ONTARIO POWER GENERATION

Barbara Reuber
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RESS and Overnight Courier

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

Dear Ms. Walli:

Re: EB-2010-0008 – Ontario Power Generation Inc. Payment Amounts for Prescribed Facilities

In accordance with Rule 10 of the Ontario Energy Board's (OEB) *Rules of Practice and Procedure* and section 5.3 of the Board's *Practice Direction on Confidential Filings* (the Practice Direction), Ontario Power Generation Inc. (OPG) requests the confidential treatment of certain of its information that has been requested by way of interrogatories in the above-noted proceeding. Specifically, OPG seeks confidential treatment, of its written responses, or the attachments, with respect to the interrogatories listed below. These are in addition to my request of August 12, 2010 for confidential treatment of written responses.

- AMPCO Interrogatory #26, found at Ex. L-02-026
- GEC Interrogatory #28, found at Ex. L-07-028
- Pollution Probe Interrogatory #11, found at Ex. L-10-011
- VECC Interrogatory #28, found at Ex. L-14-028

In accordance with section 5 of the Practice Direction, the reasons for these confidentiality requests, including the reasons why OPG considers the responses to the interrogatories listed above as confidential and the reasons why public disclosure of the information would be detrimental to OPG, are set out below. In addition, confidential, un-redacted interrogatory responses are provided as attachments.

In accordance with the Practice Direction, this letter is being provided to the OEB along with all attachments identified below. The information for which confidentiality is being requested, which is included at Attachments A.1, B.1, C.1 and D.1 is to remain confidential at least until the OEB makes its determination on this request. A copy of this letter, including all attachments other than the confidential information, is being provided to each party to the proceeding.

As an interim measure and in the interests of efficiency, prior to the OEB making its final determination, OPG is content that the OEB makes provision that Board Staff and intervenors proceed as though OPG's request has been granted. In so doing, OPG is providing the confidential information to all parties that have filed a Declaration and Undertaking in the form referenced in Procedural Order No. 1.

On a final determination, should the OEB grant OPG's request for confidentiality, OPG proposes that the OEB order that the confidential information be disclosed, subject to any conditions the OEB may find appropriate, to only those persons that have signed the Declaration and Undertaking.

OPG requests that any reference to confidential information contained in the documents produced be conducted *in camera* so as to preserve its confidential nature.

At the conclusion of the proceeding or in the event that the confidentiality request is refused and OPG requests that the information be withdrawn in accordance with 5.1.12 of the Practice Direction, all persons in possession of the information will be required to destroy or return to the OEB Secretary for destruction the confidential information in accordance with 6.1.6 of the Practice Direction.

<u>Reasons for the Request for Confidential Treatment</u>

AMPCO Interrogatory #26, found at Ex. L-02-026

Interrogatory #26 from AMPCO, along with the OPG response as filed, is provided at **Attachment A.1**. The portion of the interrogatory response for which OPG requests confidential treatment are the redactions in the Pickering B refurbishment economic assessment, which is an attachment to the interrogatory response. The proposed redactions consist of contingency information and projected cost information. OPG consistently treats this information as confidential. Disclosure of this information would prejudice OPG's competitive and negotiating positions with respect to the Darlington Refurbishment project as persons with sufficient expertise would be able to determine OPG's contingency information and projected costs regarding the Darlington Refurbishment project upon a review of the redacted information in the Pickering B refurbishment economic assessment. The OEB previously ordered in Procedural Order No. 3 that OPG's contingency and projected cost information with respect to the Darlington Refurbishment project be treated as confidential information. Confidential treatment of this type of information is specifically contemplated by Appendix B, subsections (a) i, ii and iv and (b) of the Practice Direction. A non-confidential redacted version of the BCS is provided at **Attachment A.2**.

