Environmental Defence is seeking to do, perhaps due to the references to "alternatives." However, again, that is *not* the case. Environmental Defence is seeking information about the cost of other generation options as part of an assessment of the reasonableness of the costs sought by OPG, *not* in an attempt to obtain an order that other alternatives be pursued instead of Pickering.

6. OPG has suggested that Pickering would provide $300 million in net benefits based on an IESO assessment that was filed. This would suggest that it is the least cost alternative. However, that assessment is invalid and out of date, including because:

[2] OPG 2015 Nuclear Benchmarking Report, p. 69 & 100 [F2-1-1, attachment 1].

a. It considers only one alternative, building new gas plants, and ignores a suite of lower-cost alternatives including greater use of non-firm intertie transactions, demand response, capacity auctions,[3] Quebec firm power imports, and so on;

b. It underestimates Pickering's costs;

c. It relies on old gas price forecasts, which have subsequently dropped significantly;

d. It fails to account for Pickering's high forced outage rates; and

e. It assumes the appropriate benchmark for cost-benefit purposes is Pickering's continued operation to 2020 rather than to August 31, 2018.[4]

7. Many of Environmental Defence's questions relate to these alleged problems with this net benefit analysis.

8. This overriding question for the Board in this motion is whether Environmental Defence is allowed to argue that the costs sought by OPG are unreasonable based on its "market price" argument and based on a critique of the cost-benefit analysis evidence filed in this proceeding. OPG has declined to answer a significant number of interrogatories relating to those issues. Those specific interrogatories and undertakings at issue are discussed in detail below, with the first four most important interrogatories/undertakings addressed first.

***ED Interrogatory #39***

9. This interrogatory asked that the IESO's net-benefit analysis regarding Pickering be recalculated based on a comparison with a different alternative. The IESO compared Pickering to one option: building new gas plants. Instead, we asked that Pickering be compared to a combination of an electricity trade agreement with Quebec plus the next least-cost sources. We asked that this be done for August 31, 2018, forward.

10. OPG declined to provide a response. Environmental Defence raised this question again at the technical conference and OPG responded as follows:

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[3] See Issue 6.5, IESO response to GEC #56.

[4] According to the IESO's analysis, the net benefit of the Pickering extension is substantially lower if the reference point is 2018, not 2020. See F2-2-3, Attachment 1, page 61.

> OPG declines to respond to this request on the basis of relevance. As explained in JT1.17(n), the purpose of this proceeding is not to consider system planning or to determine whether Pickering should continue to operate. Furthermore, as noted in JT1.17(m), as a practical matter, there is no basis for assuming an August 31, 2018 shut-down date.[5]

11. OPG's refusal is not justified. As noted in paragraphs 2 to 8 above, Environmental Defence is *not* asking the board to determine whether Pickering should continue to operate as suggested by OPG. Instead, it is legitimately testing the net-benefit evidence filed by OPG. It is also legitimately seeking information to support its argument that Pickering's costs should be capped at a proxy for a "market price," namely the least-costly generation alternative. Again, August 31, 2018, is a key date because by that time Pickering will simply be one among many generation options to keep our lights on, and therefore should have its price set with reference to the cost of other generation options (i.e. a market price proxy).

12. The IESO also noted that hydro power imports from Quebec are insufficient as a sole alternative to Pickering because Quebec has a capacity shortfall during their winter peak.[6] However, that is no reason that an analysis cannot be done using a combination of alternatives including as much cheap Quebec hydro power as possible plus the next least-cost alternatives during Quebec's winter peak (when summer peaking jurisdictions such as Ontario tend to have available capacity). This is precisely what Environmental Defence requested – a comparison with a combination of the least-cost alternatives.

13. Finally, it is worthy to note that in October, 2016, Ontario signed an agreement with Quebec for 2 TWh per year of power at a cost of 5 cents per kWh according to news reports. Ontario's total import capability from Quebec is 16.5 to 18.5 TWh. This deal with Quebec was completed following the IESO's net-benefit analysis of Pickering and had not been reflected in that analysis.

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[5] JT1.17, attachment P.
[6] Schedule 7 ED-039.

*ED Interrogatory #35*

14. Part (a) of this interrogatory refers to the IESO's statement that there is "ongoing contingency planning in case Pickering extended operations does not proceed."[7] Environmental Defence sought a description of the contingency plan. No response was provided on the basis that the consideration of options is still ongoing and the "costs and other attributes of options will be better defined as the planning further progresses."[8] However, a description of the current iteration of the contingency plan could be provided. This discussion of other options will be relevant to Environmental Defence's contention that the costs of Pickering should be set with reference to the cost of other generation options (i.e. the market price argument discussed above).

15. Part (b) of this interrogatory requests a comparison of the cost and benefits of operating Pickering beyond August 31, 2018 versus meetings Ontario's peak day generation requirements with a set of cost-effective alternatives.[9] OPG declined to answer this on the following grounds:

> [T]he requested information is not relevant to deciding the issue before the OEB regarding the cost of Pickering Extended Operation. As the OEB has recognized in several prior decisions, the purpose of this proceeding is to establish payment amounts and not to decide system planning issues or determine whether specific generation facilities should continue to operate.[10]

16. Again, as noted in paragraphs 2 to 8 above, Environmental Defence is *not* asking the Board to determine whether Pickering should continue to operate as suggested by OPG. Instead, it is legitimately testing the net-benefit evidence filed by OPG. It is also legitimately seeking information to support its argument that Pickering's costs should be capped at a proxy for a "market price," namely the least-costly generation alternative.

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[7] Ex. F2-2-3, Attachment 1, Page 10.
[8] Schedule 7 ED-035.
[9] Those alternatives are: "a) curtailing natural gas-fired electricity exports; b) procuring more demand response resources; c) procuring more energy efficiency resources; d) importing renewable energy from neighbouring jurisdictions; and e) procuring more Made-in-Ontario green energy; and f) by the least-cost combination of options (a) to (e) inclusive."
[10] JT1.17, attachment N.

***ED Interrogatory #30***

17. This interrogatory requested that the IESO's cost-benefit analysis of Pickering Extended Operations be recalculated based on the IESO's best *current* estimates of the key variables listed in the interrogatory. Although the IESO has stated that it has not updated its assessment, that is not a justification for not doing so. The IESO has not stated that it would be overly onerous to plug updated variables into its model to provide a more current assessment. This would clearly be relevant, both to a legitimate testing of the evidence filed on the record and to Environmental Defence's "market price" argument.

18. There are a number of ways in which the cost-benefit analysis is clearly out-of-date and requires an update. For example:

   a. Ontario signed an agreement in October 2016 with Quebec for 2 TWh per year of power at a cost of 5 cents per kWh. This occurred long after the cost-benefit analysis was completed. This would clearly impact the net cost/benefit of Pickering as well as the cost of a suite of alternatives to Pickering.

   b. Gas prices have dropped significantly. The IESO's current gas price forecasts are 43% lower for January 2017 and 21% lower for December 2024 as compared to those used in the cost-benefit analysis.[11]

   c. OPG has provided evidence in this proceeding showing that the actual Pickering OM&A costs are over **5 times** higher than the OM&A costs included the cost/benefit analysis for the test period. This is highly relevant; the IESO noted that Pickering Extended Operations would not be cost-effective it its costs were 15-22% greater than the estimates provided by OPG. They are, in fact, over 500% greater. The actual OM&A costs for the test period and those included in the cost/benefit analysis are compared below:

| | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|---|
| Pickering OM&A Included in Cost/Benefit Analysis (per ED#28) | $35 | $79 | $145 | $218 | $987 | $1,464 |
| Actual Pickering OM&A (per JT2.4) | $1,429 | $1,491 | $1,529 | $1,474 | $1,524 | $7,447 |

[11] Schedule 7 ED-028; Schedule 7 ED-029.

19. The cost/benefit analysis is very out of date. Environmental Defence asks that the model re recalculated with updated variables (including the assessment relative to Pickering to 2018 at F2-2-3, attachment 1, p. 42). To clearly communicate which variables have been updated, Environmental Defence asks that the actual underlying spreadsheets be provided.

***Undertaking JT2.05***

20. OPG undertook to reconcile Pickering's total OM&A cases with the costs that were included in the cost/benefit analysis of Pickering. The undertaking included an agreement to: "provide a table of the Pickering costs that were not included for the purposes of … this cost-benefit analysis, along with an explanation as to why they were not included".[12]

21. OPG did not provide the requested table showing the costs that were not included in the cost-benefit analysis. This is necessary to reconcile the total OM&A figures with those included in the analysis.

22. OPG also did not fully list or justify the costs excluded from the cost/benefit analysis. For example, for 2021, approximately $644 million in operating costs were excluded.[13] The items that are listed and discussed in the undertaking response add up only to $141 million, which leaves the vast majority of the excluded costs unidentified and unexplained. Furthermore, OPG only address 2021 whereas in other years the excluded costs are even high (e.g. $1,642 in 2019).[14]

23. The OM&A numbers are central to the cost/benefit analysis. Environmental Defence requests a complete response, including a full reconciliation table as requested and an explanation for each cost item that is excluded from the cost/benefit analysis.

***ED Interrogatory #27***

24. This interrogatory requested the electronic spreadsheets underlying the economic assessment of Pickering. The spreadsheets were not provided. These spreadsheets are

[12] Technical Conference Transcript Day 2, p. 35, lns. 15-20.
[13] See JT2.5 and JT2.4.
[14] See JT2.5 and JT2.4.

relevant as they would allow Environmental Defence to recalculate the economic assessment based on a set of assumptions that it believes to be more accurate. It is not onerous to provide these spreadsheets as they already exist and this would greatly assist in testing the evidence put forward by the applicant.

***ED Interrogatory #28***

25. In part (b) Environmental Defence asked for Pickering's available capacity at the time of Ontario's annual peak demand. The response included this information for the years 2015 – 2019. Environmental Defence requests the information for 2020 – 2024 as well. Although these dates are partly outside the test period, they are relevant because they match the period covered by the IESO's net benefit analysis. That analysis can only be properly tested if intervenors can explore all the years covered by the original analysis.

***ED Interrogatory #29***

26. This interrogatory asked for the IESO's "best current estimates" of the input assumptions for its Pickering extension study and for the responses to be fully justified. The response contained some specific gaps that Environmental Defence requests be addressed:

   a. In part (b) Environmental Defence asked for the IESO's best "current" estimate of Pickering's forecast *available* capacity at the time of Ontario's annual peak demand. The response (i) provides the *installed* capacity figures for 2020 and 2022-2024, which fail to account for expected forced outages, and (ii) provided figures from the "Ontario Planning Outlook" report without confirming that those are the latest and current figures. Environmental Defence asks that those issues be addressed and that the IESO state their methodology and assumptions for calculating Pickering's available capacity at the time of Ontario's peak demand as requested in the interrogatory.

   b. In part (d) Environmental Defence asked for the IESO's best "current" estimate of the avoided generation by fuel type as a result of Pickering's extended operation. The IESO provided the "original" estimates that they provided in response to ED

#28. Environmental Defence requests the best current estimate or a justification as to why the estimate has not changed.

c. In part (e) Environmental Defence asked for the IESO's best "current" estimate of Pickering's forced outage rate, but the IESO referred again to its original estimate. Environmental Defence requests the best current estimate or a justification as to why the estimate has not changed.

d. In part (f) Environmental Defence asked for the IESO's "current" best estimate of the "available" capacity of new gas-fired peaking capacity as a percent of its installed capacity. In its response it stated that its "Indicative Capacity Contribution" is 89%. We request confirmation that this is identical to "available" capacity.

e. In part (g) Environmental Defence asked for the IESO's "best current estimate" of Pickering's fuel and operating costs per kWh, but the IESO did not provide it. As noted above, there is a huge disparity between the "incremental" costs that OPG provided to the IESO for its cost/benefit analysis and Pickering's total costs as provided by OPG in this proceeding. In light of this disparity, Environmental Defence requests the IESO's best current estimate, or a justification as to why its estimate has not changed.

f. In part (h) Environmental Defence asked for the IESO's "best current estimate" of Pickering's incremental capital expenditures, but the IESO did not provide it. Environmental Defence requests this information

g. In part (l) Environmental Defence asked for Ontario's incremental peaking capacity requirements if Pickering is not extended. Environmental Defence requests confirmation that the figures provided are indeed the current estimates versus the original estimates used in the cost/benefit analysis.

h. In part (m) Environmental Defence asked for the IESO's best estimate of meeting the NPCC resource adequacy criterion by: a) domestic supply sources; b) demand response resources; c) energy efficiency resources; and d) electricity imports from neighbouring jurisdictions. OPG and the IESO declined to provide this information and merely repeated that the cost of new gas-fired peaking capacity is used as a "proxy" for the costs of the other options. This answer is not satisfactory since the cost of some or all of these options could be significantly lower. For example, the maximum capacity shortage will be 2,316 MW and according to the IESO, Ontario has the ability to import 5,200 MW from neighbouring jurisdictions. Imports are just one example of the alternative options that are less expensive than the cost of new gas-fired peaking capacity.

***ED Interrogatory #33***

27. This interrogatory asked for information about the quantity and price/cost of surplus baseload generation and curtailed wind, water and solar generation due to Pickering's extended operation. OPG declined to answer this based on relevance.[15] However, this information is relevant to the market price issue discussed above (i.e. whether Pickering is the least cost alternative to meet our electricity needs and hence whether all its costs should be included in rates).

28. The forecasts of surplus generation and curtailed generation will help determine how much of Pickering's forecast generation will be displacing Ontario gas-fired generation to meet our domestic electricity needs. This will help determine feasibility of water power imports from Quebec and energy efficiency investments as potential alternatives in a cost-benefit analysis of Pickering (because it may not be necessary to assume that 100% of Pickering's forecast generation would need to be replaced).

29. The forecast revenues from Pickering's electricity exports and the forecast cost of curtailed water, wind and solar generation are also needed to properly assess and test a cost-benefit analysis of Pickering.

***Undertaking JT1.17 G (Re ED Interrogatory #28)***

30. Undertaking Response JT1.17, Attachment G, states that the Pickering extended operations cost benefit analysis assumes the following forced outage rates for Pickering between 2016 and 2022:

[15] JT1.17, attachment M.

a. Between 7.0% and 7.2% for units 1 & 4; and

b. 4% for Units 5 – 8.

31. Environmental Defence asks that a more fulsome response be provided which explains how those figures were derived, especially in light of the following:

a. According to the IESO's *Ontario Margin Reserve Requirements: 2016 -2020* (December 21, 2015), the available capacity of thermal generating units are derived using an "analysis of a rolling five-year history of actual forced outage data" (p. 10);

b. Pickering's average forced outage rate between 2010 and 2015 was 8.5% (Issue 5.1, Board Staff Interrogatory #83);

c. Pickering's rolling average forced loss rate in 2014 as defined by OPG's 2015 Nuclear Benchmarking Report was 10.8% [Response to ED #28 (e)]; and

d. Pickering's average forced outage rate between 2006 and 2015 was 12.38% (ED #19).

***Undertaking JT1.17, Attachment I (re: ED Interrogatory #34)***

32. OPG undertook to provide the following information: "for the years 2021 to 2024 inclusive: please provide for each year the IESO's estimate of: a) Pickering's installed capacity; and b) available capacity at the summer peak. Please describe the IESO's methodology and show its calculations for calculating the difference between installed and available capacity." This was not done and no explanation was provided as to why not. According to the IESO's *Ontario Reserve Margin Requirements: 2016-2020,* (December 21, 2015), the available capacity of thermal generating units are derived using an "analysis of a rolling five-year history of actual forced outage data" (p. 10). Environmental Defence asks that the requested information be provided.

***Undertaking JT1.17, Attachment J (re: ED Interrogatory #36)***

33. Environmental Defence asked for the MW adjustments made to account for the forced outage rates of Pickering and, if no adjustments were made, for this be reconciled with the IESO's *Ontario Reserve Margin Requirements: 2016 – 2020* report, which states:

"Equivalent forced outage rates (EFOR) of existing units are derived based on analysis of a rolling five-year history of actual forced outage data." [p. 10]

34. The data provided showed that the Pickering's available capacity for 2016, 2019, and 2020 equals its installed capacity (i.e. no adjustments were made for forced outage rates). Environmental Defence asks that this be reconciled with the *Reserve Margin* report.

***Conclusion***

35. OPG has put forward an IESO analysis purporting to show that Pickering will provide $300 million in net benefits despite being the most expensive nuclear station in North America in terms of non-fuel operating costs and despite the very high test period costs of $7.5 billion.[16] Environmental Defence respectfully submits that it should be permitted to test and challenge this evidence because it has been put forward in support of OPG's application and because it is relevant to Environmental Defence's contention that the costs for Pickering should be capped at the level of the least-cost alternatives as a proxy for a market price.

**THE FOLLOWING DOCUMENTARY EVIDENCE will be used at the hearing of the motion:**

a. Evidence on the record in this proceeding; and

b. Any further evidence as counsel may advise and the Board may permit.

**Date: December 2, 2016**

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[16] JT2.2; OPG 2015 Nuclear Benchmarking Report, p. 69 [F2-1-1, attachment 1].


Achieving Balance
Ontario's Long-Term Energy Plan
Ontario

# In Summary

## Nuclear

- Ontario will not proceed at this time with the construction of two new nuclear reactors at the Darlington Generating Station. However, the Ministry of Energy will work with Ontario Power Generation (OPG) to maintain the site licence granted by the Canadian Nuclear Safety Commission.
- Nuclear refurbishment is planned to begin at both Darlington and Bruce Generating Stations in 2016.
- During refurbishment, both OPG and Bruce Power will be subject to the strictest possible oversight to ensure safety, reliable supply and value for ratepayers.
- Nuclear refurbishment will follow seven principles established by the government, including minimizing commercial risk to the government and the ratepayer, and ensuring that operators and contractors are accountable for refurbishment costs and schedules.
- The Pickering Generating Station is expected to be in service until 2020. An earlier shutdown of the Pickering units may be possible depending on projected demand going forward, the progress of the fleet refurbishment program, and the timely completion of the Clarington Transformer Station.
- Ontario will support the export of our home-grown nuclear industry expertise, products and services to international markets.

## Renewable Energy

- By 2025, 20,000 MW of renewable energy will be online, representing about half of Ontario's installed capacity.
- Ontario will phase in wind, solar and bioenergy over a longer period than contemplated in the 2010 LTEP, with 10,700 MW online by 2021.
- Ontario will add to the hydroelectricity target, increasing the province's portfolio to 9,300 MW by 2025.
- Recognizing that bioenergy facilities can provide flexible power supply and support local jobs in forestry and agriculture, Ontario will include opportunities to procure additional bioenergy as part of a new competitive process.
- Ontario will review targets for wind, solar, bioenergy and hydroelectric annually as part of the Ontario Energy Report.
- The Ministry of Energy and the OPA are developing a new competitive procurement process for future renewable energy projects larger than 500 kilowatts (kW), which will take into account local needs and considerations. The ministry will seek to launch this procurement process in early 2014.
- Ontario will examine the potential for the microFIT program to evolve from a generation purchasing program to a net metering program.

## Natural Gas/Combined Heat and Power

- Natural gas-fired generation will be used flexibly to respond to changes in provincial supply and demand and to support the operation of the system.
- The OPA will undertake targeted procurements for Combined Heat and Power (CHP) projects that focus on efficiency or regional capacity needs, including a new program targeting greenhouse operations, agri-food and district energy.

## Clean Imports

- Ontario will consider opportunities for clean imports from other jurisdictions when such imports would have system benefits and are cost effective for Ontario ratepayers.

## Toronto Area

### New Copeland Transformer Station (formerly Bremner Transformer Station)

***Est. Cost: $195 million***

***Exp. In-Service: 2014****

Downtown Toronto's power distribution system is currently served by five transformer stations. The new Copeland Transformer Station will ensure reliable supply for the fast-growing downtown core, and take stress off the existing Windsor Transformer Station, which currently serves 9 of the 10 largest buildings in Toronto. It will also provide power to the redeveloped waterfront.

This new station in downtown Toronto will help to alleviate the strain on neighbouring stations and will help to serve the growing customer base. It will also permit critical asset renewal at neighbouring stations to take place.

*First Phase. Source: Toronto Hydro

## Clarington Transformer Station

### New Transformer Station

***Est. Cost: $297 million***

***Exp. In-Service: 2017***

The Pickering Nuclear Generating Station is a critical source of electricity for the eastern part of the Greater Toronto Area. The Clarington Transformer Station, which will connect high voltage 500 kV lines and 230 kV lines in the area, will be required to come into service before Pickering Generating Station can be shut down, to ensure reliable supply for customers in the Eastern Greater Toronto Area.

The station will also enhance the reliability of supply to parts of Durham region. The project is pending a decision from the Minister of the Environment on whether an individual Environmental Assessment is required.

## In Summary

- Hydro One will be expected to begin planning for a new Northwest Bulk Transmission Line to increase supply and reliability to the area west of Thunder Bay. The area faces growth in demand, some of which is beyond what today's system can supply. Hydro One and Infrastructure Ontario will be expected to work together to explore ways to ensure cost-effective procurement related to the line.
- Connecting remote northwestern First Nation communities is a priority for Ontario. Ontario will continue to work with the federal government to connect remote First Nation communities to the electricity grid or explore on-site alternatives for the few remaining communities where there may be more cost-effective solutions to reduce diesel use.
- All regions of the province can expect timely local transmission enhancements as needs emerge. Upgrades and investments will meet system goals, such as maintaining or improving reliability or providing the infrastructure necessary to support growth.

## ED Interrogatory #28

**Issue Number: 6.5**
**Issue:** Are the test period expenditures related to extended operations for Pickering appropriate?

### Interrogatory

**Reference:**
Reference: "Pickering extension to 2022/2024 yields a net benefit in the range of $0.3B-$0.6B…" Exhibit F2-2-3, Attachment 1, Page 6 of 116

With reference to the above captioned study, please provide its assumptions with respect to the following inputs for each year of its analysis:

(a) Pickering's total installed capacity (MW);

(b) Pickering's available capacity (MW) at the time of Ontario's peak annual demand;

(c) Pickering's generation (MWh);

(d) The avoided generation (MWh), by fuel type, as a result of Pickering's extended operation;

(e) Pickering's rolling average forced loss rate as defined by OPG's *2015 Nuclear Benchmarking Report;*

(f) The installed capacity (MW) of the replacement peaking generation capacity;

(g) The available capacity (MW) of the replacement peaking generation capacity at the time of Ontario's peak annual demand;

(h) Pickering's fuel and operating cost per kWh;

(i) Pickering's incremental capital expenditures to permit its extension to 2022/24;

(j) The natural gas price at Henry Hub;

(k) Ontario's carbon price;

(l) Ontario's incremental peaking requirements (MW) to meet the NPCC resource adequacy criterion if Pickering is not extended to 2022/24; and

(m) Ontario's cost per MW of incremental peaking requirements to meet the NPCC resource adequacy criterion if Pickering is not extended to 2022/24.

**Response**

The following response has been prepared by the IESO, except for part (e), which has been provided by OPG:

(a) The following table summarizes Pickering's total installed capacity (MW) in different scenarios:

| | Case with +65 TWh of Pickering Production, Pickering to 2020 | Case with +65 TWh of Pickering Production, Pickering to 2022/2024 | Case with +62 TWh of Pickering Production, Pickering to 2020 | Case with +62 TWh of Pickering Production, Pickering to 2022/2024 |
|---|---|---|---|---|
| 2015 | 3094 | 3094 | 3094 | 3094 |
| 2016 | 3094 | 3094 | 3094 | 3094 |
| 2017 | 3094 | 3094 | 3094 | 3094 |
| 2018 | 3094 | 3094 | 3094 | 3094 |
| 2019 | 3094 | 3094 | 3094 | 3094 |
| 2020 | 3094 | 3094 | 3094 | 3094 |
| 2021 | 0 | 3094 | 0 | 3094 |
| 2022 | 0 | 3094 | 0 | 3094 |
| 2023 | 0 | 2064 | 0 | 2064 |
| 2024 | 0 | 2064 | 0 | 2064 |

(b) The following table summarizes Pickering's estimated available capacity (MW) at the time of Ontario's peak annual demand. The available capacity is lower than the installed capacity shown in part (a) because of forced and planned outages among Pickering units.

| | Case with +65 TWh of Pickering Production, Pickering to 2020 | Case with +65 TWh of Pickering Production, Pickering to 2022/2024 | Case with +62 TWh of Pickering Production, Pickering to 2020 | Case with +62 TWh of Pickering Production, Pickering to 2022/2024 |
|---|---|---|---|---|
| 2015 | 2579 | 2579 | 2579 | 2579 |
| 2016 | 2578 | 2578 | 2578 | 2578 |
| 2017 | 2579 | 2063 | 2063 | 1547 |
| 2018 | 2064 | 2063 | 2064 | 2063 |
| 2019 | 2579 | 2063 | 2064 | 2063 |
| 2020 | 3094 | 3094 | 3094 | 2579 |
| 2021 | 0 | 3094 | 0 | 3094 |
| 2022 | 0 | 3094 | 0 | 3094 |
| 2023 | 0 | 2064 | 0 | 2064 |
| 2024 | 0 | 2064 | 0 | 2064 |

(c) The following table summarizes Pickering's generation (MWh) in different scenarios:

| | Case with +65 TWh of Pickering Production, Pickering to 2020 | Case with +65 TWh of Pickering Production, Pickering to 2022/2024 | Case with +62 TWh of Pickering Production, Pickering to 2020 | Case with +62 TWh of Pickering Production, Pickering to 2022/2024 |
|---|---|---|---|---|
| 2015 | 23,887,836 | 23,887,836 | 23,887,836 | 23,887,836 |
| 2016 | 21,269,076 | 21,269,076 | 21,269,076 | 21,269,076 |
| 2017 | 20,130,936 | 19,240,032 | 20,130,936 | 19,240,032 |
| 2018 | 20,585,928 | 19,300,818 | 20,585,928 | 19,424,418 |
| 2019 | 21,442,720 | 19,593,600 | 20,651,680 | 19,049,760 |
| 2020 | 24,289,248 | 20,884,154 | 23,930,808 | 19,902,158 |
| 2021 | - | 19,730,040 | - | 18,963,000 |
| 2022 | - | 21,301,800 | - | 20,312,064 |
| 2023 | - | 14,836,032 | - | 13,956,768 |
| 2024 | - | 16,716,336 | - | 16,295,280 |

(d) The following tables summarize the avoided generation (MWh) by fuel type as a result of Pickering's extended operation in the plus 65 TWh of Pickering Production case. Blue and positive numbers represent increase in production and red and negative numbers represent decrease in production as a result of Pickering's extended operation. Please note that besides Ontario resources, Pickering's extended operation also has impact on the transactions of interconnections.

