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October 3, 2016

**BY COURIER (2 COPIES) AND RESS**

**Ms. Kirsten Walli**
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700, P.O. Box 2319
Toronto, Ontario M4P 1E4

Dear Ms. Walli:

**Re: EB-2016-0152 – Ontario Power Generation ("OPG") – 2017 to 2018 Payment Amounts**

Enclosed please find the interrogatories of Environmental Defence to OPG.

I have also enclosed a letter to the Independent Electricity System Operator (IESO) requesting that it file responses to certain interrogatories regarding evidence in OPG's application that the IESO produced.

Yours truly,

Kent Elson

Encl.

cc: Applicant and parties in EB-2016-0152

**Ontario Power Generation (OPG) Payment Amounts Commencing January 1, 2017**
**EB-2016-0152**

## Environmental Defence Interrogatories for OPG

### Topic 4.3 – Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Note, the interrogatories in this section could also be relevant to issues 2.2 (DRP rate base) and 4.5 (DRP in-service additions).

**4.3-ED-1**

Reference: "OPG has a high level of confidence in the DRP cost estimate of $12.8B, which includes contingency, capitalized interest and escalation." Ex. D2, Tab 2, Schedule 1, Page 2.

Please provide OPG's estimate of the probability that the cost of the DRP will exceed $12.8 billion.

**4.3-ED-2**

Reference: "OPG has a high level of confidence in the DRP cost estimate of $12.8B, which includes contingency, capitalized interest and escalation." Ex. D2, Tab 2, Schedule 1, Page 2.

Please provide OPG's estimate of the probability that the cost of the DRP will exceed $12.8 billion by 10% or greater.

**4.3-ED-3**

Reference: "OPG has a high level of confidence in the DRP cost estimate of $12.8B, which includes contingency, capitalized interest and escalation." Ex. D2, Tab 2, Schedule 1, Page 2.

Please provide the proportions (%) of the DRP cost overruns that will be passed on to OPG assuming the DRP experiences cost overruns of: a) 25%; b) 50%; c) 75%; d) 100%; e) 125%; f) 150%; g) 175%; h) 200%, and i) 250%. Please assume that the cost overrun percentages are applied equally to each of the program components (e.g. a 25% increase of each work bundle cost, 25% increase of the safety improvement costs, 25% increase of the facility & infrastructure project costs, and so on). See Ex. D2, tab 2, schedule 1, page 3 for a list of program components. Please assume that the cost overruns are in addition to the amounts set aside for contingency (seeing as "contingency refers to amounts that are *expected* to be expended" per Ex. D2, Tab 2, Schedule 7, p. 1)). Please apply the cost overruns both to the contractor costs (i.e. the work bundles) and the cost of the work to be undertaking by OPG itself. Please also account for the consequential increases to interest and escalation.

**4.3-ED-4**

Reference: Exhibit D2, tab 2, schedule 3, p. 14

Please provide the total cost of the DRP based on cost overrun scenarios of: a) 25%; b) 50%; c) d) 100%; e) 150%; f) 200%, and g) 250%. Please assume that the cost overrun percentages are applied equally to each of the program components (e.g. a 25% increase of each work bundle cost, 25% increase of the safety improvement costs, 25% increase of the facility & infrastructure project costs, and so on). Please apply the cost overruns both to the contractor costs (i.e. the work bundles) and the cost of the work to be undertaking by OPG itself. Please assume that the cost overruns are in addition to the amounts set aside for contingency (seeing as "contingency refers to amounts that are *expected* to be expended" per Ex. D2, Tab 2, Schedule 7, p. 1)). Please also calculate and include the consequential increases to interest and escalation.

Please provide a breakdown of each scenario in a chart similar to chart 4 on page 14 of Ex. D2-2-3 (pasted below). This will require adding rows for the other work bundles, the sub-components of the other work bundles, the remainder of the work components, interest and escalation, and contingency to the chart. The chart will help confirm that all costs are included and how the overrun scenarios have been applied.

