ONTARIOPOWER GENERATION

EB-2016-0152

OEB Application

for

Payment Amounts for OPG's Prescribed Facilities

Argument-in-Chief

Ontario Power Generation Inc.

May 3, 2017

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1.0 OVERVIEW

By any measure, this is a significant Application. It includes review of the Darlington Refurbishment Program ("DRP" or the "Program"), the single largest capital project ever to come before the OEB, and requests approval of some $5,177.4M of DRP-related in-service additions. It requests funding to extend Pickering's operation. It introduces new ratemaking methodologies for both the nuclear and hydroelectric payment amounts. It covers five years.

In the course of this Application, OPG filed thousands of pages of evidence supported by dozens of company witnesses. It responded to more than a thousand interrogatories and undertakings. Numerous benchmarking reports were filed covering nuclear performance, compensation and benefits, corporate costs and hydroelectric costs. In certain key areas, OPG sponsored the testimony of expert witnesses. All this material was provided in aid of explaining what is a complex business.

OPG is the only generator regulated by the OEB. It is a large generating company producing over half the energy generated in Ontario. It operates two nuclear facilities that differ in size, number of units and vintage of CANDU technology employed. It has extensive regulated hydroelectric facilities that range from the very large and complex generation at Niagara Falls to much smaller facilities on rivers across the Province. The diversity of technology, the numerous facilities of different sizes and vintages, the geographic dispersion and the shear scope of OPG, all contribute to making it a complicated entity to operate and to regulate.

In this Application, as in past filings, OPG has tried to present a large volume of information in an organized and understandable way. But these efforts cannot make simple what is inherently complex. Even without the DRP, OPG is unique among Ontario regulated companies, electric or natural gas, in terms of scope, scale and complexity.

In recognition of these inherent differences, OPG respectfully requests that the OEB evaluate the evidence and decide the issues in this proceeding based on the size, nature and complexity of OPG's business and develop regulatory approaches that fit OPG.

The Application presents a number of issues not previously addressed in the context of an OPG proceeding, including:

- Substantial capital funding for refurbishing Darlington Unit 2 and other aspects of the DRP that will enable the plant to operate safely and reliably for an additional 30 years;
- Costs to extend the operating life of Pickering to 2022/24;
- Two new ratemaking approaches: a price-cap incentive rate-setting methodology ("IRM") for OPG's hydroelectric prescribed facilities, and custom incentive rate-setting ("Custom IR") for OPG's Nuclear business;
- A five-year term (2017-2021) ("IR term");
- A mid-term nuclear production review; and
- Rate smoothing for the nuclear payment amounts as required by amendments to O. Reg. 53/05.

Beyond the new issues listed above, the Application includes all the key elements addressed in establishing OPG's nuclear payment amounts in prior proceedings. These include:

- Nuclear and allocated Corporate Support Operations, Maintenance and Administration ("OM&A") costs;
- Benchmarking of nuclear performance and staffing;
- Compensation;
- Nuclear production forecast;
- Nuclear and Corporate Support capital expenditures and rate base; and
- Nuclear liabilities.

The Application also addresses some issues common to both nuclear and hydroelectric prescribed facilities such as capital structure, cost of capital, deferral and variance accounts, and the effective date for the payment amounts. As noted in the applicable sections that follow, some issues have been settled or partially settled.

While the lists above are not exhaustive, they provide a sense of the scope of this proceeding and highlight how many important issues are being addressed in an OPG proceeding for the first time. In the remainder of this Overview, OPG summarizes the major issues in the Application. Detailed submissions on all unsettled issues follow in the subsequent sections.

The Darlington Refurbishment Project

The DRP will refurbish all four Darlington units over the span of almost 10 years at a cost of $12.8B. This is a destiny project; the company's future depends on its successful execution, which means returning the units to service safely, on time, on budget, and with the requisite quality to support safe, reliable operation to 2055. It is a "mega-program" in scope and complexity, which are both increased by the need to refurbish each unit while other units continue to operate. The material that follows describes how OPG has taken all reasonable steps to ensure the program's success.

The refurbishment of Darlington Unit 2 began in October 2016, with “breaker open” whereby the unit was electrically separated from the grid. This event was the culmination of 10 years spent planning, preparing and assembling the internal and external resources necessary to provide the DRP with the best possible chance for successful execution. During this 10-year period, OPG:

- Evaluated DRP’s feasibility;
- Identified program risks and mitigation measures and established appropriate contingency;
- Developed and refined the project’s scope and cost;
- Produced a detailed schedule for completing the approved scope;
- Formulated contracting strategies and executed all of the major contracts pursuant to those strategies;
- Created DRP-specific tools and constructed a reactor face mock-up to test the tools and train the workforce;
- Completed design engineering for all Unit 2 scope; and
- Produced a Release Quality Estimate (“RQE”) to support project approval by both OPG’s Board of Directors and the Ministry of Energy.