GEC Interrogatory #28 found at Ex. L-07-028

Interrogatory #28 from GEC, along with the OPG response as filed, is provided at **Attachment B.1**. The portion of the interrogatory response for which OPG is seeking confidential treatment relates to the information on the price for the replacement steam generators for the Darlington Refurbishment project and the impact of steam generator replacement on the estimated LUEC for Darlington Refurbishment. OPG submits that it is reasonable for the OEB to regard or determine such information to be included as part of the information previously ordered to be treated as confidential pursuant to Procedural Order No. 3. In the alternative, OPG submits that such information should be treated as confidential because it is commercially sensitive to OPG's business. OPG consistently treats this information as confidential and disclosure of it would prejudice OPG's competitive and negotiating positions should steam generator replacement eventually be required at any of its facilities. Confidential treatment of this type of information is specifically contemplated by Appendix B, subsections (a) i, ii and iv and (b) of the Practice Direction. A non-confidential redacted version of the response to this interrogatory is provided at **Attachment B.2**.

Pollution Probe Interrogatory #11, found at Ex. L-10-011

Interrogatory #11 from Pollution Probe, along with the OPG response as filed, is provided at **Attachment C.1**. The portion of the interrogatory response for which OPG is seeking confidential treatment relates to the LUEC range and the break-out of this range for the capital costs, OM&A costs, fuel costs, and CO2 adders, for Combined Cycle Gas Turbines (CCGT). The basis for seeking confidential treatment for this CCGT information is that this information would allow derivation of the Darlington Refurbishment project LUECs (and of the detailed LUEC breakdown for that project) for which OPG has previously been granted confidential treatment pursuant to Procedural Order No. 3. In fact, similar information, though not with the granularity in this interrogatory response, has already been filed confidentially pursuant to Procedural Order No. 3, in Ex. D2-2-1, Attachment 4 at page 34. OPG consistently treats this information as confidential and disclosure of it would prejudice OPG's competitive and negotiating positions. Confidential treatment of this type of information is specifically contemplated by Appendix B, subsections (a) i, ii and iv and (b) of the Practice Direction. A non-confidential redacted version of the response to this interrogatory is provided at **Attachment C.2**.

VECC Interrogatory #28, found at Ex. L-14-028

Interrogatory #28 from VECC, along with the OPG response as filed, is provided at **Attachment D.1**. The portion of the interrogatory response for which OPG is seeking confidential treatment relates to the revenues associated with Surplus Heavy Water Sales and Other Heavy Water Services. In its response to VECC interrogatory #27, found at Ex. L-14-027, OPG has provided, on a non-confidential basis, its costs for 2011 and 2012 associated with sales of heavy water. Non-confidential disclosure of its revenues from heavy water sales in response to VECC interrogatory #28, would therefore disclose OPG's commercially sensitive information which would prejudice its competitive and negotiating position with respect to future sales of heavy water. Disclosure of the revenues for Other Heavy Water Services would allow calculation of the revenues for Surplus Heavy Water Sales based on the total revenues for Heavy Water Sales and Processing. Confidential treatment of this type of information is specifically contemplated by Appendix B, subsections (a) i, ii and iv and (b) of the Practice Direction. A non-confidential redacted version of the response to this interrogatory is provided at **Attachment D.2**.

Respectfully submitted,

[Original signed by]

Barbara Reuber
Director, Ontario Regulatory Affairs
Ontario Power Generation

Attach:

cc: Charles Keizer Torys LLP
Carlton Mathias OPG
EB-2010-2008 Intervenors (attachments A.1, B.1, C.1 and D.1, not included for parties who have not signed the Declaration and Undertaking)

Attachment – A2

AMPCO Interrogatory #026
(NON-CONFIDENTIAL VERSION)

Ref: Ex. F2-T2-S3, page 4

Issue Number: 6.11
Issue: Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes appropriate?

Interrogatory

Please provide the analysis presented to the Board of Directors that lead OPG to decide to not refurbish Pickering B.

Response

See the response in Ex. L-01-070 for factors that contributed to the decision not to refurbish Pickering B Generating Station.

A copy of the requested analysis is provided in the confidential attachment (Attachment 1).

UPDATE ON THE PICKERING B REFURBISHMENT PROJECT

1. Background

The Pickering B units were initially placed in service in 1983-1986. The nominal expected life was 30 calendar years, based on a pressure tube life of 210,000 EFPH at 80% capacity factor, with the possibility of extending life through replacement of major components. The current predicted nominal ends of service life are 2014 for Units 5, 6, and 7, and 2016 for Unit 8.

In June 2006, the Ontario Government directed OPG to assess the feasibility of refurbishing the existing nuclear plants and to begin an Environmental Assessment of the impacts of refurbishing Pickering B.