**Chart 4 - Illustrative Scenarios of RFR Target Pricing (Contractor 10% Cost Overrun)**

| | | | % Contractor Cost Overrun = 10% | | | | |
|---|---|---|---|---|---|---|---|
| # | Category ($ Million) | Contract Costs (from table 3) | Contractor Cost | Cost Variance | Impact to Contractor | Impact to OPG | OPG Payment to Contractor |
| 1 | Definition Phase Target Cost (Incl RWPB) | 185 | 204 | 19 | 0 | 19 | 204 |
| 2 | Definition Phase Fixed Fee | 74 | 81 | 7 | 7 | 0 | 74 |
| 3 | Definition Phase Fixed Fee Incentive/ Disincentive | 0 | | | 0 | 0 | 0 |
| 4 | Execution Phase Target Cost | 1,667 | 1,834 | 167 | 0 | 167 | 1,834 |
| 5 | Execution Phase Fixed Fee | 492 | 541 | 49 | 49 | 0 | 492 |
| 6 | Execution Phase Fixed Fee Incentive/ Disincentive | 0 | 0 | 0 | 18 | (18) | (18) |
| 7 | Mock-up Fixed Price | 38 | 42 | 4 | 4 | 0 | 38 |
| 8 | Non-target Reimbursable Costs | 6 | 7 | 1 | 0 | 1 | 7 |
| 9 | Tooling Fixed Price | 375 | 413 | 38 | 38 | 0 | 375 |
| 10 | OSM with Fee(estimate) | 579 | 637 | 58 | 0 | 58 | 637 |
| 11 | Goods with Fee(estimate) | 48 | 53 | 5 | 0 | 5 | 53 |
| 12 | Total | 3,464 | 3,810 | 346 | 116 | 230 | 3,694 |

**4.3-ED-5**
Reference: Ex. E2, Tab 1, Schedule 1, Table 1

Please provide the output (TWh), installed capacity (MW) and capacity utilization rates for each year of the Darlington Nuclear Station's commercial operation.

**4.3-ED-6**
Reference: "For the purpose of OPG's request for approval of in-service additions, $4,800.2M is forecast to come into service in 2020 for the Unit 2 refurbishment." Ex. D2, Tab 2, Schedule 1, Page 5

Please provide OPG's forecast of its cumulative capital expenditures and interest costs with respect to the Unit 2 refurbishment, at the end of each quarter, starting with the first quarter in 2017 and ending with the 4$^{th}$ quarter in 2020. Please include contingency amounts. Please base the quarterly estimates based on the $4,800.2M high confidence budget. Presumably the cumulative capital expenditures for the 4$^{th}$ quarter of 2020 will equal approximately $4,800.2 million, but if that is not the case please explain why not.

**4.3-ED-7**
Reference: "For the purpose of OPG's request for approval of in-service additions, $4,800.2M is forecast to come into service in 2020 for the Unit 2 refurbishment." Ex. D2, Tab 2, Schedule 1, Page 5

Please provide OPG's estimate of the probability that the cost of the Unit 2 refurbishment will exceed $4,800.2 M.

**4.3-ED-8**
Reference: "For the purpose of OPG's request for approval of in-service additions, $4,800.2M is forecast to come into service in 2020 for the Unit 2 refurbishment." Ex. D2, Tab 2, Schedule 1, Page 5

Please provide OPG's estimate of the probability that the cost of the Unit 2 refurbishment will exceed $4,800.2 M by 10% or greater.

**4.3-ED-9**
Reference: "OPG plans to issue status reports to the public for the duration of the Program." Ex. D2, Tab 2, Schedule 1, Page 5

Is OPG planning to report its actual cumulative capital expenditures and interest costs with respect to the Unit 2 refurbishment in its quarterly financial reports? If "no", please explain why not.

**4.3-ED-10**
Reference: "Management has completed the Definition Phase has high confident that the 4 unit cost estimate is $10.4B (2015$). The $10.4B (2015$) estimate is $12.8B including capitalized interest and future inflation." Ex. D2, Tab 2, Schedule 8, Attachment 1, Page 2

"An average capability factor of 88% continues to be used in this economic assessment with a range of 83% to 93%." Ibid., Page 17

Please provide OPG's Levelized Unit Energy Cost (LUEC) for the Darlington reactors post-refurbishment assuming:

a) A total capital cost of $12.8 billion, an annual average capacity utilization rate of 88% and a 30 year operating life;
b) A total capital cost of $19.2 billion, an annual average capacity utilization rate of 88% and a 30 year operating life;
c) A total capital cost of $25.6 billion, an annual average capacity utilization rate of 88% and a 30 year operating life;
d) A total capital cost of $32 billion, an annual average capacity utilization rate of 88% and a 30 year operating life;
e) A total capital cost of $12.8 billion, an annual average capacity utilization rate of 84.8% and a 30 year operating life;
f) A total capital cost of $19.2 billion, an annual average capacity utilization rate of 84.8% and a 30 year operating life;

g) A total capital cost of $25.6 billion, an annual average capacity utilization rate of 84.8% and a 30 year operating life;
h) A total capital cost of $32 billion, an annual average capacity utilization rate of 84.8% and a 30 year operating life;

Please provide a break-out of your LUEC estimates according to the following categories: a) capital costs; b) operating costs; c) fuel costs; and d) long-term (perpetual) storage of spent fuel.

