EB-2016-0152

GEC Cross Materials Panels 1a & 1b

GEC Interrogatory #6

Issue Number: 4.5
Issue: Are the proposed test period in-service additions for the Darlington Refurbishment Program appropriate?

Interrogatory

Reference:

Please confirm that OPG in effect seeks a prudency ruling in advance on the $4.8B in DRP costs included in this application as coming into service by 2020 such that only variances there from will be subject to subsequent Board review.

Response

The determinations that OPG is seeking with regard to Darlington Refurbishment Program costs are clearly stated in its evidence (Ex. A1-2-2, pp. 4-5 and Ex. D2-2-1, p. 6) as follows:

i. In-service additions to rate base of: (i) $350.4M in the 2016 Bridge Year; and (ii) for the test period, $374.4M in 2017, $8.9M in 2018, $4,809.2M in 2020, and $0.4M in 2021 on a forecast basis. These amounts reflect the addition to rate base of $4,800.2M related to Unit 2 in-service addition in 2020 and 2021, as well as $743.1M related to Unit Refurbishment Early In-Service Projects, Safety Improvement Opportunities, and Facilities & Infrastructure Projects. If actual additions to rate base are different from forecast amounts, the cost impact of the difference will be recorded in the Capacity Refurbishment Variance Account (CRVA) and any amounts greater than the forecast amounts added to rate base will be subject to a prudence review in a future proceeding; and

ii. OM&A expenditures of $41.5M in 2017, $13.8M in 2018, $3.5M in 2019, $48.4M in 2020, and $19.7M in 2021 (Ex. F2-7-1).

11. Approval to continue existing deferral and variance accounts, including interest, as proposed in Ex. H1-1-1.

12. Approval of a hydroelectric payment rider to recover the approved balances of the hydroelectric deferral and variance accounts (except the Pension & OPEB Cash Versus Accrual Differential Deferral Account) at a rate of $1.44/MWh applied to the output from the hydroelectric facilities, beginning January 1, 2017 and terminating December 31, 2018.

13. Approval of a nuclear payment rider to recover the approved balances of the nuclear deferral and variance accounts (except the Pension & OPEB Cash Versus Accrual Differential Deferral Account) at a rate of $2.85/MWh applied to the output from the nuclear facilities, beginning January 1, 2017 and terminating December 31, 2018.

14. Approval to establish the following deferral and variance accounts as described in Ex. H1-1-1:
    i. Darlington Refurbishment Rate Smoothing Deferral Account;
    ii. Mid-term Nuclear Production Variance Account;
    iii. Nuclear ROE Variance Account; and
    iv. Hydroelectric Capital Structure Variance Account.

Project Approvals

15. OPG seeks the following approvals for the Darlington Refurbishment Program:
    i. In-service additions to rate base of: (i) $350.4M in the 2016 Bridge Year; and (ii) for the 2017-2021 period, $8.5M in 2017, $8.9M in 2018, $4,809.2M in 2020, and $0.4M in 2021 on a forecast basis. These amounts reflect the addition to rate base of $4,800.2M related to Unit 2 in-service addition in 2020 and 2021, as well as $377.2M related to Unit Refurbishment Early In-Service Projects, Safety Improvement Opportunities, and Facilities & Infrastructure Projects. If actual additions to rate base are different from

forecast amounts, the cost impact of the difference will be recorded in the Capacity Refurbishment Variance Account ("CRVA") and any amounts greater than the forecast amounts added to rate base will be subject to a prudence review in a future proceeding; and

ii. OM&A expenditures of $41.5M in 2017, $13.8M in 2018, $3.5M in 2019, $48.4M in 2020, and $19.7M in 2021 (Ex. F2-7-1).

<u>Interim Payment Amounts</u>

16. An order from the OEB declaring OPG's current payment amounts for regulated hydroelectric and nuclear facilities interim as of January 1, 2017, if the order or orders approving the payment amounts are not implemented by January 1, 2017.

Excerpt from OEB ACT S. 78.1

Board orders

(4) The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment. 2004, c. 23, Sched. B, s. 15.

Fixing other prices

(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; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Burden of proof

(6) Subject to subsection (7), the burden of proof is on the applicant in an application made under this section. 2004, c. 23, Sched. B, s. 15.

Excerpt from Reg. 53/05

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.

Workers complete installation of a mock calandria in the Darlington Energy Centre. It will be used to test tooling and train workers before beginning refurbishment work inside the reactor vaults of the Darlington Nuclear Generating Station

3

A Reliable and Clean Supply

While Conservation First is an important element of the LTEP, a clean, reliable and affordable supply of electricity also requires a diversity of generation types. Ontario will continue to develop new sources of supply to ensure that we reach these goals.

Nuclear

Ontario has made important investments in nuclear generation. The Canadian Manufacturers and Exporters reports that 15,600 people are employed in the operation and support of nuclear plants in Ontario, and 9,000 more would be employed for the refurbishment of the Ontario plants, for a total employment of approximately 25,000 people during the refurbishment period. The Organization of Canadian Nuclear Industries reports that an additional 30,000 people are employed in the nuclear manufacturing, engineering, construction and consulting, fuel fabrication, research and development, and medical isotopes sectors, in support of domestic and offshore nuclear projects.

The industry has been successful in exporting Canadian technology around the world to countries including Argentina, South Korea, China, Romania and India. International opportunities to use the nuclear expertise based in Ontario will continue to be explored.

Nuclear power is also part of Canada's science and innovation advantage, involving more than 30 universities and six major research centres, many of them in Ontario. The nuclear industry generates $2.5 billion in direct and secondary economic activity in Ontario every year. Retaining this nuclear expertise is crucial.

The province's nuclear generating stations at Darlington, Bruce and Pickering have historically provided about half of the province's electricity supply. The 2010 LTEP forecast that new capacity would need to be built at Darlington. New nuclear capacity is not needed at this time because the demand for electricity has not grown as expected, due to changes in the economy and gains in conservation and energy efficiency. The decision to defer new nuclear capacity helps manage electricity costs by making large investments only when they are needed.

Ontario continues to have the option to build new nuclear reactors in the future, should the supply and demand picture in the province change over time. The ministry will work with OPG to maintain the licence granted by the Canadian Nuclear Safety Commission, to keep open the option of considering new build in the future.

The government will ensure a reliable supply of electricity by proceeding with the refurbishment of the province's existing nuclear fleet taking into account future demand levels. Refurbishment received strong, province-wide support during the 2013 LTEP consultation process. The merits of refurbishment are clear:

- Refurbished nuclear is the most cost-effective generation available to Ontario for meeting baseload requirements.
- Existing nuclear generating stations are located in supportive communities, and have access to high-voltage transmission.
- Nuclear generation produces no greenhouse gas emissions.

Ontario plans to refurbish units at the Darlington and Bruce Generating Stations. The refurbishment has the potential to renew 8,500 MW over 16 years. The province will proceed with caution to ensure both flexibility and ongoing value for Ontario ratepayers. Darlington and Bruce plan to begin refurbishing one unit each in 2016. Final commitments on subsequent refurbishments will take into account the performance of the initial refurbishments with respect to budget and schedule by establishing appropriate off-ramps.

The nuclear refurbishment sequence shown in Figure 14 will be implemented subject to processes designed to minimize risk to ratepayers and to government. For example, appropriate off-ramps will be implemented should operators be unable to deliver the projects on schedule and within the established project budget.

The nuclear refurbishment process will adhere to the following principles:

1. Minimize commercial risk on the part of ratepayers and government;
2. Mitigate reliability risks by developing contingency plans that include alternative supply options if contract and other objectives are at risk of non-fulfillment;
3. Entrench appropriate and realistic off-ramps and scoping;
4. Hold private sector operator accountable to the nuclear refurbishment schedule and price;
5. Require OPG to hold its contractors accountable to the nuclear refurbishment schedule and price;
6. Make site, project management, regulatory requirements and supply chain considerations, and cost and risk containment, the primary factors in developing the implementation plan; and
7. Take smaller initial steps to ensure there is opportunity to incorporate lessons learned from refurbishment including collaboration by operators.

AMPCO Interrogatory #101

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: D2-2-11 Attachment 1

a) Page 5: Concentric indicates it did not independently verify the appropriateness, sufficiency or correctness of the Program schedules, cost estimates, or scope. Please confirm the third party that undertook this verification.

b) Page 6: Please provide OPG's benchmarking analysis of its Program against other CANDU refurbishments such as those at the Wolsong nuclear plant in South Korea, the Bruce nuclear plant in Ontario, and the Pt. Lapreau nuclear plant in New Brunswick.

Response

a) There was no third party review undertaken to verify or validate the final schedule duration, cost estimate, or scope definition for the refurbishment. The purpose of the third party reviews of the RQE was to validate that the processes and practices to develop the final cost, schedule, and scope for refurbishment met or exceeded industry standards, and, to confirm that OPG was effectively following those processes and practices.

b) Please refer to Ex. L-4.3-2 AMPCO-52.

AMPCO Interrogatory #53

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: D2-2-4 Page 4 Chart 1

a) Please complete the following Table to compare the nuclear stations reviewed by OPG to DRP.

Nuclear Station	Total # Units	# of Units Refurb	# Full Time Staff	Annual MW	Start Date	Planned/Actual Duration	Planned/Actual Costs	Planned/Actual LUEC cents/kWh
DRP								

Response

OPG has completed Chart 1 below with the requested information where it is available. OPG does not have information on Full Time Staff, Planned/ Actual LUEC and Annual MWh. Please see Ex. L-4.3-1 Staff-52 for a summary of similarities and differences between the DRP and the CANDU plants which have undergone refurbishment.