As confirmed by the testimony of the independent experts who evaluated these efforts, OPG met best in class industry standards for planning and implementing mega-projects and included a reasonable level of contingency in the cost and schedule estimates for the DRP.

To execute the DRP on time, on budget and with the necessary quality, OPG contracted for the major work packages that comprise the program. These contracts appropriately allocate risk between OPG and the contractors and include incentives to drive the behaviours and outcomes needed for successful execution. OPG has also established a project management structure to administer the contracts, assure appropriate project oversight and provide timely resolution of any issues that may arise. Given that OPG retains ultimate accountability for the successful execution of the DRP, active and engaged oversight on all aspects of the project by the DRP management team is critically important. Additional oversight is provided by OPG's CEO, its Board of Directors, the Ministry of Energy, and the experts they have retained.

The costs and schedule that underpin OPG's requests in this Application were derived from the RQE, which is a high confidence estimate of the full DRP. It includes the costs of the prerequisite projects for refurbishment as well as the costs of Unit 2 Refurbishment. OPG has provided extensive evidence supporting the reasonableness of its proposed spending for DRP and the resulting forecast costs and additions to rate base. Based on this information, as discussed in Section 5.3, OPG respectfully requests that the OEB determine that proposed OM&A expenditures for DRP are reasonable and approve nuclear revenue requirements based on in-service additions of $4,800.2M for Unit 2 in 2020 and 2021 and $377.2M for other DRP-related projects for 2016 and throughout the IR term.

Other New Issues

OPG seeks approval of the costs necessary to extend the operation of Pickering so that two units would close at the end of 2022 and the remaining four units would close at the end of 2024 ("Pickering Extended Operations"). Work undertaken to date on the technical feasibility of this plan has provided OPG with increasing confidence that the planned operation is achievable and that the Canadian Nuclear Safety Commission ("CNSC") will approve the proposed shut down dates. In support of Pickering Extended Operations, OPG submitted two analyses by the Independent Electricity System Operator ("IESO"), which concluded that the proposed extension is beneficial to the electricity system. In oral testimony, the IESO continued to support this conclusion and emphasized the benefits of having Pickering available given the changes anticipated in Ontario's generation resources over the next decade. As the evidence demonstrates that Pickering can operate cost-effectively over the IR term and will provide value to customers, OPG requests that the OEB approve the requested funding in determining the nuclear payment amounts.

OPG is proposing to develop hydroelectric payment amounts for the IR term based on a price-cap index that incorporates the elements and approach in the Fourth Generation IR methodology ("4GIRM") and uses the hydroelectric payment amounts approved in EB-2013-0321 as a starting point. OPG has developed an inflation factor that is based on the 4GIRM indices, appropriately weighted by the capital and non-capital costs of the hydroelectric generation industry. Based on a Total Factor Productivity ("TFP") study of North American hydroelectric generation by London Economics International LLC ("LEI"), which found a negative TFP value, OPG is proposing to set the IRM formula's productivity factor at zero, consistent with prior OEB determinations for electricity distributors. Finally, OPG is proposing a stretch factor that uses the 4GIRM methodology and incorporates the relative performance of OPG's hydroelectric facilities as determined through benchmarking conducted by Navigant Consulting.

OPG is proposing a Custom IR framework for the company's nuclear facilities that is consistent with OEB policy, recognizes that both Darlington and Pickering are undergoing significant changes during the IR term and supports the continued safe and reliable operation of these facilities. OPG's Custom IR proposal adds a stretch factor which will reduce the cost of nuclear base OM&A and Corporate Support OM&A below the amounts proposed in the Application. The cumulative reductions produced by the stretch factor mean that over the IR term OPG is committing to provide customers with over $50M in up-front cost reductions, whether or not the company is able to achieve these savings.

OPG's Application proposes to set both hydroelectric and nuclear payment amounts for five years. All previous payment amounts applications covered two years. Moving from a two-year to a five-year term will increase risk. The hydroelectric facilities will continue to face challenges associated with aging facilities and workforce demographics during the five-year IR term, which OPG will need to manage within the proposed price-cap IRM. Recognizing the particular uncertainty regarding nuclear production over the IR term, in light of DRP and the work to enable Pickering Extended Operations, OPG is proposing to file a mid-term nuclear production review to address the nuclear production forecast and associated fuel cost for the period July 1, 2019 to December 31, 2021 (the "Mid-term Production Review"). The impacts of changes adopted in the Mid-term Production Review would be addressed through the Mid-term Nuclear Production Variance Account.