**4.3-ED-11**
Reference: Ex. D2, Tab 2, Schedule 8, Attachment 1, Page 2

Please state the weighted average cost of capital that OPG uses to perform its LUEC estimates and please show its inputs assumptions (e.g., debt/equity ratio, return on equity, interest rate on debt).

**4.3-ED-12**
Reference: "The post-refurbishment costs include $4.4B (2015$) of ongoing sustaining investments to maintain the condition of the plant." Ex. D2, Tab 2, Schedule 8, Attachment 1, Page 21

(a) Please provide OPG's estimate of the LUEC of the above referenced $4.4 billion investment assuming a 30 year operating life and annual average capacity utilization rates of 84.8% and 88%;
(b) Please confirm whether the $4.4 billion of anticipated investment is accounted for in the latest Darlington LUEC estimates in the Business Case Summary at Exhibit D2-2-8, Attachment 1.

**4.3-ED-13**
Reference: "The refurbishment scope does not include replacement of steam generators." Ex. D2, Tab 2, Schedule 8, Attachment 1, Page 28

a) Please provide your best estimate of the probability that it will be necessary to replace some or all of Darlington's steam generators; and
b) Please provide your best estimate of the cost of replacing Darlington's steam generators. Please include contingency and interest and escalation.

**4.3-ED-14**
Reference: Ex. D2, Tab 1, Schedule 1, Page 2, Chart 1

If the Government of Ontario were to cancel the Darlington Refurbishment Project in 2016, please quantify the magnitude of the nuclear operations project portfolio expenditures which would no longer be necessary in each year from 2017 to 2021.

**4.3-ED-15**
Reference: Ex. D2-2-8, Attachment 1

For each of the Darlington reactors, please estimate the total incremental cost of replacement power that will be necessary while the reactor will be out of service during the refurbishment (i.e. the difference between the estimated cost of power that would be produced by that reactor during the relevant period and the estimated cost of power from the alternative source of the power that will most likely be utilized). If the estimated cost of the replacement power is not known by OPG, please request the information from the IESO.

**4.3-ED-16**
Reference: Ex. D2-2-8, Attachment 1, p. 7
Table 1 shows that the first reactor to be refurbished (unit 2) will be completed two months *after* the start of refurbishment of the next reactor (unit 3). Unit 2 is to be complete by February 15, 2020 and Unit 3 is to start on December 15, 2019. These questions relate to anticipated overlap between the first two reactor refurbishments and the Long-Term Energy Plan's requirement to have off-ramps for future reactor refurbishments, and to take smaller initial steps to ensure there is opportunity to incorporate lessons learned."

(a) Assuming that OPG's payment amounts application is approved, please discuss what approvals will be required to proceed with the unit 3 refurbishment (e.g. from the OPG Board of Directors, the Ministry of Energy, and from the Ontario Energy Board)? Please indicate the target dates for OPG to submit documents to receive those approvals and for the approvals to be granted.
(b) What information will OPG make available to (i) the Ministry of Energy, (ii) the Ontario Energy Board, and (iii) the public about whether the unit 2 refurbishment is on or off budget and schedule before a decision to proceed with unit 3 is made?
(c) Would OPG be better able to learn lessons from the unit 2 refurbishment to incorporate into the unit 3 refurbishment if there was a buffer of time between the two? Please discuss.
(d) Please discuss the pros and cons of completely "unlapping" the refurbishment of the first two reactors so that there would be a buffer of time (months or at least weeks) between the end of one and the start of the other.
(e) Is there any reason why the start of the unit 3 refurbishment *technically cannot* be pushed back by 5 months to put a 3 month buffer of time after the end of unit 2 refurbishment? Please make best efforts to estimate the cost consequences of doing so. Please assume that this would be done in the most cost-effective and safe manner. Please make and state assumptions as necessary. Please include your calculations. Please also estimate the cost of pushing back the unit 3 refurbishment by 8 months to provide a 6 month buffer of time.
(f) Figure 14 on page 30 of the Long Term Energy Plan shows a gap between the end of the first reactor refurbishment and the beginning of the second reactor refurbishment. Please explain why OPG's plan is inconsistent with this.
(g) What is the percentage probability that the unit 2 refurbishment will be completed (i) at least 2 weeks, (ii) at least 4 weeks, (iii) at least 8 weeks, or (iv) at least 12 weeks beyond the scheduled date of February 15, 2020.