While OPG has provided planned and actual costs for some refurbishments, the costs for the projects are not directly comparable. The details of what is included in the other utilities' costs are not available to OPG. While the core scope for the projects in Chart 1 included replacement of the fuel channels and all or most of the feeder pipes, the remainder of the scope is not comparable across projects. Even with the core scope, the different reactor designs result in a significant difference in the number of fuel channel replacements at Pt. Lepreau and Wolsong. A further limitation when comparing different projects is the differing operating constraints of the execution of refurbishment work.

Some of the known differences between the DRP and the Bruce 1 and 2 units are:

- Bruce Units 1 and 2 were "cold and defueled" at the start of refurbishment. In addition, the two units under refurbishment were adjacent units which simplifies defueling and islanding.

- Costs are not directly comparable because of the timing of expenditures.
- It is unclear whether interest costs are included in the Bruce Units 1 and 2 final cost of $4.8B for 2 units.

Station	Total # Units	# of Units Refurb	Start Date[1]	Planned/ Actual Duration (per unit) (months)[2]	Planned/ Actual Costs
Darlington	4	4	2016	39 per unit/not available	$12.8B/ not available
Bruce A[3]	4	2	2005	25/84 for 2 units in parallel	$2.75B / $4.8B
Pt. Lepreau	1	1	2008	18/55	$1.0B/$1.4B[4]
Wolsong	8	1	2009	22/28	not available
Gentilly	1	1	N/A	35/not available[5]	$1.9B/not available[5]

<u>Notes:</u>

(1) Timing of Darlington, Pt. Lepreau and Bruce Units 1 and 2 refurbishments are different, therefore costs cannot be directly compared (different year's dollars)

(2) Pt. Lepreau and Wolsong are for CANDU 6 designs with 380 calandria/pressure tubes and a dedicated fuelling machine versus the Darlington and Bruce designs of 480 pressure tubes and a shared fuel handling system.

(3) Refurbishment of Bruce Units 1 and 2 commenced in October 2005 with Unit 1 complete in September 2012 and Unit 2 in October 2012, for a total of 7 years (84 months). The cost estimate publicly quoted is from November 2010; it is uncertain whether this cost estimate included capitalized interest costs.

(4) An additional $1B in replacement energy costs, operations and maintenance costs, and incremental financing for non-project related costs was incurred by NB Power.

(5) Refurbishment of Gentilly 2 did not proceed after a cost re-assessment concluded in 2012 that the cost would be $4.3B.

CME Interrogatory #18

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: Exhibit D2, Tab 2, Schedule 8. Attachment 1

At page 15 of the power point presentation which OPG provided in advance of the untranscribed Technical Conference which took place in these proceedings on September 23, 2016, OPG notes that it conducted a vetting process to establish the cost of work estimate for the DRP which included "comparisons to benchmarks" and benchmarking "information from other refurbishments." The Appendix C to the Darlington Refurbishment Business Case Summary refers at page 28 to "benchmarking against publicly available costs of other CANDU refurbishment projects at Pt. Lepreau and the Bruce 1 & 2 Units.":

(a) Are Pt. Lepreau and Bruce 1 & 2 the only nuclear refurbishments that OPG benchmarked its cost estimates against? If not, what other refurbishments were considered for this purpose?

(b) Please provide the information that was used to conduct the benchmarking exercise?

(c) Please describe any adjustments which were made to the information in order to effect the costs comparison;

(d) Please provide the results of the benchmarking exercise?

(e) Did the benchmarking exercise cause OPG to increase or decrease any of its costs estimates? If so, please provide particulars. If not, why not?

Response

a) Pt. Lepreau and Bruce Units 1 & 2 are the only other completed CANDU nuclear refurbishments where OPG had sufficient information to benchmark the costs against DRP in aggregate. Given the distinct design of the CANDU stations, and the distinct nature of the CANDU refurbishment (replacement of the fuel channels), other CANDU units are the only units with which it is possible to carry out cost benchmarking at an aggregate level. Please see L-04.3-1 Staff-52 for a discussion of similarities and differences between CANDU stations which have undergone or are planned to undergo refurbishment. Also, please see Ex. L-04.3-8 GEC-014 for a discussion of cost estimates for the Gentilly station which OPG reviewed.

b) OPG did not classify the information used to do cost benchmarking separately from all of the other information used to derive lessons learned. Please see Ex. L-04.3-2 AMPCO-52, Attachment 3 which provides a summary of the lessons learned library from the Risk Management and Oversight (RMO) tool for 2014-2015.

c) The only major adjustment OPG made in carrying out the cost benchmarking was to recognize the differing sizes of the Pt. Lepreau unit versus the Bruce and Darlington units in the number of fuel channels (380 fuel channels in Pt. Lepreau vs. 480 fuel channels in the Bruce and Darlington units), and to note that Pt. Lepreau is a single unit with a dedicated fueling machine and without interferences from other units.. At a high level, OPG was also aware of scope differences between the Bruce Units 1 and 2 refurbishments and the Darlington refurbishment, specifically in the area of replacement of the steam generators. In addition, OPG was aware that the Bruce Units 1 and 2 refurbishments were begun after the units had already been defueled and “cold” for a number of years, whereas the Darlington refurbishments will commence immediately after shutdown of the units, with other operating units immediately adjacent, and that the defueling exercise would take place with other operating units needing to utilize the shared fuelling machines. Please see Ex. L-04.3-1 Staff-52.

d) There are no reports on the cost benchmarking exercise.

e) The aggregate cost estimate benchmarking was not used directly to drive discussions with its contract partners, however, specific benchmarks were used as direct input into the Re-tube and Feeder Replacement estimate.

GEC Interrogatory #3

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:

During its September 23rd presentation OPG indicated that it considered the price impact of alternate contracting approaches. Please provide the percentage impacts that were found to be associated with differing approaches for each major contract or work grouping included in the DRP.

Response

OPG cannot provide the requested analysis. In OPG's September 23, 2016 presentation to the Untranscribed Technical Conference, it was not OPG's intention to imply that, for each major work bundle or grouping, bids were received under differing pricing models.

OPG's presentation stated that "In contracting the various work packages, OPG implemented different pricing models to optimize risk transfer and value-for-money". OPG's presentation also stated that, "Different procurement methods, contracting strategies and pricing models apply to the major work packages to address varying degrees of complexity, uncertainty and need for collaboration". The risk transfer model referenced in OPG's presentation is also included in Ex. D2-2-3 p. 5, Figure 1.

What OPG intended to convey was that its contracting process was designed to ensure that the appropriate risk transfer was achieved for each work package, and that the appropriate party (OPG or the contractor) retained the risks that it was in the best position to manage, thereby achieving an appropriate price.

In preparing for the DRP, and particularly for the larger work packages (e.g. RFR and T/G), OPG first canvassed the market through Expressions of Interest or Requests for Information to determine the contractors' ability to perform the work under different pricing models. Having canvassed the market, OPG then made a determination of which was the most appropriate pricing model for each work package grouping, and issued a Request for Proposal (RFP) inviting bids under the specified pricing model. In certain RFPs, OPG also encouraged bids under alternative pricing models; however, OPG did not stipulate that bids must be submitted under alternative pricing models.

An example of where OPG adjusted its strategy to achieve an appropriate price is in the Turbine Generator work bundle. OPG's initial strategy was to attempt to achieve an

Engineer, Procure, Construct (EPC) agreement with the Original Equipment Manufacturer (OEM) for the entire T/G scope of work, partly driven by the fact that the OEM owned the intellectual property rights on the Turbine Generator sets and also by the desire not to have a different entity performing engineering for the T/G sets. However, the bid OPG received from the OEM was not acceptable, and OPG re-evaluated its approach. The outcome was that the Turbine Generator work was split into two components: a) an Engineering Support and Equipment Supply Agreement (ESES) which was sole-sourced to the OEM under a Fixed/Firm Price model with a limited target price component; and b) a competitively bid EPC contract for the remainder of the work, primarily field work, which was won by a joint venture of SNC/Aecon, under a target price model.

Board Findings

The Board will not make a finding that the commercial and contracting strategies used by OPG in the Darlington Refurbishment Project are reasonable.

OPG proposed this issue in the draft issues list filed with the application. However, during the oral phase of the hearing it was unclear how a finding of reasonableness would be defined and why such an approval by the Board was necessary. On the last day of the hearing, in response to the Board's questioning as to what the Board would be approving if it determined that the contracting strategy was reasonable, OPG clarified that the Board would not be approving the contracts, it would not be approving the conduct of the contract negotiations, and it would not be approving the procurement process. The Board would not be approving any prices established through the contracting process, nor would the Board be approving the selection of the winning proponent(s).[51]

In OPG's view, the Board would be making a finding of reasonableness in respect of the guiding principles forming the contracting strategy which OPG described as including;

1. A multi-prime contractor model in which OPG retains overall project management and design authority responsibility;
2. The division of the work into 5 work packages;
3. A model where the prime contractor is responsible for some combination of engineering, procurement and construction within each of the 5 work packages; and
4. The means by which risk would be allocated.[52]

The Board will not make the finding requested by OPG for two reasons.

First, the application before the Board is an application for payment amounts for the years 2014 and 2015. The Board is of the view that the commercial and contracting strategies approval sought by OPG extends beyond a determination of those payment amounts. While there may be a tangential link between a contracting strategy and the rates requested, the Board finds that the link in this case is not direct enough. The Board agrees with Board staff that the request, as defined by OPG, is tantamount to an

[51] Tr Vol 16 page 5
[52] Tr Vol 16 page 4 (all subject to available contract options in the market place)

approval of project management which is not the role of the Board. Project Management and project execution are the responsibility of OPG.