The feasibility assessment has now progressed significantly and management has developed an improved understanding of the regulatory requirements, environmental impacts, the scope of the project, and the costs of refurbishment.

Management has also explored the continued operation of the Pickering B units for an additional two to four years beyond their current nominal operating lives (i.e. until 2016/2018 for Units 5, 6 & 7 and 2018/2020 for Unit 8), and is of the view that continued operation is possible with additional investments. Realization of this option would be of significant benefit to Ontario's electricity system during the 2014 to 2018 period. The work necessary to support continued operation was characterized in a preliminary way in 2008 and Continued Operation of Pickering B has been established as the basis for the 2010 to 2014 Business Plan. Further development and characterization of the work required to achieve Pickering B Continued Operation is being completed as part of the 2010-2014 Business Planning process. As part of this work, a Fuel Channel Life Management initiative is also being launched, in conjunction with Bruce Power and with the participation of other industry partners, to provide Management with greater confidence in the predictions of pressure tube lives for the nuclear fleet.

2. Update on the Planning Activities Phase

Overall, all 2009 deliverables are on track. The following work has been completed to date:

a. Plant Condition Assessment

A rigorous Plant Condition Assessment of all critical components has been completed and forms the basis of the core project scope. No previously unknown component deficiencies were identified. The costs of refurbishing the critical components have been included in the feasibility assessment.

The actual condition of the calandria structure has been evaluated. A recent integrity assessment concluded the calandria structure poses no risk to the safe operation of the reactors to the end of their current operating life. It further concluded that the risk of deteriorating vessel integrity during the post-refurbishment operating period is very low. To achieve greater certainty, information is being obtained and evaluated from NB Power and Bruce Power in their current refurbishment outages.

The calandria structure will be inspected as part of the scope of the refurbishment outages.

b. Environmental Assessment

On January 26, 2009, the CNSC issued their acceptance of the EA Screening Report. The report concluded that, taking into account the identified mitigation measures, the refurbishment and continued operation of the Pickering B nuclear station is not likely to cause significant adverse environmental effects. The mitigation measures identified in the final report have been incorporated into the scope of the refurbishment.

c. Integrated Safety Review (ISR) Update

Work on the Integrated Safety Review (ISR) is on track for submission of the Final report, which includes a summary of the Global Assessment to the CNSC in September 2009.

A Global Assessment team was on site during the week of July 13 to 17, 2009. The team consisted of nuclear industry professionals. The purpose of the team was to review the resolution of issues, identified gaps without adequate strategies and recommendations identified in the August 2008 Global Assessment to ensure that the overall judgement of nuclear safety is still good. The results were 5 out of the 11 issues identified in 2008 have been resolved and of the 126 gaps without acceptable strategies only 6 remain without sufficient information or justification. Management is in the process of resolving the remaining issues prior to finalizing the ISR report. A Global Assessment final report will be issued to OPG in August.

During the 2008 Pickering B re-licensing hearing, a regulatory commitment was made to prepare a regulatory strategy for end-of-life, to be submitted to the CNSC by the end of 2009. The outcome of the ISR is being utilized in the formulation of this regulatory strategy. This strategy is highly dependent upon the ongoing dialogue Management is having with the OPA and the IESO on the utilization of the Pickering station capacity.

It is expected that the CNSC will review and approve the Final ISR Report by the end of Q2, 2010.

An Integrated Implementation Plan (IIP), which must be approved by the CNSC prior to re-starting the refurbished units, will only be developed if the Pickering B Refurbishment project is approved. The IIP document consists of the approved scope and schedule for refurbishment based on completed technical assessments, the Environmental Assessment, the Integrated Safety Review (ISR), which includes a third-party global assessment of plant safety for long term operation to determine the global risk, and an emerging safety issues assessment.

d. Budget Update

Year-to-date expenditures on the project are $2.3M on a plan of $2.4M. The project is forecasting to be $0.1M over plan at year end, or $4.9M. The focus in 2009 is to complete the Final ISR report and submit it to the CNSC on September 25, 2009.