**Topic 6.1 - Is the test period Operations, Maintenance and Administration budget for the nuclear facilities (excluding that for the Darlington Refurbishment Program) appropriate?**

**6.1-ED-17**
Reference: Exhibit F2, Tab 1, Schedule 1, Table 1

(a) Table 1 includes $6.2 million from 2017 to 2021 for Darlington New Nuclear OM&A. Please provide a detailed breakdown of these costs;
(b) Please provide all directives and correspondence from the Ministry of Energy and/or the Independent Electricity System Operator in the past 5 years relating to the possibility of building new reactors at Darlington; and
(c) Please provide a detailed justification explaining why an expense of $6.3 million for the Darlington New Nuclear Project is prudent seeing as that project is not proceeding at the current time.

**Topic 6.5 – Are the test period expenditures related to extended operations for Pickering appropriate?**
Note, the interrogatories in this section could also be relevant to issue 6.2 (nuclear benchmarking).

**6.5-ED-18**
Reference: Ex. F2, Tab 2, Schedule 3

a) Please find attached our calculations of OPG's forecast of the Pickering Nuclear Station's operating and fuel costs for 2017, 2018, 2019 and 2020 broken out by sixteen components. Please confirm and/or correct our calculations for each component and each year. Please also confirm that the table includes all components and that the total is correct.

b) Please provide the Pickering Nuclear Station's actual operating and fuel costs for 2014 and 2015 broken out by the sixteen components listed in our attached file.

**6.5-ED-19**
Reference: Ex. F2, Tab 1, Schedule 1, Attachment 4, Page 10

Please provide the actual forced loss rates for the: a) Pickering; and b) Darlington Nuclear Stations for each of the last ten years.

**6.5-ED-20**
Reference: Ex. F2, Tab 1, Schedule 1, Table 3

(a) Please break-out the total nuclear FTEs in 2016 and 2017 according to the following categories: i) employees working at the Pickering Nuclear Station, ii) employees working

at the Darlington Nuclear Station, iii) employees working at other locations (e.g. head office) in support roles relating Pickering Nuclear Station, and iv) employees working at other locations (e.g. head office) in support roles relating to Darlington Nuclear Station.
(b) If Pickering Nuclear Station were to be shut down, how many employees would OPG need to lay off?

**6.5-ED-21**
Reference: "The estimated cost of this incremental work, above normal operating costs, is $307M over 2016-2020." Ex. F2, Tab 2, Schedule 3, Page 2.

Please provide an annual break-out of these expenditures for each year from 2016 to 2020 inclusive.

**6.5-ED-22**
Reference: "OPG expects to incur severance and related costs following the eventual shutdown of Pickering. Extended Operations will defer the costs associated with the closure of the station." Ex F2, Tab 2, Schedule 3, Page 8.

Could the immediate decommissioning and dismantling of Pickering, after it is shutdown, also defer severance costs associated with the closure of the station? If "no", please explain why not. If yes, approximately what percentage of those costs could be deferred?

**6.5-ED-23**
Reference: Ex. D2, Tab 1, Schedule 1, Page 2, Chart 1

If the CNSC does not approve an extension of the Pickering Nuclear Station's operating licence beyond August 31, 2018, please quantify the magnitude of the nuclear operations project portfolio expenditures which would no longer be necessary in each year from 2018 to 2021 inclusive.

**6.5-ED-24**
Reference: Chris Fralick & Randy Pugh, "Nuclear Rate Smoothing" (September 23, 2016)

Please state OPG's proposed smoothed nuclear rate ($ per MWh) for each year from 2016 to 2036 inclusive.

**6.5-ED-25**
Reference: Ex. F2, Tab 2, Schedule 3, p. 1. "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."

(a) Please provide the document that OPG provided to the Province of Ontario to seek this approval and the formal document(s) provided by the Province of Ontario to indicate approval.
(b) Please provide all correspondence from the Province of Ontario relating to OPG's plan to operate Pickering until 2022/2024 (other than the January 11, 2016 news release).

(c) Please provide all documentation provided by OPG to the Province of Ontario prior to January 11, 2016, detailing OPG's plan to operate Pickering until 2022/2024.

**6.5-ED-26**
Reference: Ex. D2, Tab 2, Schedule 1, p. 2. OPG's evidence refers to a Ministry of Energy January 13, 2016 news release stating that the continued operation of Pickering "would protect 4,500 jobs across the Durham region."