If the Board were to make a finding on the reasonableness of the commercial and contracting strategies, the onus would be on OPG as the applicant to provide the Board with sufficient evidence to satisfy the Board that the commercial and contracting strategies are reasonable. Given the guiding principles articulated by OPG, the Board would have required far more evidence than was presented to reach those conclusions. On July 2, 2014, OPG filed reports that independently assessed the execution of some infrastructure projects related to the refurbishment. The reports prepared by Burns & McDonnell and Modus Strategic Solutions were critical of project execution and raised concerns including the impact on Darlington Refurbishment schedule and costs. In fact, the Board had to take a two-week recess from the proceeding to provide parties with the opportunity to review and analyze the reports filed on July 2, 2014.

The Board, in order to make any determination, must be satisfied that a thorough and complete hearing of this issue has taken place. The Board is not satisfied that this has occurred.

3.6.5 Darlington Refurbishment and Long-Term Energy Plan (Issue 4.12)

In Board staff's view, the Darlington Refurbishment is aligned with the Long-Term Energy Plan, however, the other parties submitted that it was premature to make a finding. OPG observed that the province has very clearly indicated that Darlington Refurbishment is a key part of the Long-Term Energy Plan and that no concerns have been raised with respect to compliance.

The Board will not opine on whether OPG's nuclear refurbishment process for Darlington aligns with the Government of Ontario's Long-Term Energy Plan. The Board considers this review to be outside of its mandate. A key component of the principles outlined in the Long-Term Energy Plan is the appropriate allocation of risk as it relates to nuclear refurbishment. The Board is of the view that for the reasons previously stated, the amount of evidence related to appropriate risk allocation would be insufficient for the Board to reach such a finding.

Board Staff Interrogatory #50

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Reference:
Ref: Exh D2-2-3, Chart 1

Interrogatory

a) Describe all “off ramps” for each major work bundle. What is the governing process for OPG to determine whether to exercise the off-ramps? How will this decision be communicated to all interested parties? What are the cost categories that will be payable to the contractors upon execution of each of the off-ramps?

b) Describe what information OPG will gather, who will receive the information, when the information will be provided, and how the decision will be made whether to the exercise the off-ramp during or after the completion of Unit 2. Provide the same information for all of the other units and the process OPG will use to assess whether to exercise the off-ramps throughout the project.

c) Describe the governing process regarding the off-ramp for when a prime contractor is substantially below expectation. What does “substantially below expectation” mean? What information will this determination be based on? Who will have access to that information, when will it be provided, and who will make that decision?

d) What actions must the contractors take to recover in the event of a project schedule delay for which the contractor is responsible?

Response

a) OPG has incorporated both a termination for convenience and a termination for default clause in each of its major work bundle contracts. This allows OPG to take an “off ramp” at any time and terminate its contracts:

Termination for Default: If the contractor defaults, OPG will be entitled to terminate the agreement and exercise a number of self-help remedies. Termination for default would permit OPG to make a claim against the contractor for full contractual damages (subject to a percentage cap formula that is linked to the total contract price and certain other amounts).

Termination for Convenience: The agreement permits OPG to terminate the agreement for convenience at any time. Certain types of direct damages (but not full contractual damages) will be payable by OPG to the contractor in such circumstances. Examples of direct damages under the contracts (with some variation between the contracts) are:

- work that has been performed to the date of the termination and for which OPG has not yet made payment;
- an equitable portion of any fees which would have otherwise been payable on the next milestone date;
- any contractor costs incurred in providing any work in progress; and
- reasonable extra direct damages suffered by the contractor arising from the termination (such as out of pocket costs for demobilization).

Each circumstance will be dealt with as appropriate based on the facts. There is no special governance process required other than compliance with the contractual terms. Formal communications will be made in accordance with the contract terms; additional communications will be made as appropriate. Prior to terminating any contract, the OPG Project Manager will request a review by OPG's Senior Management team, which includes Finance, Law and Supply Chain.

Upon decision to terminate for convenience, OPG is to provide written notice to the contractor, as set out in the contracts.

b) As discussed in L-4.3-1 Staff-44, beyond being guided by the 2013 LTEP principles for nuclear refurbishment, OPG has no insights into what factors the Government of Ontario would consider in making a decision to direct OPG to take an off-ramp.

Internally, if Unit 2, or any other Unit, was forecasting to be over budget beyond a certain threshold, OPG would be required to issue a superseding business case summary. The superseding business case summary would include information such as updated cost estimates, LUEC, and alternative proposals. The option to take an off-ramp may be one of many considered alternatives. Approval of any superseding business case summary would be sought from OPG's Board of Directors.

c) If a contractor is performing "substantially below expectation", OPG likely would terminate the agreement for default as opposed to termination for convenience.

Performance that is "substantially below expectation" will be determined on a case-by-case basis, but will include evaluation of the contractor's performance on safety, quality, schedule and cost aspects of the work being undertaken as well as their actions, or lack of action, taken to recover the performance gap.

d) OPG expects contractors to be on plan for their work. Recovery plans are required if a contractor deviates from plan and a milestone is at risk of being missed. Steering Committees consisting of senior management from both OPG and the contractor provide oversight on all aspects of contractor performance. OPG expects all defective parts of the project to be corrected at the contractor's cost. In some contracts, a schedule incentive/disincentive regime is in place to encourage the contractors to be on or ahead of schedule.

Board Staff Interrogatory #44

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: Exh A1-3-3. Page 11

In the above reference, OPG has stated that "changes to public policy, especially the Government of Ontario's Long Term Energy Plan ("LTEP") could impact OPG's nuclear production. In particular, a change to the refurbishment schedule for future units at the Darlington generating station…"

a) What is OPG's understanding of when the Government of Ontario would make a decision about whether or not there could be a change to the refurbishment schedule and possibly the cancellation of the refurbishment of units subsequent to Unit 2?

b) What is OPG's understanding of what factors the Government would consider in making such a decision?

c) If the Government of Ontario were to cancel the DRP after Unit 2 is complete, what Facilities and Infrastructure assets would no longer be required?

Response

a) At this time, OPG has no expectation that the Government of Ontario would change the refurbishment schedule for the Darlington units or cancel the refurbishment of units subsequent to Unit 2.

b) The Government has not specified what factors it would consider in assessing the on-going feasibility of the current refurbishment schedule or the planned refurbishment of units subsequent to Unit 2. OPG would expect that any decisions regarding the on-going feasibility of the schedule or the plan would only be made after a rigorous process of evaluation similar to the one which was undertaken on the decision to proceed with the refurbishment of the Darlington (and the Bruce) units. OPG expects the evaluations and decision-making would involve OPG, the Independent Electricity System Operator, the Ministry of Energy, the Ministry of Finance, other relevant Ministries, and the Cabinet.

c) If the Government of Ontario were to cancel the Darlington Refurbishment Program after Unit 2 is completed, all of the Facility and Infrastructure Project assets are expected to remain useful for the operation of the Darlington Nuclear Station.

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MR. POCH: So just based on -- and these are -- these would be overnight costs?

MR. ROSE: These were overnight costs in 2013 dollars. That's correct.

MR. POCH: So they would be comparable to the $10 billion figure as opposed to the 12.9?

MR. ROSE: That is correct.

MR. POCH: Under an -- interest and escalation...

MR. ROSE: Are excluded from this estimate.

MR. POCH: Right. Okay. These would go up if we counted interest and escalation, but we're on an apples-and-apples basis.

So that would be 6.55 percent of the 10? 655 million?

MR. ROSE: That is 6.55 percent of the 10.

MR. POCH: So in other words, 93.45 percent of the cost estimate, of the $10 billion cost estimate, is either OPG cost or is under target -- in which case you bear the whole risk, or is target pricing with shared risk, or is still in the contingency and reserve pools; correct?

MR. ROSE: That is correct.

MR. POCH: Obviously you bear the risk?

MR. ROSE: There are some non-OPG costs, you know, insurance, fuel, that are not -- that are OPG's to pay, but they're not OPG labour. Just to clarify that.

MR. POCH: No, I understand. I'm just -- who is bearing the risk on these different pots? And so apart from that 6.55 percent, you're either bearing all of the risk or sharing the risk under the target pricing

In SEC and CME's view, OPG's request is an attempt to "buy insurance" and to insulate OPG from commercial and contractual risks and from criticism in future proceedings. Approval of contracting and commercial strategies is neither necessary nor desirable.

OPG argued that a finding of reasonableness by the Board does not eliminate the need for future prudence review, but will enable the review to be assessed in the appropriate context.

Both GEC and Environmental Defence submitted that OPG's commercial and contracting strategies are contrary to the Long-Term Energy Plan as they expose ratepayers to too much risk. The evidence suggests that OPG bears the primary risk for overruns with respect to 93% of the project costs.[49] Environmental Defence was critical of cost overruns on previous projects including most recently the Niagara Tunnel Project and the Darlington Refurbishment campus plan projects. Environmental Defence submitted that there is no ratepayer protection for replacement power associated with project delays.

OPG clarified that the 93% of project costs includes OPG internal costs, and that only 27% of the $10 billion estimate is on a target price basis.[50]

GEC submitted that the project risk will not be monetized until the release quality estimate is complete; therefore, it is premature to structure the commercial arrangements and contract strategy. While OPG has stated that allocating more risk to contractors would have significant cost, GEC submitted that the commercial and contracting strategy should be informed by an understanding of the risks. Optimal allocation of those risks will enable compliance with the principles of the Long-Term Energy Plan.