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|---|
| Gas | 0 | 0 | **332,680** | **274,744** | **470,923** | **456,172** | **-6,756,544** | **-6,473,855** | **-4,730,629** | **-4,167,951** |
| Hydroelectric | 0 | 0 | **19,589** | **61,943** | **99,731** | **303,070** | **-373,796** | **-183,024** | **-106,101** | **-228,202** |
| Wind | 0 | 0 | **30,636** | **19,706** | **21,952** | **213,356** | **-42,286** | 0 | 0 | **-11,202** |

The following tables summarize the avoided generation (MWh) by fuel type as a result of Pickering's extended operation in the plus 62 TWh of Pickering Production case. Blue and positive numbers represent increase in production and red and negative numbers represent decrease in production as a result of Pickering's extended operation. Please note that besides Ontario resources, Pickering's extended operation also has impact on the transactions of interconnections.

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|---|
| Gas | 0 | 0 | **332,680** | **209,640** | **351,228** | **763,473** | **-6,424,056** | **-6,111,821** | **-4,473,760** | **-4,108,400** |
| Hydroelectric | 0 | 0 | **19,589** | **61,943** | **83,710** | **287,308** | **-357,001** | **-182,338** | **-99,313** | **-219,580** |
| Wind | 0 | 0 | **30,636** | **19,706** | **16,050** | **140,642** | **-28,515** | 0 | 0 | **-11,202** |

(e) Pickering's rolling average forced loss rate in 2014 as defined by OPG's 2015 Nuclear Benchmarking Report was 10.08% (see Ex. F2-1-1 Attachment 1, p. 51).

(f) The following table summarizes the installed capacity (MW) of the replacement generation capacity.

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|---|
| Capacity Deficit of the case of Pickering to 2020 | 0 | 0 | 0 | 0 | 0 | 0 | 2,316 | 2,301 | 2,931 | 1,090 |
| Capacity Deficit of the case of Pickering to 2022/2024 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 867 | 0 |
| Installed capacity (MW) of replacement peaking generation capacity | 0 | 0 | 0 | 0 | 0 | 0 | 2,316 | 2,301 | 2,064 | 1,090 |

(g) The answer is the same as part (f). For simplicity, it is assumed that 100% of replacement peaking generation capacity is available at the time of Ontario's peak annual demand.

(h) The following table summarizes Pickering's fuel cost per KWh (2015 real cents per KWh). The OM&A expenditures is included in the answer of part (i). These values were provided to the IESO by OPG.

| | Case with +65 TWh of Pickering Production, Pickering to 2020 | Case with +65 TWh of Pickering Production, Pickering to 2022/2024 | Case with +62 TWh of Pickering Production, Pickering to 2020 | Case with +62 TWh of Pickering Production, Pickering to 2022/2024 |
|---|---|---|---|---|
| 2016 | 0.58 | 0.58 | 0.58 | 0.58 |
| 2017 | 0.57 | 0.57 | 0.57 | 0.57 |
| 2018 | 0.54 | 0.54 | 0.54 | 0.54 |
| 2019 | 0.53 | 0.53 | 0.53 | 0.53 |
| 2020 | 0.53 | 0.53 | 0.53 | 0.53 |
| 2021 | | 0.53 | | 0.53 |
| 2022 | | 0.53 | | 0.53 |
| 2023 | | 0.54 | | 0.54 |
| 2024 | | 0.54 | | 0.54 |

(i) The following table summarizes Pickering's incremental capital and total OM&A expenditures (2015 real $M) to permit its extension to 2022/24. These values were provided to the IESO by OPG.

| 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|
| $7 | $35 | $79 | $145 | $218 | $987 | $902 | $631 | $494 |

(j) The following table summarizes the projected natural gas price at Henry Hub (2015 real US$/MMBTU). Sensitivity cases were also considered.

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 4.38 | 4.36 | 4.27 | 3.95 | 3.95 | 3.97 | 3.99 | 3.99 | 4.00 | 4.01 | 4.04 | 4.19 |
| 2016 | 4.99 | 4.96 | 4.87 | 4.52 | 4.52 | 4.54 | 4.57 | 4.57 | 4.58 | 4.60 | 4.69 | 4.87 |
| 2017 | 5.54 | 5.50 | 5.40 | 5.04 | 5.05 | 5.07 | 5.10 | 5.10 | 5.11 | 5.13 | 5.24 | 5.45 |
| 2018 | 5.53 | 5.50 | 5.40 | 5.04 | 5.04 | 5.06 | 5.10 | 5.10 | 5.10 | 5.12 | 5.24 | 5.45 |
| 2019 | 5.53 | 5.50 | 5.39 | 5.04 | 5.04 | 5.06 | 5.09 | 5.10 | 5.10 | 5.12 | 5.23 | 5.44 |
| 2020 | 5.53 | 5.49 | 5.39 | 5.03 | 5.04 | 5.06 | 5.09 | 5.09 | 5.10 | 5.12 | 5.23 | 5.44 |
| 2021 | 5.52 | 5.49 | 5.39 | 5.03 | 5.03 | 5.05 | 5.09 | 5.09 | 5.09 | 5.11 | 5.23 | 5.43 |
| 2022 | 5.52 | 5.49 | 5.38 | 5.03 | 5.03 | 5.05 | 5.08 | 5.09 | 5.09 | 5.11 | 5.22 | 5.43 |
| 2023 | 5.52 | 5.49 | 5.38 | 5.03 | 5.03 | 5.05 | 5.08 | 5.09 | 5.09 | 5.11 | 5.22 | 5.43 |
| 2024 | 5.52 | 5.49 | 5.38 | 5.03 | 5.03 | 5.05 | 5.08 | 5.09 | 5.09 | 5.11 | 5.22 | 5.43 |
| 2025 | 5.52 | 5.49 | 5.38 | 5.03 | 5.03 | 5.05 | 5.08 | 5.09 | 5.09 | 5.11 | 5.22 | 5.43 |
| 2026 | 5.52 | 5.49 | 5.38 | 5.03 | 5.03 | 5.05 | 5.08 | 5.09 | 5.09 | 5.11 | 5.22 | 5.43 |
| 2027 | 5.52 | 5.49 | 5.38 | 5.03 | 5.03 | 5.05 | 5.08 | 5.09 | 5.09 | 5.11 | 5.22 | 5.43 |
| 2028 | 5.52 | 5.49 | 5.38 | 5.03 | 5.03 | 5.05 | 5.08 | 5.09 | 5.09 | 5.11 | 5.22 | 5.43 |
| 2029 | 5.52 | 5.49 | 5.38 | 5.03 | 5.03 | 5.05 | 5.08 | 5.09 | 5.09 | 5.11 | 5.22 | 5.43 |
| 2030 | 5.52 | 5.49 | 5.38 | 5.03 | 5.03 | 5.05 | 5.08 | 5.09 | 5.09 | 5.11 | 5.22 | 5.43 |
| 2031 | 5.52 | 5.49 | 5.38 | 5.03 | 5.03 | 5.05 | 5.08 | 5.09 | 5.09 | 5.11 | 5.22 | 5.43 |
| 2032 | 5.52 | 5.49 | 5.38 | 5.03 | 5.03 | 5.05 | 5.08 | 5.09 | 5.09 | 5.11 | 5.22 | 5.43 |

(k) Ontario's carbon price is zero in all scenarios.

(l) The assessment of replacement peaking generation capacity in part (f) accounts for the NPCC resource adequacy criterion.

(m) As shown in EB-2016-0152 Exhibit F2-2-3 Attachment 1 Page 93 of 116, additional peaking requirements are assumed to be met by new unspecified capacity based resources priced at SCGT (represents the least-cost supply resource), which is $130/KW-year from a ratepayer perspective based on York Region SCGT. DR, NUG contract renewals, coal conversions, or firm imports can also provide capacity if similarly prices.

## ED Interrogatory #29

**Issue Number: 6.5**
**Issue:** Are the test period expenditures related to extended operations for Pickering appropriate?

### Interrogatory

**Reference:**

Reference: "Pickering extension to 2022/2024 yields a net benefit in the range of $0.3B-$0.6B…" Exhibit F2-2-3, Attachment 1, Page 6 of 116

For each year of the Pickering extension to 2022/2024 analysis, please provide the IESO's *best current estimate* of:

a) Pickering's total installed capacity (MW);

b) Pickering's available capacity (MW) at the time of Ontario's peak annual demand;

c) Pickering's generation (MWh);

d) The avoided generation (MWh), by fuel type, as a result of Pickering's extended operation;

e) Pickering's rolling average forced loss rate as defined by OPG's *2015 Nuclear Benchmarking Report*;

f) The available capacity at the time of Ontario's peak annual demand of new gas-fired peaking capacity as a percent of its installed capacity;

g) Pickering's fuel and operating cost per kWh;

h) Pickering's incremental capital expenditures to permit its extension to 2022/24;

i) Natural gas prices at Henry Hub;

j) The NYMEX natural gas futures prices at Henry Hub;

k) Ontario's carbon prices;

l) Ontario's incremental peaking requirements (MW) to meet the NPCC resource adequacy criterion if Pickering is not extended to 2022/24;

m) Ontario's cost, per MW, of meeting the NPCC resource adequacy criterion if Pickering is not extended to 2022/24 by: a) domestic supply resources; b) demand response resources; c) energy efficiency resources; and c) electricity imports from neighbouring jurisdictions.

Please fully justify all your responses. In particular, please state your methodology and assumptions for calculating Pickering's available capacity (MW) at the time of Ontario's peak annual demand.

## Response

The following response has been prepared by the IESO, except for part (e), which has been provided by OPG:

(a) The following table summarizes Pickering's total installed capacity (MW) as shown in 2016 Ontario Planning Outlook.

| | |
|---|---|
| 2016 | 3094 |
| 2017 | 3094 |
| 2018 | 3094 |
| 2019 | 3094 |
| 2020 | 3094 |
| 2021 | 3094 |
| 2022 | 3094 |
| 2023 | 2064 |
| 2024 | 2064 |

(b) The following table summarizes Pickering's available capacity (MW) at the time of Ontario's peak annual demand as shown in 2016 Ontario Planning Outlook.

| | |
|---|---|
| 2016 | 2578 |
| 2017 | 2579 |
| 2018 | 2063 |
| 2019 | 2063 |
| 2020 | 3094 |
| 2021 | 2579 |
| 2022 | 3094 |
| 2023 | 2064 |
| 2024 | 2064 |

(c) The following table summarizes Pickering's generation (MWh) as shown in 2016 Ontario Planning Outlook.

| | |
|---|---|
| 2016 | 21,177,276 |
| 2017 | 19,351,248 |
| 2018 | 19,411,674 |
| 2019 | 19,602,972 |
| 2020 | 20,007,314 |
| 2021 | 18,972,174 |
| 2022 | 20,528,508 |
| 2023 | 13,913,424 |
| 2024 | 16,332,432 |

(d) Not applicable, as the simulation run of Pickering operates to 2020 is not available.

(e) Please see Ex. L-6.5-7 ED-28 part (e).

(f) Not applicable, as the simulation run of Pickering operates to 2020 is not available.

(g) The IESO has not analyzed any updates to Pickering's fuel and operating cost per KWh since the analysis of November 2015, which is available at EB-2016-0152 Exhibit F2-2-3 Attachment 1 Page 1 to Page 10.

(h) The IESO has not analyzed any updates to Pickering's incremental capital expenditures to permit its extension to 2022/24 since the analysis of November 2015, which is available at EB-2016-0152 Exhibit F2-2-3 Attachment 1 Page 1 to Page 10.

(i) The following table summarizes the natural gas price at Henry Hub (2016 real US$/MMBTU) as shown in 2016 Ontario Planning Outlook.

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2016 | 2.39 | 2.38 | 2.33 | 2.13 | 2.13 | 2.15 | 2.18 | 2.20 | 2.19 | 2.22 | 2.28 | 2.40 |
| 2017 | 3.14 | 3.13 | 3.07 | 2.80 | 2.80 | 2.83 | 2.87 | 2.89 | 2.88 | 2.91 | 2.99 | 3.16 |
| 2018 | 3.61 | 3.60 | 3.53 | 3.22 | 3.22 | 3.25 | 3.30 | 3.32 | 3.31 | 3.35 | 3.44 | 3.63 |
| 2019 | 4.06 | 4.05 | 3.97 | 3.63 | 3.62 | 3.66 | 3.71 | 3.74 | 3.73 | 3.77 | 3.87 | 4.09 |
| 2020 | 4.25 | 4.24 | 4.16 | 3.80 | 3.79 | 3.83 | 3.88 | 3.91 | 3.91 | 3.95 | 4.06 | 4.28 |
| 2021 | 4.25 | 4.24 | 4.16 | 3.80 | 3.79 | 3.83 | 3.88 | 3.91 | 3.91 | 3.95 | 4.06 | 4.28 |
| 2022 | 4.25 | 4.24 | 4.16 | 3.80 | 3.79 | 3.83 | 3.88 | 3.91 | 3.91 | 3.95 | 4.06 | 4.28 |
| 2023 | 4.25 | 4.24 | 4.16 | 3.80 | 3.79 | 3.83 | 3.88 | 3.91 | 3.91 | 3.95 | 4.06 | 4.28 |
| 2024 | 4.25 | 4.24 | 4.16 | 3.80 | 3.79 | 3.83 | 3.88 | 3.91 | 3.91 | 3.95 | 4.06 | 4.28 |
| 2025 | 4.25 | 4.24 | 4.16 | 3.80 | 3.79 | 3.83 | 3.88 | 3.91 | 3.91 | 3.95 | 4.06 | 4.28 |
| 2026 | 4.25 | 4.24 | 4.16 | 3.80 | 3.79 | 3.83 | 3.88 | 3.91 | 3.91 | 3.95 | 4.06 | 4.28 |
| 2027 | 4.25 | 4.24 | 4.16 | 3.80 | 3.79 | 3.83 | 3.88 | 3.91 | 3.91 | 3.95 | 4.06 | 4.28 |
| 2028 | 4.25 | 4.24 | 4.16 | 3.80 | 3.79 | 3.83 | 3.88 | 3.91 | 3.91 | 3.95 | 4.06 | 4.28 |
| 2029 | 4.25 | 4.24 | 4.16 | 3.80 | 3.79 | 3.83 | 3.88 | 3.91 | 3.91 | 3.95 | 4.06 | 4.28 |
| 2030 | 4.25 | 4.24 | 4.16 | 3.80 | 3.79 | 3.83 | 3.88 | 3.91 | 3.91 | 3.95 | 4.06 | 4.28 |
| 2031 | 4.25 | 4.24 | 4.16 | 3.80 | 3.79 | 3.83 | 3.88 | 3.91 | 3.91 | 3.95 | 4.06 | 4.28 |
| 2032 | 4.25 | 4.24 | 4.16 | 3.80 | 3.79 | 3.83 | 3.88 | 3.91 | 3.91 | 3.95 | 4.06 | 4.28 |
| 2033 | 4.25 | 4.24 | 4.16 | 3.80 | 3.79 | 3.83 | 3.88 | 3.91 | 3.91 | 3.95 | 4.06 | 4.28 |
| 2034 | 4.25 | 4.24 | 4.16 | 3.80 | 3.79 | 3.83 | 3.88 | 3.91 | 3.91 | 3.95 | 4.06 | 4.28 |
| 2035 | 4.25 | 4.24 | 4.16 | 3.80 | 3.79 | 3.83 | 3.88 | 3.91 | 3.91 | 3.95 | 4.06 | 4.28 |

(j) The NYMEX natural gas future prices at Henry Hub can be found at this link:

http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html

(k) The following table summarizes Ontario's carbon price (2016 real US$/kg CO2) as shown in 2016 Ontario Planning Outlook.

| | |
|---|---|
| 2016 | 0 |
| 2017 | 0.013391 |
| 2018 | 0.014074 |
| 2019 | 0.014763 |
| 2020 | 0.015487 |
| 2021 | 0.016246 |
| 2022 | 0.017043 |
| 2023 | 0.017878 |
| 2024 | 0.018754 |
| 2025 | 0.019674 |
| 2026 | 0.020638 |
| 2027 | 0.02165 |
| 2028 | 0.022711 |
| 2029 | 0.023824 |
| 2030 | 0.024992 |
| 2031 | 0.026217 |
| 2032 | 0.027503 |
| 2033 | 0.028851 |
| 2034 | 0.030265 |
| 2035 | 0.031749 |

(l) Not applicable, as the simulation run of Pickering operates to 2020 is not available.

(m) Not applicable, as the simulation run of Pickering operates to 2020 is not available.

# UNDERTAKING JT2.4

## *Undertaking*

TO RECONCILE ED 18, BOARD STAFF 116, AND GEC 38, AND ADVISE THE DIFFERENCES WHAT COSTS WERE INCLUDED OR EXCLUDED AS BETWEEN THE THREE.

## *Response*

The numbers used in the three referenced documents are different because they were produced to respond to specific questions from the requesting parties. However, they are consistent and are reconciled below.

Exhibit L-6.5-1 Staff-116 (Staff-116) provides the values for the variables in Chart 1 at Ex. F2-2-3. Chart 1 at Ex. F2-2-3 shows the estimated operating costs to enable Extended Operations and operate Pickering in each year of the IR Term as proposed to be recovered in the revenue requirement. These costs include OM&A expenses and capital costs, but exclude fuel costs. As shown in Staff-116, the total planned fully allocated operating costs for Pickering are $1,395M in 2021.

Exhibit L-6.5-8 GEC-38 (GEC-38) asks for Pickering's "total allocated operating costs." As this term is not precisely defined, OPG responded based on a standard industry definition. OPG benchmarks its financial performance against other utilities based on industry accepted (EUCG) metrics including Total Generating Cost (TGC) per MWh. GEC 38 (and by reference Ex. L-6.2-15 SEC-063) provides a derivation of TGC per MWh, and shows the 2021 TGC as $1,526.9M. As established by EUCG, TGC includes Base OM&A, Outage OM&A, Project OM&A, Corporate Support & Administrative costs, component of centrally held costs (excluding OPEB and Pension amounts and IESO Non-energy Charges as noted in Ex. L-6.2-1 Staff-104), fuel costs, and capital costs.

As shown in the reconciliation provided in Chart 1 in GEC-38, OPG started with the total planned operating costs in Staff 116 and made necessary adjustments to arrive at the TGC. Specifically, OPG made the following adjustments:

<u>Additions:</u>

- Fuel costs: TGC includes fuel costs. As noted above, Chart 1 at Ex. F2-2-3 and therefore L-6.5-1 Staff 116 excluded fuel costs (although fuel costs are included in the Business Case Summary supporting Extended Operations at Attachment 2 to that exhibit, as indicated in Ex. L-6.5-1 Staff-118 (b)).
- Pickering portion of Tritium Removal Facility: TGC includes these costs but for purposes of Chart 1 at Ex. F2-2-3 and therefore L-6.5-1 Staff 116, these costs were excluded for the reasons discussed at JT2.05.
- Inventory Obsolescence: TGC includes inventory obsolescence costs but for purposes of Chart 1 at Ex. F2-2-3 and therefore L-6.5-1 Staff 116, these costs were excluded for the reasons discussed at JT2.05

<u>Subtraction:</u>

- Asset User (Service) Fee: These costs are excluded from the TGC per industry standards but are included for purposes of Chart 1 at Ex. F2-2-3.

Exhibit L-6.5-7 ED-18 (ED-18) asked OPG to confirm Environmental Defense's calculations of Pickering Nuclear Station's operating and fuel costs for 2017, 2018, 2019 and 2020 broken out by sixteen components. OPG noted in its response to ED-18, that Environmental Defence's methodology for allocating costs is inconsistent with OPG's approved allocation methodology (see Ex. F3-1-1) and that certain of the sixteen components such as depreciation, property tax and income tax are not classified as "OM&A," which is why OPG excludes those cost elements from its calculation of total operating costs.

As per GEC-38, TGC in 2021 is $1,526.9M. Chart 1 in ED-18 establishes in the first subtotal an amount of $1,537.6M in 2021. The TGC in 2021 can be reconciled to the $1,537.6M by subtracting the asset service fee of $10.7M (rounded to $11M in Chart 1 of GEC-38), which is excluded from TGC, but included within Environmental Defense's sixteen cost components.

In preparing this undertaking, OPG noted that there is an inadvertent spreadsheet error in Chart 1 in ED-18 for the year 2021. The amount of -$22.7M in the line item designated "Other" was not deducted in the spreadsheet totals. As a result, the $1,654.0M grand total for 2021 should be revised to $1,631.4M. A revised Chart 1 is included below.

The remaining difference between the $1,526.9M in GEC-38 and the $1,631.4M grand total in Chart 1 below is explained by the removal of capital costs of $23.1M, as well as the exclusion of various non-operating cost components listed in the chart below the second subtotal for the reasons set out in JT2.5.

| | Pickering Costs | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| ($M, unless otherwise stated) | 2014 Actual | 2015 Actual | 2016 Budget | 2017 Plan | 2018 Plan | 2019 Plan | 2020 Plan | 2021 Plan |
| **Total Operating Costs - Initial** | **1,319.4** | **1,347.2** | **1,364.0** | **1,351.4** | **1,351.4** | **1,391.7** | **1,337.9** | **1394.5** |
| **Add** | | | | | | | | |
| Inventory Obsolescence[1] | 0.0 | 0.0 | 12.4 | 12.4 | 12.4 | 12.4 | 12.4 | 12.4 |
| Pickering portion of Tritium Removal Facility[1] | 0.0 | 0.0 | 10.4 | 11.2 | 11.6 | 10.9 | 12.2 | 12.8 |
| Fuel Costs | 113.5 | 120.4 | 120.2 | 114.4 | 115.5 | 116.5 | 120.5 | 117.9 |
| **Subtotal** | **1,432.9** | **1,467.6** | **1,507.0** | **1,489.4** | **1,490.9** | **1,531.5** | **1,483.0** | **1537.6** |
| **Less** | | | | | | | | |
| Capital | 119.5 | 90.9 | 124.3 | 85.2 | 29.8 | 28.0 | 23.2 | 23.1 |
| **Subtotal** | **1,313.4** | **1,376.7** | **1,382.7** | **1,404.2** | **1,461.1** | **1,503.5** | **1,459.8** | **1514.5** |
| **Add** | | | | | | | | |
| OPEB and Pension excluded from Centrally Held Costs | 10.7 | 45.8 | 48.5 | 62.7 | 39.2 | 25.5 | 15.7 | 10.0 |
| IESO Non energy Charges[2] | 32.2 | 51.5 | 27.6 | 30.6 | 28.2 | 25.7 | 28.7 | 22.3 |
| Other[1] | 0.0 | 0.0 | -3.7 | -68.6 | -37.3 | -25.8 | -30.6 | -22.7 |
| **Subtotal** | **1,356.3** | **1,474.0** | **1,455.1** | **1,428.8** | **1,491.2** | **1,529.0** | **1,473.5** | **1,524.2** |
| **Add** | | | | | | | | |
| Depreciation and Amortization _Pickering[2] | 140.9 | 147.3 | 165.7 | 199.9 | 223.2 | 226.7 | 233.3 | 53.1 |
| Depreciation and Amortization- Pickering Generic[2] | 44.2 | 53.5 | 34.2 | 38.6 | 37.1 | 34.9 | 36.7 | 20.4 |
| Income Tax - Pickering[2] | -25.7 | -15.2 | -8.3 | -9.2 | -9.2 | -9.1 | 26.9 | 27.5 |
| Property Tax- Pickering | 4.9 | 4.9 | 5.0 | 5.4 | 5.5 | 5.7 | 5.8 | 6.3 |
| **Total** | | | | | | | | |
| Planned Operating Costs | **1,520.5** | **1,664.5** | **1,651.7** | **1,663.6** | **1,747.9** | **1,787.2** | **1,776.2** | **1631.4** |
| Pickering Generation - TWh | **20.1** | **21.2** | **20.8** | **19.1** | **19.2** | **19.4** | **19.6** | **18.8** |
| Planned Operating Costs- $/MWh | **75.7** | **78.4** | **79.5** | **87.3** | **91.1** | **92.3** | **90.5** | **86.7** |

[1] Included in Total Operating Costs- Initial in 2014 actual and 2015 actual
[2] Allocation based on Pickering % of generation

# UNDERTAKING JT2.5

## *Undertaking*

OF THE COSTS INCLUDED IN ED 18, BOARD STAFF 116, AND GEC 38, TO ADVISE WHICH WERE INCLUDED OR EXCLUDED FROM THE ECONOMIC ASSESSMENT OF PICKERING, INCLUDING THE CALCULATION OF THE 6.5 CENTS PER KILOWATT-HOUR

## *Response*

OPG notes that levelized unit energy cost (LUEC) is an economic measure and as such is based on incremental costs and generation. The approach used to calculate LUEC differs from a rate calculation. For example, LUEC calculations exclude "non-cash" items such as depreciation and amortization expense, and instead include the incremental capital expenditures in the year incurred. As well, LUEC calculations exclude non-incremental costs that are considered to be independent of the decision being made. Please see also OPG's response to Ex. L-04.3-6 EP-014. OPG's response to JT 1.17E Attachment 1 provides an explanation of the LUEC methodology.