(a) Please provide all correspondence between OPG and the Ministry of Energy which may have led the Ministry of Energy to believe that 4,500 jobs would be saved by the continued operation of Pickering GS. If OPG searches for said correspondence and it does not exist, please clearly state so. If that is the case, please provide OPG's best estimate of how that figure was derived based on OPG's knowledge of the underlying facts and the materials that would likely be available to the Ministry of Energy.
(b) Has OPG made a final and irreversible decision on whether it will undertake a deferred versus direct/immediate decommissioning when Pickering GS is shut down?
(c) The OECD Nuclear Waste Agency's *Selection of Strategies for Decommissioning of Nuclear Facilities* states that "the present trend is in favour of immediate dismantling." It discusses benefits of immediate dismantling such as the increased availability of qualified staff, a more smooth transition for the local economy, local public opinion, an increasing availability of new techniques to allow for immediate decommissioning, and decreased financial risks and uncertainties with immediate versus deferred decommissioning. Please discuss which, if any, of the benefits of immediate decommissioning discussed in this paper would *not* apply to Pickering GS? (for the OECD NEA paper see https://www.oecd-nea.org/rwm/docs/2006/rwm-wpdd2006-1-rev1.pdf, p. 7-9).
(d) The International Atomic Energy Agency's ("IAEA") safety standards regarding decommissioning state that "The preferred decommissioning strategy shall be immediate dismantling." Is OPG aware of the reasons that the IAEA recommends immediate dismantling? If yes, please discuss and analyze those factors as they pertain to a decommissioning of Pickering GS. (see IAEA, Safety Standards, Decommissioning of Facilities, No. GSR Part 6, section 5.1 http://www-pub.iaea.org/MTCD/publications/PDF/Pub1652web-83896570.pdf).
(e) If Pickering were to be permanently shut down and immediately decommissioned at the end of its license on August 31, 2018: (i) What would the approximate cost of decommissioning be? (ii) Would the decommissioning costs be added to the rates paid by electricity consumers or paid out of OPG's decommissioning fund (if it is a combination of both, please indicate how much for each)? (iii) How much money is currently available in OPG's decommissioning fund? (iv) How many person-years of employment would be required for the direct decommissioning and over what period?
(f) What is the difference in cost between a deferred versus a direct decommissioning of Pickering?

For all of the above, an approximate, best-efforts answer is sufficient. Please make and state assumptions as necessary.

**6.5-ED-27**

Reference:  Ex. F2, Tab 2, Schedule 3,  Attachment 2, p. 16-18

(a) Please provide the detailed data and electronic spreadsheets underlying OPG's economic assessment of Pickering Continued Operations, including its assessment of the system economic value. The economic assessment appears at pages 12 to 14 of OPG's business case (using the numbering at the bottom right corner).
(b) As part of its assessment of the system economic value of continuing to operate Pickering until 2022/2014, did OPG consider the possibility of a contract for Quebec power as the primary source of replacement power for Pickering?
(c) Please redo OPG's system economic value analysis based on the assumption that replacement power is sourced primarily from an electricity import agreement with Quebec.

**OPG's Forecast of the Pickering Nuclear Station's Operating and Fuel Costs ($/MWh)**

| | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|
| **Base OMA**[i] | 24.05 | 24.45 | 24.44 | 24.10 |
| **Support OMA**[ii] | 11.76 | 11.6 | 11.69 | 12.55 |
| **Pickering Extended Operations OMA**[iii] | 1.34 | 2.88 | 5.52 | 5.32 |
| **Corporate Support & Administration**[iv] | 11.78 | 11.36 | 11.35 | 11.9 |
| | | | | |
| **Project OMA - Pickering**[v] | 0.67 | 1.56 | 0.95 | 0.95 |
| **Project OMA Nuclear**[vi] | 1.96 | 1.41 | 1.9 | 2.16 |
| **Pickering Outage OMA**[vii] | 7.51 | 8.48 | 10.8 | 8.98 |
| **Outage Support Division**[viii] | 3.15 | 2.86 | 2.37 | 1.95 |
| **Fuel Cost**[ix] | 4.18 | 4.16 | 4.1 | 4.17 |
| **Other Fuel**[x] | 1.5 | 1.55 | 1.83 | 1.63 |
| **Asset Services Fee**[xi] | 0.73 | 0.72 | 0.73 | 0.61 |
| **Pickering depreciation & amortization**[xii] | 10.47 | 11.63 | 11.69 | 11.90 |
| **Generic depreciation & amortization**[xiii] | 2.02 | 1.93 | 1.81 | 1.87 |
| **Pickering taxes**[xiv] | 0.48 | 0.49 | 0.49 | 0.51 |
| **Generic taxes**[xv] | -0.48 | -0.48 | -0.47 | 1.37 |
| **Centrally Held Costs - Nuclear**[xvi] | 1.97 | 2.93 | 2.64 | 2.29 |
| **Total** | 83.09 | 87.53 | 91.84 | 92.26 |