OPG argued that GEC and Environmental Defence have taken a narrow view of risk. There is a multi-faceted risk minimization approach including OPG's retention of project management responsibility, a significant testing effort in advance of the release quality estimate and continuous internal and external oversight. While the parties claim that a fixed price turnkey arrangement is the only means to minimize risk, this is not possible for a mega project like Darlington Refurbishment as there are risks that contractors would not be willing to take on.

[49] Tr Vol 15 page 56
[50] Reply Argument page 107

Board Findings

The Board will not make a finding that the commercial and contracting strategies used by OPG in the Darlington Refurbishment Project are reasonable.

OPG proposed this issue in the draft issues list filed with the application. However, during the oral phase of the hearing it was unclear how a finding of reasonableness would be defined and why such an approval by the Board was necessary. On the last day of the hearing, in response to the Board's questioning as to what the Board would be approving if it determined that the contracting strategy was reasonable, OPG clarified that the Board would not be approving the contracts, it would not be approving the conduct of the contract negotiations, and it would not be approving the procurement process. The Board would not be approving any prices established through the contracting process, nor would the Board be approving the selection of the winning proponent(s).[51]

In OPG's view, the Board would be making a finding of reasonableness in respect of the guiding principles forming the contracting strategy which OPG described as including;

1. A multi-prime contractor model in which OPG retains overall project management and design authority responsibility;
2. The division of the work into 5 work packages;
3. A model where the prime contractor is responsible for some combination of engineering, procurement and construction within each of the 5 work packages; and
4. The means by which risk would be allocated.[52]

The Board will not make the finding requested by OPG for two reasons.

First, the application before the Board is an application for payment amounts for the years 2014 and 2015. The Board is of the view that the commercial and contracting strategies approval sought by OPG extends beyond a determination of those payment amounts. While there may be a tangential link between a contracting strategy and the rates requested, the Board finds that the link in this case is not direct enough. The Board agrees with Board staff that the request, as defined by OPG, is tantamount to an

[51] Tr Vol 16 page 5
[52] Tr Vol 16 page 4 (all subject to available contract options in the market place)

approval of project management which is not the role of the Board. Project Management and project execution are the responsibility of OPG.

If the Board were to make a finding on the reasonableness of the commercial and contracting strategies, the onus would be on OPG as the applicant to provide the Board with sufficient evidence to satisfy the Board that the commercial and contracting strategies are reasonable. Given the guiding principles articulated by OPG, the Board would have required far more evidence than was presented to reach those conclusions. On July 2, 2014, OPG filed reports that independently assessed the execution of some infrastructure projects related to the refurbishment. The reports prepared by Burns & McDonnell and Modus Strategic Solutions were critical of project execution and raised concerns including the impact on Darlington Refurbishment schedule and costs. In fact, the Board had to take a two-week recess from the proceeding to provide parties with the opportunity to review and analyze the reports filed on July 2, 2014.

The Board, in order to make any determination, must be satisfied that a thorough and complete hearing of this issue has taken place. The Board is not satisfied that this has occurred.

3.6.5 Darlington Refurbishment and Long-Term Energy Plan (Issue 4.12)

In Board staff's view, the Darlington Refurbishment is aligned with the Long-Term Energy Plan, however, the other parties submitted that it was premature to make a finding. OPG observed that the province has very clearly indicated that Darlington Refurbishment is a key part of the Long-Term Energy Plan and that no concerns have been raised with respect to compliance.

The Board will not opine on whether OPG's nuclear refurbishment process for Darlington aligns with the Government of Ontario's Long-Term Energy Plan. The Board considers this review to be outside of its mandate. A key component of the principles outlined in the Long-Term Energy Plan is the appropriate allocation of risk as it relates to nuclear refurbishment. The Board is of the view that for the reasons previously stated, the amount of evidence related to appropriate risk allocation would be insufficient for the Board to reach such a finding.

UNDERTAKING JT1.20

Undertaking

TO RECALCULATE IR 3 AND 4 BASED ONLY ON FUTURE COSTS, OR WHY OPG WILL NOT ANSWER.

Response

Please note that OPG's response to this undertaking should be read in conjunction with the responses to interrogatory L-4.3-7 ED-003 and interrogatory L-4.3-7 ED-004 with particular emphasis on the qualifications OPG has noted in preparing these scenario assessments.

This response is an update to interrogatories L-04.3-7 ED-003 and L-04.3-7 ED-004 to apply the cost overruns scenarios to only the future costs. These calculations assume all costs to date are on plan with respect to the cost incentive and disincentive calculations.

As in interrogatories L-04.3-7 ED-003 and L-04.3-7 ED-004, OPG has provided the results of pro-rating OPG's RQE estimate on costs remaining to be spent by: a) 25%; and, d) 100%.

Update to Interrogatory L-04.3-7 ED-003

The calculated percentage of these cost overruns that would be passed on to OPG when the cost overrun percentages are applied only to the future costs are: a) 85% of the 25% cost overrun; d) 86% of the 100% cost overrun.

Update to Interrogatory L-04.3-7 ED-004

When the cost overrun percentages are applied only to the future costs:

a) For the 25% cost overrun scenario, the total cost of the DRP mathematically evaluates to $14.7B

b) For the 100% cost overrun scenario, the total cost of the DRP mathematically evaluates to $20.6B.

The detailed cost breakdowns for the above two scenarios, in a similar format to Chart 4 in Ex. D2-2-3 p. 14 are provided in Attachment 1 (Attachment 1 contains confidential information).

Attachment to L-04.3-7 ED-004 (includes summary calculations for L-04.3-7 ED-003) - Amended for JT1.20

Cost Overrun Scenarios

2015$M (except for Interest and Escalation line item)				ED-004/ JT-1.20					ED-003	ED-004/ JT-1.20					ED-003
				1.25	25% Cost Growth					2	100% Cost Growth				
Major Category		Category/ Contract Type	RQE Base Costs (1)	Base cost + % Increase on Remaining Costs	Cost Variance on Remaining Costs	Impact to Contractor	Impact to OPG	Actual Cost to OPG	Proportion of Increase paid by OPG	Base cost + % Increase on Remaining Costs	Cost Variance on Remaining Costs	Impact to Contractor	Impact to OPG	Actual Cos to OPG	Proportion of Increase paid by OPG
Retube Feeder Replacement		OPG Project Management & Oversight Costs	167	191	24		24	191		265	98		98	265	
	Contractor Costs	Definition Phase Target Price (Incl RWPB)	185	186	1	0	1	186		190	5	0	5	190	
	Contractor Costs	Definition Phase Fixed Fee	74	76	2	2	0	74		83	10	10	0	74	
	Contractor Costs	Definition Phase Fixed Fee Incentive/ Disincentive		0		0	0	0		0		0	(0.400)	(0)	
	Contractor Costs	Execution Phase Target Price	1,667	2,076	409	0	409	2,076		3,301	1,634	0	1,634	3,301	
	Contractor Costs	Execution Phase Fixed Fee	492	613	121	121	0	492		974	482	482	0	492	
	Contractor Costs	Execution Phase Fixed Fee Incentive/ Disincentive		0		67	(67)	(67)		0		236	(236)	(236)	
	Contractor Costs	Mock-up Fixed Price	38	38	0	0	0	38		38	0	0	0	38	
	Contractor Costs	Non-target Reimbursable Costs	6	8	2	0	2	8		12	6	0	6	12	
	Contractor Costs	Tooling Fixed Price	375	377	2	2	0	375		383	8	8	0	375	
	Contractor Costs	OSM with Fee(estimate)	579	704	125	0	125	704		1,078	499	0	499	1,078	
	Contractor Costs	Goods with Fee(estimate)	48	60	12	0	12	60		96	48	0	48	96	
Fuel Handling/ Defueling		OPG Project Management & Oversight Costs	49	58	9		9	58		85	36		36	85	
	Cont. Costs	Defueling - Eng Services (Fixed/Firm Price)	16	16	0	0	0	16		16	0	0	0	16	
	Cont. Costs	Defueling - Eng Services (Misc Reimbursable)	7	7	0	0	0	7		7	0	0	0	7	
	Cont. Costs	Fuel Handling (ESMSA - see assumptions)	126	155	29	[redacted]				242	117	[redacted]			
Steam Generators		OPG Project Management & Oversight Costs	13	15	2		2	15		22	9		9	22	
	Contractor Costs	[redacted]							73%	[redacted]					74%
Turbine Generator		OPG Project Management & Oversight Costs	41	48	7		7	48		69	28		28	69	
	Contractor Costs	ESES - Fixed/ Firm Cost - Equipment Supply	257	299	43	43	0	257		428	171	171	0	257	
	Contractor Costs	ESES - Target Cost Installation & Static Commissioning	38	48	10	0	10	48		77	38	0	38	77	
	Contractor Costs	ESES - Target Cost - Incentive/ Disincentive		0		5	(5)	(5)		0		19	(19)	(19)	
	Contractor Costs	ESES - Target Cost - Dynamic Commissioning	14	17	3	0	3	17		28	14	0	14	28	
	Contractor Costs	ESES - Target Cost - Incentive/ Disincentive		0		2	(2)	(2)		0		7	(7)	(7)	
	Contractor Costs	ESES - Reimbursable (no markup)	28	33	5	0	5	33		47	19	0	19	47	
	Contractor Costs	EPC - Definition Phase Target Cost	21	22	0	0	0	22		23	2	0	2	23	
	Contractor Costs	EPC - Definition Phase Fixed Fee	13	13	0	0	0	13		14	1	1	0	13	
	Contractor Costs	EPC - Definition Phase Fixed Fee Incentive/ Disincentive		0		0	0	0		0		0	(0)	(0)	
	Contractor Costs	EPC - Execution Phase Target Cost	161	201	39	0	39	201		318	157	0	157	318	
	Contractor Costs	EPC - Execution Phase Fixed Fee	53	66	13	13	0	53		104	52	52	0	53	
	Contractor Costs	EPC - Execution Phase Fixed Fee Incentive/ Disincentive		0		7	(7)	(7)		0		25	(25)	(25)	
	Contractor Costs	EPC - Dynamic Commissioning Work (Trades)	2	3	1	0	1	3		5	2	0	2	5	
	Contractor Costs	EPC - Goods	5	6	1	0	1	6		10	5	0	5	10	
	Contractor Costs	EPC - Reimbursable Costs with no-markup	11	14	3	0	3	14		23	11	0	11	23	
Balance of Plant		OPG Project Management & Oversight Costs	183	213	30		30	213		304	122		122	304	
		Contractor Costs (mainly ESMSA)	784	933	149	[redacted]				1,382	598	[redacted]			
F&IP & SIO Projects		Facility and Infrastructure Projects (mainly ESMSA)	640	655	15	[redacted]				699	59	[redacted]			
		Safety Improvement Opportunities (mainly ESMSA)	205	239	34					239	34				
Functions		Project Execution	322	395	73		73	395		614	293		293	614	
		Contract Management	52	62	10		10	62		92	40		40	92	
		Engineering	283	330	47		47	330		471	188		188	471	
		Managed Systems Oversight	41	47	6		6	47		66	25		25	66	
		Planning & Controls	136	150	14		14	150		191	54		54	191	
		Nuclear Safety	83	94	11		11	94		127	44		44	127	
		Program Fees & Other Support	341	413	72		72	413	100%	630	290		290	630	100%
		Supply Chain	86	103	17		17	103		155	69		69	155	
		Work Control	80	96	16		16	96		144	65		65	144	
		Operations and Maintenance	805	984	179		179	984		1,523	718		718	1,523	
		Early Release 3	102	102	0		0	102		102	0		0	102	
		Early Release 4	7	7	0		0	7		7	0		0	7	
Contingency			1,706	1,706	0		0	1,706	N/A	1,706	0		0	1,706	N/A
Sub Total			**10,429**	**11,987**	**1,557**	**288**	**1,269**	**11,699**		**16,556**	**6,127**	**1,114**	**5,013**	**15,442**	
Interest & Escalation ($M)			2,371	2,799	429		429	2,799	100%	4,057	1,686		1,686	4,057	100%
Total			**12,800**	**14,786**	**1,986**	**288**	**1,698**	**14,498**	**85%**	**20,613**	**7,813**	**1,114**	**6,699**	**19,499**	**86%**