The LUEC calculation referenced in the Pickering Extended Operations Economic Assessment (Ex. F2-2-3 Attachment 2) includes the following cost categories:

1. Base OM&A (Station  and Nuclear Support)
2. Outage OM&A (Station Direct and Nuclear Support)
3. Project OM&A
4. Capital
5. Corporate Support
6. Fuel Costs

Using 2021 as an example, the sum of the above cost categories excluding Fuel Costs is $1,395M, on a fully allocated basis (as provided in Ex. L-06.5-1 Staff-116 and Ex. L-06.5-1 GEC-38, and the first line of Chart 1 in Ex. L-06.5-7 ED-018). With the exception of Fuel Costs, these categories are itemized in Ex. L-06.5-1 Staff-118 (a) & (b). Incremental Fuel Costs are $118M in 2021, as provided in Ex. L-06.5-7-ED-018 and Ex. L-06.5-1 GEC-38. All of these values are expressed in escalated dollars.

As described in the Pickering Extended Operations Economic Assessment, the financial evaluation and the related LUEC are calculated using incremental operating costs relative to a 2020 Pickering shutdown. The incremental OM&A and Capital costs are shown in constant 2015 M$ in Interrogatories Ex. L-6.5-7 ED-028 part (i) and Ex. L-6.5-1 Staff-126, Chart 2. For the year 2021, the non-fuel incremental Operating Costs assumed in the Pickering Extension Business Case are $987M (2015$). The difference in 2021 operating costs between the $987M and the $1,395M described above is related to escalation from constant to nominal dollars and the exclusion of non-incremental costs (i.e., the assumed non-incremental portion of nuclear and corporate support costs).

Cost categories shown in Ex. L-06.5-7 ED-018 that are not included in the economic assessment or LUEC calculation are provided below. Amounts provided below refer to 2021 values from Chart 1 in Ex. L-06.5-7 ED-018, for reference purposes:

1. Inventory Obsolescence ($12.4M) – These costs are excluded as a non-cash item.
2. Pickering Portion of Tritium Removal Facility ($12.8M) -- These costs are considered non-incremental as they would be borne by OPG in the absence of operating Pickering units.
3. OPEB and Pension excluded from Centrally Held Costs and Other Costs ($-12.7M) – These costs primarily represent non-current service components of pension and OPEB amounts that largely would be incurred whether or not the operation of the Pickering station were extended, as well as the pension and OPEB adjustment for cash to accrual differences shown at Ex. F4-4-1 Table 3 line 2.
4. IESO Non-Energy Charges ($22.3M) – If not paid by OPG, these costs (e.g., transmission charges or IESO administration fees) are assumed to be recovered from other transmission system customers and therefore are not incremental.
5. Depreciation and Amortization Pickering ($53.1M) – These costs are non-cash accounting transactions related to matching capital costs to the period when benefits are considered to be realized. Instead, incremental capital costs associated with the extending Pickering operations are reflected in the LUEC.
6. Depreciation and Amortization Pickering Generic ($20.4M) – These costs are non-cash accounting transactions related to matching capital costs to the period when benefits are considered to be realized.
7. Income Tax Pickering ($27.5M) – Income taxes are not directly related to costs of operating an asset; rather, they result from earning income from the asset.
8. Property Tax Pickering ($6.3M) – Property taxes for the Pickering site were assumed to be payable in the post-2020 period regardless of whether or not the operation of the station were extended, and are therefore not incremental.

Ontario

# ONTARIO ENERGY BOARD

**FILE NO.:** **EB-2016-0152** **Ontario Power Generation Inc.**

**VOLUME:** **Technical Conference**

**DATE:** **November 15, 2016**

which were included or excluded from the economic assessment of Pickering, including the calculation of the 6.5 cents per kilowatt-hour?

MR. BLAZANIN: We will take that undertaking.

MR. MILLAR: Is that part of the same undertaking, Mr. Elson?

MR. ELSON: Let's do another undertaking.

MR. MILLAR: JT2.5.

**UNDERTAKING NO. JT2.5: OF THE COSTS INCLUDED IN ED 18, BOARD STAFF 116, AND GEC 38, TO ADVISE WHICH WERE INCLUDED OR EXCLUDED FROM THE ECONOMIC ASSESSMENT OF PICKERING, INCLUDING THE CALCULATION OF THE 6.5 CENTS PER KILOWATT-HOUR**

MR. ELSON: And could you explain, in each case when numbers were not included in the economic assessment, why that was the case?

MR. BLAZANIN: We will provide the basis for not including certain values in the economic assessment.

MR. ELSON: And could you please calculate the LUEC that would include all of the costs that were included in each of those, in each of those interrogatory responses for the test period years as another undertaking?

MR. KEIZER: I don't think we are going to do that.

MR. ELSON: I am just trying to have a comparison between what was included and what wasn't. So it could be by way of a LUEC, or just somehow a monetary figure to let us know the difference between the total costs and what were included in the economic assessment. Can you provide that?

MR. KEIZER: Well, I think the point is we calculated an economic assessment and obviously, whatever went into the economic assessment, OPG believes the correct and proper numbers were included.

Therefore, taking other numbers and putting them into the assessment which have no basis to be there, at least in the view of the OPG, is a number that OPG doesn't believe to be relevant.

So we are not going to undertake to do that.

MR. ELSON: With respect, Mr. Keizer, I think our role is to test that evidence, and what we are asking for is pretty simple.

You can provide it in a different way, if you wish to provide the percentage of costs of the total costs, all-in costs that are and are not included, if that would address any concerns that you have. If not, that's a refusal --

MR. KEIZER: I think I have expressed my concerns in respect of doing that calculation.

MR. ELSON: Okay, I think that should be fine. My understanding is that the -- we will be able to calculate that on our own, that the undertaking response in doing the reconciliation will let us know what was included and what wasn't included. We will have to take a look at the undertaking response and go from there.

Can you turn to 6.5 ED 28, and so if you scroll down, continuing to H – actually, I am looking at I here. This shows Pickering's incremental capital cost in 2021 as being

978.

MR. BLAZANIN:  The actual value is 987.

MR. ELSON:  My apologies, I am guilty of doing that frequently.

Can you reconcile this with what was in the undertaking -- sorry, the interrogatory responses we discussed previously, which were ED 18, Board Staff 116 and GEC 38?

It may be the same as the previous answer, but if we could get a separate undertaking, that would be helpful.

MR. KEIZER:  Sorry, just, as I recall those three, they dealt with the overall Pickering costs.  This is incremental capital and OM&A, so I don't understand what you are asking us to reconcile relative to those numbers of the previous three.

MR. ELSON:  What of the overall costs aren't included in these incremental numbers.

MR. KEIZER:  Sorry, in other words, what of the total doesn't -- aren't incremental OM&A and capital; is that what you are saying?

MR. ELSON:  I guess you could say provide a table of the Pickering costs that were not included in Table I in ED 28 that were included in the other interrogatory responses.

MR. KEIZER:  In other words, just so I -- sorry, I don't mean to be stupid, but what you are saying is you want to understand all other costs that would add up to that total, excluding the incremental OM&A and incremental capital; is that right? Incremental capital and total OM&A.

MR. ELSON: I am trying to determine what kinds of costs or what cost categories were not included in this number here out of the overall costs. By "this number here" I mean the 987 on page 4 of ED 28.

MR. KEIZER: I leave it to -- I think I understand what you are asking about. Maybe the witness can help.

MR. BLAZANIN: So these are the incremental costs associated with extended operations over and above our normal operating cost. They are in constant dollars in 2015 dollars, so there is various steps in terms of reconciling the overall values from this. This shows the incremental cost in total.

MR. ELSON: And so can you provide a table of the Pickering costs that were not included for the purposes of this table and this cost-benefit analysis, along with an explanation as to why they were not included?

MR. BLAZANIN: That would have been part of that previous question, I think, or undertaking that you asked.

MR. ELSON: Okay. That's fine.

I am getting to the end here, and I am trying to get at the amount of Pickering's power that is -- would be used versus exported over the test period. And so maybe the best way to ask about that is if OPG could provide a table showing the anticipated annual output of Pickering and the annual decrease of Ontario's power exports in a scenario where Pickering wasn't there so as to show us how much

# Hydro deal with Quebec to save Ontario electricity grid $70M

**7-year agreement will help Ontario move away from natural gas, reduce greenhouse gases, sources says**

By Keith Leslie, The Canadian Press Posted: Oct 21, 2016 5:50 AM ET Last Updated: Oct 21, 2016 10:06 PM ET

Ontario will import enough electricity from Quebec to power a city of more than 200,000 people under a seven-year agreement signed Friday, but the provinces won't say how much Ontario is paying Hydro Quebec.

Premiers Kathleen Wynne and Philippe Couillard signed the deal, which will see Ontario import up to two terawatt hours of electricity from Quebec annually, allowing the province to reduce its use of natural gas to generate power.

"We wanted to do this, but I said it would have to be a good deal for the people of Ontario," said Wynne. "And it is a good deal for Ontario, and for Quebec."

The agreement is expected to save Ontario's electricity system about $70 million in costs over the seven years, but the two government's cited "commercial sensitivities" for refusing to say how much Ontario will pay for the electricity.

However, Montreal newspaper *La Presse* reports the agreement is worth $1-billion, and calculates Ontario will pay five cents a kilowatt hour for the electricity.

The agreement will also allow Ontario to reduce its greenhouse gas emissions by one million tonnes a year by replacing gas-fired generation with clean power generated from Quebec's hydro dams.

"The reality about gas plants is that they are peaker, they often sit idle when that power is not needed," and are turned on when there's high demand, said Wynne. "The whole point of the gas plants is they are only used when that power is needed."

Wynne declined to say how much the $70 million in reduced costs would impact electricity bills in Ontario, if at all.

- Ontario Liberals rethink $1.9B cap-and-trade projection in uncertain market
- Environmentalists, automakers applaud Ontario's $8.3B climate change plan
- Ontarians see higher hydro bills as consumption comes down

NDP environment critic Peter Tabuns welcomed the import of more clean power from Quebec, but said the impact on consumers' electricity bills and the actual reduction in greenhouse gas emissions from the agreement will be minuscule.

"Scientists and economists will be able to detect it," said Tabuns, "but ordinary people will not be able to detect it."

Ontario plans to join the cap-and-trade market with Quebec and California next January, and Canada's two largest provinces have been finding more ways to work together on initiatives to combat climate change.

There has long been talk of an east-west power grid in Canada, and Couillard said it only makes sense to start with the two largest, neighbouring provinces.

"We always said when this question was mentioned that first and foremost the priority should be given to regional deals, and Quebec-Ontario is the most obvious example of that," said Couillard.

Environmentalists have long urged Ontario to import more clean power from Quebec's hydro-electric dams, but officials always said that would require huge and expensive upgrades to the transmission lines linking the two provinces.

However, the provinces say the existing transmission lines can support their new power agreement.

"The reality seems to be the transmission lines can handle a fair chunk of power and we should be looking at this as an option to deal with high hydro rates," said Tabuns.

Green Party of Ontario Leader Mike Schreiner called the Quebec deal a step in the right direction, but said the province should not extend the life of the Pickering nuclear station or rebuild the reactors at the Darlington station.

"The Liberals made the right decision to import low cost water power from Quebec," Schreiner said in a release. "Now they need to save billions by closing Pickering on schedule and cancelling the Darlington rebuild."

The new agreement will also allow Ontario to keep up to 500 gigawatt hours of power behind Quebec's dams in what is called a "pump storage" system, which will allow the province to reduce its surplus generation.

Wynne's Liberals face daily attacks from the opposition over soaring electricity prices, and the government is looking to do whatever it can to ease upward pressure on rates.

"This is one in the list of things that we are doing to remove costs from the system, whether it's the suspension of the long-term energy plan, whether it's renegotiating the Samsung (green energy) deal ... and removing the eight per cent provincial portion of the HST (from hydro bills) as of January," she said.

Ontario already has a surplus of power, and has signed 20-year contracts for electricity from two new natural-gas fired generating stations being built in Sarnia and Napanee.

Those gas-fired plants were originally going to be built in Mississauga and Oakville until the Liberals cancelled them days before the 2011 election, which the auditor general said would cost ratepayers up to $1.1 billion.

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## GEC Interrogatory #56

**Issue Number: 6.5**
**Issue:** Are the test period expenditures related to extended operations for Pickering appropriate?

### Interrogatory

**Reference:**
Exhibit F2-2-3 Attachment 1, page 36 (IESO's presentation evaluating the economic case for extending Pickering's operations until 2024.)

(Note: On page 48 of OEB staff's interrogatories, OPG is asked to consult with the IESO as necessary to respond to interrogatories related to the IESO's analysis of the Pickering Extended Operations. GEC makes the same request here.)

a. IESO states that Pickering's closure would present challenges related to the deployment of replacement supply. However, the government's 2013 Long Term Energy Directive directed OPG to plan for Pickering's closure in 2020 and potentially as early as 2017. What planning and procurement did the IESO undertake in response to the 2013 LTEP directive in order to secure adequate replacement supply to replace Pickering in 2020?

b. What is the IESO's current plan to secure replacement supply if OPG doesn't gain approval from either the CNSC or the OEB to extend Pickering's operational life until 2024?

c. In light of the province's "Conservation First" policy, did the IESO's cost analysis of Pickering's extended operations consider the additional cost effective conservation potential outlined in its June 2016 "Achievable Potential Study: Short Term Analysis" and how cancellation of the continued operations could affect conservation potential? If so, please provide details.

### Response

The following response has been prepared by the IESO:

a. The IESO has supported implementation of various aspects of the 2013 LTEP since its publication in 2013. Conservation, supply and transmission resources that were planned, acquired and/or brought online since then are identified in the IESO's 2016 Ontario Planning Outlook, which is available at: http://www.ieso.ca/Pages/Ontario's-Power-System/Ontario-Planning-Outlook/default.aspx.

Planning has taken into account the nuclear refurbishment principles laid out in the 2013 Long-Term Energy plan. For example, the Ontario Planning Outlook identifies a variety of implementation and performance risks that will have to be managed in coming years, including risks related to nuclear operations and refurbishment plans. Likewise, planning and contracting has helped provide for nuclear refurbishment off-ramps among some nuclear units planned for refurbishment in Ontario. In parallel, among other things, market renewal initiatives at the IESO are underway, including a capacity auction work stream which would continue to evolve the demand response auction in the province; facilitate short term capacity trade; and implement an incremental capacity auction.

b. Options for addressing resource requirements in the event that Pickering does not operate to 2024 include taking greater advantage of supply resources whose existing contracts expire in coming years, taking advantage of resource options via capacity auctions, and greater use of non-firm intertie transactions. The plan to address such needs should they arise is touched upon in the Ontario Planning Outlook at http://www.ieso.ca/Documents/OPO/MODULE-4-Supply-Outlook-20160901.pdf. Irrespective of the particular options to be selected, mitigating and managing risks in the years ahead will be supported by well understanding the risks and their drivers, assessing them systematically and in cooperation with others, identifying and communicating needs and having the appropriate mechanisms to address them.

c. No, the analysis of Pickering's extended operation was completed in 2015 while the Achievable Potential studies were finished in June 2016. However, the most recently identified achievable potentials are consistent with the conservation forecast used in Pickering analysis. The cancellation of the continued operations would have minimal impact on conservation potential.

**UNDERTAKING JT1.17**
**ATTACHMENT I**

## *Undertaking*

**ED INTERROGATORY #34**

1. With respect to the numbers in Section T4 for the years 2021 to 2024 inclusive: please provide for each year the IESO's estimate of: a) Pickering's installed capacity; and b) available capacity at the summer peak. Please describe the IESO's methodology and show its calculations for calculating the difference between installed and available capacity.

2. With respect to the load forecasts shown in Section T3: are any of them consistent with the IESO's MARS program? If no, please provide the MARS load forecasts for these years. [Note: The IESO uses General Electric's Multi-Area Reliability Simulation (MARS) program to derive its load forecast to estimate its reserve margin requirements. See IESO, *Ontario Reserve Margin Requirements 2016 – 2020: Issue 1.0* (December 21, 2015).]

3. Please provide a response to part (b). The IESO outlined a methodology but did not provide an answer.

## *Response*

The following response has been prepared by the IESO. OPG has inserted the evidence reference in square brackets.

1. The following table summarizes Pickering's total installed capacity (MW) in different scenarios:

| | Case with +65 TWh of Pickering Production, Pickering to 2020 | Case with +65 TWh of Pickering Production, Pickering to 2022/2024 | Case with +62 TWh of Pickering Production, Pickering to 2020 | Case with +62 TWh of Pickering Production, Pickering to 2022/2024 |
|---|---|---|---|---|
| 2015 | 3094 | 3094 | 3094 | 3094 |
| 2016 | 3094 | 3094 | 3094 | 3094 |
| 2017 | 3094 | 3094 | 3094 | 3094 |
| 2018 | 3094 | 3094 | 3094 | 3094 |
| 2019 | 3094 | 3094 | 3094 | 3094 |
| 2020 | 3094 | 3094 | 3094 | 3094 |
| 2021 | 0 | 3094 | 0 | 3094 |
| 2022 | 0 | 3094 | 0 | 3094 |
| 2023 | 0 | 2064 | 0 | 2064 |
| 2024 | 0 | 2064 | 0 | 2064 |

As a starting point, the Pickering capacity that is available at the time of peak demand is assumed to be the installed capacity, provided that it is not on planned outage or forced outage or in a derated state. IESO's assessment of the overall performance of Pickering further units includes accounting for forced outage and planned outage rates and derates, which are considered in reserve margin calculations and power system production simulations.

2. Yes. The forecasts are consistent, but are not identical; this reflects different vintages of production. For example, the more recently produced demand outlooks contained in the Ontario Planning Outlook depict ranges rather than a single projection.

3. Per IR 34 [Ex. L-6.5-7 ED-34] response (b), the total amount of incremental firm capacity (MWs) that can be imported into Ontario is a function of: import capacity (the physical wires), real-time system constraints (physical constraints based on real-time internal and external supply/demand balances and transmission limitations) and economics (cost). The current physical import capacity is up to approximately 6,900 MW. This represents a theoretical level that could be achieved only with a substantial reduction in generation dispatch in the West and Niagara transmission zones. In practice, the generation dispatch required for high import levels would rarely, if ever, materialize. Therefore, at best, due to internal constraints in the Ontario transmission network in conjunction with external scheduling limitations, Ontario has an expected coincident import capability of approximately 5,200 MW.

# IESO Response to Questions from the Ontario Clean Air Alliance

1. **How much energy (TWh) can Ontario currently import per year from Quebec using the existing interties and transmission system?**

   Ontario cannot rely on the energy from Quebec to meet the IESO's adequacy requirements without the enhancements to the transmission system that are described in the *Review of Ontario Interties* report. Without those enhancements Ontario would not be able to import the energy when it needs it the most (i.e. under low water conditions and peak load levels in Ontario). To plan the system in a manner capable of reliably delivering power to consumers, firm imports must meet adequacy planning criteria as set out by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC) and the IESO. These take into account variables such as operating characteristics, weather and extreme weather patterns, generator and transmission outages, transmission transfer capabilities, and availability of fuel. All of these variables factor into the analysis to determine the amount of *firm* energy that can be relied upon to serve Ontario consumers. Ontario's ability to import firm energy from Quebec is limited by transmission constraints in the Ottawa area, as noted in the Review of Ontario Interties.

   Unlike Ontario's interties with other neighbours (e.g. New York); most of the interties with Quebec are radial interconnections that can only be used to deliver power from very specific generators in Quebec. Ontario has one non-radial intertie with Quebec (the "HVdc intertie"), which can be used to deliver power from any generator in Quebec. The IESO estimates that the non-radial HVdc intertie has the hypothetical capability of delivering between 8.7 and 9.8 TWh of energy from Quebec in 2015. Additionally if the radial interties with Quebec are considered, then this hypothetical range becomes 16.5 TWh to 18.5 TWh. Quebec's ability to export this hypothetical amount of energy is dependent on the availability of the specific generators in Quebec that could connect to the radial interties.

   Although Ontario is able to hypothetically import between 16.5 and 18.5 TWh in a year from Quebec, Ontario typically imports 3 TWh of energy and exports 1.6 TWh of energy. This indicates that either energy is not available in Quebec to export to Ontario or it is not economical to export this energy to Ontario.

2. **What is the breakdown of the $500 million transmission upgrade cost estimate for each of the three measures listed in Appendix F of *Review of Ontario Interties*?**

| Item | Cost |
|---|---|
| New 230 kV double circuit line between Cornwall and Ottawa | $300 M |

| | |
|---|---|
| New 230 kV circuit, approximately 8 km in length, to connect existing circuits in the west of Ottawa | $75 M |
| Additional voltage control equipment in the Ottawa area | $75 M |
| Other enhancements (e.g. converting circuit H9A to 230 kV operation) | $50 M |

3. **What is the breakdown of the $1.4 billion transmission cost estimate for each of the measures listed in Appendix F and on Page 25 of the Review of Ontario Interties report?**

| Item | Cost |
|---|---|
| New HVdc Interconnection | $1.1 B |
| New 500 kV double circuit line from Bowmanville to Cherrywood | $225 M |
| Replacement of existing phase-angle regulating transformers | $40 M |

4. **What is the IESO's estimate of how many MW Ontario's firm import capability from Quebec will be increased for every 1 MW of incremental conservation and demand management (CDM) and/or distributed generation (DG) in the west end of Ottawa?**

Reducing the demand in the west end of Ottawa, either through CDM or DG, would increase Ontario capability to source firm capacity from Quebec. However, the precise ratio would depend on a number of variables that would require further clarification, including:

- future transmission system enhancements
- where the CDM and/or DG is located in the Ottawa area (on the 230 kV network or the 115 kV network)
- type of CDM and/or DG

These types of considerations would be part of the work conducted through an Integrated Regional Resource Plan process. For more information please visit: http://www.powerauthority.on.ca/power-planning/regional-planning/greater-ottawa/ottawa.

5. **If the IESO were to assume that imports from Quebec were used to replace the output of Bruce B, would that change the conclusions of the Review with respect to the transmission upgrades needed to accommodate firm water power imports from Quebec?**

   The upgrades identified in the *Review of Ontario Interties* would remain as described in the report. However, the loss of the Bruce B facilities and accompanying energy would necessitate further analysis and likely require transmission system changes to accommodate such a significant change to the overall Ontario electricity system.