Life-to-date expenditures as of July 1, 2009 for the Pickering B Refurbishment Planning Activities Project are $47.0M, including $44.9M in prior years, assessing the feasibility of refurbishing Pickering B. The project is forecasting to be at $49.8M at year end, 2009. An additional $1.4M is expected to be spent in 2010 in order to obtain approval of the Final ISR report from the CNSC resulting in a project total cost, for this phase of the project, at $51.2M.

3. Summary of the Feasibility Assessment

Management has performed a review of the key inputs to the economic assessment. This includes a review of the cost estimate, the outage schedule, and the key risks considering results of the regulatory work programs including the EA and the comments from the CNSC on the individual Safety Factor Reports. The major assumptions, considerations and conclusions are summarized below.

The following table summarizes the key refurbishment costs, including contingencies, and schedule durations used in the feasibility assessment.

Refurbishment High Confidence Estimates	Average Cost / Unit (Overnight $M 2009)	Comments
Refurbishment Costs		
Fuel Channels and Feeders replacement	[redacted]	Based on Vendor Technical Study. Pt. Lepreau earlier estimate $352M (2005$).
Steam Generators Replacement	[redacted]	Based on Vendor Technical Study.
Plant System & Equipment Maintenance	[redacted]	Based on Plant Condition Assessments, known deficiencies and system upgrades. Estimates by OPG personnel. Pt. Lepreau non-reactor work costs approx. $260 million (2005$)
Other(1)	420	Technical Studies of D2O Management, Waste Management and Construction Islanding. Other estimates by OPG personnel. Overheads comparable to recent OPG experience with major projects.
Contingency for Project Estimate Uncertainties & Risk	[redacted]	Includes contingency for asymmetry in cost estimates and potential labour/materials cost and schedule uncertainties.
Contingency for Regulatory Uncertainties	[redacted]	Based on detailed analysis of gaps and probabilities of needing to implement changes
Total Investment Including Contingencies (2)	[redacted]	**Total Cost of Refurbishing two Bruce units now estimated at $3.1 to $3.4B; Cost of Pt. Lepreau without SG Replacement currently estimated at $1.1 B (includes interest during construction).** **OPG's total high confidence overnight costs for 4 units is [redacted] (2009$).**
Refurbishment Schedule		
Refurbishment Schedule	33 months	Pt. Lepreau target for fuel channels and feeders only was 19 months. Latest Pt. Lepreau forecasts are 26 months. Bruce Unit 1 is estimated to be 33 months. This duration represents OPG's high confidence schedule duration.

(1) Other refers to D2O Management Strategy, Waste Management, Unit Islanding Work, Construction Island Barriers, New Fuel Charge, Commissioning & Power Ascension and OPG/PMO Project Management, Financial Securities, Project Insurance.
(2) The total investment is higher for the first unit [redacted] than for the subsequent units [redacted]

The future operating costs and performance of Pickering B are another significant aspect of uncertainty related to the feasibility assessment. Analysis has been completed of past performance and of the information from the Plant Condition Assessments in order to forecast the expected capability factor for the Pickering B units in the post-refurbishment period. Given the historical performance and the bottom-up analysis carried out by Pickering B Operations, a high confidence post-refurbishment capability factor of 75% is felt to be a reasonable forecast at this time.

The following table summarizes the key post-refurbishment costs and performance assumptions used in the feasibility assessment.