Notes and assumptions:

1. Based on OPG's Release Quality Estimate (RQE). All numbers except interest and escalation are in 2015$.
2. These are illustrative examples; assumption is that all contractor incentives/disincentives and performance fee mechanisms are applicable.
3. Cost overrun factors are modelled based on remaining to go costs only.
4. Cost overrun factors are not applied to contingency.
5. RFR contract costs are as per Ex. D2-2-3, pp. 10 and 11.
6. De-fuelling contract is mainly fixed/ firm price. Reimbursable fixed fees are capped for certain costs; however, this was not incorporated into the calculations due to lack of materiality.
7. Steam Generator contract includes [redacted]
8. For work bundles that are mainly under ESMSA contracts (e.g. BOP, FH, FIP, SIO), it was assumed, for simplicity, that the increase is caused by the contractor; therefore, the cost to OPG is [redacted] of the cost overrun (performance fee of [redacted] withheld).
9. For simplicity, for all of the larger target cost contracts, a 20% cost disincentive was applied above any neutral band specified in the contracts. The actual percentage is calculated using a graded approach.
10. For simplicity, interest and escalation were pro-rated.

GEC Calculation of OPG Portion of a 25% DRP Cost Overrun

Project cost before overrun: $12.8B

25% = $3.2B

125% = $16B

Allocation of overrun according to JT1.20: 85% to OPG

85% of $3.2 = $2.72B

Total OPG Cost 12.8 + 2.72 = $15.52B

15.52/16 X 100 = 97%

AMPCO Interrogatory #71

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: Exhibit D2-2-7 Page 6

a) Please explain further what is meant by "Program contingency is derived from overarching Program risks managed at the executive level that could influence the overall Program's objectives, may require Program-wide response and may have a global impact on the Program".

b) Please provide a listing of the key Program risks managed at the executive level and the corresponding probability.

c) Please provide more details on the types of unforeseen changes to financial and other economic factors beyond those assumed in the Program.

Response

a) Program risks are risks to the refurbishment that are not specific to one project bundle (sub-project) or another, but could have a global impact on multiple project bundles. For example, the unavailability of skilled trade workers would impact multiple project bundles and requires an integrated program level strategy to mitigate it. Managing this risk locally within each project bundle would be inefficient and cause confusion due to potential conflicting strategies.

b) The following table lists the title of the program risks that were included in the contingency analysis and their residual risk probability. For each risk title identified in the table, a detailed risk description is included in the refurbishment risk register which clearly outlines the adverse event, the cause of the event, and the impact on refurbishment objectives in the event that the risk occurs. For brevity, only risks with a residual risk probability of 40% or greater are shown.

Program Function	**Risk Title**	**Residual Risk Probability at RQE**
Contract Management	Potential Contract Management Function Resources Required for future Master Services Contract(s) or Replacement Contracts	50%
Program Support	P&M Executed F&IP and SIO Projects Exceed Forecasted Life Cycle Costs	50%
Program Support	Heavy Water Storage Building Costs Exceed Planned Budget	50%
Program Support	Foreign Exchange Impacts	40%
Operations and Maintenance	O&M Procedure Update Program may not have sufficient Funding	50%
Operations and Maintenance	Civil Functions to support Radiation Protection	70%
Operations and Maintenance	Chemistry Laboratory Support	50%
Operations and Maintenance	Acute Tritium Release above Station IIL during NR Primary Side Drain and Dry Operation	50%
Operations and Maintenance	Chemistry Control Procedural Review Risk	50%
Operations and Maintenance	The Cyclic Maintenance budget may not have enough funds to cover Shutdown Maintenance Backlog	50%
Operations and Maintenance	Materials budget for emergent broke-fix maintenance during Shutdown, Layup and Run-up	50%
Operations and Maintenance	Availability of DN Authorized Staff for Station and Refurb Support	50%
Refurbishment Execution	Key skilled craft resources not available when required for Units 1, 3, 4 Execution	45%
Refurbishment Execution	Estimated Cost of RPPE Laundry may be underestimated	40%
Refurbishment Execution	Risk of Vendor Purchased or Owner Supplied Materials not arriving in time to support the NR Execution Schedule	50%
Refurbishment Execution	Estimated Cost of General Services contract underestimated	60%
Refurbishment Execution	Refurbishment does not retain key trades and supporting staff	60%
Refurbishment Execution	Vendor Default	50%

c) There is a residual risk that financial factors such as interest rates, escalation rates, and labour market demands could change dramatically over the DRP's execution period of 2016-2026.

For example, nominal escalation rates built into the DRP are approximately 2% per annum. There is a low-probability, high consequence risk that Ontario's economy could enter a period of runaway inflation during the DRP execution phase, which would invalidate the assumptions regarding escalation in the RQE, and result in the RQE potentially being exceeded.

Another example would be a return to a period of high interest rates, such as those which existed in the 1980s, which would result in accumulation of much higher than planned interest charges.

These types of risks are unpredictable and outside of the control of DRP management and, therefore, not included in the development of the contingency.

UNDERTAKING JT1.10

Undertaking

TO PROVIDE A VERSION OF THE TABLE OF THE FORECAST SPEND LIFE FOR THE DARLINGTON REFURBISHMENT PROJECT THAT IS THE COST TO DECEMBER 2016.

Response

The following table represents the December 2016 life to date forecast spend against the categories in Table C1 in Ex. D2-2-8 Attachment 1 page 29.

Bundle Name	Forecast Spend, Life-to-Date @Dec 2016 $ x 1000
01 - RFR (Retube Feeder Replacement)	972,240
02 - TG (Turbine Generator)	158,394
03 - BOP (Balance of Plant)	119,275
04 - FH (Fuel Handling)	21,830
05 - DF (Defueling)	33,092
06 - SG (Steam Generator)	19,919
07 - SP (Specialized Projects)	36,415
08 - SL (Shutdown Layup)	45,653
09 - RSF (Refub Support Facilities)	32,111
10 - IL (Unit Islanding)	45,606
Subtotal Bundles	**1,484,534**
11 - Campus Plan - F&IP	619,634
12 - Campus Plan - SIO	250,369
Subtotal Campus Plan F&IP, SIO	**870,003**
Subtotal Bundles & Campus Plan	**2,354,536**
13 - Functions (excl O&M) - Project Execution	40,050
14 - Functions (excl O&M) - Contract Management	13,259
15 - Functions (excl O&M) - Engineering	103,106
16 - Functions (excl O&M) - Managed Systems Oversight	16,690
17 - Functions (excl O&M) - Planning & Controls	86,600
18 - Functions (excl O&M) - Nuclear Safety	40,326
19 - Functions (excl O&M) - Program Fees & Other Supp	57,718
20 - Functions (excl O&M) - Supply Chain	19,052
21 - Functions (excl O&M) - Work Control	24,239
Subtotal Functions (excl O&M)	**401,041**
22 - Functions (O&M) - OMA Training Program	10,983
23 - Functions (O&M) - Waste Disposal	959
24 - Functions (O&M) - Ops & Maintenance	96,380
Subtotal Functions - Ops & Mtce	**108,321**
25 - Functional - Release 3	104,546
26 - Functional - Advance Release 4 (incl Eng'g Reactor)	7,524
Subtotal Functions - Early Release Funds	**112,070**
Subtotal Before Contingency	**2,975,969**
27 - Project & Program Contingency *(2) (3)	-
Subtotal Contingency	**-**
Subtotal before Interest & Inflation	**2,975,969**
28 - Interest	**248,006**
29 - Inflation	-
Subtotal Interest & Inflation	**248,006**
Total Cost Estimate (Expressed as Nominal $)	**3,223,975**

1

Board Staff Interrogatory #49

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:

Ref: Exh A2-1-1 Attachment 5, page 55
Ref: Exh D2-2-3, Attachment 6, RFR Contract, Article 16.2
Ref: Exh A1-6-1 Attachment 1, O. Reg 53/05, page 3

The first reference above provides the total commitments related to DRP, should OPG close the project, as $284M. The second reference details the payments due by OPG to the RFR contractor should the contract be terminated early by OPG. The third reference is the regulation directing the OEB to ensure that OPG recovers firm financial commitments incurred with respect to DRP, if OGP makes the financial commitments prudently.

a) Please provide details of what is included in the $284M from reference one.

b) Does the $284M include all the payments to all contractors that OPG would be responsible for upon termination, such as those outlined in the second reference above?