# How we can close the Pickering Nuclear Station and lower bills

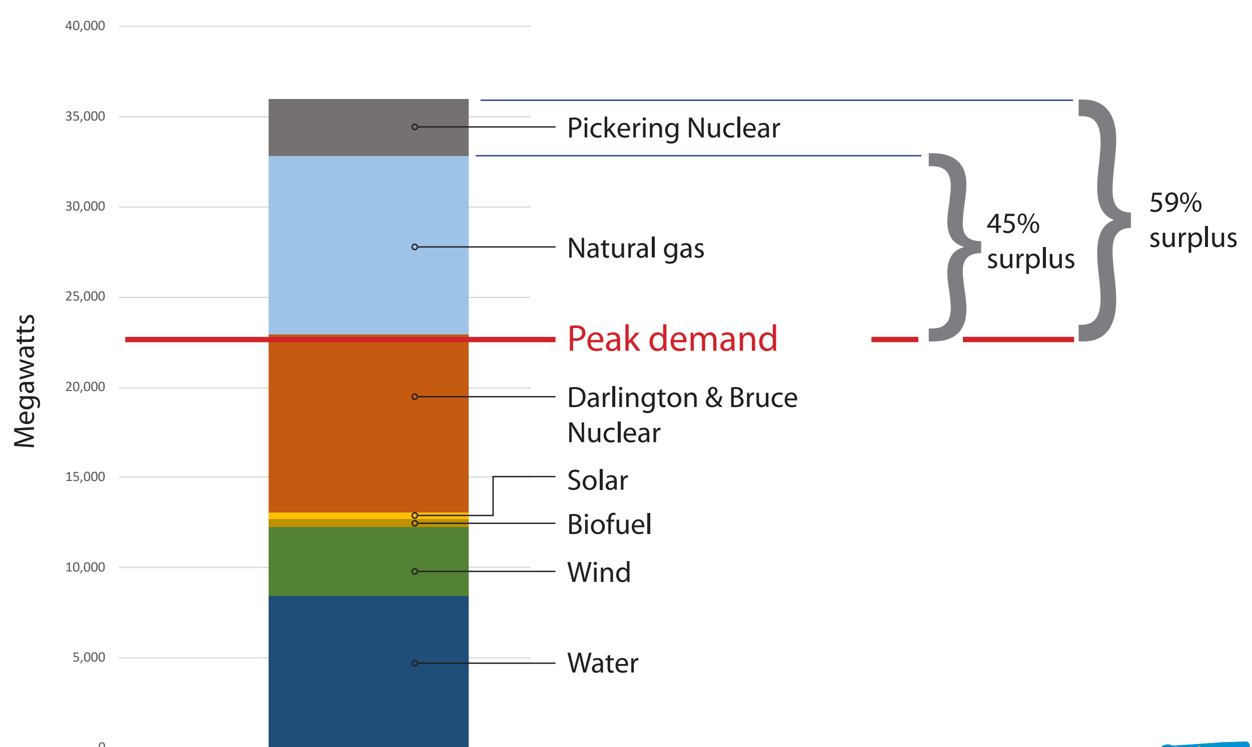
ONTARIO CLEAN AIR ALLIANCE RESEARCH | www.cleanairalliance.org SEPT. 27 2016

## Ontario has a large electricity surplus

Ontario's peak-hour demand for electricity has declined by 17% between 2006 and 2015.[1] In addition, our electricity supply increased by 25% between 2005 and 2015.[2] As a result of this falling demand and rising supply, Ontario now has a large electricity surplus. As Figure 1 shows:

1. The total capacity of Ontario's renewable and gas-fired generation and the Bruce and Darlington Nuclear Stations now exceeds our forecast peak day demand during the summer of 2017 by 45%; and
2. Adding the Pickering Nuclear Station, Ontario's total generation capacity exceeds our forecast peak day demand during the summer of 2017 by 59%.[3]

**Figure 1: Ontario's Electricity Surplus**




Data source: IESO, *18 Month Outlook: An Assessment of the Reliability and Operability of the Ontario Electricity System from July 2016 to December 2017*, (June 21, 2016), pages 4 & 9.

ONTARIO CLEAN AIR ALLIANCE RESEARCH

CleanAirAlliance.org

Ontario, therefore, does not need to keep the Pickering Nuclear Station running beyond 2018 (when its operating licence expires). Even if one or more units at the Darlington Nuclear Station are offline for rebuilding, Ontario can meet its electricity needs without Pickering by increasing the output of its surplus gas-fired power plants; by importing water power from Quebec; and/or by investing in energy efficiency.

**Replace Pickering with gas-fired generation**

Pickering is Ontario's oldest and highest-cost nuclear station. According to an Ontario Power Generation (OPG) benchmarking study, Pickering's operating costs per kWh are higher than those of any other nuclear station in North America.[4] In 2014, Pickering's fuel and operating costs *alone* were 8.16 cents per kWh.[5] OPG is forecasting that Pickering's fuel and operating costs will range from 8.3 to 9.2 cents per kWh between 2017 and 2020.[6]

This means that Pickering's fuel and operating costs alone are more than **three times** greater than Ontario's average wholesale market price of electricity. In 2015, Ontario's average wholesale market price of electricity was 2.36 cents per kWh.[7] This is approximately equal to the fuel and operating costs of our surplus gas-fired generation capacity.[8]

Quebec has sufficient excess water power during 99% of the hours of the year to replace all the power supplied by Pickering for use in Ontario

Therefore, by closing Pickering and increasing the output of our surplus gas-fired generating stations, Ontario could reduce its electricity costs by approximately $1 billion per year.[9] This is equivalent to 5% of our $20 billion total annual electricity bill.[10] But this is not Ontario's best option since it will lead to a rise in our greenhouse gas emissions.

*Impact on Greenhouse Gas Emissions*

As a result of Ontario's large electricity surplus, a high percentage of Pickering's output is exported to the U.S. Therefore, even with one Darlington reactor shutdown for re-building, the Independent Electricity System Operator (IESO) estimates that only 54% of Pickering's output would be needed to meet the demands of Ontario's domestic consumers.[11] Therefore we would only need to increase the output of our gas-fired plants by 10.3 billion kWh per year to replace Pickering's power that is consumed by Ontarians.[12] This would increase Ontario's greenhouse gas (GHG) emissions by three megatonnes per year or 1.7%.[13]

**A better option: Import water power from Quebec**

With our *existing* electricity transmission interconnections with Quebec, we can import 16.5 billion–18.5 billion kWh of water power per year from Quebec.[14]

According to Quebec's Energy Commission, approximately two-thirds of Hydro Quebec's exports are sold at an average price of only 3 cents per kWh. And according to the Commission, Hydro Quebec's low-price electricity exports will grow by 50% between 2014 and 2022, from 20.1 billion to 31.1 billion kWh per year.[15] This low-price export power is currently available on the spot market rather than under long-term contracts.

Therefore, by importing 10.3 billion kWh per year from Quebec, at a cost that is certain to be less than Pickering's fuel and operating cost (8.3 to 9.2 cents per kWh), we can close Pickering and lower our electricity bills without increasing our GHG emissions.

Quebec has sufficient quantities of power available for export during at least 99% of the hours of the year.[16] During the remaining 1%, Ontario can use its gas plants, pay for demand reductions or increase its made-in-Ontario renewable energy capacity. Quebec can also easily increase the power it has available for export by implementing peak demand reduction measures.

*Investing in Energy Efficiency*

According to the IESO, the cost of saving electricity is only 3-5 cents per kWh.[17] Furthermore, according to a recent report prepared for the IESO, energy efficiency investments can cost-effectively reduce Ontario's electricity consumption by 31% by 2035.[18] This is equivalent to more than twice the entire output of the Pickering Nuclear Station.

Continuing to increase our energy efficiency can help us to lower our bills, reduce the need for expensive rebuilt reactors, reduce the need for new transmission infrastructure, and reduce our GHG emissions.

Thus by importing water power from Quebec and by pursuing all of our cost-effective energy efficiency opportunities, we can close Pickering and lower our electricity bills without increasing our GHG emissions.

**Jobs**

We can create 16,000 person-years of employment by completely decommissioning and dismantling the Pickering Nuclear Station by 2030.[19]

The estimated cost of decommissioning and dismantling Pickering by 2030 is $4.1 billion. This cost will be paid from the "Nuclear Decommissioning Fund," a special savings fund OPG is required to maintain and which, as of January 2015, had a balance of more than $7 billion.[20]

The best people to deal with dismantling the plant are current employees who understand the systems and modifications of this 45-year-old plant. However, OPG currently intends to wait 30 years before beginning to dismantle the plant, long after the current workforce is gone.

International best practices, as recommended by the International Atomic Energy Agency, call for immediate dismantling on the basis that there are no safety advantages to waiting decades to start the process.[21] Reactors must be de-fueled and de-watered immediately after permanent shutdown in any case and radiation levels inside reactors will be little changed in 30 years. OPG wishes to delay dismantling simply to defer costs.

It will be better for the surrounding community and workers to begin work on dismantling the plant immediately and returning its prime waterfront site to a safe state as quickly as possible.

Studies undertaken for the IESO show that Ontario's efficiency potential is more than double Pickering's output

## Endnotes

1 Independent Electricity System Operator (IESO), "IESO Releases 2015 Ontario Electricity Data: Sector-Wide Changes Continue to Impact Supply, Demand, Price", *News Release*, (January 12, 2016); and http://www.ieso.ca/Pages/Power-Data/demand.aspx.

2 IESO, *Data Tables for the OPO Technical Report*, (September 1, 2016), Page 3.

3 While only 10% and 30% of our wind and solar generation capacity respectively will be available at the time of the summer peak demand, Ontario can also import up to 6,513 MW of supply from neighbouring jurisdictions to meet its domestic needs. IESO, *Ontario Planning Outlook: A technical report on the electricity system prepared by the IESO*, (September 1, 2016), page 12; Ontario Ministry of Energy, *Achieving Balance: Ontario's Long-Term Energy Plan*, pages 40 and 41; and IESO, *Ontario Reserve Margin Requirements 2016 – 2020*, (December 21, 2015), page 2.

4 OPG, *2015 Nuclear Benchmarking Report*, page 69.

5 Ontario Energy Board Docket No. EB-2013-0321, Exhibit JT1.14 (Refiled: 2014-06-03).

6 Ontario Clean Air Alliance Research, *Closing the Pickering Nuclear Station in 2018: A Cost-Benefit Analysis*, (June 17, 2016), page 3.

7 http://www.ieso.ca/Pages/Power-Data/price.aspx

8 On September 16, 2016 the spot price of natural gas at Dawn (near Sarnia) was approximately $3 per MMBtu (U.S. $) or approximately $3.95 per MMBtu (CDN $). Assuming a heat rate of 6,770 Btu/kWh and a gas cost of $3.95 per MMBtu, the fuel cost of a combined-cycle gas-fired plant is 2.7 cents per kWh. http://www.naturalgasintel.com/data/data_products/daily?location_id=MCWDAWN&region_id=midwest1

9 OPG is forecasting that Pickering will produce 19.1 billion kWh in 2017. 19.1 billion kWh x (8.3 – 2.36 cents per kWh) = $1.135 billion. See Ontario Energy Board Docket No. EB-2016-0152, Exhibit E2, Tab 1, Schedule 1, Table 1.

10 IESO, *Ontario Planning Outlook: A technical report on the electricity system prepared by the IESO*, (September 1, 2016), page 40.

11 IESO, *Assessment of Pickering Life Extension Options: October 2015 Update*, (October 30, 2015), page 12.

12 OPG is forecasting that Pickering will produce 19.1 billion kWh in 2017. 19.1 billion kWh x 0.54 = 10.3 billion kWh.

13 The greenhouse gas emission rate of a combined-cycle natural gas-fired power plant is 290 kg/MWh. Ontario Power Authority, *Supply Mix Analysis Report*, Volume 2, (December 2005), page 213.

14 Email from Jordan Penic, IESO to Jack Gibbons, Ontario Clean Air Alliance, (November 21, 2014).

15 Commission sur les enjeux energetiques du Quebec, *Maitriser Notre Avenir Energetique*, (2 fevrier 2014), pages 176 – 183.

16 Ontario Clean Air Alliance Research, *Can water power from Quebec avoid the need for the Darlington Re-Build?*, (April 7, 2015).

17 IESO, *Ontario's Planning Outlook: A technical report on the electricity system prepared by the IESO*, (September 1, 2016), page 12.

18 Nexant, *Achievable Potential Study: Long Term Analysis*, (June 30, 2016), pages 3 & 4.

19 Torrie Smith Associates, *Direct Decommissioning of the Pickering Nuclear Station: Economic and Other Benefits,* (March 2016), page 3.

20 Torrie Smith Associates, *Direct Decommissioning of the Pickering Nuclear Station: Economic and Other Benefits,* (March 2016), pages 1 & 2.

21 International Atomic Energy Agency Safety Standards Series No. GSR Part 6, *Decommissioning of Facilities*, (2014), page 12.

Thanks to the Echo Foundation and the Taylor Irwin Family Fund at the Toronto Foundation for their generous financial support.

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THE GLOBE AND MAIL



<p>Hydro-Québec is counting on the adoption of a bill in Massachusetts that would make room for the importation of a huge chunk of hydro power from Canada, and Quebec in particular.</p>
Bloomberg

# Hydro-Québec eyes new long-term power accords in U.S. Northeast

Frederic Tomesco And Jim Polson
Published Tuesday, Dec. 06, 2016 02:41PM EST
Last updated Wednesday, Dec. 07, 2016 04:53AM EST

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Hydro-Québec, Canada's biggest electricity utility, wants to expand power sales to U.S. Northeast states hungry for green energy to meet climate change goals.

The power supplier can generate as many as 3,000 additional megawatts that could be shipped south of the border without having to build a new dam, Chief Executive Officer Eric Martel said in an interview at Bloomberg headquarters in New York. It has an annual generating capacity of about 37,000 megawatts.

"We can probably already commit to 3,000 megawatts without building anything other than the transmission line," Martel said Tuesday. "Today we are limited by the number of transmission lines."

Martel wants to double revenue by 2030, targeting takeovers in the Americas and Europe while increasing sales of hydro-generated power to the U.S. Hydro-Québec hopes to win long-term contracts from states like Massachusetts and New York that want to lower emissions of heat-trapping carbon dioxide.

“The states we are working with, mainly New England and New York, are really engaged in reducing emissions. They have their own targets.”

Power sales outside Quebec generated $1.7-billion ($1.3-billion U.S.) of revenue last year, representing about 13 per cent of the company’s sales. Three lines in the planning process– the Champlain Hudson Power Express, the New England Clean Power Link, and Northern Pass – could allow the provincially owned utility to boost exports south.

“Those three projects are about the same size, about 1,000 megawatts of power each, and we could participate in all three,” Martel said in the interview. “We would be comfortable doing that if we got a long-term commitment.”

With most exports currently sold at spot rates, Hydro-Québec would prefer to sign long-term, fixed-rate contracts for the additional power, Martel said. Agreements could last as long as 40 years, he added.

“There is interest on our side and from our customers to have longer-term contracts with stability on pricing,” he said. “That’s one thing that we are working on for the future.”

Hydro-Québec had net income of about $2.2-billion on revenue of about $9.9-billion in the first nine months of 2016. More than 99 per cent of the power that the provincial-owned utility generates comes from renewable sources, according to the company’s 2015 annual report.

By 2030, power exports and acquisitions could propel annual revenue to about $27-billion, with annual profit of about $5.2-billion, Martel said Tuesday.

# SUMMARY OF APPLICATION

## OVERVIEW AND CONTEXT

Ontario Power Generation Inc. ("OPG") produces about half of the electricity Ontarians use every day, and it is committed to doing so safely, reliably, and using technologies that are environmentally sustainable. In 2014, OPG ceased burning coal for electricity production, delivering North America's single largest action to combat climate change.

At the same time, OPG remains the low cost generator in Ontario. OPG controls costs and continuously improves performance through a number of processes, including top-down target setting for key resource envelopes such as OM&A and Capital. OPG continues to look for ways to improve its performance and the value it delivers to electricity customers; finding efficiencies is an ongoing goal for OPG.

OPG is committed to safety in all aspects of its operations. In 2015, the Canadian Electricity Association awarded OPG the *President's Silver Award for Safety Excellence*. OPG is proud of achieving top quartile performance in the company-wide All Injury Rate and Accident Severity Rate. Given the inherent hazards of nuclear and hydroelectric generation, OPG will continue working to reduce and eliminate risks to public and employee safety.

In the period covered by this application, 2017 to 2021, OPG will undertake several major initiatives aimed at ensuring that it can continue to deliver safe, reliable, sustainable electricity. In 2016, OPG began the execution phase of the $12.8 billion refurbishment of the Darlington Nuclear Generating Station ("Darlington"). Through this massive endeavour, OPG will renew a workhorse of Ontario's electricity grid. Darlington provides approximately 20 per cent of Ontario's electricity needs. The Darlington Refurbishment Program ("DRP") will also contribute to the province's economy. According to the *Conference Board of Canada*, the construction phase alone is expected to generate $14.9 billion in economic benefits to Ontario. At its peak, refurbishment will create 11,700 jobs per year, with an average of 8,800 annually between 2014 and 2023. It is also expected to increase household revenues in Ontario by $8.5 billion.

total factor productivity ("TFP") with input cost indices, Z-factors, and off-ramps) in the immediate future."[2] Given the cost and scale of the DRP and the planned extension of the life of Pickering, OPG would not be able to execute the planned nuclear work under a pure IR framework (like the one proposed for the hydroelectric facilities).

**Pickering Extended Operations**

OPG plans to extend the operations of Pickering until 2024.[3] This extension will benefit Ontario's electricity system by mitigating capacity uncertainties during the refurbishment of the Darlington and Bruce Nuclear Generating Stations. It will also benefit Ontario's electricity customers by moderating the upward pressure on rates that would otherwise occur during the height of the Darlington refurbishment. The estimated cost of the incremental work required to safely extend the operations of the Pickering facility is $307M over the 2016-2020 period. The IESO has conducted an independent analysis for the Ministry of Energy that calculates the Ontario Electricity System benefits of Pickering Extended Operations at between $300M and $500M. Details on the extended operation of Pickering are provided in Ex. F2-2-3.

**Rate Smoothing and Mid-term Production Review**

OPG proposes that nuclear payment amounts increase at 11 per cent per year during the term of the application. OPG based the rate smoothing proposal on O. Reg. 53/03, which was recently amended with several new requirements related to OPG's nuclear payment amounts during and following the DRP. An 11% annual increase achieves the objective established in O. Reg. 53/05 of "making more stable the year-over-year changes in the payment amount" while balancing other considerations including the overall customer bill impacts resulting from the total deferred revenue requirement and associated carrying costs, minimizing the transition when rate smoothing ends, and maintaining OPG's financial viability.

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[2] EB-2012-0340, *Report of the Board: Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets*, p. 8.
[3] All six units at the Pickering facility will continue operating until 2022, at which point two units will be shut down. The facility was previously scheduled to end commercial operations in 2020.

# DRIVERS OF DEFICIENCY

## 1.0 PURPOSE

This evidence presents the major drivers of revenue deficiency for the nuclear facilities over the 2017-2021 period as determined in Ex. I1-1-1 Table 3.

## 2.0 OVERVIEW

The revenue deficiency for the nuclear facilities over the 2017-2021 period is driven in largely equal parts by (i) lower nuclear production, which reflects the commencement of Darlington refurbishment outages and outage days related to Pickering Extended Operations[1], and (ii) increases in revenue requirement relative to the annual average of the 2014 and 2015 revenue requirement approved in EB-2013-0321.

The largest drivers of changes in revenue requirement are described below, the largest of which is the Darlington Refurbishment Program ("DRP"). The annual revenue deficiency impact of the production and revenue requirement drivers are detailed in Chart 1 and explained in section 3.0 below.

## 3.0 DRIVERS OF DEFICIENCY FOR THE NUCLEAR FACILITIES

### 3.1 Lower Production

Relative to the annual average of the OEB-approved nuclear production for 2014 and 2015, forecast nuclear production declines by 9.7TWh for 2017, 9.3TWh for 2018, 8.8TWh for 2019, 10.4TWh for 2020, and 12.4TWh for 2021. The comparison of production forecasts in Ex. E2-1-2 identifies the drivers of production forecast changes. The primary drivers of lower production are the units taken out of service for DRP,[2] and the incremental outage requirements resulting from Pickering Extended Operations between 2017 and 2020.

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[1] The overall impact of Pickering Extended Operations is to increase production in the 2017-2021 test period relative to the original planned end of commercial operations in 2020. Pickering Extended Operations is a driver of deficiency relative to 2014/15 payment amounts due to decreased production and increased costs in 2017-2020 in order to execute outages to enable extension.

[2] Unit 2 in 2016, Unit 3 in 2020 and Unit 1 in 2021.

### 3.2 Darlington Refurbishment (42 per cent of revenue requirement impact)

The DRP impacts primarily reflect an increase in the cost of capital and depreciation expense, and related income taxes resulting from rate base in-service additions for refurbishment capital projects. OPG forecasts over $700M in such rate base additions over the 2016-2019 period, and approximately $4.8B in 2020 when Unit 2 returns to service.[3] The DRP impacts also include DRP-related nuclear OM&A expenses, which are related to the removal activities associated with existing structures or facilities including re-tube and feeder replacement and waste management costs.[4]

### 3.3 Pickering Extended Operations Enabling Costs (10 per cent of revenue requirement impact)

The positive economic evaluations of Pickering Extended Operations from OPG and the IESO are provided at Ex. F2-2-3. Forecast OM&A expenses to 2020 to enable Pickering Extended Operations are another driver of the higher revenue requirement relative to EB-2013-0321 approved levels. These costs total $292M over the 2017 to 2020 period as presented in Ex. F2-2-3 Chart 2.

### 3.4 Impact of Changes in Nuclear Station End-of-Life Dates on Nuclear Liabilities (13 per cent of revenue requirement impact)

Accounting changes in nuclear station end-of-life dates[5] impact OPG's nuclear decommissioning and nuclear used fuel and waste management liability ("nuclear liabilities") costs. As further discussed in Ex. C2-1-1 and detailed in Ex. C2-1-1 Table 5, the net impact (for both prescribed and Bruce facilities and including associated income taxes) relates to the increase in the nuclear asset retirement obligation ("ARO") and corresponding increase in nuclear asset retirement costs ("ARC") of approximately $2.3B recorded by OPG at the end of 2015. This increase was primarily driven by the extension of the accounting service life for the Bruce B nuclear units to recognize the Province's December 2015 announcement of an updated refurbishment agreement between the IESO and Bruce Power L.P. The net increase

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[3] Ex. D2-2-10.
[4] Ex F2-7-1 Table 1, footnote 1.
[5] Effective December 31, 2015. Discussed in Ex. F4-1-1.

# BUSINESS PLANNING AND BENCHMARKING NUCLEAR

## 1.0 PURPOSE

This evidence presents the business plan and benchmarking results for OPG's Nuclear Operations and provides a summary of nuclear operating costs in support of the application.

## 2.0 OVERVIEW

OPG's 2017-2021 rate application for its nuclear facilities is based on OPG's 2016-2018 Business Plan, including an additional three-year financial projection for the later years of the test period (2019-2021) both prepared on the same basis and through a consistent process (see Ex. A2-2-1 Attachment 1, Appendix 5: Nuclear Financial Plan, Operational Targets, and Initiatives, for further details). It is also aligned to the guiding principles of Ontario's 2013 Long-Term Energy Plan as it pertains to cost-effectiveness, reliability, clean energy, and community engagement.[1] This application reflects unprecedented and significant changes in OPG's nuclear operations which pose unique challenges in terms of business planning and benchmarking. These include the implementation of the Darlington Refurbishment Program ("DRP") and Pickering Extended Operations ("Extended Operations").

OPG's 2016-2018 Business Plan continues to achieve a sustainable cost structure for the nuclear operations by building on the success of major programs undertaken by OPG over the past few years, including; a) Pickering Continued Operations, where the work program was completed on time, on budget and is on plan to achieve 4-6 additional years of station operation to 2020, b) Business Transformation, where staffing targets were fully realized through the successful implementation of the program, and c) completion of various fleet-wide and site initiatives (Fuel Handling Reliablity, 3k3 Equipment Reliablity and Days Based Maintenance) that were focused on improving operational and cost performance. These initiatives are described in greater detail in section 3.5 below.

[1] Executive Summary, Ontario 2013 Long-Term Energy Plan as found at http://www.energy.gov.on.ca/en/ltep/achieving-balance-ontarios-long-term-energy-plan/

Pickering's TGC/MWh is high, compared to Darlington, reflecting its small unit size and first generation CANDU technology. To better understand Pickering's fourth quartile performance in TGC/MWh, OPG examined costs separately and compared TGC on a unitized basis in order to eliminate generation impacts due to extensive outage programs, reactor design and unit size. On a cost performance assessment, Pickering and Darlington compare very favourably to PWR/BWR reactors by reference to TGC per unit. Pickering's performance, similar to Darlington, is that it is among the lowest cost nuclear generators in North America, as shown in Chart 3. In addition, over the 2009-2014 review period, Pickering maintained a relatively stable cost profile, experiencing a compound annual growth rate of only 0.5 per cent while the industry median quartile experienced a compound annual growth rate of approximately 4.9 per cent over the same period (see Attachment 1 to this exhibit, Nuclear Benchmarking Report, page 67). Pickering's stable cost performance, similar to Darlington, also reflects OPG's implementation of various business transformation initiatives that allowed OPG to achieve significant staff reductions. Finally, when examining the performance of Pickering against other generation options as part of the "Extended Operations" plan, the IESO independently concluded that extending operations saved rate payers between $300M and $500M (see Ex. F2-2-3).