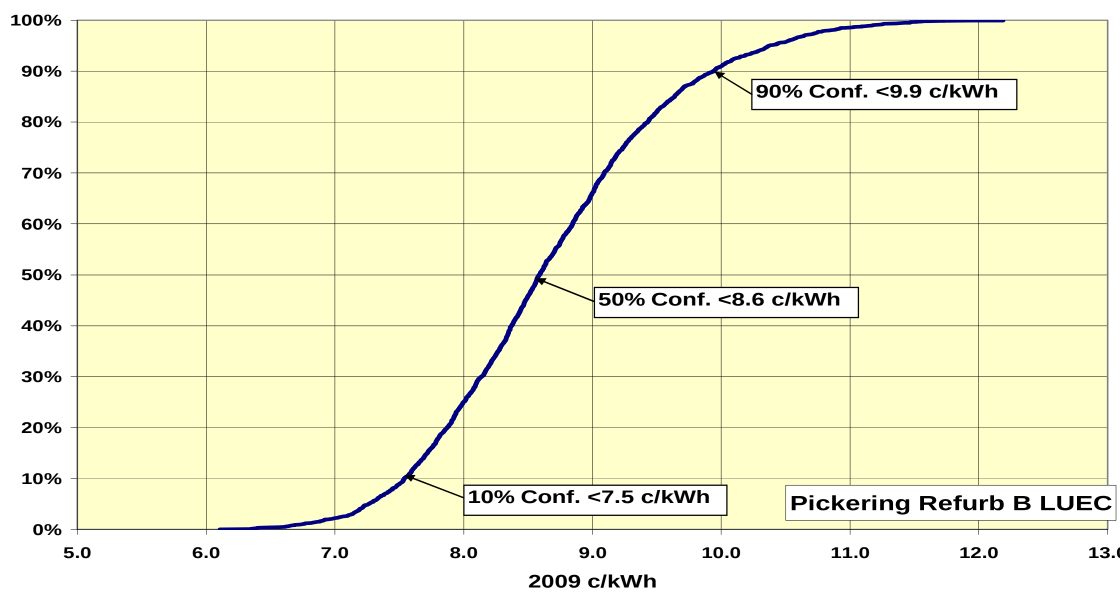
Post-Refurbishment Operations High Confidence Estimates	Average Cost / Unit (Overnight $M 2009)	Comments
Annual Direct Station Costs Post-Refurbishment	130	Current 2008-2010 Business Plan Avg. is $102M. The $130 M used is adjusted for historical average spending on projects and is OPG's high confidence estimate.
Annual Support Costs Post-Refurbishment (1)	30	Consistent with 2008 Business Plan adjusted for high confidence. Incremental analysis performed by OPG personnel
Plant Performance Post Refurbishment	75%	Lifetime performance is 77%; including strikes, management shutdowns, major outages for SLAR, etc. Range of 75% to 85% used. Bottom-up detailed forecast for post-refurbishment period is 84%

(1) The Annual Support Costs shown are the incremental costs of Corporate and Nuclear Support

Based on these inputs, the expected high confidence Levelized Unit Energy Cost (LUEC) for refurbishment of Pickering B, and continued operation for a period of 30 years after refurbishment, is estimated to be approximately 9.9 ¢/kWh (2009$). The high confidence estimated cost for the refurbishment project is [redacted] (overnight 2009$) which includes a total contingency amount of [redacted] The contingency amount of [redacted] includes [redacted] to cover potential costs of major regulatory upgrades required beyond those already included in the base scope of work.

The project uncertainties and future performance have been analyzed in a Monte Carlo analysis resulting in a LUEC range of 7.5 ¢/kWh (low confidence) to 9.9¢/kWh (high confidence). At a medium confidence level the LUEC is 8.6 ¢/kWh.

Figure 1: LUEC Range for Pickering B Refurbishment



4. Continued Operation Of Pickering B

During the initial development of the Pickering B Feasibility Assessment in 2007, it became apparent that there is an opportunity to continue to operate the Pickering B units by 4 years or more beyond their current nominal operating lives of 2014/2016 by taking actions to maximize pressure tube life. Management developed a comprehensive work plan to explore and develop the Continued Operation option, i.e. to take the actions necessary to safely and reliably operate Pickering B for an additional

30,000 effective full power hours at 80% capacity factor, thereby extending the projected end-of-service lives to approximately 2018/2020.

Dependencies of Pickering A upon Pickering B operation were also explored, with the preliminary conclusion that it would be very difficult to operate Pickering A beyond the end of life of the last two units of Pickering B without making significant modifications and seeking regulatory changes. Continued operation of Pickering B during the period 2014 to 2018/2020 is now the basis for the 2010 to 2014 Business Plan. In addition, further work is underway to explore the option to operate the plant beyond 2018, e.g. through prolonged outages or seasonal operation of one or more of the units in order to maximize overall plant life of both Pickering B and A. Management is continuing to explore this option and is in discussions with the Ontario Power Authority (OPA) and the Independent Electricity System Operator (IESO), which have both expressed strong support for the Continued Operation option.