Response

a) The $284M total commitments related to DRP, should OPG close the project, includes $134M in accruals as at December 31, 2015. It also includes an estimate of $150M as at December 31, 2015 for commitments not recorded as project costs. These include procurement commitments, costs to place the work in a safe state, as well as the costs of demobilizing the contractors from the DRP.

b) The $284M includes all the payments to contractors that OPG would be responsible for upon termination, consistent with the termination clauses in the contracts as at December 31, 2015.

GEC Interrogatory #2

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:

Please provide illustrative examples for the portion of each part of the DRP budget that is avoidable if the project is cancelled or curtailed at various stages. Please break this out to indicate the portion avoidable that falls within the amounts included in the current application. Please ensure that one scenario provided indicates what financial commitments would be avoidable if the project was cancelled today and what proportion of those avoidable commitments are included in the approvals sought in this case.

Response

OPG began refurbishment of Unit 2 on October 15, 2016 and has no plans to cancel or curtail the refurbishment at this stage or at future stages. OPG is unable to provide the requested illustrative examples. Any attempt to do so would be speculative, as it would be entirely dependent on assumptions that have no basis in fact. If OPG were to cancel or curtail DRP during the period covered by this application, OPG would inform the OEB and seek direction.

If the DRP were to be cancelled, the costs incurred to the date of cancellation, including accruals for work completed but not invoiced, would not be avoidable. Additionally, certain costs related to procurement commitments and demobilization costs, including costs to place the work in a safe state would not be avoidable.

The project spend to August 2016 was $2.6B (L-4.3-6 EP-18, Attachment 1, p. 2). In addition, as of September 30, 2016, accruals and commitments related to DRP were estimated at $478M (see L-4.3-13 PWU-8).

UNDERTAKING JT1.17
ATTACHMENT D

Undertaking

ED INTERROGATORY #7
This interrogatory requested OPG's estimate of the probability that the unit 2 refurbishment will exceed its budget of $4,800.2 M. OPG stated that "OPG does not estimate the probability associated with in-service additions. In-service additions are not analogous to cost estimates." However, OPG indicated in ED interrogatory #1 that the probability of the total refurbishment process exceeding its estimate to be 10%.

OPG has not indicated an impediment to estimating the probability of the unit 2 refurbishment costs exceeding the cost estimate for that unit. Please provide the cost estimate for the unit 2 refurbishment, including interest, escalation, and contingency (if it is different than the in-service addition amount of $4,800.2M). Please provide an estimate of the probability that the actual cost will exceed that estimate.

Response

Please refer to the following Ex. L-4.3-1 Staff-55, Attachment 1, p.13 which shows the Unit 2 refurbishment cost estimate (excluding Definition Phase costs to be placed in-service with Unit 2) of $3.4B, consistent with the Unit 2 Execution Estimate. As the Unit 2 cost estimate is a part of the $12.8B 4-unit estimate and the contingency was calculated on an integrated 4-unit basis, OPG estimates the probability that the actual Unit 2 cost will exceed that estimate to be 10%.

The following chart provides a reconciliation of the Unit 2 refurbishment execution cost estimate with the costs to be placed in-service with Unit 2.

Total I/S Amount	**$4.8 B**
Unit 2 EE Remaining Contingency	$0.7B
Unit 2 EE Costs to completion excluding Contingency	$2.4B
Unit 2 EE Life-to-Date Actual Costs thru June 2016 (Unit 2 Execution Estimate)	$1.7B

UNDERTAKING JT1.19

Undertaking

FOR D2, 28, ATTACHMENT NUMBER 1, PAGE 29, TO PROVIDE A UNIT BREAKOUT OF THE CUMULATIVE SPEND

Response

Life-to-date costs to September 2016 are $2,900 million. The unit breakout is as follows:

Unit/Category	LTD Cost ($M)	Comments
Unit 2	1,881	Includes Definition Phase costs
Unit 3	26	Primarily Engineering for the T/G controls
Unit 1	0	
Unit 4	0	
Early In Service Projects	972	Including FIP/SIO
Project OM&A	20	
Total Life-to-Date	**2,900**	**To September 2016**

Board Staff Interrogatory #113

Issue Number: 6.4
Issue: Is the test period Operations, Maintenance and Administration budget for the Darlington Refurbishment Program appropriate?

Interrogatory

Reference:
Ref: Exh F2-7-1, pages 1 and 2

	2013 Budget	2013 Actual	2014 Approved	2014 Actual	2015 Approved	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
DRP	10	4.6	4.3	4.3	9	1.4	1	41.5	13.8	3.5	48.4	19.7
F&IP	8.2	1.7	2.3	2	9.3	0.1	0.3	0	0	0	0	0
Total	18.2	6.3	6.6	6.3	18.2	1.6	1.3	41.5	13.8	3.5	48.4	19.7

=$128.2

The above table shows the approved and actual OM&A for DRP for 2014 and 2015 and the forecasted OM&A for 2016 to 2021.

a) Given the capitalization criteria at Exh D4-1-1, please explain why these costs are not capitalized

b) OPG explains the variance between the 2015 approved and actual as primarily due to reclassification of expenses to Nuclear Operations. Was the DRP budget adjusted for these reclassifications?

c) OPG states that in 2017, $24.7M is related to Retube and Feeder Replacements for Unit 2 and in 2020, $30.3 M is related to Retube and Feeder Replacements for Unit 3. Please explain why the OM&A costs for Unit 3 are greater than Unit 2.

Response

a) Approximately 90% of the 2017-2021 forecast OM&A costs referenced in the question relate to removal costs. Exhibit D4-1-1, p. 2, line 2, notes that OPG charges removal costs for existing assets to OM&A as incurred. This approach remains unchanged from previous proceedings (for example, see EB-2013-0321, Ex. D4-1-1, p. 2, line 3, and EB-2013-0321 Ex. L6.11-1 Staff-141, p. 2, lines 12-17).

   OPG charges removal costs to OM&A in accordance with US GAAP.

b) The approved Release Quality Estimate baseline does not include costs that were reclassified.

c) Removal costs for Unit 3 are higher than for Unit 2 due to cost escalation and radiation protection costs.

AMPCO Interrogatory #105

Issue Number: 4.5
Issue: Are the proposed test period in-service additions for the Darlington Refurbishment Program appropriate?

Interrogatory

Reference:
Ref: D2-2-10 Page 9

Preamble: OPG indicates that it has reviewed the cost classification of DRP projects that resulted in reclassification of certain projects from DRP to the Nuclear Operations Portfolio and certain OM&A costs to Nuclear Operations.

a) Please discuss the criteria OPG used to classify projects within and outside of the DRP.

b) How has the reclassification analysis of DRP projects changed since EB-2013-0321?

c) By year, please provide a complete reconciliation of all of the DRP reclassified costs (capital and OM&A) including a description of the costs and where they have been reclassified to.

Response

a) Key principles included in the review include:

- The scope of the Darlington Refurbishment Program (DRP) is bounded and limited to the replacement of life limiting components, regulatory and safety improvement work, as well as approved balance of plan (BOP) components best performed in a defueled and dewatered state.
- DRP is a major capital project and as such should exclude OM&A work programs, but continue to include removal costs and low and intermediate level waste (L&ILW) waste costs.

Criteria for costs included in the DRP baseline include:

- Direct costs for DRP scope.
- Costs for resources that directly support DRP projects and program deliverables.
- Incremental facilities and infrastructure required to enable DRP to complete its approved scope.
- Pre-requisite activities if directly related to scope in the DRP execution window.

Criteria for costs excluded from the DRP cost baseline include:

- Costs of activities including operations, maintenance and engineering activities that will continue through the DRP outage period and would be performed even if the DRP project did not occur.
- Incremental costs by corporate or nuclear organizations that do not directly support DRP project and program deliverables.
- Maintaining Darlington's work force capabilities including training costs.
- Facilities and work programs funded by Nuclear Liabilities Waste Provision.

b) In support of the RQE process, Finance conducted an assessment of the RQE cost elements to ensure consistency with OPG's financial policies and governance in establishing the DRP cost baseline.

c) See Chart 1 below. Project costs were reclassified to the Nuclear Operations project portfolio as described in Ex. D2-2-10 p. 9. OM&A costs that were assessed not to be part of DRP were those identified consistent with the criteria for costs not included in DRP listed in part a) above. These costs form part of Darlington OM&A.