In summary, OPG believes that the nuclear operations OM&A (as shown on Ex. F2-1-1 Table 1 line 4, being the total of base, project and outage OM&A) included in the revenue requirements during the test period represent realistic and appropriate amounts to meet all nuclear safety and regulatory requirements, while demonstrating continuous improvement and executing the nuclear operations activities required to support ongoing nuclear operations and Pickering Extended Operations. OPG's 2016-2018 Business Plan limits the average annual increase in these costs to 0.9 per cent per year over the period 2015-2021. In addition, OPG's Custom IR proposal in this application includes a benchmarking-based stretch factor to drive continuous improvement in elements of the company's nuclear operations that can be implemented without jeopardizing safety, reliability or the execution of the multi-billion dollar nuclear capital work planned during the application period. In computing the nuclear payment amounts, OPG has applied a 0.3 per cent stretch-factor to the revenue requirement resulting from the company's Nuclear Base OM&A and corporate support services allocated to the Nuclear business (see Ex. A1-3-2).

# PICKERING EXTENDED OPERATIONS

## 1.0 PURPOSE

The purpose of this evidence is to discuss OPG's plan to extend the safe operation of Pickering ("Extended Operations") and to describe its associated costs and benefits. Under OPG's plan, as approved by the Province of Ontario, all six units at Pickering would operate until 2022, at which point two units would be shut down and the remaining four units would operate until 2024. Achievement of the plan is subject to the results of certain ongoing investigations and requires Canadian Nuclear Safety Commission ("CNSC") approval. While the activities comprising Extended Operations and their associated costs are discussed in this evidence, recovery of all costs discussed here is requested through the Nuclear OM&A and capital exhibits and associated tables presented elsewhere in this application.

## 2.0 OVERVIEW

The Pickering Nuclear Generating Station consists of six operating 540 MW reactors that were placed into service between 1971 and 1986 (see Ex. A1-4-3 for additional background information). OPG had planned to safely operate all six units until 2020; it now plans to safely operate six units until the end of 2022 and the remaining four units until 2024 as per the 2016-18 Business Plan.[1]

OPG has conducted assessments to demonstrate that extending operations is safe, technically feasible and has economic benefits for Ontario. These efforts build on the work OPG has successfully undertaken as part of the Pickering Continued Operations initiative to enable operation to 2020.[2]

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[1] The Business Case Summary (Attachment 2) shows Units 1 and 4 operating until the end of 2022 and Units 5-8 operating until the end of 2024, but confirmation of the planned shutdown date of each unit is subject to further testing and analysis.

[2] In EB-2010-0008, OPG presented the Pickering Continued Operations initiative aimed at operating the Pickering B Units for a further four calendar years (i.e., Units 5 and 6 to 2018 and Units 7 and 8 to 2020) by achieving 240,000 Effective Full Power Hours ("EFPH"). (See EB-2010-0008, Ex. F2-2-3). As part of the Pickering Continued Operations initiative and in association with other CANDU operators, OPG initiated the Fuel Channel Life Management ("FCLM") project in order to develop ways of managing technical risks associated with pressure tubes (fuel channels), which are seen as the life limiting component.

In EB-2013-0321, OPG filed an updated Pickering Continued Operation's Business Case, indicating that the FCLM project was revised to achieve high confidence that the fuel channels could attain an operational life of

Extended Operations involves incremental activities comprised of additional outage scope (inspections and maintenance), projects (plant modifications), work to respond to potential regulatory requirements and other necessary improvements. The estimated cost of this incremental work, above normal operating costs, is $307M over 2016-2020.[3] Normal operating activities and their associated costs will continue through to 2024 with amounts forecast for 2017 through 2021 included in the test period costs. The incremental investment will allow OPG to generate approximately 62 additional TWh over the remaining life of the plant, which equates to a levelized unit energy cost ("LUEC") of about 6.5 cents/KWh for the additional production.

The IESO has conducted an independent analysis for the Ministry of Energy that calculates the Ontario Electricity System benefits of Extended Operations at between $300M and $500M. Copies of the IESO's updated October 2015 and original March 2015 analyses are included as Attachment 1 to this exhibit. Extending the operation of Pickering mitigates capacity uncertainties during the refurbishments of the Darlington and Bruce stations. The overall system economic value is positive because Pickering's availability reduces the need to construct and operate more expensive gas-fired capacity. It is also projected to reduce $CO_2$ emissions by approximately 17 million tonnes over the 2021 to 2024 period. On January 11, 2016, the Government of Ontario announced the approval of OPG's plan to operate Pickering to 2024.

## 3.0 EXTENDING PICKERING OPERATIONS

### 3.1 The Decision to Extend Pickering Operations

In November 2015, the OPG Board of Directors approved Pickering Extended Operations.

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247,000 EFPH. (See EB-2013-0321, Ex. F2-2-3, page 1). The Fuel Channel Life Management project was successfully completed in 2015 and provided the information necessary to enable a high confidence fitness-for-service statement for the Pickering fuel channels to reach 247,000 EFPH as the project intended. This work also underpinned OPG's successful application to the CNSC to allow Pickering to operate to 247,000 EFPH.

OPG subsequently commenced the Fuel Channel Life Extension ("FCLE)" project. While the majority of the cost of the FCLE project relates to Darlington, not Pickering, the project did help to provide high confidence for Pickering Fuel Channels to achieve 261,000 EFPH, allowing all units to operate until December 2020 without life management outages. (See EB-2013-0321, Ex. F2-3-3, Attachment 1, Tab 11, page 3).

[3] Of this amount, about $290M is expected to be expended in the 2017-21 test period.

The Business Case Summary ("BCS") supporting Extended Operations is attached as Attachment 2 to this exhibit. The BCS included a partial release of $52M, of the $307M in costs to enable Extended Operations, primarily to complete the Periodic Safety Review, the Fuel Channel Life Assurance Project, component condition assessments and to execute incremental maintenance and inspections during planned outages in 2017. OPG's Management will seek a full release of the remaining funds following completion of both the Fuel Channel Life Assurance Project and the Periodic Safety Review.

On January 11, 2016, the Minister of Energy announced that the Government had approved OPG's plan to pursue Extended Operations. Leading up to this announcement, the Ministry of Energy had been working with OPG and the IESO to analyze the technical feasibility, costs and benefits of Extended Operations.

### 3.2 CNSC Requirements

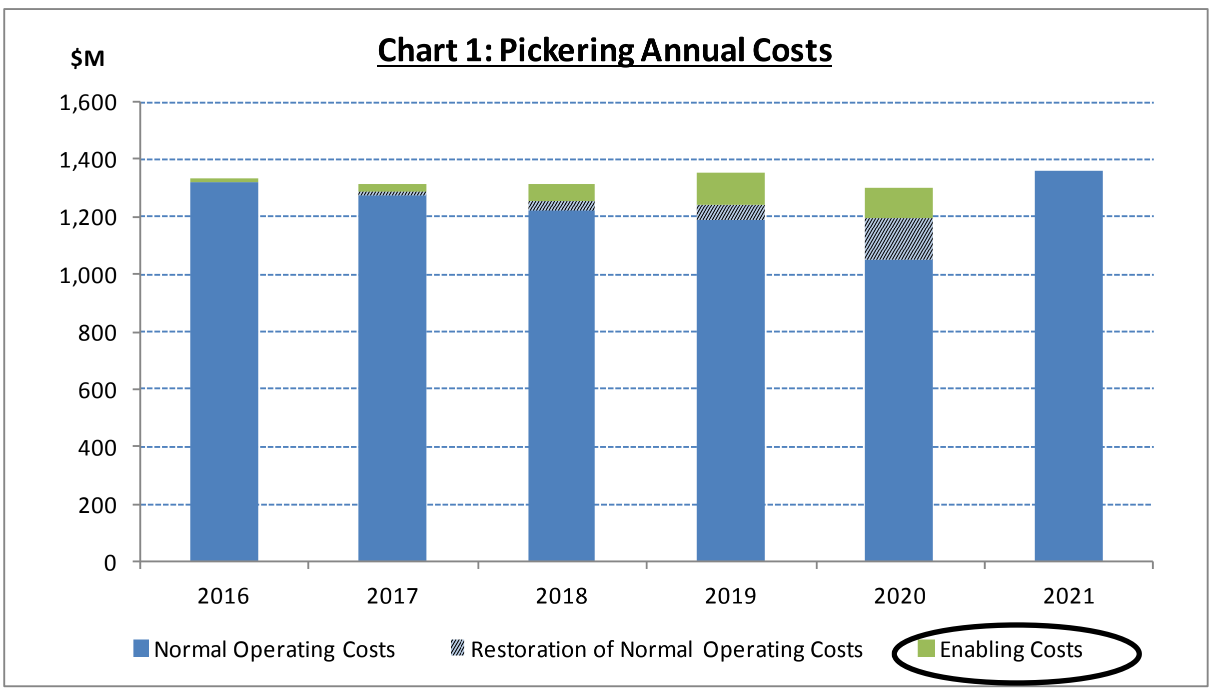
The current five-year power reactor operating licence for Pickering is set to expire August 31, 2018. Based on the success of OPG's Continued Operations project, in June 2014 the CNSC approved OPG's request to remove the hold point for operation past 210,000 Equivalent Full Power Hours ("EFPH"). By this action, the CNSC authorized operation up to 247,000 EFPH, which would allow the plant to operate to OPG's previously planned shutdown dates in 2020.

OPG's operating license requires it to provide written confirmation of the planned end-of-life date for Pickering to the CNSC by June 30, 2017. OPG will provide that confirmation in 2017 as part of the licence renewal application for the next operational period. OPG expects to request a 10-year licence renewal, which will take the units through both the end of commercial operations and the safe storage project period (i.e., until the units are in a safe stored state). OPG anticipates that the CNSC decision addressing operation beyond 2020 will occur as part of the Pickering licence renewal.

### 3.3 The Work Required for Extended Operations and its Cost

In order to achieve the operating lives in OPG's 2016-2018 Business Plan, certain work must be undertaken over the test period. This work is comprised of enabling actions required to extend operations and secure the necessary CNSC approvals. In addition, funds necessary to support the plant's normal operating activities have been included over the 2016-2021 period. The cost of these activities would have previously been forecast to decline when the plant was scheduled to shutdown in 2020.

Chart 1 below shows the estimated costs to enable Extended Operations and operate Pickering in each year of the test period. While this exhibit discusses these costs, they are recovered primarily through the base, project and outage OM&A exhibits (Exhibits F2-2-1, F2-3-1 and F2-4-1, respectively) with the relatively smaller amount of capital expenditures for Pickering projects and minor fixed assets recovered through Ex. D2-1-2. Thus, there is no additional revenue requirement request associated with this exhibit.




### 3.3.1 Enabling Work and its Associated Cost

In advance of recommending Extended Operations, OPG completed an initial technical assessment of the Pickering units' continued ability to operate to the proposed shutdown required to restore on-going operating and maintenance programs back to normal resource levels over the 2017-2020 period.

The 2021 normal operating costs are those required to maintain ongoing base operations, project and outage OM&A work as well as the capital projects necessary to continue the safe operation and maintenance of the plant. These costs also include funds for a scheduled Vacuum Building Outage in 2021.

**3.4 The Benefits of Extending Pickering Operations**

For the Ontario Electricity System, extending the operation of Pickering will mitigate capacity uncertainties during the refurbishments of the Darlington and Bruce stations. The overall system economic value is positive because having Pickering available reduces the need to operate more expensive gas-fired capacity and the costs associated with siting and building additional gas-fired generation, and possible carbon pricing costs. Extended Operations also reduces the need for imports and reduces $CO_2$ emissions by approximately 17 million tonnes over the 2021 to 2024 period.

The IESO completed an updated assessment of Extended Operations in October 2015 (see Attachment 1). This assessment shows a present value benefit ranging from $300M to $500M ($2015). The IESO's assessment closely corresponds to OPG's internal assessment, which shows benefits ranging from $500M to $600M, with the difference arising primarily because the IESO uses a lower real discount rate (4 per cent versus approximately 5 per cent used by OPG) and different system assumptions for items such as load growth and the price of gas-fired generation.

For electricity customers, the primary benefit is to moderate the rate impacts, prior to rate smoothing, which would otherwise occur during the height of the Darlington refurbishment following shutdown of the Pickering units (See Ex. A1-3-3). This is made possible by increased nuclear generation after 2020, which results in a larger OPG generation base over which to spread the impacts of the Darlington Refurbishment costs being placed into the rate base.

OPG expects to incur severance and related costs following the eventual shutdown of Pickering. Extended Operations will defer the costs associated with closure of the station. Delaying the incurrence of these costs by up to four years reduces their present value. This is true even if there is no change in their nominal value. Additional deferral benefits come from delaying the costs to place the Pickering Units in a safe-stored state and eventually dismantling the units. Extending the time before these costs are incurred also permits additional growth in the decommissioning funds.

## 4.0 VARIANCE ACCOUNT

Differences between forecast and actual Extended Operations spending, including amounts spent in 2016 where no forecast was incorporated in the 2014-15 approved payment amounts, will be included in the Capacity Refurbishment Variance Account for disposition in a future proceeding. This variance account is discussed in Ex. H1-1-1, section 5.6.

## Board Staff Interrogatory #116

**Issue Number: 6.5**
**Issue:** Are the test period expenditures related to extended operations for Pickering appropriate?

## Interrogatory

**Reference:**
Ref: Exh F2-2-3 page 4 Chart 1

Please provide in table format the values for the variables noted in Chart 1 at the above reference.

## Response

The values for the variables noted in Chart 1 at Ex. F2-2-3, p. 4 are provided below:

| *($ Millions)* | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|---|---|
| Normal Operating Costs | 1,349 | 1,311 | 1,264 | 1,229 | 1,086 | 1,395 | 7,634 |
| Restoration of Normal Operating Costs | 0 | 15 | 32 | 56 | 147 | 0 | 250 |
| Enabling Costs | 15 | 26 | 55 | 107 | 104 | 0 | 307 |
| Total Costs | 1,364 | 1,351 | 1,351 | 1,392 | 1,338 | 1,395 | 8,191 |

OPG notes that there was an error in the data used to construct Chart 1 in Ex. F2-2-3, p. 4. A new chart will be filed as an evidence correction.

Ontario

**NEWS**

**Ministry of Energy**

# Ontario Moving Forward with Nuclear Refurbishment at Darlington and Pursuing Continued Operations at Pickering to 2024

*Projects will Boost Economic Activity, Create Jobs and Help Fight Climate Change*

January 11, 2016 2:00 P.M.

Ontario is moving forward with nuclear refurbishment at Darlington Generating Station, securing 3,500 megawatts of affordable, reliable, and emission free power.

Nuclear refurbishment at Darlington will contribute $15 billion to Ontario's gross domestic product (GDP) throughout the project and create up to 11,800 jobs annually. The refurbishment of all four units is expected to involve about 30 million hours of work over 10 years and will support Ontario's globally recognized CANDU nuclear supply chain, with more than 180 companies employing thousands of highly skilled workers.

Ontario Power Generation (OPG) is on track to begin refurbishment of the first unit at Darlington in October 2016. To best protect Ontario ratepayers and ensure OPG delivers refurbishment on-time and on-budget, the government has established off-ramps that require OPG to obtain government approval prior to proceeding with each of the remaining unit refurbishments. The budget for the project is $12.8 billion, about $1.2 billion less than originally projected by OPG, and all four units are scheduled for completion by 2026.

The Province has also approved OPG's plan to pursue continued operation of the Pickering Generating Station beyond 2020 up to 2024, which would protect 4,500 jobs across the Durham region, avoid 8 million tonnes of greenhouse gas emissions, and save Ontario electricity consumers up to $600 million. OPG will engage with the Canadian Nuclear Safety Commission and the Ontario Energy Board to seek approvals required for the continued operation of Pickering Generating Station.

Securing clean, reliable power for decades to come is part of the government's plan to build

Ontario up. The four-part plan includes investing in people's talents and skills, making the largest investment in public infrastructure in Ontario’s history, creating a dynamic, innovative environment where business thrives and building a secure retirement savings plan.

**QUOTES**

" Proceeding with the refurbishment at Darlington will ensure that nuclear continues to be Ontario’s single largest source of power. The Darlington refurbishment project will create up to 11,800 jobs annually and contribute $15 billion to Ontario’s GDP. Continuing operations at Pickering will protect 4,500 jobs across the Durham region, provide emissions-free electricity, and save Ontario electricity consumers up to $600 million."
- Bob Chiarelli
Minister of Energy

" Refurbishing Darlington is an investment in Ontario. It’s good for the customers, it’s good for the economy and it’s good for the environment. We’re confident we have done the work and have the people in place to deliver this project safely, on schedule and on budget."
- Jeffrey Lyash
President and CEO, Ontario Power Generation

" With these investments, nuclear will continue its role in ensuring Ontarians have enough power when and where they need it. The plan to refurbish the Darlington nuclear units and to keep Pickering in operation longer during the refurbishment period is a cost effective way to meet our future power needs."
- Bruce Campbell
President and CEO, Independent Electricity System Operator

**QUICK FACTS**

- Nuclear energy plays a fundamental role in Ontario’s electricity system. Ontario’s nuclear fleet currently supplies enough power to meet about 60 per cent of Ontario’s daily electricity needs, and is our largest source of reliable, affordable power.
- OPG electricity rates are regulated by the Ontario Energy Board (OEB). All costs for the Darlington refurbishment will be subject to review and approval by the OEB through a public and transparent process to ensure they are prudently incurred. The average cost

of power from Darlington nuclear units post-refurbishment is estimated to range between $72/MWh and $81 MWh, or 7 and 8 cents per kilowatt hour.

- The average cost of power from Darlington after refurbishment is within the range assumed in the 2013 Long-Term Energy Plan for refurbished nuclear energy and lower than the average price of electricity generation in Ontario, which in 2015 was $92/MWh.
- The Pickering Generating Station employs about 4,500 people and is the largest employer in Durham Region.
- Continuing operations at Pickering Generating Station will avoid 8 million tonnes of greenhouse gas emissions, which is the equivalent to taking 490,000 cars off Ontario roads.

## LEARN MORE

- Learn about OPG's Darlington Refurbishment Project
- Read the Conference Board of Canada's report on the economic impact of the Darlington Refurbishment
- Read Ontario's 2013 Long-Term Energy Plan

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Second Session, 41st Parliament

Assemblée législative de l'Ontario

Deuxième session, 41e législature

# Official Report of Debates (Hansard)

**Wednesday 26 October 2016**

# Journal des débats (Hansard)

**Mercredi 26 octobre 2016**

**Standing Committee on Estimates**

**Comité permanent des budgets des dépenses**

Ministry of Energy

Ministère de l'Énergie

Chair: Cheri DiNovo
Clerk: Eric Rennie

Présidente : Cheri DiNovo
Greffier : Eric Rennie

**Mr. Serge Imbrogno:** Serge Imbrogno, Deputy Minister of Energy. The studies that are being undertaken are being done by MOECC and other ministries. The stage at which those studies are under way—I don't know. I think that's a question for MOECC and MNR and the other ministries that are undertaking those studies.

**Mr. John Yakabuski:** It's almost six years. It sounds to me like that's a delay tactic.

We'll move on. Let's talk about Northland Power and the $95-million award by a lower court, I guess it was, and then it went to the Ontario Court of Appeal, which dismissed the appeal, or stayed the appeal. Now the OEFC is taking it to the Supreme Court of Canada.

It's highly unlikely, if the Ontario Court of Appeal saw no reason to even proceed—they stayed the request, at the Court of Appeal, which leaves us on the hook for the money. In fact, that money, I believe, has been retroactively advanced to Northland. They may have to repay it if they lose, but the reality is that they're probably not going to lose. I know you won't comment on the court case, but every court along the line has ruled in their favour. That's another $95 million.

It was an Ontario regulation that led to the court case. It was a regulation passed by your government that led to the court case. This is another $95 million. We're hearing every minute about $70 million over seven years like it was the second coming. Now we have another $95 million that we could be on the hook for, if this goes through to its end.

Can you tell me—

**The Chair (Ms. Cheri DiNovo):** Mr. Yakabuski, you have about three minutes.

**Mr. John Yakabuski:** My, time flies, eh?

Can you tell me how many other Northland Powers are out there with respect to the decision—and I don't have the regulation. If I had faster eyes—there is a number of that regulation. I did have it—Ontario regulation 398/10. How many other Northland Powers are out there that are affected by this? What is the total amount that Ontario could be on the hook for, if all of those rulings go against us?

**Hon. Glenn Thibeault:** Thanks for the question. From my understanding, the Ontario Electricity Financial Corp., which is under the Ministry of Finance's purview, made a decision relating on how the NUGs were paid. They disagreed with that and went through the court process. Through the court process, it is now once again under appeal. From me having lots of lawyers giving me advice, I'm not able to comment on any of that, because it is under the appeal process right now.

**Mr. John Yakabuski:** But you could tell us what the total amount is that could be at stake here.

**Hon. Glenn Thibeault:** What I've been told very clearly is, because this is under appeal right now, it is not something that I'm able to comment on.

**Mr. John Yakabuski:** So you do know the total amount, but your lawyers are telling you not to comment on that.

The amount that is at stake with respect to Northland Power is public, and we asked questions on it today in the Legislature. You took one of those questions. It wasn't shuffled off to the Minister of Finance, so you took the question.

**1510**

**Hon. Glenn Thibeault:** And I answered the same way I just did.

**Mr. John Yakabuski:** Not exactly, but—

**Hon. Glenn Thibeault:** Well, I answered, and then I talked about some of our programs, but I don't think you want me to talk about our programs right now. I know you only have three minutes.

**Mr. John Yakabuski:** Not again, no. I'm fairly familiar with your programs at this point.

So are you saying you don't know how much is at stake, or that you just aren't able to disclose that based on lawyer's advice?

**Hon. Glenn Thibeault:** All I'm saying right now is that because the process is under appeal, I can't comment on anything to do with this file or this case.

**Mr. John Yakabuski:** Wow. It's just amazing how we can have this kind of—yesterday, we find out, and I noticed too that the Premier again said yesterday in the Legislature, "no additional financial impact." But how can you say that when you know that—no additional impact other than the original decision, award, change or whatever—

**The Chair (Ms. Cheri DiNovo):** I'm afraid your time is up, Mr. Yakabuski.

**Mr. John Yakabuski:** Can I get an extra minute?

**The Chair (Ms. Cheri DiNovo):** Sorry. We now move on to the third party: Mr. Tabuns.

**Mr. Peter Tabuns:** Good afternoon, Minister and Deputy Minister.

**Hon. Glenn Thibeault:** Good afternoon.

**Mr. Peter Tabuns:** I was asking yesterday about the Pickering life extension and whether or not the government had actually looked at the cost comparison between conservation on the one hand and the Pickering life extension on the other. You referred me to the Ontario Energy Board filings on the extension. I poked around. I found them. There is no mention of conservation. The only comparison for the Pickering life extension is to combined-cycle or single-cycle gas turbines, not conservation.

Conservation is much cheaper than gas. I understand that gas-fired power in Ontario is around 11 to 12 cents a kilowatt hour. I've seen your numbers showing 3 to 6 cents a kilowatt hour for conservation. Why did you not compare the Pickering life extension to the option of expanding our investment in conservation?

**Hon. Glenn Thibeault:** The deputy was the one who was explaining that piece, so I'll hand that back to the deputy.

**Mr. Serge Imbrogno:** Just a couple of points, Mr. Tabuns. The Pickering life extension: The government has given OPG the green light to pursue the approvals through the regulator, both the OEB and the CNSC, and then to return to the government after we have all the information. I just want to clarify that. They still have to report back once they have gone through the regulatory process with the OEB and the CNSC.

**Mr. Peter Tabuns:** I'll come back to that question. Your whole thing is conservation first. I hear that all the time. The minister spoke eloquently about it the other day. Why aren't you using conservation as a comparator when you're making decisions on generation?

**Mr. Serge Imbrogno:** When we do our long-term planning, we take into account conservation. When you look at the demand curve, it already takes into account all the conservation that we've put forward. In the $2 billion-plus that we're going to spend on conservation in this next framework, all that is taken into account. If you were to do it the other way, you would add that back in. We've already taken it into account through all the measures that we've announced that the demand curve would be reduced by that amount. Then, the IESO does their analysis from that basis.

What I'm saying is that we've already taken into account all the conservation when you see the analysis that the IESO does in that piece.

**Mr. Peter Tabuns:** We had this discussion the other day. You're not planning at this point—we'll see what happens with your long-term energy plan—to take advantage of all the conservation opportunities that have been identified. There is a lot more conservation opportunity out there than is currently planned for. Why, when you say conservation is your first option, do you not compare it to life extension for Pickering? Why does it not even feature in the documentation that is put together?

**Mr. Serge Imbrogno:** I think our conservation targets are very aggressive. That's already incorporated. I think the study you're referring to talks about economic conservation if you have no budget constraint. I'm sure you could drive further conservation if there was no budget constraint. I think what we'd do is optimize through the IESO: Where's the best return for your investment? That's what we've built into the plan.

Going forward, as we electrify, for example, there'll be more opportunities for more conservation—more opportunity for different funding from the cap-and-trade proceeds, for example.

At this point, we believe we've captured all of the conservation that's appropriate. Going forward, there's opportunity to do more.