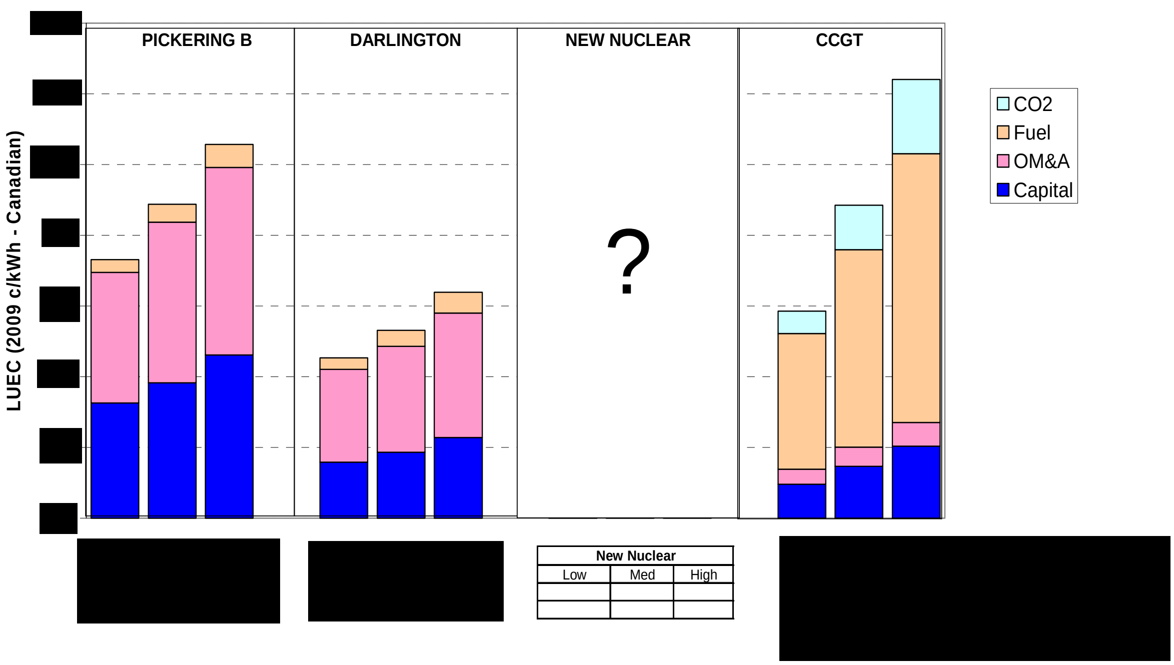
Work continues to improve the confidence that the pressure tubes will remain fit-for-service for the Continued Operation period and also to ensure that any potential regulatory (CNSC) concerns with the Continued Operation option are fully addressed. OPG is in the process of launching a Fuel Channel Life Management initiative, jointly funded with Bruce Power and with the participation of other industry partners, to provide Management with greater confidence in the predictions of pressure tube lives for the nuclear fleet.

5. Analysis of Alternatives

The following (Figure 2) provides a comparison of the Pickering B Refurbishment LUEC to other generation options. The assessment found that the Levelized Unit Energy Cost (LUEC) of refurbishing and continuing to operate the Pickering B units for a further 30 years would be between 7.5 ¢/kWh and 9.9 ¢/kWh. Within this LUEC range, the Pickering B Refurbishment is less favourable than Darlington Refurbishment and Combined Cycle Gas Turbines (CCGT) at gas prices reflective of recent experience.

The costs of New Nuclear remain speculative and this time, thus, a firm comparison to Pickering is not possible.

Figure 2: LUEC Range for Pickering B Refurbishment and Comparators



(1) If only ten years of post-refurbishment operation were achieved, the LUEC of Pickering B would increase by approximately 4 ¢/kWh (high confidence).

6. Next Steps

Over the course of the next few months, Management will complete the Pickering B Final ISR Report and submit it to the CNSC for review and acceptance in Q2, 2010. Management will continue to work with the OPA and the IESO to define the best utilization (refurbishment, continued operation and/or seasonal operations) of the Pickering station capacity and expects to make a recommendation to the Board by year end.