[i] E2-1-1, Table 1; and F2-2-1, Table 1
[ii] Ibid.
[iii] F2-2-3, page 6
[iv] F3-1-1, Table 3
[v] F2-3-1, Table 1
[vi] F2-3-1, Table 1

[vii] F2-4-1, Table 1
[viii] Ibid.
[ix] F2-5-1, Table 1
[x] Ibid.
[xi] F3-2-1, Table 2
[xii] F4-1-1, Table 2
[xiii] Ibid.
[xiv] F4-2-1, Table 2
[xv] Ibid.
[xvi] F4-4-1, Table 3

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October 3, 2016

**BY EMAIL**

**Miriam Heinz**
Senior Regulatory Advisor
Independent Electricity System Operator
1600-120 Adelaide St. W.
Toronto ON M5H 1T1
miriam.heinz@ieso.ca

Dear Ms. Heinz:

**Re: EB-2016-0152 – Ontario Power Generation (“OPG”) – Payment Amounts Commencing January 1, 2017**

I am writing on behalf of Environmental Defence to request that the Intendent Electricity System Operator (IESO) file responses to the attached interrogatories regarding evidence in OPG’s application that the IESO produced. All of the questions relate to the IESO’s analysis regarding OPG’s plan to continue to operate Pickering Generating Station until 2022/2024. This information is highly relevant to this proceeding and we anticipate that it is under the purview of the IESO, not OPG.

Although the IESO is not the applicant here, it has not been uncommon for the IESO or its predecessor organization, the Ontario Power Authority (OPA), to file evidence in similar situations. Indeed, the OPA filed evidence in the most recent OPG payment amounts application (EB-2013-0321).

Environmental Defence may request that the IESO put forward one or more witnesses to address the continued operations of Pickering Generating Station. However, we will wait to review the interrogatory responses before deciding whether to make that request. For the meantime, we respectfully request that the IESO file responses to the attached interrogatories.

I would be happy to discuss any of the above with you.

Yours truly,

Kent Elson

Encl.

Cc: Board and parties in EB-2016-0152

**Ontario Power Generation (OPG) Payment Amounts Commencing January 1, 2017**
**EB-2016-0152**

**Environmental Defence Interrogatories for the**
**Independent Electricity System Operator (IESO)**

**Topic 6.5 – Are the test period expenditures related to extended operations for Pickering appropriate?**

Note, the interrogatories in this section could also be relevant to issue 6.2 (nuclear benchmarking).

**6.5-ED-28**

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.

**6.5-ED-29**

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.

**6.5-ED-30**
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

Please re-calculate the net benefit of the Pickering extension to 2022/24 using the IESO's *best* *current* *estimates* for each year of:

a) Pickering's available capacity (MW) at the time of Ontario's peak annual demand;
b) Pickering's fuel and operating cost per kWh;
c) Pickering's incremental capital expenditures to permit its extension to 2022/24;
d) The natural gas price at Henry Hub;
e) Ontario's carbon price;
f) Ontario's incremental peaking requirements (MW) to meet the NPCC resource adequacy criterion if Pickering is not extended to 2022/24;
g) Ontario's least-cost combination of resources to meet the NPCC resource adequacy criterion if Pickering is not extended to 2022/24.

Please also re-calculate the net benefit of the Pickering extension to 2022/24 using all of the above-noted assumptions with the following exception, namely, substitute the NYMEX natural gas futures prices at Henry Hub for the IESO's best estimate of the natural gas prices at Henry Hub.

Please fully describe your analysis and state and justify your assumptions.

**6.5-ED-31**
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 forecast, for each year of its analysis, of:

a) Ontario's surplus base-load generation (MWh) due to the Pickering extension;
b) Ontario's curtailed water power generation (MWh) due to the Pickering extension;
c) Ontario's curtailed wind power generation (MWh) due to the Pickering extension; and
d) Ontario's curtailed solar power generation (MWh) due to the Pickering extension.

Please provide a response on a best-efforts basis and make and state assumptions as necessary.

**6.5-ED-32**
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

(a) With reference to the above captioned study, please provide its forecast, for each year of its analysis, of:
  i. Ontario's total revenue from its surplus base-load generation due to the extended operation of Pickering;
  ii. The cost to Ontario's electricity consumers of Ontario's curtailed water power generation due to the extended operation of Pickering;
  iii. The cost to Ontario's electricity consumers of Ontario's curtailed wind power generation due to the extended operation of Pickering;
  iv. The cost to Ontario's electricity consumers of Ontario's curtailed solar power generation due to the extended operation of Pickering;
  v. The total cost to Ontario's electricity consumers of all power that must be curtailed due to the extended operation of Pickering.