**Mr. Peter Tabuns:** I have to say, the way you appear to be using conservation is, if you need a filler in your graphs, you put it in as a filler. You never compare it to actual generation investments. So if you're making a generation investment here, in a province where people are hard-pressed with high hydro bills, you have an opportunity with conservation to provide electricity services at a much lower price than the extension of Pickering, yet you didn't do that.

Conservation is clearly not first in your assessment of options. Frankly, you could make an assessment of conservation compared to Pickering and, in five years or 10 years from now, as technologies develop, look at other conservation options to deal with the need for electricity services. Deputy Minister and Minister, conservation is not first. Conservation apparently, in your scheme, is a filler. It is not actually compared to generation.

**Mr. Serge Imbrogno:** I think it's the opposite, because when we do our forecasts of our supply need, we first start with conservation and reduce demand by that amount. Once we reduce demand, then we forecast what additional supply we need. So we actually do start with conservation, reduce the demand accordingly and then we fill in the supply, based on what's left. In doing that, we try and optimize how much conservation is achievable, and that's what the achievable potential study does, from the IESO. Once we've done that, then we fill in the difference with supply.

**Mr. Peter Tabuns:** Minister, if you were going to make the decision around the extension of Pickering—and I'll be interested to hear exactly what you're charging per kilowatt hour for power from that plant—and you have the opportunity to fill that gap with conservation today, why are you not putting conservation on one side of the balance and Pickering life extension on the other and looking to see which is most cost-effective?

**Hon. Glenn Thibeault:** Thanks for the question. To reiterate the piece—I am aware of the time, so I won't reiterate a lot of what the deputy minister was talking about. It is important for me to highlight that the framework specific to this is talking about—we're working on trying to achieve seven terawatts of savings to assist the province in achieving its long-term conservation target of 30 terawatts by 2032. When we're comparing those two, we're wanting to make sure, as the deputy minister said, that conservation does come in first, we reduce that demand and then we meet the needs in our capacity accordingly.

On the specifics of Pickering, I know, Deputy, that you can talk about those costs and those types of things.

**Mr. Serge Imbrogno:** I could provide more detail, if you want, on Pickering.

**Mr. Peter Tabuns:** I will ask specific questions about that.

**Mr. Serge Imbrogno:** Okay.

**Mr. Peter Tabuns:** Moving on to that, in the last long-term energy plan, your projection was closing Pickering by 2020. In fact, in the plan you say that there are opportunities to close it earlier. Why are you extending it to 2024 and why are you doing that without a public consultation on that?

**Mr. Serge Imbrogno:** The IESO is always looking for opportunities to find efficiencies. OPG is also looking for opportunities to run their existing plants more efficiently.

The opportunity exists to extend the life of Pickering. It's not a refurbishment. It's using the existing facility. It's doing more testing to determine if the life could be extended, which is part of the return to the CNSC.

For a marginal investment in extending the life of Pickering, we're able to continue with that zero-GHG-emission power. We'll save money, because it will be extended at the existing relatively low price for nuclear power. That saves us money, going forward. The IESO analysis says, on a system-cost basis only, that it's $600 million. That doesn't include the additional GHG reductions. It doesn't include extending the workers at Pickering as well. There are other economic benefits that we haven't incorporated into that $600 million. We think that for a modest increase in extending the life, we have a large benefit.

**Mr. Peter Tabuns:** Just to be clear, you have not yet made a final decision to extend to 2024. Is that correct?

**Mr. Serge Imbrogno:** That's correct. We've given OPG the authority to go forward, to go through the OEB, and also to the CNSC for regulatory approvals, and then to return, closer to 2017, I believe, for a final decision.

**Mr. Peter Tabuns:** That will be a decision made at the cabinet level?

**Mr. Serge Imbrogno:** It will be made by the minister and, I would suggest, at the cabinet level as well.

**1520**

**Mr. Peter Tabuns:** Are you currently in the process of putting in place plans should the CNSC or the OEB give you a red light on this?

**Mr. Serge Imbrogno:** That's the job of the IESO. They would take into account all of the different options and be ready in case we go one way or the other. That's something that the IESO does. It's part of their job.

**Mr. Peter Tabuns:** So are they doing it?

**Mr. Serge Imbrogno:** Yes, that's what they do.

**Mr. Peter Tabuns:** They do all kinds of things. Sometimes, they may miss something. Can you tell us that they are currently planning for contingencies in case they don't proceed with the Pickering extension?

**Mr. Serge Imbrogno:** The IESO is planning for contingencies in all events in Pickering's service life. Whether it's shorter or longer would be one of the contingencies that they would take into account.

**Mr. Peter Tabuns:** And do you know what the contingencies are—what they are currently planning as the alternatives to the life extension?

**Mr. Serge Imbrogno:** I don't know. There are contracts that are coming due that they could extend. There are other measures that they could take. I don't know the specifics.

I guess that an obvious one would be to continue to run the gas plants that are currently running, which we were going to get the GHG reductions from. That's always an option for the IESO, but one that we're trying to reduce in order to reduce the GHG footprint.

**Mr. Peter Tabuns:** What is the cost per kilowatt hour of power from the Pickering reactors? I gather that four of them are at one cost and two are at a different cost. What is the cost?

**Mr. Serge Imbrogno:** It's estimated in the $65-per-megawatt-hour range.

**Mr. Peter Tabuns:** That's the average between all six of them?

**Mr. Serge Imbrogno:** When we extend the life of Pickering, that's what we're forecasting for the cost of the production.

**Mr. Peter Tabuns:** So $65 per megawatt hour for production as a whole?

**Mr. Serge Imbrogno:** That's correct.

**Mr. Peter Tabuns:** And there's no differentiation between the reactors?

**Mr. Serge Imbrogno:** They would just get the price that the OEB provides—the nuclear rate.

**Mr. Peter Tabuns:** I've seen in the past a price of nine cents per kilowatt hour for power from two of the reactors at Pickering. You're telling me that that's not the case?

**Mr. Serge Imbrogno:** I don't know where that number comes from. I think that Pickering's performance has improved dramatically, so you may be referring to an older number.

**Mr. Peter Tabuns:** So you're currently saying $65 per megawatt hour?

**Mr. Serge Imbrogno:** That's the forecast of what the price would be for the extended terawatt hours that we'll be receiving.

**Mr. Peter Tabuns:** Is the government of Ontario currently seeking to negotiate an electricity supply contract with Hydro-Québec which would permit Ontario to close Pickering earlier?

You were able to get something like five cents a kilowatt hour in the most recent deal, according to La Presse. This is six and half cents a kilowatt hour. Are you looking at a deal to give us lower-priced power, as opposed to that extension?

**Hon. Glenn Thibeault:** I think that, when it comes to the deal that we announced with Quebec last week, we were pretty excited at the deal that we were able to get. The two terawatts that we are getting now, we're going to target, as mentioned, to our natural gas utilities during peak times. We're helping them, doing the 500-gigawatt swap in their peaking hours, and then we're going to do the storage component as well.

I think that it's important for us to say that we're always going to look at opportunities that present themselves with Quebec in relation to where that goes. We just finished a three-year deal. I think that we're all taking a breath right now. But it's important for us to—

**Mr. Peter Tabuns:** Minister, I think that you're getting off-track from my question. Are you looking now, given that you were able to get a good price from Quebec, at a cheaper price than the one that the deputy minister just cited for the Pickering plant?

**Hon. Glenn Thibeault:** I was going to say, in answer to your question, the importance for us to continue working with Quebec on all aspects—I don't think that any door is shut. I think that this three-year agreement that we've been able to come forward with is exciting news for Ontario because it just shows that we can continue to have negotiations with Quebec. But any of those specifics, Deputy?

**Mr. Serge Imbrogno:** I'll just add—

**Mr. Peter Tabuns:** No, I would like to go back to the minister, sorry.

I'm not talking about doors open or closed. Are you negotiating with Quebec right now to follow up on that five cents a kilowatt hour—which is cheaper than Pickering—to see if you can replace power from Pickering that we will be paying a lot more for until 2024?

**Hon. Glenn Thibeault:** As I was saying, the agreement that we had over the last three years was a landmark deal. We're excited to have the opportunity to have this deal with Quebec. The IESO and Hydro-Québec were the two entities that sat down and had that conversation. I know the IESO is always in negotiations and always looking for ways to benefit the province. But when it comes to those specifics, I do believe that the deputy would have more details for you.

**Mr. Peter Tabuns:** Are they negotiating a deal to replace the power from Pickering?

**Mr. Serge Imbrogno:** I would just add that the power from Pickering is different in the sense that—it's baseload power, but it's 24/7/365 and an 80%-plus capacity factor. So this is our baseload power. The negotiations with Quebec were really at the margins to try to reduce our gas burn, so it's not throughout the year. It's a different type of negotiation. That's why Pickering provides us with such an important part of extending that life, because of the type of power we get and when we get it.

**Mr. Peter Tabuns:** So you're not negotiating with them.

**Mr. Serge Imbrogno:** I think we always have discussions between the IESO and Hydro-Québec—

**Mr. Peter Tabuns:** But you're not negotiating with them right now to see if you can replace some or all of the power from Pickering with lower-cost power from Quebec. Is that correct?

**Mr. Serge Imbrogno:** I wouldn't frame it that way. I would just say that—

**Mr. Peter Tabuns:** Well, you can say no.

**Mr. Serge Imbrogno:** The other thing, the minister and I haven't confirmed that it's five cents, just to make that clear.

**Mr. Peter Tabuns:** No, I understand. It was La Presse who did the calculation: the number of years, the total amount of power, the total price. You do the math; you do the division.

If you have a different price, I'm quite happy to have you put it on the table today.

**Mr. Serge Imbrogno:** No, I just didn't want to give the impression that we were confirming it was five cents or not. We'll leave it to—it was in La Presse.

**The Chair (Ms. Cheri DiNovo):** Mr. Tabuns, you have about four minutes.

**Mr. Peter Tabuns:** Thank you.

So you're not negotiating with Quebec to try to replace some or any of the power from the Pickering life extension.

On another matter related to Pickering, the International Atomic Energy Agency, when talking about decommissioning of facilities, says that best practices call for immediate dismantling of a plant that has been shut down on the basis that there's no safety advantage in waiting decades to start the process. Are you planning to tell OPG, when Pickering is shut down, to start dismantling it so it's in line with the International Atomic Energy Agency's standard recommendations?

**Mr. Serge Imbrogno:** The plan right now for Pickering, like all the other nuclear facilities—the CNSC reviews those plans and approves those plans and the OPG sets aside funds for decommissioning and for used fuel disposal. The CNSC has approved a 30-year safe storage period. That allows the facility to sit for 30 years and then we begin the decommissioning. So that's approved by the CNSC, and OPG funds according to that plan.

**Mr. Peter Tabuns:** Do you have the funds now to decommission or do you have to wait 30 years for interest to accumulate to be able to decommission?

**Mr. Serge Imbrogno:** There are two parts of the funds that have been established. There are the funds for decommissioning and there are funds for the used fuel disposal. The Ministry of Finance through the OFA manages those funds, along with OPG. There's full disclosure. I believe the decommissioning funds are fully funded and then the used-fuel funds, over time, will be invested and contributed to in order to be fully funded. But that information is available.

**Mr. Peter Tabuns:** So the funding is available for doing a decommissioning consistent with international best practices. That's what you're telling me.

**Mr. Serge Imbrogno:** Consistent with what the regulator requires.

**Mr. Peter Tabuns:** I'm sure the regulator doesn't see a big problem giving you a 30-year pass, but I'm sure the regulator may also be totally open to having you do it very quickly, because there's a job creation opportunity here in Pickering that would put an awful lot of people to work. Is there a reason that you're not going to do it now, in 2024 or earlier, which would put a lot of people to work?

I'm glad to hear that there's money in the kitty so that we actually could do it now, if we wanted. That's great.

**Mr. Serge Imbrogno:** Every five years, the liability estimate is updated and OPG goes before the regulator. I guess there will be opportunity for the regulator to determine a different course, but OPG would provide its evidence and best advice on how to move forward with decommissioning. I don't think there are any plans to change that from a 30-year safe storage to a prompt decommissioning.

**1530**

**Mr. Peter Tabuns:** Is there a reason you wouldn't take advantage of this job creation opportunity?

**Mr. Serge Imbrogno:** I think there are pros and cons. We leave it up to the regulator to provide whatever they believe is the best course. I think the longer you have the safe storage, the longer you can accumulate the funds and invest them and have that money available for decommissioning.

**Mr. Peter Tabuns:** But I gather it's fully funded now, correct?

**Mr. Serge Imbrogno:** Well, there are assumptions about when you do the decommissioning and what you're going to get when you invest those funds over the next 30 years. All of those things are factored in.

**Mr. Peter Tabuns:** So it's not fully funded now. It's fully funded if we have 30 years of interest accumulation on it.

**Mr. Serge Imbrogno:** Well, we would classify it as fully funded.

**Mr. Peter Tabuns:** And that means the money could be used to decommission within the next five years, within the next eight years.

**Mr. Serge Imbrogno:** No, they would be fully funded according to the plan that you have in place, that they would be available 30 years from when you start.

**The Chair (Ms. Cheri DiNovo):** I'm afraid your time is up now, Mr. Tabuns. We move to the government side: Mr. Dong.

**Mr. Han Dong:** Good afternoon, Deputy. Good afternoon, Minister. I want to talk about the Green Energy Act, because it actually made Ontario a leader in clean energy. From my experience travelling, I've seen emerging economies and jurisdictions that, although they're doing well in terms of GDP, do pay a hefty environmental cost, and health care costs as well. I think that as globalization deepens, entrepreneurs and innovative minds will pick and choose where they want their families to reside. That's why Ontario and Canada keep being, perhaps, some of the most popular destinations for immigration. Just thinking on the reverse side of that, there are countries that are losing talent and entrepreneurs, and it partly has to do with the quality of air and water and all of these basic necessities to provide for their families.

I'm very pleased that the Green Energy Act has actually made us a leader in clean energy. I wanted to ask the minister for your thoughts on how Ontario has benefited from integrating these renewable energies into our system, and whether or not other jurisdictions are following our path to achieve cleaner energy systems, if you can give us some explanation.

**Hon. Glenn Thibeault:** Sure. Thanks for the question. I think it's important to talk about our commitment to renewable energy. We currently have 18,000 megawatts of power contracted or online. That's very, very important to say because we've seen significant reductions in GHGs that relate to that.

Another important thing in relation to your question is how we eliminated our coal-fired plants. When we stopped polluting our air, the benefits that we're seeing in health care—we're talking about $4.3 billion in savings in health care. The Toronto's Vital Signs Report talked about how we've seen a 41% reduction in air pollution deaths. That's significant and something that we should all be proud of in relation to our investments that we've made when it comes to green energy and the importance of having a clean, reliable system. Some of the specifics on what we've done since 2003, even—I know, Deputy, that you can get into some of those details.

**Mr. Serge Imbrogno:** Yes, thank you. I was going to ask Kaili Sermat-Harding, our ADM who works in the renewables division, to come up and say a few words, but I would just say, as the minister said, we have 18,000 megawatts of solar and wind energy, bioenergy and hydroelectric energy.

In terms of other jurisdictions, our Independent Electricity System Operator has been able to integrate renewables into our grid. I think we're looked upon as a leading jurisdiction for that. One part of the piece that some people forget is how the IESO has been able to integrate wind and solar into our system.

But I'll let Kaili walk you through the investments we've made over time and how they've contributed to our greenhouse gas reduction.

**Ms. Kaili Sermat-Harding:** Thank you, Deputy. My name is Kaili Sermat-Harding. I'm the assistant deputy minister of the conservation and renewable energy division at the Ministry of Energy. I appreciate the opportunity to dive into some of the details around the initiatives that Ontario has been pursuing, as well as to put it into a bit of global context and outline some of the very tangible benefits that have come about as a result of our series of initiatives.

In 2013, wind and solar power represented 8% of Ontario's energy supply mix. Today they comprise approximately 17%, and are expected to rise to approximately 23% by 2025. To date, as the minister mentioned, Ontario has over 18,000 megawatts of wind, solar, bioenergy and hydroelectric generation contracted or online. Of the almost 16,000 megawatts of renewable energy that is online, that includes 4,500 megawatts of wind power, roughly 2,200 megawatts of solar PV, approximately 8,800 megawatts of hydroelectric capacity and roughly 500 megawatts of bioenergy.

The province is home to five of the 10 largest wind projects in Canada as of the end of the 2015 calendar year, more than 99% of all installed solar PV capacity in the country, and the largest 100% biomass facility in North America at the Atikokan Generating Station.

Ontario has established itself as a leader in renewable energy through a variety of initiatives, including the Green Energy Investment Agreement, the feed-in tariff and microFIT programs, the large renewable procurement program and net metering.

With respect to the Green Energy Investment Agreement, Ontario's partnership with Samsung through the agreement, referred to as the GEIA, has supported the creation of a strong and thriving clean energy industry in the province. The agreement set a framework to build renewable energy projects and manufacturing plants in Ontario. It was signed in 2010 between Ontario and Samsung, with amendments negotiated in 2011 and 2013.

In June 2013, the ministry worked collaboratively with Samsung to update and revise the agreement, and this resulted in reducing contract costs by $3.7 billion. The revised agreement includes protecting the original agreement's job commitments and adding a commitment to solar manufacturing jobs in 2016, reducing the agreement's total commitment for renewable energy projects from 2,500 megawatts to 1,369 megawatts and requiring

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

# EB-2007-0905

IN THE MATTER OF AN APPLICATION BY

## ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES

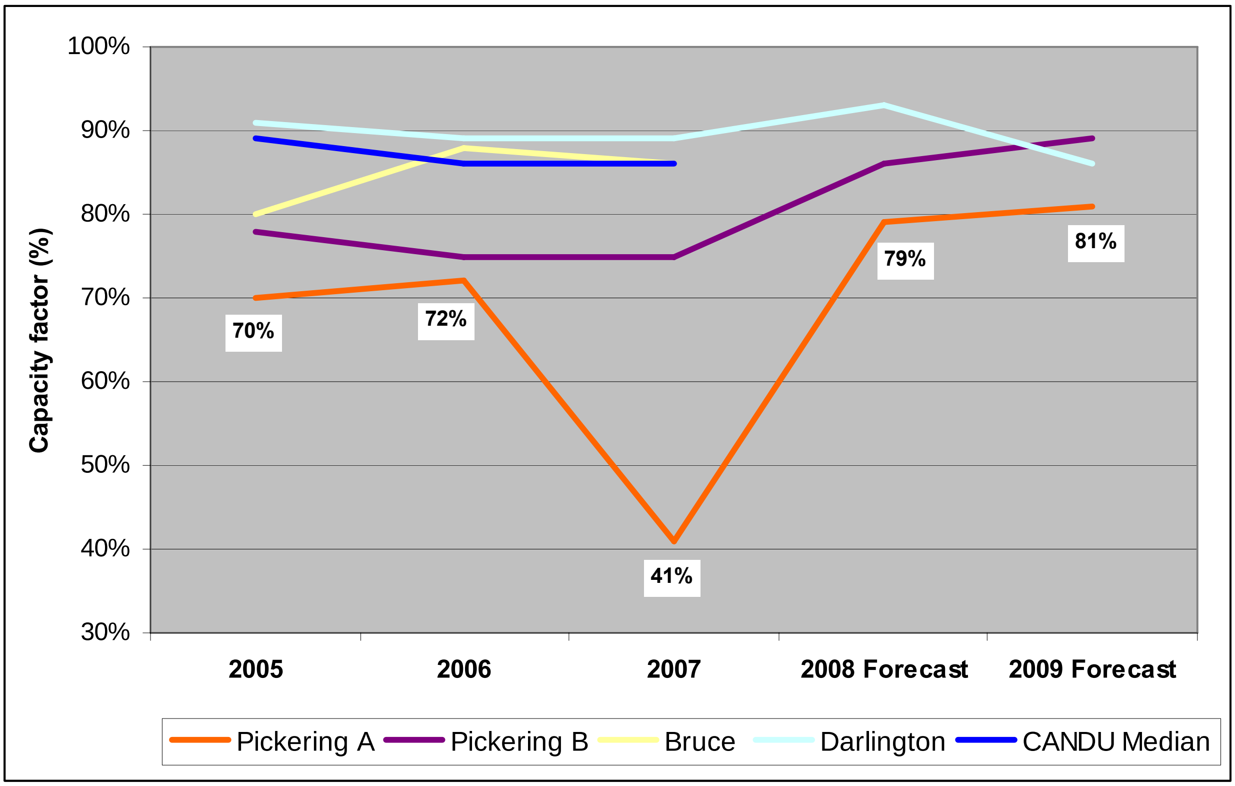
DECISION WITH REASONS

November 3, 2008

Chart 2-2 shows the capacity factors for the OPG-operated plants compared to the capacity factors of Bruce Power and the Canadian CANDU median. The capacity factors shown on the face of the chart are for the Pickering A station, which had the lowest capacity factor of the plants included in the chart.

OPG stated that in the first quarter of 2008, the capacity factors achieved at its nuclear stations were: Darlington – 99%; Pickering A – 79%; and Pickering B – 86%.

**Chart 2-2: OPG's Nuclear Capacity Factors Compared to Bruce and Canadian CANDU Median**




*Source:* Ex. J5.4, Ex. L-4-2, Attachment 3

Darlington's performance over the three-year period 2005 to 2007 was similar to that of Bruce Power and the Canadian CANDU median; however, Pickering A and Pickering B operated at lower capacity factors, especially in 2007. Over the three-year period 2005 to 2007, the average capacity factor at Pickering A was 61% compared to 85% at Bruce Power and 87% for the CANDU median.

A number of parties questioned the long-term viability of the Pickering plants, particularly Pickering A. Energy Probe noted that the operating costs of Pickering A exceeded the value of the electricity generated and asked the Board to withhold payments for any facility that raises the cost of power for consumers.

AMPCO argued that over the 2005 to 2007 period, the average cost of Pickering A power was double the Hourly Ontario Energy Price and the nuclear payment amount received by OPG under O. Reg. 53/05. AMPCO concluded that even with the forecasted cost of 8.1 cent/kWh (AMPCO's calculation) in the test period, the prudence of continued operation of Pickering A remains a concern. AMPCO argued that OPG should be required to file a long-term assessment of the viability of Pickering A in the next rates application. SEC also argued that OPG should be directed to file a plan which demonstrates that Pickering A and Pickering B can operate at costs similar to other generators.

OPG responded that the Board's role in this application is to review the costs of Pickering A, and based on these costs, set reasonable payment amounts. OPG argued that the Board should not, and cannot, decide the ultimate viability of Pickering A, as this is beyond the scope of Section 78.1 of the *OEB Act*.

Regarding the AMPCO and SEC submissions that OPG's costs are excessive given the benchmarking results, OPG responded that the intervenors used selective data and disregarded technical differences regarding Pickering A and Pickering B. OPG also argued that AMPCO's assertion that OPG was resistant to benchmarking was unsupported. OPG maintained that it is committed to benchmarking and is in full compliance with the requirements in the MOA.

OPG also noted that it expects Pickering A and B's performance to improve substantially in the future and submitted that Darlington will continue to perform as well as it has in the past. Most of the intervenors countered that the forecasted results for 2008 and 2009 are unduly optimistic and the Board should discount these projections.

OPG also questioned the arguments by a number of intervenors that the Navigant Study supports the conclusion that 2006 staffing levels were 12% higher than benchmark. OPG claimed that the Navigant Study cannot be used to test the level and reasonableness of OPG's labour cost because the Navigant Study is not representative of staffing levels in the test period.

Regarding the suggestion that the OM&A budget should be treated on an envelope basis, OPG responded that while it should be free to manage specific expenditures within an OM&A envelope, it is opposed any determination of the OM&A costs through a benchmarking exercise.

**Board Findings**

This aspect of the decision gives rise to two significant issues. The first is whether the Board has the jurisdiction to determine the viability of the Pickering stations. The second is the extent to which the Board should use the detailed benchmarking evidence to assess the reasonableness of the costs OPG seeks to recover.

With respect to the first issue, the Board agrees with OPG that the Board's role in this application is to review the proposed costs of the prescribed facilities and to order reasonable payment amounts.

As discussed in Chapter 9 of this decision, the Board has rejected OPG's proposed payment structure for the nuclear plants (which was to include a fixed amount of $1.2 billion during the test period plus a per MWh payment amount to cover the balance of the revenue requirement). Instead, the Board has decided to retain the current variable payment structure of an amount per MWh regardless of the level of production. If OPG operates its plants at a unit cost higher than the approved payment amount, the excess costs will be borne by OPG and its shareholder. Consumers will not be at risk for costs in excess of the costs used to set the payment amount. Therefore, the Board does not accept the suggestion of intervenors that it order OPG to file a study on the long-term viability of Pickering. The long-term viability of the Pickering stations is an assessment more properly made by the shareholder knowing that the Board will only allow the recovery of reasonable costs and that the payment structure will be such that consumers will not bear production risk.