Attachment – B2

GEC Interrogatory #028
(NON-CONFIDENTIAL VERSION)

Ref: Ex. D2-T2-S1

Issue Number: 4.5
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

Interrogatory

The statement on page 4 of attachment 4 of D2-2-1: "As recommended by Management in April, 2009, steam generator (SG) replacement has been excluded from the reference outage scope" is notable because other CANDU refurbishment projects have included steam generator replacement.

a) Please provide the low, medium and high risk end-of-life estimates for the Darlington steam generators.

b) Please provide an approximate cost estimate for purchasing replacement steam generators for the Darlington nuclear station.

c) Please provide a description of the cost and work required to replace Darlington's steam generators?

d) If steam generator replacement were to take place at a date following of the proposed 36 month refurbishment outages, what would be the outage time required to replace the steam generators?

e) Have the costs of eventual steam generator replacement at Darlington been included in the LUEC price for the Darlington refurbishment? If not please provide the impact of a subsequent SG replacement on LUEC.

f) Has the Canadian Nuclear Safety Commission approved the exclusion of steam generator replacement from the scope of the Darlington refurbishment?

g) Has OPG evaluated the cost effectiveness of replacing Darlington steam generators if refurbishment outages were to take place as originally envisioned post 2018?

Response

Contrary to the suggestion in the preamble to this question, not all CANDU refurbishments include steam generator replacements. Steam generator replacement is not included in the project scope for the Pt. Lepreau, Wolsong and Gentilly II refurbishments.

a) OPG does not have low, medium and high risk end-of-life estimates. See response to Interrogatory L-07-016 for the analysis supporting the decision not to include steam generator replacement in the outage scope.

The analysis included a large range of uncertainty in known factors which could affect the performance of the steam generators over the extended life post-refurbishment, such as steam generator tube fouling. OPG combined technical factors, the forecast cost of the preventative maintenance programs, performance expectations and the cost of replacing the steam generators into a comprehensive technical and economic assessment. This assessment concluded that, with high confidence, it was preferable to retain the existing steam generators.

b) OPG has a range of estimates for the purchase and installation of new steam generators at the Darlington Generating Station. OPG has also compared the estimated costs of steam generator replacement against the known costs of replacing steam generators in those United States plants which have either already completed or have planned replacements.

Based on these estimates, OPG estimates the cost of steam generator replacement to be [redacted]M/unit at Darlington. These costs would include purchase and installation. In addition, there are costs of waste management of the replaced steam generators, estimated at approximately [redacted]M per unit.

c) The estimated cost is provided in part b) above. The work involved would include draining and drying the existing steam generators, removing the existing steam generators, installing the new steam generators, re-connecting to the existing pipes, then refilling and testing the new steam generators during re-commissioning of the units.

d) The duration could range from 10 – 20 months depending on the assumptions made about the methodology for carrying out the work.

e) No, the eventual cost of steam generator replacement has not been included in the Levelized Unit Energy Cost ("LUEC") range provided for Darlington Refurbishment. However, OPG believes that the range adequately covers such potential costs. The specific impact on the estimated LUEC if the steam generators needed to be replaced in a subsequent outage would be less than [redacted]. However, the impact on the LUEC is very dependent on the timing of when that replacement would occur.

f) Canadian Nuclear Safety Commission ("CNSC") approval of this decision is not required.

g) OPG has never previously established a plan for the refurbishment of Darlington Generating Station and therefore cannot respond to this question. The meaning of the reference to "refurbishment outages … as originally envisioned post 2018" is unclear.

Attachment – C2

Pollution Probe Interrogatory #011
(NON-CONFIDENTIAL VERSION)

Ref: Ex. D2-T2-S1, Attachment 4

Issue Number: 4.5
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

Interrogatory

According to OPG's prefiled evidence: "Based on publicly available information, the economics of Darlington Refurbishment are more attractive than alternative generation options including New Nuclear and Combined Cycle Gas Turbines (CCGT)."

Please provide OPG's best estimates of the LUECs for both new nuclear and combined-cycle gas turbines.

Please also provide a break-out of your LUEC estimates according to at least the following categories:
a) capital costs;
b) fixed operating, maintenance & administration;
c) fuel cost;
d) variable operating, maintenance & administration; and
e) short-term, medium-term and long-term costs associated with the management of used fuel.

Please also state the key input assumptions for your LUEC calculations, including: capital costs per MW; capital structure; costs of equity and debt; heat rates, commodity cost of gas; annual capacity utilization rates.