(b) Are the costs of curtailed generation included in the IESO's Pickering extension cost-benefit analysis?

Please provide a response on a best-efforts basis and make and state assumptions as necessary.

**6.5-ED-33**
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

Please compare the option of Pickering GS shutting down on August 31, 2018 versus OPG's plan to operate it until 2022/2024 by providing a forecast for each relevant year of:

a) Ontario’s surplus base-load generation (MWh) due to Pickering’s continued operation after August 31, 2018;
b) Ontario’s curtailed water power generation (MWh) due to Pickering’s continued operation after August 31, 2018;
c) Ontario’s curtailed wind power generation (MWh) due to Pickering’s continued operation after August 31, 2018;
d) Ontario’s curtailed solar power generation (MWh) due to Pickering’s continued operation after August 31, 2018;
e) Ontario's total revenue from its surplus base-load generation due to Pickering’s continued operation after August 31, 2018;
f) The cost to Ontario's electricity consumers of Ontario's curtailed water power generation due to Pickering’s continued operation after August 31, 2018;
g) The cost to Ontario's electricity consumers of Ontario's curtailed wind power generation due to Pickering’s continued operation after August 31, 2018;
h) The cost to Ontario's electricity consumers of Ontario's curtailed solar power generation due to Pickering’s continued operation after August 31, 2018; and
i) The total cost to Ontario’s electricity consumers of all power that must be curtailed due to Pickering’s continued operation after August 31, 2018.

Please provide a response on a best-efforts basis and make and state assumptions as necessary.

**6.5-ED-34**
Reference: “Ongoing contingency planning in case Pickering extended operations does not proceed” Ex. F2-2-3, Attachment 1, Page 10 of 116.

If the CNSC does not extend Pickering’ operating licence beyond August 31, 2018:

a) Please provide the IESO’s best estimate of Ontario’s incremental peaking requirements (MW), if any, to achieve compliance with the NPCC resource adequacy criterion in each year from 2018 to 2024 inclusive;
b) Please provide the IESO’s best estimate of Ontario’s potential to meet its incremental peaking requirements by electricity imports from neighbouring jurisdictions for each year from 2018 to 2024 inclusive; and
c) Please provide the IESO’s best estimate of Ontario’s potential to meet its incremental peaking requirements by demand response resources for each year from 2018 to 2024 inclusive.

**6.5-ED-35**
Reference: “Ongoing contingency planning in case Pickering extended operations does not proceed” Ex. F2-2-3, Attachment 1, Page 10 of 116.

a) Please fully describe the IESO’s contingency plan to meet Ontario’s peak day generation requirements for each year from 2018 to 2024 inclusive if the CNSC does not extend Pickering’s operating licence beyond August 31, 2018. Please provide a break-out of its incremental costs, incremental gas-fired generation and incremental greenhouse gas emissions for each year from 2018 to 2024 inclusive;

b) Please provide an analysis of the costs and benefits of meeting Ontario's peak day generation requirements for each year from 2018 to 2024 inclusive, if the CNSC does not extend Pickering's operating licence beyond August 31, 2018, by: 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.

Please fully describe your analysis and state and justify your assumptions.

**6.5-ED-36**
Reference: "Ongoing contingency planning in case Pickering extended operations does not proceed" Ex. F2-2-3, Attachment 1, Page 10 of 116; and IESO, *Ontario Reserve Margin Requirements 2016-2020*, Issue 1.0, (December 21, 2015)

Table 3 of *Ontario Reserve Margin Requirements 2016-2020* provides the IESO's estimate of Ontario's Available Capacity at Peak for each year from 2016 to 2020 inclusive.

a) Please state for each year from 2016 to 2020 inclusive the quantum of this capacity that is provided by: i) the Pickering Nuclear Station; and ii) the Darlington Nuclear Station.
b) Please state your methodology and assumptions, and show your calculations, for estimating Pickering's and Darlington's available capacity (MW) at the time of Ontario's peak annual demand.

**6.5-ED-37**
Reference: "Ongoing contingency planning in case Pickering extended operations does not proceed" Ex. F2-2-3, Attachment 1, Page 10 of 116;

Please provide your best estimate of:
a) The total amount of electricity (GWhs) that Ontario will be able to import from each of its neighbouring jurisdictions in each year from 2018 to 2024 inclusive; and
b) The total nameplate capacity (MW) of Ontario's import connections with each of its neighbouring jurisdictions from each year from 2018 to 2024 inclusive (i.e. the sum of the nameplate import capacity of the interties with each jurisdiction).