Chart 1

	2015 LTD	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**
OM&A	12	32	62	48	44	54	63	73	70	49	27	0	533
Capital	200	20	31	15	12	14	35	-	-	-	-	-	327

=$860

PWU Interrogatory #4

Issue Number: 4.2
Issue: Are the proposed nuclear capital expenditures and/or financial commitments (excluding those for the Darlington Refurbishment Program) reasonable?

Interrogatory

Reference:
Ref (a): Exhibit D2-1-3, Page 5 of 19, Lines 18-22:

> Project #73706 Darlington Highway 401 and Holt Road Interchange: This project is to improve traffic flow and capacity at the Holt Road interchange by replacing the existing partial interchange with a new interchange with additional access points. This project is cost-shared with the Ministry of Transport with OPG's share of the project cost being $28.6M. Planned final in-service is December 2016.

a) What is the Ministry of Transportation's share of the project cost?

b) How was the Ministry of Transportation's share determined?

c) Does OPG still expect the project to be completed by December 2016?

Response

a) The Ministry of Transportation's share of the total project cost is $9.5M.

b) The Holt Road interchange work was originally planned by the Ministry of Transportation (MTO) to occur after the completion of the Darlington Refurbishment project. Earlier completion date was negotiated by OPG to improve the traffic flow in and out of the site as well as minimize the impact of this increased traffic on Highway 401 and the surrounding local roads. As such, the MTO agreed to pay for some portions of the project that supported OPG's needs and the full cost of changes that primarily support the 401-407 interconnection to be constructed west of Holt Road.

   The Ministry paid the following portions of the project:

   i. 64% of cost of clearing the site in advance of construction
   ii. 14% of cost of Highway 401 modifications
   iii. 8% of electrical relocations
   iv. 34% of construction administration, utilities and other overheads

   The Ministry paid the full amount of the following changes:

   i. Relocation of the Waterfront Trail

ii. South Service Road west of Holt Road
iii. Solina Road
iv. Park Road

c) The project was declared complete by the Ministry in August, 2016.

UNDERTAKING JT1.25

Undertaking

TO SPLIT OUT THOSE PROJECTS AGAINST THE FOUR CRITERIA THAT ARE ON PAGE 2 AS WELL AS THOSE ON PAGE 1 OF L-04.3-2 AMPCO 105.

Response

In response to Ex. L-04.3-2 AMPCO-105, OPG provided a list of criteria used to help establish whether a cost was to be included or excluded from the DRP cost baseline. The criteria are reproduced below:

1. Include: Direct cost of major bundle scope (vendor cost)
2. Include: Cost of resources (OPG cost) that directly support DRP project/program deliverables
3. Include: Incremental facilities and infrastructure required to enable DRP to complete its approved scope
4. Include: Pre-requisite activities if directly related to scope in the DRP execution window
5. Exclude Costs of OM&A activities that will continue through the DRP outage and would be performed even if the DRP project did not occur
6. Exclude: Incremental costs incurred by corporate/nuclear groups that do not directly support DRP project/program deliverables
7. Exclude: Costs of maintaining workforce capabilities, including training costs
8. Exclude: Facilities and programs funded by the Nuclear Liabilities Waste Provision

Additional criteria were established for emergent work:

a) If the work was required for continued operations of 1st life, then not DRP
b) Resulting scope from inspections funded by DRP are DRP scope
c) Resulting scope from inspections funded through operations OM&A are project portfolio scope

Mapping of Excluded Costs to the Above Criteria:

Capital

- Operations Support Building Refurbishment – Not #3 or #4, therefore, excluded from DRP
- Darlington Auxiliary Heating System – Not #3 or #4, therefore, excluded from DRP
- Emergency Service Water Pipe and Component Replacement – Not #3 or #4, therefore, excluded from DRP
- Primary Heat Transport Pump Motor Replacement/Overhaul – (a)
- Highway 401 and Holt Road Interchange – (a)

Exhibit L-04.3-1 Staff-071 part c) provides a detailed explanation for the above 5 projects

OM&A

- Unit Maintenance/Operations - #5
- Contracted Maintenance Programs - #5

- Engineering Systems Surveillance Activities - #5
- Operator Training Program - #7

Project #80078 Darlington Digital Control, Common Process and Sequence of Events Monitoring Computer Aging Management: This project is to replace certain components of Darlington digital control, common process and sequence of event computers. Most of the obsolete computer components were custom designed for Darlington, using 1980s technology, which can no longer be supported. The replacement of the majority of these computer components is a regulatory commitment, and is necessary to preserve system configuration and functionality and maintain capability of interfacing with existing computer equipment prior to, during and post refurbishment. The total project cost is $47.3M (plus additional inventory of spares of $9.1M) with an iniital partial release of $1.7M. Planned final in-service is June 2025.

Project #80111 Darlington Generator Stator Core Spare: This project is to purchase a generator stator core as a spare. Darlington's existing generator stator cores are showing signs of degradation and are not expected to reach end of the post-refurbishment period without major failure or a significant maintenance/refurbishment. OPG does not currently have a spare and in the event of a catastrophic failure of the unit, OPG would be at risk of a forced outage of up to two years duration. Purchasing a spare generator stator core will allow OPG to swap it with an existing stator core for replacement/refurbishment. The total project cost is $35.0 with a full release of $35.0M. Planned final in-service is July 2019.

Project # 82816 Darlington Vault Cooling Coil Replacement: This project is to reduce risk to Darlington operations by replacing life expired vault cooling coils. Vault cooling coils provide cooling to the reactor vault under operating conditions and remove heat under a loss of coolant accident condition. The total project cost is $26.3M with an partial release of $11.9M. Planned final in-service is September 2020.

#73566/80144 Darlington Primary Heat Transport Pump Motor Replacement/Overhaul: This project is to replace/refurbish the sixteen primary heat transport ("PHT") pump motors and spare at Darlington, which are approaching the end of their service lives. Primary heat transport pump motors are 100 per cent duty with no installed redundancy. Failure of any one of the operating motors (there are four PHT motors per unit) will result in a forced outage and could result in an extended outage depending on availability of spare motors. In June 2015, OPG experienced an unbudgeted planned outage of 25.75 days (lost production of 0.54 TWh) to replace one PHT pump motor, which was showing high levels of degradation. Additionally, there was a forced outage in December 2015 due to a PHT pump motor mechanical failure. Current condition assessments indicate a medium to very high risk of failure on the remaining PHT pump motors and priority will be given to replacing those motors with the highest risk of failure. The total project cost is $129.5M with a partial release of $53.8M. Planned final in-service is December 2022.

Project #40976 Pickering B Fuel Handling Reliability Modifications: This project is to replace life-expired mechanical and control components and install modifications to improve the reliability of the Pickering B fuel handling systems. Problems with the fuel handling systems have resulted in forced generation losses. This project will help OPG achieve its forced loss rate targets in the test period. The total project cost is $37.3M with an execution phase release of $30.9M. Planned final in-service is July 2017.

Projects #41023 and #49247 Pickering Unit 1 & 4 Fuel Channel East Pressure Tube Shift/Reconfigure: This project is to develop tooling for the repositioning and reconfiguration of the fuel channel assemblies in Pickering Units 1 and 4. The pressure tubes, under the influence of the neutron flux as well as pressure and temperature, elongate over time. The pressure tubes are fixed at one end and are allowed to grow out at the other end. To ensure that the end fittings stay on their bearings, the fuel channels have to be repositioned or reconfigured. The total cost is $38.6M which consists of a full release for execution of $28.8M, with a superceding release for an additional $9.8M to authorize the change in scope, from repositioning the majority of fuel channels to reconfiguring all fuel channels, in Units 1 and 4. The planned final in-service is March 2016.

Project #41027 Pickering Fukushima Phase 2 Beyond Design Basis Event Emergency Mitigation Equipment: This project is to provide portable equipment and install modifications to manage water and protect containment long term following a beyond design basis event. This project is required to meet Canadian Nuclear Safety Commission (“CNSC”)

The high confidence schedule, as shown in Table 4, includes contingency for certain schedule risks that may be encountered during the execution of the refurbishment outages, and will form the basis of program controlled schedule contingency. This schedule will also be the basis for external communication and measurement. The high confidence duration for each unit is 37 to 40 months.

Table 4: Refurbishment 4-Unit HIGH Confidence Project Schedule

Unit	Start[1]	Finish	Duration (Months)	Month when Unit Reaches 235,000 EFPH
Unit 2	15-Oct-16	15-Feb-20	40	Feb-22
Unit 3	15-Dec-19	15-Apr-23	40	Dec-22
Unit 1	15-Apr-21	15-Jun-24	38	Sep-22
Unit 4	15-Jan-23	15-Feb-26	37	Sep-23
4 Units	**15-Oct-16**	**15-Feb-26**	**112**	

(1) Based on early start date, aligned with the Medium Confidence schedule duration and logic.

Based on the current high confidence that each of the 4 units will operate to 235,000 Effective Full Power Hours (EFPH), this schedule results in no idle time on operating units.

Management recommends approval of the 4-unit high confidence schedule with a total duration of 40 months for Unit 2 and 112 months for all 4 units.

3. OPG is ready to transition to the Execution Phase and commence Unit 2 mobilization activities.

With the Board's approval to proceed to the Execution Phase of the project, Management is expecting to spend $1,021 Million to October 15, 2016 (Unit 2 Breaker Open) for continued construction of the remaining Facility & Infrastructure and Safety Improvement projects and to commence Unit 2 mobilization, training, and installation of in-station support facilities. The release also includes some funding to commence long lead procurement for Unit 3 turbine control system and stator and Re-tube and Feeder Replacement engineering for subsequent units.