The benchmarking issue is more important. The direction given by the Province to OPG in the MOA is very specific. OPG is directed to seek "continuous improvement in its nuclear generation business." To this end, the MOA states: "OPG will benchmark its performance in these areas against CANDU Nuclear plants worldwide as well as against the top quarter of private and publicly owned nuclear electricity generators in North America." And finally, the MOA states: "OPG's top operational priority will be to improve the operation of its existing nuclear fleet."

The Board in this proceeding is faced with the task of determining whether the costs OPG seeks to recover are reasonable. A very important tool available to the Board is the benchmarking analysis.

Very little benchmarking evidence was filed by OPG in its initial application. This evidence was largely produced during cross-examination when OPG filed the Navigant Study.

The most common measure of productivity in nuclear generation industry is PUEC. The PUECs of the two Pickering stations are far above industry averages as Chart 2-1 indicates; in fact, the operating cost performance of Pickering A may be the worst of any nuclear station in North America. In 2006, Pickering A had a PUEC three times the U.S. average ($75.60 per MWh compared to $24.00 for the U.S. Median) and twice the Bruce unit cost of $38.00 per MWh; in 2007 Pickering A had increased to $130.00 per MWh compared to $23.00 for the U.S. median and $42.00 at Bruce.

Pickering B's 2006 PUEC was better at $55.00 per MWh but was still more than twice the U.S. median and significantly above Bruce. In 2007, Pickering B remained relatively constant at $56.00 per MWh, which was still more than twice the U.S. median and 30% greater than Bruce. The Darlington plant demonstrates a more respectable performance at $29.00 per MWh in 2006 and $32.00 per MWh in 2007.

The unit costs at Pickering A and Pickering B are forecast to improve in 2008 due to higher planned capacity factors. OPG claimed that the Pickering A operating costs will decline from $130.10 per MWh in 2007 to $76.00 in 2008 and $77.00 in 2009. Similarly, OPG claimed that the Pickering B costs will decline from $56.00 in 2007 to $50.00 in both 2008 and 2009. A number of intervenors were skeptical of these promised results.

OPG made two arguments concerning the PUEC benchmarking data. The first argument made by OPG was that the productivity results flow from technology decisions made in the past that should not be questioned using hindsight. In other words, the Board must assume that the technology decisions were prudent at the time they were made and the poor productivity results evident today, while unfortunate, are consequences of those decisions to be borne by the Ontario consumer. The Board finds this an unsatisfactory response.

OPG's primary argument was that the benchmarking data is unreliable.

The Board does not believe it is sufficient for OPG to simply discount the benchmarking studies on the basis of data quality. The studies are all based on standard measures used by the nuclear industry throughout the United States and Canada. While caution should be exercised when reviewing such data, the Board is satisfied that the studies provide meaningful insights into OPG's operations. Moreover, even if there are frailties in the data, the differentials remain striking, particularly with respect to Pickering A. The reason why the MOA emphasized benchmarking was because such studies can and do shine a light on inefficiencies and lack of productivity improvement.

While OPG criticizes the data, the Board notes that few steps have been taken to improve the quality of studies. The Board also notes that benchmarking studies were not filed as a matter of course but rather were reluctantly produced during the course of cross-examination.

Moreover, the Board was surprised that OPG has not followed up with the suggested Phases 2, 3 and 4 of the benchmarking analysis suggested by Navigant. While the benchmarking is critical to the Board (and it would seem to the shareholder), it appears that OPG has done little since the completion of the Navigant Study. The Navigant Study was delivered two years ago on September 15, 2006. There appear to be no benchmarking studies underway. And OPG has not decided what benchmarking evidence, if any, it will present at the next rates case.

Navigant completed Phase I of its study in 2006. Phase 2 as described at page 9 of the Navigant Report was to set OPG's strategy and performance targets. Specifically, Phase 2 was to address the question "what level of cost and operational performance improvement is justified". Phase 3 was to develop and execute an implementation plan. Specifically, Phase 3 was to address the questions "what specific initiatives and actions are needed to achieve identified performance improvement targets".

The questions Navigant suggested should be addressed in the second and third phases of the study are important questions. They are directly responsive to paragraph A.3 of the MOA.[14]

[14] "OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly-owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet."

The Board directs OPG to produce further benchmarking studies in its next application that specifically address the questions raised in the proposed Phase 2 and Phase 3 of the Navigant Report. Whether these studies are performed by Navigant or another firm is a matter to be determined by the applicant.

The production costs of the Pickering A station are a particular concern. In the past, a major reason for the high PUEC for Pickering A has been the extent of unplanned outages and the resulting low capacity utilization. OPG has forecast significantly higher capacity factors for Pickering A in 2008 and 2009. But, as Chart 2-1 illustrates, even at those higher production levels, the PUEC for Pickering will still remain well above the PUEC for Pickering B, will be significantly higher than the PUEC of the Darlington station, and will stay well above the PUEC achieved by the Bruce station over the period 2005 to 2007. Thus, poor capacity factors are not the whole reason for a high PUEC at Pickering A.

The Board estimated the PUEC for Pickering A assuming it were able to reach the forecast capacity factors of the Pickering B station in 2008 and 2009. Even if Pickering A were able to increase its planned capacity factors by that much (from 79% in 2008 and 81% in 2009 to 86% in both years), the Board estimates that the PUEC of Pickering A would only fall to around $70 per MWh, a level that is still much higher than the next highest cost station in Chart 2-1. In the Board's view, this indicates an issue with the overall level of production costs at Pickering A.

Under these circumstances, the Board believes that a reasonable action is to disallow 10% of the Base OM&A costs of Pickering A. This represents a test period disallowance of $14.9 million in 2008 and $20.1 million in 2009. Even with those amounts removed from the revenue requirement, the amount of the operating costs of Pickering A will still remain well above those of other nuclear plants.

The Board will have an opportunity to reexamine this issue when the benchmarking studies are updated in the next proceeding. At that time the Board will examine any improvement or deterioration in production unit energy costs compared to other utilities, and the reasons for those changes.

Aside from this adjustment, the Board will allow the OM&A forecast by OPG. The Board understands the concern of the intervenors regarding the level of costs, but believes it is important to examine underlying cost drivers. A number of the planned expenditures are

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

Ontario

# EB-2010-0008

**IN THE MATTER OF AN APPLICATION BY**

# ONTARIO POWER GENERATION INC.

**PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES FOR 2011 AND 2012**

## DECISION WITH REASONS

**March 10, 2011**

In the project business case, OPG estimated that the project will cost $190.2 million, all of which is OM&A. The test period costs are $92.9 million. However, OPG acknowledged that it had double counted the cost of the fuel channel life management project ($8.8 million), and therefore the forecast is actually $84.1 million. The business case analysis indicated that the project has a net present value of $1.1 billion ($2010). OPG has assigned a medium level of confidence to achieving the expected four years of additional life. Accordingly, OPG's Depreciation Review Committee has not proceeded with approval to extend life for depreciation purposes. PWU and the Society supported OPG's position.

CCC submitted that it would be premature for the Board to approve the project at this time and suggested that the need and economics should be considered within the context of the Ontario Power Authority's ("OPA") long term supply plan which will come before the Board for approval. Energy Probe submitted that it had low confidence in the success and good performance of the project and stated its preference to have the project funded by a private shareholder. In reply, OPG repeated that the work must be undertaken in the test period as otherwise the units will start to close in 2014.

Board staff questioned the costing of the Pickering B Continued Operations project. Outside of the admitted double counting for the fuel channel life management project, staff questioned the range of cost estimates in the public domain of $190.2 million in the application and $300 million in other OPG documents as well as the lack of contingency in the $190.2 million figure. OPG dismissed Board staff's concerns in Reply Argument, stating that, "For some reason Board staff is unable to distinguish between numbers that appear in press releases and sustainability reports and the testimony of the senior OPG executive that is actually accountable for the project." [23] OPG asserted that the cost of $190.2 million is OPG's best estimate.

Board staff also questioned the estimated benefits associated with the project and recommended that OPG provide an independent analysis of the project to support future cost recovery. For example, staff submitted the use of a price of approximately $50/MWh is inappropriate in assessing Pickering relative to replacement generation and that the appropriate figure to use is Total Generating Cost. Staff also questioned the assumed unit capability factors since they were much higher than the actual unit capability factors at the Pickering stations. SEC agreed with Board staff that the

[23] Reply Argument, p. 201.

benefits of the project appear to be over stated. SEC submitted that OPG should curtail further spending until an independent analysis of the benefits is carried out.

OPG argued that no parties provided competing analyses of the benefits. In OPG's view, references to the assumptions used in its analysis were selective and it is clear that the OPA supports the test period expenditures. OPG further submitted that using Total Generating Cost for the benefits analysis should be rejected since it includes costs that will exist notwithstanding the shutdown of Pickering. With respect to unit capability factors, OPG noted that it had performed a sensitivity analysis with varying levels of unit capability factors and the net present value is significantly positive even for the lower end of the range.

Board staff argued that, given the confidence expressed by OPG's witnesses that the project will come in on budget and that no contingency is required, there should be no need to use the capacity refurbishment variance account. If the Board has discretion, staff recommended that the Board restrict the use of the account to those costs that are not routine OM&A activities (i.e., the fuel channel life cycle management project). Staff also noted its concerns that OPG stated it is counting on the variance account to the extent a contingency is required. AMPCO supported the approach proposed by Board staff. OPG maintained that the entire project is clearly within the scope of the account. OPG noted that even work for which there is high confidence can have a variance. Further, if the project comes in under budget, excluding it from the variance account would mean that ratepayers would be denied a credit.

**Board Findings**

The Board approves $84.1 million in costs for Pickering B Continued Operations in this test period.

In this proceeding, the Board is of the view that its role is limited to determining the following:

- whether the planned spending on the Pickering B Continued Operations in 2011 and 2012 is reasonable based on the business case; and
- whether OPG's decision not to extend the end of life for Pickering B for accounting purposes is reasonable. This issue is addressed in Chapter 8.

The Board will consider spending for years beyond the current test period in OPG's next application, at which time there will be examination of the progress to date and an assessment of project economics and the company's confidence level on the basis of that experience and more current information.

With respect to the planned spending during the test period, the Board has determined that the proposed O&M budget is reasonable, except for the double counting of the fuel channel life cycle management project which will be corrected. The Board is satisfied that the business case substantiates the reasonableness of test period expenditures. However, the Board does have concerns with respect to the analysis. Parties have raised a number of other issues regarding the specifics of the benefits analysis, including the unit capability factors, the price used for comparative purposes and the absence of a contingency component in the cost estimate. The Board expects OPG to address these issues more fully in its next application when the Board considers the next segment of spending, as well as any variance in the account. In seeking to provide the best evidence, OPG should consider seeking an independent assessment by the OPA to be filed with its next application.

With respect to the operation of the variance account, the Board agrees with OPG that section 6(2)4 of O. Reg. 53/05 applies to Pickering B Continued Operations as the project is designed to increase output of a generating facility to which O. Reg. 53/05 applies.

Although this project is to be funded entirely through operating expenditures, it has many similarities with a capital project because O. Reg. 53/05 requires the tracking of any variances through the operation of the capacity refurbishment variance account. In the normal course, for projects funded through operating expenditures, the company would bear the risk of budget variances and would therefore need to manage the costs within its overall revenue envelope. For this project, however, any variances will be captured in the variance account for later prudence determination by the Board. The Board is concerned that ratepayers bear a particular risk in relation to these large nuclear projects, which have a history of going over budget. In examining the prudence of any incremental expenditure (over the approved level for the test period) the Board will consider whether OPG might prudently have offset the cost increases through cost reductions or cost deferrals elsewhere in its operations.

required of Hydro One.[37] Board staff noted that, given total compensation costs of almost $2.8 billion over the test period, the cost of such a study would be reasonable.

OPG argued that an external study of compensation was not required because the study would be expensive, at a cost of about $0.5 million to $1 million, there are a limited number of nuclear operators in Canada, and OPG is bound by its collective agreements. OPG stated that if it was directed to complete a study, it would do so provided funding was allocated.

**Board Findings**

Compensation makes up a very significant component of OPG's total operating costs. The Board is concerned with both the number of staff and the level of compensation paid in light of the overall performance of the nuclear business. Each of these issues will be addressed separately.

The lack of comparable data (use of headcount for the historical period and FTEs for the future) make comparison and trending of staffing levels difficult. The Board must be able to see proposed staffing levels and compare those to previous period actuals. The Board therefore will direct OPG to file on a FTE basis in its next application and to restate historical years on that basis.

One of the reasons for the discontinuity between headcount and FTEs may be the extensive use of overtime, particularly in the nuclear division. The Board expects to examine the issue of overtime more closely in the next proceeding. The Board expects OPG to demonstrate that it has optimized the mix of potential staffing resources.

Despite this difficulty in comparing proposed staffing levels with past periods, the Board is of the view that OPG has opportunities to reduce the overall number of employees further as a means of controlling total costs and enhancing productivity. This was demonstrated by OPG's own evidence, as explained by OPG's witness and by Mr. Sequeira from ScottMadden, with respect to the Radiation Protection Function.[38]

The ScottMadden Phase 2 report observed that OPG's staffing levels per unit exceed both the industry median and Bruce Power, and that OPG staff levels are generally higher than the comparison panels (while noting that this may be influenced by OPG's

[37] Decision with Reasons, EB-2006-0501, August 16, 2007, p. 33.
[38] Tr. Vol. 3, p. 24.

practice of contracting out relatively few project based outage functions).[39] For this reason, the Board has also directed OPG to conduct a staff level analysis as part of its benchmarking studies for the next proceeding. (This issue is discussed more fully in Section 4.2, Benchmarking.) ScottMadden also conducted a pilot top-down staffing analysis for a single OPG function: the Radiation Protection Function. ScottMadden concluded that there was room for a potential reduction of 48 FTEs (28%) in the Radiation Protection Function, of which 13 FTEs could be eliminated altogether. Despite these findings, OPG failed to act on an opportunity to eliminate 13 FTEs, and instead eliminated only one.[40] This is only a single example concerning relatively few positions, but the Board is concerned that OPG has not acted more aggressively in a case where it has clear information that a particular function is overstaffed. Although collective agreements may make it difficult to eliminate positions quickly, it is not reasonable for ratepayers to bear these additional costs in the face of strong evidence that the positions are in excess of reasonable requirements. With 20 to 25% of staff expected to retire between 2010 and 2014, the Board concludes that OPG has a timely opportunity to review its organizational structure, taking actions to reassign functions and eliminate positions. The Board is not suggesting that a specific percentage of the retiring staff will not need to be replaced, but this may provide an opportunity for reducing the overall staffing complement without disrupting negotiated commitments with the unions.

As to the compensation, the Board finds that the compensation benchmark should generally be set at the 50th percentile. OPG suggests there is no evidence to support this conclusion, but the Board disagrees. This target level is consistent with the recommendations of the Agency Review Panel for executive employees, and indeed for management employees, OPG uses the 50th percentile as the benchmark. In the Board's view, there would need to be strong evidence to conclude that a higher percentile is warranted for non-management staff. OPG provided no such compelling evidence, but merely asserted that positions in the nuclear business required greater skills overall than the comparators. There was no documentation or analysis to support these assertions.

The evidence provided does not substantiate the assertion that the positions selected by OPG are sufficiently different to warrant the use of the 75th percentile. Although OPG stressed that its work requirements (particularly on the nuclear side) are highly

[39] Exh. F5-1-2, p. 26.
[40] Tr. Vol. 3, p. 27.

technical, the Board observes that many of the comparators in the Towers Perrin study would also require highly technical skills, and some of the comparators also operate nuclear facilities. Indeed the job classifications used in the Towers Perrin report are compared against each other on the basis that they are at least broadly speaking comparable. A number of the positions selected by OPG, such as labourer, also do not appear to be specifically related to highly technical nuclear plant work. In addition, most of the comparators were similarly large and unionized, and perform highly technical, though not necessarily nuclear plant, work. The Board recognizes that the analysis conducted by OPG to produce the chart is not comprehensive, and indeed was not likely intended to be comprehensive. Well over half of OPG's employees are not covered by the 30 positions listed in the chart. The data was not specifically prepared for the purpose of conducting a comprehensive comparison, and the data used in preparing the chart references base salary only.[41] Despite these limitations, the analysis provides sufficient evidence to conclude that for a significant proportion of OPG's staff the compensation is excessive based on market comparisons.

PWU argued that the comparative analysis, which uses non-nuclear entities, is not evidence of imprudence by OPG, and therefore there is no evidence to rebut the presumption that the expenses arising from the collective agreements are prudent. The Board does not agree.

The ratepayers should only be required to bear reasonable costs – and in determining reasonable costs the Board can be guided by market comparisons. It is the responsibility of the Board to send a clear signal that OPG must take responsibility for improving its performance. In order to achieve this, the Board will reduce the allowance for nuclear compensation costs by $55 million in 2011. This amount is derived by considering a number of factors:

- Reducing the compensation for the 30 positions from the Towers Perrin data would require a reduction of $37.7 million.
- Given the breadth of positions in the analysis and the prevailing pattern that wages are well in excess of the $50^{th}$ percentile, it is reasonable to conclude that the same pattern exists for the vast majority of all staff positions in the company. There was certainly no evidence to suggest otherwise. Therefore, the total

[41] The Towers Perrin survey was filed confidentially with the Board as undertaking J8.5. The Towers Perrin Survey includes data both for base salary and total cash compensation. However, OPG appears to have used only the base salary information in preparing the chart. See Tr. Vol. 8, pp. 175-176.

adjustment to move all regulated staff to the 50th percentile is substantially in excess of $37.7 million.

- In determining the appropriate adjustment, the Board recognizes that it will be difficult for OPG to make significant savings through compensation levels alone in the short to medium-term given the collective agreements with its unions.
- OPG has already indicated that there will be no increase in management salaries through April 1, 2012, and this reduction was not incorporated into the original filing.
- The ScottMadden benchmarking analysis supports the conclusion that there is excess staff overall and that this is one component of OPG's relatively poor performance (in comparison to its peers). A further reduction in the allowance for compensation is warranted for this factor.
- The ScottMadden benchmarking analysis also demonstrates that OPG's overall performance is poor on certain key benchmarks, for example non-fuel operating costs. Compensation is a significant cost driver for this metric, and OPG's poor ranking supports the Board's decision to make reductions on account of compensation costs

The same reduction will apply in 2012, but there will also be an additional reduction of $35 million to represent further progress toward the 50th percentile, further progress in reducing excess headcount, and further progress toward achieving a reasonable level of cost performance. The total reduction for 2012 is $90 million.

While a more aggressive reduction was argued by some intervenors, the Board recognizes that changes to union contracts, to staffing levels and movement to the 50th percentile benchmark will take time. Indeed, the Board recognizes that OPG may not be able to achieve $145 million in savings in the test period through compensation reductions alone. The Board is making these adjustments so that payment amounts are based on a reasonable level of performance. If costs are in excess of a reasonable level of performance, then those excess costs are appropriately borne by the shareholder.

The Board is allocating this adjustment solely to the nuclear business for the purposes of setting the payment amounts. The Board is not ordering any reductions for the hydroelectric business because the benchmarking evidence for that business supports the conclusion that it is operated reasonably efficiently from an overall perspective, and therefore the Board is less concerned with the specific compensation levels for that part of the company. For the nuclear business the evidence is clear that overall performance is poor in comparison to its peers and the staffing levels and compensation exceed the comparators. On this basis an adjustment is necessary to ensure the payment amounts are just and reasonable.

Lastly, the Board directs OPG to conduct an independent compensation study to be filed with the next application. As noted above, OPG's compensation benchmarking analysis to date has not been comprehensive. The Board remains concerned about compensation costs, in light of the company's overall poor nuclear performance, and would be assisted by a comprehensive benchmarking study comparing OPG's total compensation with broadly comparable organizations. The study should cover a significant proportion of its positions. Compensation costs are a signification proportion of the total revenue requirement; OPG's position that such a study would be too expensive and of little value is therefore not reasonable. Consultation with Board staff and stakeholders concerning the scope of the study, in advance of issuing a Terms of Reference, is advised. The costs of the study are to be absorbed within the overall revenue requirement allowed for in this Decision. This has been already accounted for in the Regulatory Affairs budget, which anticipates studies in support of the company's next application.

## 6.2 Pension and Other Post Employment Benefits

Costs related to Pension and Other Post Employment Benefits ("OPEB") for the test period were forecast based on discount rates and assumptions in OPG's 2010-2014 business plan. The total amount requested for the test period is approximately $633 million. On September 30, 2010, OPG filed an Impact Statement in which it identified a significant decline in discount rates causing an increase in forecast pension and OPEB costs for the test period. Rather than revising the proposed revenue requirement, OPG requested approval for a variance account, "to record the revenue requirement impact of differences between forecast and actual pension and OPEB costs." The total forecast increase as a result of the update is $264.2 million, as summarized in the following table.

Ontario Energy Board

Commission de l'énergie de l'Ontario

# EB-2013-0321

**IN THE MATTER OF AN APPLICATION BY**

# ONTARIO POWER GENERATION INC.

**PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES FOR 2014 AND 2015**

## DECISION WITH REASONS

**November 20, 2014**

OPG's CANDU plants require 1,431 more Full Time Equivalents ("FTEs") than comparator plants and eliminated these FTEs from the staffing study. OPG estimated that this represents $184M of unavoidable OM&A.

As the shareholder has concurred with the business plans that underpin the application, OPG replied that the shareholder has no concerns with OPG's performance under the Memorandum of Agreement.[38] OPG argued that it is not contractually committed to, or required to target or perform to top quartile standards, and that it is not aware of any case where the Board considered failure to achieve top quartile performance in setting rates.

**Board Findings**

The benchmarking of OPG's nuclear operations is an important reference for the Board. OPG has continued to produce annual nuclear benchmarking reports based on the format and methodology set out in 2009 by the consulting firm ScottMadden. The benchmarking is responsive to the Memorandum of Agreement with the Shareholder and provides the Board with comparative information for its review in a cost of service application. It is the Board's expectation that OPG will continue to produce annual nuclear benchmarking reports based on the ScottMadden methodology and that OPG will file these reports in future cost of service applications.

The benchmarking results for 2008 to 2013 and the targets for the test period were reviewed in this proceeding. The analysis was complicated by the presentation of rolling averages for the historical period and annual targets for the future period. The analysis was further complicated by the reorganization of Pickering. The Board recognizes that some individual units at Pickering and Darlington have improved performance in one or more of the metrics. In OPG's view, it has improved as a major operator in the three key metrics, but in comparison to the industry, OPG is just stable, because the industry also is changing.

Despite these factors, there is no dispute that OPG's performance in the three key metrics is not top quartile, nor does it demonstrate continuous improvement. In fact, for many of the measures OPG remains in the third or fourth quartile. It is also reasonable to conclude that OPG will not reach the aspirational 2014 targets set by ScottMadden and OPG in 2009 in order to close the gap. This is not the type of performance that

[38] Reply Argument page 134

ratepayers would expect. OPG is not satisfied with its performance either: "… clearly we would like to see better performance from our plants."[39]

In its submission, Board staff included calculations of the cost of OPG's performance relative to the midpoint for comparators' total generating cost for 2011 for illustrative purposes. CME submitted that a $150M OM&A reduction per year was appropriate on the basis of this gap. The Board agrees with OPG that reductions of $150M to $300M per year on the basis of nuclear benchmarking is not appropriate as the impact of Business Transformation is not reflected in the 2011 total generating costs. However, the Board notes that OPG's total generating cost targets for 2014 and 2015 take into account Business Transformation and those targets are second and third quartile.

OPG also argued that the Board staff and CME calculations were flawed as there is unavoidable OM&A related to the CANDU technology. The Board does not agree that the calculations were flawed for this reason. The ScottMadden methodology, which has been accepted by OPG for benchmarking, considered technology differences and found that the best overall financial comparison metric for OPG facilities is total generating cost per MWh.

Both Environmental Defence and GEC have proposed significant reductions related to poor economic performance of the Pickering units. The Board does not agree with these submissions. The government's direction on the operation of Pickering is set out in the Long-Term Energy Plan.

The Board finds that OPG's proposed nuclear OM&A costs should be reduced. The Memorandum of Agreement provides that "OPG's top operational priority will be to improve the operation of its existing nuclear fleet." In conjunction with ScottMadden, OPG itself set targets for 2014 that will not be met. Although the Memorandum of Agreement is not a contract for this purpose, it is clearly OPG's shareholder's intention that OPG improve continually, and at least target top quartile performance. OPG accepts that benchmarking is a valuable tool, and accepts that it has not achieved the results it wanted to achieve. It does not appear to accept, however, that there should be any repercussions from this poor performance in the way of disallowances. Benchmarking serves as a guide only. However, it is clear that OPG's inability to achieve even average performance imposes a significant cost on ratepayers. The Board finds that it is not reasonable to pass all of these costs on to ratepayers.

[39] Tr Vol 6 page 13

There is no specific budget "line item" related to overall nuclear performance and benchmarking. However, the majority of OM&A costs are predominantly related to staffing levels, compensation and pension related costs. Therefore, the Board's disallowances with respect to this issue are incorporated within its disallowances under the compensation section of this Decision.