Please state your assumptions regarding the transmission system reinforcements that the IESO anticipates will be made during that period that will impact Ontario's import capacity.

**6.5-ED-38**
Reference: "Ongoing contingency planning in case Pickering extended operations does not proceed" Ex. F2-2-3, Attachment 1, Page 10 of 116; and *Memorandum of Understanding Between the Government of Quebec and the Government of Ontario Regarding Continued Energy Collaboration and Potential Opportunities for Ontario-Quebec Electricity Trade*

*Agreement to Support Greenhouse Gas Reductions During Ontario's Nuclear Refurbishments* (September 2015)

According to the above-referenced *Memorandum*, HQ Energy Marketing and the IESO will conclude a medium-term electricity trade agreement no later than 120 days following the finalization of the design of Ontario's cap and trade system as it relates to or impacts Ontario's electricity sector.

a) Has the medium-term electricity agreement been concluded? If yes, please provide it. If no, when does the IESO expect the agreement to be concluded?

**6.5-ED-39**
Reference: Ex. F2-2-3, Attachment 1

The September 2016 Mandate Letter to the Minister of Energy asks that he "Continue to partner and collaborate with the Province of Québec on key energy issues, including … In co-operation with the IESO and Hydro-Québec, further the intention to explore an electricity trade agreement that would provide value to Ontario ratepayers."

(a) Please compare the net present value of the overall costs and benefits of following three scenarios:
    i. OPG's proposal to continue operating Pickering until 2022/2024;
    ii. Pickering shutdown in August 31, 2018, with replacement power to come from an electricity trade agreement with Quebec (to the extent that it is technically feasible, with any additional power that cannot be imported to be provided by the next least-cost alternative); and
    iii. Pickering shutdown in December 31, 2020, with replacement power to come from an electricity trade agreement with Quebec (to the extent that it is technically feasible, with any additional power that cannot be imported to be provided by the next least-cost alternative).

Please make best efforts to estimate the cost of replacement power from an electricity trade agreement with Quebec. Please include provisos is necessary. Please consider including a number of agreement scenarios or ranges to address uncertainty regarding the terms of such an agreement. Please indicate and state assumptions and calculations.

**6.5-ED-40**
Reference: Ex. F2-2-3, Attachment 1

The September 2016 Mandate Letter to the Minister of Energy asks that he "Continue to partner and collaborate with the Province of Québec on key energy issues, including … In co-operation with the IESO and Hydro-Québec, further the intention to explore an electricity trade agreement that would provide value to Ontario ratepayers."

Please provide a breakdown of the transmission upgrade projects that would be necessary to replace the power from Pickering with imports from Quebec. Please indicate an approximate cost for each project and an estimate of the amount of time it would take for the project to be completed.

**6.5-ED-41**
Reference: Ex. F2-2-3, Attachment 1

The IESO's recent *Ontario Planning Outlook* states as follows: "To facilitate any potential large firm import capacity arrangement from Quebec/Newfoundland, major system reinforcements in eastern Ontario would be required – a new high-voltage direct current (HVDC) intertie to Lennox would be an example. The incorporation of new resources in Southwestern Ontario would require reinforcement of the transmission system, such as in the West of London area, as well as additional enabling facilities. Similarly, investments in new resources in the Greater Toronto Area might also trigger the need to reinforce the bulk transmission system."

(a) In relation to the jurisdictions referred to in the above quote please provide the import capacity from the jurisdiction without making the system reinforcements referred to above; and
(b) In relation to the projects referred to in the above quote, please provide a list of each of the reinforcement projects indicating (i) the approximate cost, (ii) the location of the project, (iii) the import capacity that it would enable, and (iv) and the approximate time required to undertake the project.

**6.5-ED-42**
Reference: Ex. F2, Tab 2, Schedule 3, p. 1. "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."

Please provide all documentation provided by the IESO to the Province of Ontario prior to January 11, 2016 (the date the Province of Ontario news release relating to Pickering), detailing OPG's plan to operate Pickering until 2022/2024.

**6.5-ED-43**
Reference: Ex. F2, Tab 2, Schedule 3, p. 1. "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."

A January 11, 2016, news release from the Ministry of Energy referred to in OPG's evidence states as follows: "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.**"

(a) Based on the IESO's discussions with the Province of Ontario and OPG, does the IESO believe that approval from the Ontario Energy Board is needed for OPG to implement its plan to continue operating Pickering until 2022/2024?
(b) Has an irreversible and fully final decision been made with respect to OPG's plan to continue to operate Pickering until 2022/2024, or is it still possible for another alternative option to be chosen (e.g. if it becomes clear that another option is preferable and more cost-effective)?