Response

OPG does not have a definitive range estimate for the Levelized Unit Energy Cost ("LUEC") for new nuclear. OPG's statement referenced above is based on its high-level assessment of the range estimates of the capital costs of new nuclear (see response to the interrogatory in Ex. L-7-027).

Based on these publicly available sources, OPG used a range for the overnight costs of new nuclear of approximately $3,800/kW (low) to $6,100/kW (high). When this range of capital costs is combined with a reasonable range of estimated operating and fuel costs, based on OPG's experience for the ranges for these costs, this indicates that the LUEC for new nuclear would be higher than the LUEC for Darlington Refurbishment.

With respect to Combined Cycle Gas, please also refer to Ex. L-7-027 where OPG provided a range of estimates for the overnight cost in $/kW of Combined Cycle Gas Plant.

OPG's confidential filing (Ex. D2-T2-S1, Attachment 4, page 34), shows a range of LUECs for Combined Cycle Gas. The total LUECs shown on that chart and the breakdown of the LUECs for Combined Cycle Gas are as follows:

	Combined Cycle Gas Plant LUECs (¢/kWh)		
	Low Estimate	**Median Estimate**	**High Estimate**
Capital Cost	[redacted]	[redacted]	[redacted]
OM&A	[redacted]	[redacted]	[redacted]
Fuel	[redacted]	[redacted]	[redacted]
CO_2	[redacted]	[redacted]	[redacted]
Total[1]	[redacted]	[redacted]	[redacted]

The range of estimates OPG used as inputs to this analysis are as follows:

- Capital Costs: Approximately $800/kW to approximately $1550/kW.
- OM&A Costs: Approximately $15/kW/yr to approximately $30/kW/yr.
- Fuel Costs: The range of natural gas prices assumed were approximately U.S. $4/MMBtu (low) to U.S. $9/MMBtu (high).
- Capacity Factor: A range of 75 per cent (low) to 85 per cent (high) was assumed.
- Heat Rates: 7000 Btu/kWh for low, medium and high.
- Capital Structure: 55 per cent Debt, Cost of Debt 6.2 per cent; 45 per cent Equity, ROE (after-tax) 10 per cent.

Please also refer to the answer to interrogatory Ex. L-1-069, part a) which provides details of the median gas price forecast between 2010 and 2020, and the response to interrogatory Ex. L-7-027 which provides additional information on the publicly available estimates that OPG used to develop its range of capital costs for combined cycle gas.

[1] Numbers may not add due to rounding.

Attachment – D2

VECC Interrogatory #028
(NON-CONFIDENTIAL VERSION)

Ref: Ex. G2-T1-S1, page 5

Issue Number: 7.2
Issue: Are the proposed test period nuclear business non-energy revenues appropriate?

Interrogatory

Lines 5-16 discuss the "Heavy Water Services" business, and refer to Exhibit G2, tab 1, schedule 1, Table 1 as summarizing the total revenues from "Heavy Water Services". However there appears to be no line item quantifying the "Heavy Water Services" revenues as a distinct revenue stream. Please provide a table showing the revenues from "Heavy Water Services" from 2007-2012, including a description of the methodology used to forecast such revenues in 2011 and 2012. In the event the revenues from "Heavy Water Services" form a component of the line item "Heavy Water Sales and Processing", please separate out the revenues from "Heavy Water Sales" that OPG is proposing to exclude from the revenue requirement from the "Heavy Water Services" that OPG is proposing to maintain as an offset to the Revenue Requirement.

Response

Ex. G2-T1-S1, Table 1, line 1 combines all revenues from Heavy Water Sales and Processing to avoid disclosing commercially sensitive information relating to heavy water sales.

The table below provides revenues from 2007 – 2012 for surplus heavy water sales and other heavy water services.

Revenues ($M)	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Surplus HW Sales (now excluded)	[redacted]	[redacted]	[redacted]	[redacted]	-	-
Other HW Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heavy Water Sales & Processing	30.3	28.5	25.5	23.1	17.3	15.6

For other heavy water services (primarily detritiation services), 2011 – 2012 forecasts were determined by examining the annual capacity of facilities such as the Tritium Removal

Facility, and then holding discussions with existing external clients including Bruce Power to determine their requirements. This information was used to develop forecast information.