As of November 2014, $2,548 Million was released to the project with a forecast to spend $2,207 Million by the end of the Definition Phase. Incremental funding of $681 Million is required to complete these activities. A breakdown of the funding request is included in Appendix 6.

In August 2016, OPG will return to the Board with a request for funding to complete the refurbishment of Unit 2, commencing October 2016. Management will provide regular progress updates to the Board.

Management recommends approval for the project team to transition from the Definition Phase to the Execution Phase including a release of funds in the amount of $681 Million for mobilization activities for the first unit, to October 2016.

Board Staff Interrogatory #28

Issue Number: 4.2
Issue: Are the proposed nuclear capital expenditures and/or financial commitments (excluding those for the Darlington Refurbishment Program) reasonable?

Interrogatory

Reference:
Ref: Exh D2-1-3, Attachment 1, Tab 20

The BCS for the Darlington Powerhouse Water Air Cooler Units Replacements project states that a full release BCS is expected to be approved with a target date of April 2016, following completion of detailed engineering for all units and procurement of all materials under the current BCS. The BCS also states that OPG Project Management and Engineering costs will be significantly higher than previously estimated.

a) Please provide an update on the project schedule and cost including whether the full release BCS has been approved as planned.

b) Please explain the underlying basis for the higher OPG Project Management and Engineering costs relative to the EPC contractor's work scope and responsibilities.

Response

a) A partial execution BCS was approved in September 2016 (see Attachment 1 which contains confidential information as marked). The updated total project cost is $26.6M. The increase is mainly due to equipment, engineering and construction cost increases. The cost of Air Cooling Units (ACUs), based on costs obtained from competitive bids, is higher than the original estimate. Engineering and construction costs are higher, due to the addition of mist eliminators and required relocation of some ACUs and interfering services. The target in-service date has changed from December 2019 to January 2023, as a result of the delay encountered in issuing the equipment purchase order, and delays in completing detailed engineering. The project schedule was re-evaluated and associated dates have been reflected in the latest BCS.

b) Based on experience from similar projects, OPG project oversight and cost has increased to support the resolution of construction issues. In the latest BCS, OPG Project Management and Engineering costs were reviewed and adjusted to reflect actual experience to-date on this project.

UNDERTAKING JT1.17
ATTACHMENT K

Undertaking

ED INTERROGATORY #13

OPG has not provided an estimate of the probability that some or all of the steam generators will need to be replaced; nor has it provided its best estimate of the cost of replacing them. The fact that OPG believes that the generators will operate reliably does not mean that there is *no* probability that it will turn out that they will need to be replaced. Nor does it mean that the question is irrelevant or need not be answer. Please provide the information requested in this interrogatory.

Response

OPG declines to respond to this request on the basis of relevance. As OPG has determined not to include steam generator replacement within the scope of the DRP and is not seeking funding in this application to replace the steam generators, the information is not relevant to the issues before the OEB. In any event, OPG has already provided a full response to ED 13 in Ex. L-4.3-7 ED-13. This response incorporates by reference the responsive material in that OPG had previously provided in EB-2010-0008.

Chart 4

OPG Proposed Deferred Nuclear Revenue Requirement[17]

	2017	2018	2019	2020	2021
Proposed Revenue Requirement ($M)	$ 3,190	$ 3,250	$ 3,285	$ 3,775	$ 3,489
Forecast Production (TWh)	38.10	38.47	39.03	37.36	35.38
Smoothed Rate ($/MWh)	$ 65.81	$ 73.05	$ 81.09	$ 90.01	$ 99.91
Smoothed Revenue ($M)	$ 2,507	$ 2,810	$ 3,165	$ 3,362	$ 3,535
Deferred Revenue Requirement ($M)	$ 683	$ 440	$ 121	$ 413	$ (46)
Non-Smoothed Rate	$83.73	$83.27	$84.16	$101.04	$98.61

Chart 4 from Exhibit A1, Tab 3, Schedule 3, Page 10 of 14

Non-Smoother Rate = Proposed Rev. Req./Forecast Prod.

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.

This Regulation is made in English only.

Definition

0.1 (1) In this Regulation,

"approved reference plan" means a reference plan, as defined in the Ontario Nuclear Funds Agreement, that has been approved by Her Majesty the Queen in right of Ontario in accordance with that agreement;

"Darlington Refurbishment Project" means the work undertaken by Ontario Power Generation Inc. in respect of the refurbishment, in whole or in part, of some or all of the generating units of the Darlington Nuclear Generating Station;

"deferral period" means the period beginning on January 1, 2017, and ending when the Darlington Refurbishment Project ends;

"nuclear decommissioning liability" means the liability of Ontario Power Generation Inc. for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel;

"nuclear facilities" means the nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2;

"Ontario Nuclear Funds Agreement" means the agreement entered into as of April 1, 1999 by Her Majesty the Queen in right of Ontario, Ontario Power Generation Inc. and certain subsidiaries of Ontario Power Generation Inc., including any amendments to the agreement. O. Reg. 23/07, s. 1; O. Reg. 353/15, s. 1.

(2) For the purposes of this Regulation, the output of a generation facility shall be measured at the facility's delivery points, as determined in accordance with the market rules. O. Reg. 312/13. s. 1.

Prescribed generator

1. Ontario Power Generation Inc. is prescribed as a generator for the purposes of section 78.1 of the Act. O. Reg. 53/05, s. 1.

Prescribed generation facilities

2. The following generation facilities of Ontario Power Generation Inc. are prescribed for the purposes of section 78.1 of the Act:

1. The following hydroelectric generating stations located in The Regional Municipality of Niagara:
    i. Sir Adam Beck I.
    ii. Sir Adam Beck II.
    iii. Sir Adam Beck Pump Generating Station.
    iv. De Cew Falls I.
    v. De Cew Falls II.
2. The R. H. Saunders hydroelectric generating station on the St. Lawrence River.
3. Pickering A Nuclear Generating Station.
4. Pickering B Nuclear Generating Station.
5. Darlington Nuclear Generating Station.

period (i.e., approximately $120/MWh), and an estimated average monthly customer bill impact over the full deferral and recovery periods.

Chart 3

Smoothing Alternatives – Outcomes

2017 - 2021 Rate Increase	12.0%	11.0%	10.0%	9.0%	8.0%
2022- 2026 Rate Increase	12.0%	11.0%	10.0%	9.0%	8.0%
2027 - 2035 Rate Increase	(6.4)%	(3.4)%	(0.3)%	2.6%	5.4%
Peak Account Balance ($B)	$2.4	$3.5	$5.0	$6.9	$9.5
2017 - 2036 Total Interest ($B)	$0.7	$1.6	$3.0	$4.5	$5.9
Interest Cost / Deferred Revenues Ratio	0.2	0.5	0.8	0.9	0.9
	3.7 / 6.3	3.6 / 5.3	3.5 / 4.5	3.5 / 3.9	3.4 / 3.3
DEBT to EBITA < = 5.5* (2017-2021) / (2022-2026)	6.1 / 5.1	6.2 / 5.3	6.3 / 5.5	6.3 / 5.7	6.4 / 6.0
Transition Impact: 2037 Rate Change ($/MWh / %)	$26/MWh / 27%	$2/MWh / 2%	$(28)/MWh / (19%)	$(60)/MWh / (33%)	$(95)/MWh / (44%)
Average Bill Impact: 2017-2036 (%)	0.2%	0.3%	0.4%	0.6%	0.8%
Average Bill Impact: 2017-2036 ($ / month)	$0.24	$0.42	$0.65	$0.90	$1.16

*Weakest Ratio

2.5 Application of the Criteria and OPG's Proposal

Based on its assessment of the alternatives above, using the considerations described in section 2.3, OPG proposes an 11 per cent annual nuclear base rate increase for the 2017 to 2021 period. A discussion of the rationale OPG applied to evaluate each option for each of the assessment considerations[16] is provided below.

[16] Rate Stability is not included as a specific consideration for assessing the relative merits of the five alternatives as all five alternatives reflect a constant rate change each year in both the deferral and recovery periods.

EP Interrogatory #14

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Exhibit D2-2-8, Attachment 1, page 16

Does the Levelized Unit Energy Cost (LUEC) include the cost of interest that will be owed due to rate smoothing and deferral? If not, Can OPG calculate what they will add to the LEUC estimate?

Response

The question makes an assumption that the LUEC would be influenced by decisions on OPG's approach to cost recovery through rates. Rates and LUECs are not the same (see below). The deferral of revenue recovery through rate smoothing, which is what generates the interest costs, does not affect the LUEC calculation. Therefore, OPG cannot calculate what amount the inclusion of interest costs associated with rate smoothing would add to the LUEC.

LUEC is an economic measure used to compare the relative economics of alternative generation options. The calculation of the LUEC utilizes present value techniques to ensure full recovery of all investment, operating and post-operation costs (e.g., decommissioning) over the operating life of the option.

While LUEC can provide an indication of the long-term rate of a generation option over the life of that option required to fully recover the costs of that option, it is not the electricity rate. Because LUEC is "levelized", it is one constant number (usually expressed in a particular year's dollars). LUEC escalates at the rate of inflation.

Annual rates reflect annual specifics such as: (1) fluctuations in generation by year; (2) fluctuations in operating costs by year (e.g., costs are higher in years with vacuum building outages); (3) in-service amounts added to the rate base. These impacts are all "smoothed out" in a LUEC calculation, which represents an average over a full life cycle period.