## 3.3 Nuclear Fuel

**(Issue 6.5)**

Nuclear fuel costs include the cost of fuel bundles, used fuel storage cost and fuel oil for standby generators. As updated in Exhibit N2, OPG has forecast an amount of $266.5M for nuclear fuel procurement for 2014 and $260.5M for 2015.

AMPCO submitted that based on the average of 2010 to 2013 actuals, the test period fuel oil expense should be reduced by $3.5M. OPG did not respond to this submission.

In response to direction from the previous cost of service decision, OPG filed the Uranium Procurement Program Assessment Study prepared by Longenecker and Associates ("Longenecker").[40] Longenecker confirmed that US nuclear generators require inventory of 30 to 35% of annual requirements. OPG stated that test period carrying costs would be reduced by $4.7M if OPG's inventory levels were reduced to 30%. CME submitted that a reduction of $4.7M is appropriate. OPG argued that CME's proposal was unreasonable as contractual obligations as well as financial and physical risk coverage limits need to be considered.

CME observed that the proposed fuel costs are higher than historical and submitted that each test year be no more than the 2013 expense of $244.7M. OPG replied that there is no support for this submission as fuel expense is a function of production. In addition, OPG indicated that the 2013 fuel expense was based on production of 44.7 TWh and the production forecast for each test year is higher.

Board staff suggests that OPG be required as part of its next payments application to provide a study demonstrating how its nuclear fuel requirements and cost estimates reflect appropriate strategies for balancing costs and risks. Further, Board staff suggested that the analysis be based on the approaches that OPG has found

[40] Exh F5-2-1

# Ontario Energy Board Act, 1998
# Loi de 1998 sur la Commission de l'énergie de l'Ontario

## ONTARIO REGULATION 53/05

## PAYMENTS UNDER SECTION 78.1 OF THE ACT

**Consolidation Period:** From January 1, 2016 to the e-Laws currency date.

Last amendment: O. Reg. 353/15.

**Rules governing determination of payment amounts by Board**

**6.** (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,

   i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and

   ii. the revenues and costs are accurately recorded in the account.

2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.

3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.

4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs and firm financial commitments incurred in respect of the Darlington Refurbishment Project or incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,

   i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or

   ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,

   i. the costs were prudently incurred, and

   ii. the financial commitments were prudently made.

**Ontario Energy Board** *Appellant*

*v.*

**Ontario Power Generation Inc., Power Workers' Union, Canadian Union of Public Employees, Local 1000 and Society of Energy Professionals** *Respondents*

and

**Ontario Education Services Corporation** *Intervener*

**Indexed as: Ontario (Energy Board) *v.* Ontario Power Generation Inc.**

**2015 SCC 44**

File No.: 35506.

2014: December 3; 2015: September 25.

Present: McLachlin C.J. and Abella, Rothstein, Cromwell, Moldaver, Karakatsanis and Gascon JJ.

ON APPEAL FROM THE COURT OF APPEAL FOR ONTARIO

*Public utilities — Electricity — Rate-setting decision by utilities regulator — Utility seeking to recover incurred or committed compensation costs in utility rates set by Ontario Energy Board — Whether Board bound to apply particular prudence test in evaluating utility costs — Whether Board's decision to disallow $145 million in labour compensation costs related to utility's nuclear operations reasonable — Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sch. B, s. 78.1(5), (6).*

*Administrative law — Boards and tribunals — Appeals — Standing — Whether Ontario Energy Board acted improperly in pursuing appeal and in arguing in favour of reasonableness of its own decision — Whether*

**Commission de l'énergie de l'Ontario** *Appelante*

*c.*

**Ontario Power Generation Inc., Syndicat des travailleurs et travailleuses du secteur énergétique, Syndicat canadien de la fonction publique, section locale 1000 et Society of Energy Professionals** *Intimés*

et

**Corporation des services en éducation de l'Ontario** *Intervenante*

**Répertorié : Ontario (Commission de l'énergie) *c.* Ontario Power Generation Inc.**

**2015 CSC 44**

N° du greffe : 35506.

2014 : 3 décembre; 2015 : 25 septembre.

Présents : La juge en chef McLachlin et les juges Abella, Rothstein, Cromwell, Moldaver, Karakatsanis et Gascon.

EN APPEL DE LA COUR D'APPEL DE L'ONTARIO

*Services publics — Électricité — Décision d'un organisme de réglementation des services publics relativement à l'établissement de tarifs — Demande d'un service public en vue d'obtenir le recouvrement de dépenses de rémunération faites ou convenues grâce aux tarifs établis par la Commission de l'énergie de l'Ontario — La Commission avait-elle l'obligation d'employer une méthode particulière axée sur la prudence pour apprécier les dépenses du service public? — Le refus de la Commission d'approuver 145 millions de dollars au titre des dépenses de rémunération liées aux installations nucléaires du service public était-il raisonnable? — Loi de 1998 sur la Commission de l'énergie de l'Ontario, L.O. 1998, c. 15, ann. B, art. 78.1(5), (6).*

*Droit administratif — Organismes et tribunaux administratifs — Appels — Qualité pour agir — La Commission de l'énergie de l'Ontario a-t-elle agi de manière inappropriée en se pourvoyant en appel et en faisant valoir*

The judgment of McLachlin C.J. and Rothstein, Cromwell, Moldaver, Karakatsanis and Gascon JJ. was delivered by

[1] ROTHSTEIN J. — In Ontario, utility rates are regulated through a process by which a utility seeks approval from the Ontario Energy Board ("Board") for costs the utility has incurred or expects to incur in a specified period of time. Where the Board approves of costs, they are incorporated into utility rates such that the utility receives payment amounts to cover the approved expenditures. This case concerns the decision of the Board to disallow certain payment amounts applied for by Ontario Power Generation Inc. ("OPG") as part of its rate application covering the 2011-2012 operating period. Specifically, the Board disallowed $145 million in labour compensation costs related to OPG's nuclear operations on the grounds that OPG's labour costs were out of step with those of comparable entities in the regulated power generation industry.

[2] OPG appealed the Board's decision to the Ontario Divisional Court. A majority of the court dismissed the appeal and upheld the decision of the Board. OPG then appealed that decision to the Ontario Court of Appeal, which set aside the decisions of the Divisional Court and the Board and remitted the matter to the Board for redetermination in accordance with its reasons. The Board now appeals to this Court.

[3] OPG asserts that the Board's decision to disallow these labour compensation costs was unreasonable. The crux of OPG's argument is that the Board is legally required to compensate OPG for all of its prudently committed or incurred costs. OPG asserts that prudence in this context has a particular methodological meaning that requires the Board to assess the reasonableness of OPG's decisions to incur or commit to costs at the time the decisions to incur or commit to the costs were made and that OPG ought to benefit from a presumption of prudence. Because the Board did not employ this prudence

Version française du jugement de la juge en chef McLachlin et des juges Rothstein, Cromwell, Moldaver, Karakatsanis et Gascon rendu par

[1] LE JUGE ROTHSTEIN — En Ontario, la tarification d'un service public est réglementée, de sorte que ce dernier doit obtenir de la Commission de l'énergie de l'Ontario (« Commission ») l'approbation des dépenses qu'il a faites ou qu'il prévoit faire pendant une période donnée. Lorsque cette approbation est obtenue, les tarifs sont rajustés de manière que l'entreprise touche des paiements qui correspondent à ses dépenses. Le présent pourvoi vise la décision de la Commission de refuser certains paiements à Ontario Power Generation Inc. (« OPG ») par suite de sa demande d'approbation de tarifs pour la période 2011-2012. Plus particulièrement, la Commission a refusé d'approuver des dépenses de 145 millions de dollars au titre de la rémunération du personnel affecté aux installations nucléaires au motif que le coût de la main-d'œuvre d'OPG était en rupture avec celui d'organismes comparables dans le secteur réglementé de la production d'énergie.

[2] OPG en a appelé devant la Cour divisionnaire de l'Ontario, dont les juges majoritaires ont rejeté l'appel et confirmé la décision de la Commission. OPG s'est alors adressée à la Cour d'appel de l'Ontario, qui a annulé les décisions de la Cour divisionnaire et de la Commission, puis renvoyé le dossier à la Commission afin qu'elle rende une nouvelle décision conforme à ses motifs. La Commission interjette aujourd'hui appel devant notre Cour.

[3] OPG soutient que le refus de la Commission d'approuver ces dépenses de rémunération de ses employés est déraisonnable. Sa thèse veut essentiellement que la Commission soit légalement tenue de l'indemniser de la totalité des dépenses faites ou convenues avec prudence. OPG prétend que, dans ce contexte, la prudence se définit selon une méthode particulière qui exige de la Commission qu'elle détermine si, au moment où elles ont été prises, les décisions de faire les dépenses ou de convenir des dépenses étaient raisonnables. Elle soutient en outre qu'une présomption de prudence

methodology, OPG argues that its decision was unreasonable.

doit s'appliquer à son bénéfice. La Commission n'ayant pas eu recours à pareille méthode pour se prononcer sur la prudence d'OPG, sa décision serait déraisonnable.

[4] The Board argues that a particular "prudence test" methodology is not compelled by law, and that in any case the costs disallowed here were not "committed" nuclear compensation costs, but are better characterized as forecast costs.

[4] La Commission rétorque que la loi ne l'oblige pas à employer quelque méthode pour appliquer le « principe de la prudence » et que, de toute manière, les dépenses de rémunération des employés du secteur nucléaire refusées en l'espèce n'étaient pas des dépenses « convenues », mais bien des dépenses prévues.

[5] OPG also raises concerns regarding the Board's role in acting as a party on appeal from its own decision. OPG argues that in this case, the Board's aggressive and adversarial defence of its original decision was improper, and that the Board attempted to use the appeal to "bootstrap" its original decision by making additional arguments on appeal.

[5] OPG déplore par ailleurs que la Commission soit partie à l'appel de sa propre décision. Selon elle, la manière agressive et conflictuelle dont la Commission a défendu sa décision initiale n'était pas justifiée, et la Commission tente de se servir de l'appel pour « s'auto-justifier » en formulant de nouveaux arguments à l'appui de sa décision initiale.

[6] The Board asserts that the scope of its authority to argue on appeal was settled when it was granted full party rights in connection with the granting of leave by this Court. Alternatively, the Board argues that the structure of utilities regulation in Ontario makes it necessary and important for it to argue the merits of its decisions on appeal.

[6] La Commission fait valoir que la Cour a circonscrit la faculté qu'elle avait de plaider en appel lorsqu'elle lui a reconnu tous les droits d'une partie au moment d'autoriser le pourvoi. Subsidiairement, elle soutient que la manière dont les services publics sont réglementés en Ontario fait en sorte qu'il est nécessaire et important qu'elle défende la justesse de ses décisions portées en appel.

[7] In my opinion, the labour compensation costs which led to the $145 million disallowance are best understood as partly committed costs and partly costs subject to management discretion. They are partly committed because they resulted from collective agreements entered into between OPG and two of its unions, and partly subject to management discretion because OPG retained some flexibility to manage total staffing levels in light of, among other things, projected attrition of the workforce. It is not reasonable to treat these costs as entirely forecast. However, I do not agree with OPG that the Board was bound to apply a particular prudence test in evaluating these costs. The *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch. B, and associated regulations give the Board broad latitude to determine the methodology it uses in assessing utility

[7] Il convient mieux, à mon sens, de voir dans les dépenses de rémunération qui ont été refusées à raison de 145 millions de dollars en partie des dépenses convenues et en partie des dépenses relevant du pouvoir discrétionnaire de la direction. Elles sont en partie convenues parce qu'elles résultent de conventions collectives intervenues entre OPG et deux syndicats, et elles relèvent en partie de la discrétion de la direction parce qu'OPG conserve une certaine marge de manœuvre dans la gestion des niveaux de dotation globale compte tenu, entre autres, de l'attrition projetée de l'effectif. Il est déraisonnable de considérer qu'il s'agit en totalité de dépenses prévues. Je ne crois cependant pas, malgré ce qu'affirme OPG, que la Commission était tenue d'appliquer un principe de prudence donné pour apprécier les dépenses. La *Loi de 1998 sur la*

costs, subject to the Board's ultimate duty to ensure that payment amounts it orders be just and reasonable to both the utility and consumers.

*Commission de l'énergie de l'Ontario*, L.O. 1998, c. 15, ann. B, et ses règlements connexes accordent à la Commission une grande latitude dans le choix d'une méthode pour apprécier les dépenses d'un service public, sous réserve de l'obligation de faire en sorte que, au final, les paiements qu'elle ordonne soient justes et raisonnables vis-à-vis à la fois du service public et du consommateur.

[8] In this case, the nature of the disputed costs and the environment in which they arose provide a sufficient basis to find that the Board did not act unreasonably in disallowing the costs.

[8] Dans la présente affaire, la nature des dépenses litigieuses et le contexte dans lequel elles ont vu le jour permettent de conclure que la Commission n'a pas agi de manière déraisonnable en refusant de les approuver.

[9] Regarding the Board's role on appeal, I do not find that the Board acted improperly in arguing the merits of this case, nor do I find that the arguments raised on appeal amount to impermissible "bootstrapping".

[9] En ce qui concerne la participation de la Commission au pourvoi, je ne crois pas qu'il soit inapproprié qu'elle défende la justesse de sa décision, ni que les arguments qu'elle invoque en appel équivalent à une « autojustification » inadmissible.

[10] Accordingly, I would allow the appeal, set aside the decision of the Court of Appeal, and reinstate the decision of the Board.

[10] Je suis donc d'avis d'accueillir le pourvoi, d'annuler la décision de la Cour d'appel et de rétablir la décision de la Commission.

I. Regulatory Framework

I. Cadre réglementaire

[11] The *Ontario Energy Board Act, 1998* establishes the Board as a regulatory body with authority to oversee, among other things, electricity generation in the province of Ontario. Section 1 sets out the objectives of the Board in regulating electricity, which include:

**1.** (1) . . .

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

[11] La *Loi de 1998 sur la Commission de l'énergie de l'Ontario* fait de la Commission un organisme de réglementation investi du pouvoir de surveiller, entre autres choses, la production d'électricité en Ontario. Son article premier énonce les objectifs de la Commission dans la réglementation de l'électricité, dont les suivants :

**1.** (1) . . .

1. Protéger les intérêts des consommateurs en ce qui concerne les prix, ainsi que la suffisance, la fiabilité et la qualité du service d'électricité.

2. Promouvoir l'efficacité économique et la rentabilité dans les domaines de la production, du transport, de la distribution et de la vente d'électricité ainsi que de la gestion de la demande d'électricité et faciliter le maintien d'une industrie de l'électricité financièrement viable.

Accordingly, the Board must ensure that it regulates with an eye to balancing both consumer interests and the efficiency and financial viability of the

La Commission doit donc s'acquitter de sa fonction de réglementation dans le souci d'établir un équilibre entre l'intérêt du consommateur, d'une part, electricity industry. The Board's role has also been described as that of a "market proxy": 2012 ONSC 729, 109 O.R. (3d) 576, at para. 54; 2013 ONCA 359, 116 O.R. (3d) 793, at para. 38. In this sense, the Board's role is to emulate as best as possible the forces to which a utility would be subject in a competitive landscape: *Toronto Hydro-Electric System Ltd. v. Ontario (Energy Board)*, 2010 ONCA 284, 99 O.R. (3d) 481, at para. 48.

et l'efficacité et la viabilité financière du secteur de l'électricité, d'autre part. On lui attribue aussi un rôle de « substitut du marché » (2012 ONSC 729, 109 O.R. (3d) 576, par. 54; 2013 ONCA 359, 116 O.R. (3d) 793, par. 38). Sa fonction consiste alors à reproduire au mieux les forces auxquelles serait soumis un service public dans un contexte concurrentiel (*Toronto Hydro-Electric System Ltd. c. Ontario (Energy Board)*, 2010 ONCA 284, 99 O.R. (3d) 481, par. 48).

[12] One of the Board's most powerful tools to achieve its objectives is its authority to fix the amount of payments utilities receive in exchange for the provision of service. Section 78.1(5) of the *Ontario Energy Board Act, 1998* provides in relevant part:

(5) The Board may fix such other payment amounts as it finds to be just and reasonable,

(a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; . . .

[12] L'un des leviers les plus puissants dont dispose la Commission pour atteindre ses objectifs réside dans son pouvoir de fixer le montant des paiements que touche l'entreprise pour la prestation du service. Voici l'extrait pertinent du par. 78.1(5) de la *Loi de 1998 sur la Commission de l'énergie de l'Ontario* :

(5) La Commission peut fixer les autres paiements qu'elle estime justes et raisonnables :

a) dans le cadre d'une requête en vue d'obtenir une ordonnance prévue au présent article, si elle n'est pas convaincue que le montant du paiement qui fait l'objet de la requête est juste et raisonnable; . . .

[13] Section 78.1(6) provides: ". . . the burden of proof is on the applicant in an application made under this section".

[13] Le paragraphe 78.1(6) dispose pour sa part : « . . . le fardeau de la preuve incombe au requérant dans une requête présentée en vertu du présent article ».

[14] As I read these provisions, the utility applies for payment amounts for a future period (called the "test period"). The Board will accept the payment amounts applied for unless the Board is not satisfied that the amounts are just and reasonable. Where the Board is not satisfied, s. 78.1(5) empowers it to fix other payment amounts which it finds to be just and reasonable.

[14] Suivant mon interprétation de ces dispositions, le service public demande des paiements pour une période à venir (appelée « période de référence »). La Commission fait droit à la demande, sauf lorsqu'elle n'est pas convaincue que les paiements demandés sont justes et raisonnables. Lorsqu'elle n'en est pas convaincue, le par. 78.1(5) lui permet de déterminer les paiements qui lui paraissent justes et raisonnables.

[15] This Court has had the occasion to consider the meaning of similar statutory language in *Northwestern Utilities Ltd. v. City of Edmonton*, [1929] S.C.R. 186. In that case, the Court held that "fair and reasonable" rates were those "which, under the circumstances, would be fair to the consumer on

[15] Dans l'arrêt *Northwestern Utilities Ltd. c. City of Edmonton*, [1929] R.C.S. 186, la Cour a eu l'occasion de se prononcer sur le sens d'un libellé législatif semblable. Elle a alors statué que la tarification « juste et raisonnable » était celle [TRADUCTION] « qui, dans les circonstances, était juste pour le

the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested" (pp. 192-93).

[16] This means that the utility must, over the long run, be given the opportunity to recover, through the rates it is permitted to charge, its operating and capital costs ("capital costs" in this sense refers to all costs associated with the utility's invested capital). This case is concerned primarily with operating costs. If recovery of operating costs is not permitted, the utility will not earn its cost of capital, which represents the amount investors require by way of a return on their investment in order to justify an investment in the utility. The required return is one that is equivalent to what they could earn from an investment of comparable risk. Over the long run, unless a regulated utility is allowed to earn its cost of capital, further investment will be discouraged and it will be unable to expand its operations or even maintain existing ones. This will harm not only its shareholders, but also its customers: *TransCanada Pipelines Ltd. v. National Energy Board*, 2004 FCA 149, 319 N.R. 171.

[17] This of course does not mean that the Board must accept every cost that is submitted by the utility, nor does it mean that the rate of return to equity investors is guaranteed. In the short run, return on equity may vary, for example if electricity consumption by the utility's customers is higher or lower than predicted. Similarly, a disallowance of any operating costs to which the utility has committed itself will negatively impact the return to equity investors. I do not intend to enter into a detailed analysis of how the cost of equity capital should be treated by utility regulators, but merely to observe that any disallowance of costs to which a utility has committed itself has an effect on equity investor returns. This effect must be carefully considered in light of the long-run necessity that utilities be able to attract investors and retain earnings in order to survive and operate efficiently and effectively, in accordance with the statutory objectives of the Board in regulating electricity in Ontario.

consommateur, d'une part, et qui permettait à l'entreprise d'obtenir un juste rendement sur les capitaux investis, d'autre part » (p. 192-193).

[16] Dès lors, le service public doit pouvoir à long terme recouvrer, grâce à la tarification approuvée, ses dépenses d'exploitation et ses coûts en capital, ces derniers s'entendant alors de tous les coûts liés aux capitaux investis par le service public. Le pourvoi vise principalement les dépenses d'exploitation. Si leur recouvrement n'est pas autorisé, le service public n'obtient pas l'équivalent du coût du capital, soit le rendement exigé par les investisseurs pour investir dans le service public. Le rendement exigé équivaut à celui qu'ils pourraient réaliser sur un investissement comportant un risque comparable. À long terme, à moins que le service public réglementé ne puisse obtenir l'équivalent du coût du capital, les nouveaux investissements seront découragés et l'entreprise ne pourra accroître ses activités, ni même les poursuivre. Ce sont non seulement ses actionnaires, mais aussi ses clients, qui en souffriront (*TransCanada Pipelines Ltd. c. Office national de l'Énergie*, 2004 CAF 149).

[17] Évidemment, la Commission n'est pas tenue pour autant d'accepter toute dépense avancée par le service public, et le rendement obtenu par les actionnaires n'est pas non plus garanti. À court terme, ce rendement peut fluctuer, notamment lorsque la consommation d'électricité est supérieure ou inférieure à celle prévue. De même, le refus d'approuver des dépenses d'exploitation dont le service public a convenu aura un effet défavorable sur le rendement des actions. Je n'entends pas me livrer à une analyse détaillée de la manière dont le coût du capital-actions devrait être considéré par les organismes qui réglementent les services publics, mais seulement faire observer que tout refus d'approuver une dépense dont un service public a convenu a un effet sur le rendement des actions. Cet effet justifie une grande attention au vu de la nécessité qu'un service public attire les investissements à long terme et réinvestisse ses bénéfices afin de survivre et de fonctionner de manière efficace et rentable, conformément aux objectifs légaux de la Commission applicables à la réglementation de l'électricité en Ontario.

[18] As noted above, the burden is on the utility to satisfy the Board that the payment amounts it applies for are just and reasonable. If it fails to do so, the Board may disallow the portion of the application that it finds is not for amounts that are just and reasonable.

[19] Where applied-for operating costs are disallowed, the utility, if it is able to do so, may forego the expenditure of such costs. Where the expenditure cannot be foregone, the shareholders of the utility will have to absorb the reduction in the form of receiving less than their anticipated rate of return on their investment, i.e. the utility's cost of equity capital. In such circumstances it will be the management of the utility that will be responsible in the future for bringing its costs into line with what the Board considers just and reasonable.

[20] In order to ensure that the balance between utilities' and consumers' interests is struck, just and reasonable rates must be those that ensure consumers are paying what the Board expects it to cost to efficiently provide the services they receive, taking account of both operating and capital costs. In that way, consumers may be assured that, overall, they are paying no more than what is necessary for the service they receive, and utilities may be assured of an opportunity to earn a fair return for providing those services.

II. Facts

[21] OPG is Ontario's largest energy generator, and is subject to rate regulation by the Board. OPG came into being in 1999 as one of the successor corporations to Ontario Hydro. It operates Board-regulated nuclear and hydroelectric facilities that generate approximately half of Ontario's electricity. Its sole shareholder is the Province of Ontario.

[22] It employs approximately 10,000 people in connection with its regulated facilities, 95 percent of whom work in its nuclear business. Approximately 90 percent of its employees in its regulated

[18] Rappelons qu'il incombe au service public de convaincre la Commission du caractère juste et raisonnable des paiements qu'il sollicite. S'il n'y parvient pas, la Commission peut rejeter la demande en partie à raison du montant qui, selon elle, n'est pas juste et raisonnable.

[19] En cas de refus d'approbation, le service public peut renoncer, si cela lui est possible, aux dépenses d'exploitation en cause. S'il ne peut y renoncer, ses actionnaires absorbent le déficit en touchant un rendement inférieur à celui prévu, c'est-à-dire le coût du capital-actions pour le service public. Il appartient dès lors à la direction de ce dernier de faire en sorte que ses dépenses correspondent à celles que la Commission tient pour justes et raisonnables.

[20] Lorsqu'il s'agit d'assurer l'équilibre entre les intérêts du service public et ceux du consommateur, la tarification juste et raisonnable est celle qui fait en sorte que le consommateur paie ce que la Commission prévoit qu'il en coûtera pour la prestation efficace du service, compte tenu à la fois des dépenses d'exploitation et des coûts en capital. Ainsi, le consommateur a l'assurance que, globalement, il ne paie pas plus que ce qui est nécessaire pour obtenir le service, et le service public a l'assurance de pouvoir toucher une juste contrepartie pour la prestation du service.

II. Faits

[21] OPG est le plus grand producteur d'énergie de l'Ontario, et sa tarification est réglementée par la Commission. Elle a vu le jour en 1999 et fait partie des entreprises qui ont succédé à Ontario Hydro. Elle exploite des installations nucléaires et hydroélectriques soumises à la réglementation de la Commission qui produisent environ la moitié de l'électricité consommée dans la province. Son unique actionnaire est la province d'Ontario.

[22] Son effectif se compose d'environ 10 000 personnes pour ses activités réglementées, dont 95 p. 100 travaillent dans le secteur nucléaire. Environ 90 p. 100 des employés affectés à ses activités