OPG has proposed an approach for smoothing the company's nuclear payment amounts in accordance with the requirements of O. Reg. 53/05, as amended on March 2, 2017. Under this proposal, the OEB would defer recovery of approximately $1B of the approved 2017-2021 nuclear revenue requirement. The deferred amounts would be recovered over a period of up to 10 years following the DRP. The proposed deferral will limit the year-over-year increases in OPG's weighted average payment amounts ("WAPA") during the IR term to 2.5%. OPG's proposal reflects a reasonable balance among the following considerations: rate stability, OPG financial viability, intergenerational equity, transition impacts after the recovery period, and overall cost to customers.

Nuclear Payment Amount Issues

OPG's forecast nuclear OM&A costs constitute the expenditures necessary to safely, reliably and efficiently operate and maintain the Darlington and Pickering stations over the IR term. Nuclear OM&A costs are relatively flat over the five-year IR term and show an overall decline by the last year. Corporate services such as information technology, finance and human resources support the Nuclear business with the directly assigned and allocated portion of these costs forming part of the nuclear revenue requirement. These costs continue to be determined using the cost allocation methodology approved in EB-2013-0321 and are relatively flat over the IR term.

OPG's Nuclear business continues to rely on benchmarking and gap-based nuclear business planning. Benchmarking provides useful insights into relative cost and performance, but OPG believes it is not a precise tool because of the inherent technological and regulatory differences between OPG and the comparators and the aggregate nature of the data used in benchmarking.

As the OEB directed in the last proceeding, OPG produced and filed annual nuclear benchmarking reports using the methodology developed by ScottMadden. This benchmarking demonstrates strong safety performance, but shows a decline in overall reliability and cost performance due primarily to the need for increased capital investment and production declines at Darlington as the station reaches the end of its initial life and moves into refurbishment. Based on the Goodnight staffing benchmarking study filed in the last application, OPG used the Goodnight approach to develop updated staffing benchmarking information in this proceeding. This information shows that OPG's 2016 staffing level was below the 2014 Goodnight staffing benchmark.

Compensation and benefits cost for OPG's regulated facilities are equivalent to almost 50% of OPG's forecast 2017 nuclear revenue requirement, reflecting the vital role OPG employees play in producing electricity for Ontario. This Application demonstrates that OPG has made notable progress in addressing the compensation and pension issues identified in previous proceedings. As discussed in detail in Section 7.7.5, benchmarking shows that OPG's total compensation, not including pension and benefits, is "at market." OPG has also negotiated (for represented employees) or implemented (for management employees) increased employee pension contributions and changes in retirement eligibility. Pending the outcome of the OEB's generic proceeding on pension and post-employment benefits costs, OPG has proposed continuing the treatment of these issues adopted in EB-2013-0321 and used cash amounts in establishing the forecast revenue requirement.

OPG's nuclear production planning process establishes annual production forecasts for its individual nuclear units, an aggregated forecast for each station and an overall corporate forecast. The nuclear production forecast in this Application represents a challenging forecast during a period of unprecedented change in OPG's nuclear operations due to DRP and Pickering Extended Operations. Despite these changes, OPG has continued to base its production forecast on demanding Forced Loss Rate ("FLR") targets to drive efficiency. OPG remains subject to unanticipated production disruptions due to events such as the unbudgeted planned outage in 2015 to replace primary heat transport pump motors at Darlington. As OPG's revenues are 100%, OPG has experienced significant revenue shortfalls because actual nuclear generation has been less than the production forecasts that underpin the OEB approved nuclear payment amounts.

The nuclear capital projects within OPG's project portfolio are developed to meet regulatory commitments to the CNSC, increase fleet or unit reliability, address obsolescence, or optimize station generation. OPG forecasts a consistent level of nuclear capital expenditures from 2017 through 2020 to replace obsolete and/or life-expired plant equipment at Darlington outside of the DRP and maintain capital investment at Pickering. Capital expenditures are forecast to decline in 2021 as Pickering approaches the end of commercial operations.

OPG's Board of Directors approves the annual nuclear projects portfolio budget and a group of senior executives, the Asset Investment Screening Committee, administers this budget and approves specific project expenditures. Resulting forecasts of in-service amounts over the IR term have been included in OPG's proposed nuclear rate base, which consists of forecast net fixed/intangible in-service assets (including nuclear asset retirement costs or "ARC") and working capital. Nuclear rate base is relatively stable to 2020, when it increases substantially based on the planned return to service of Darlington Unit 2.

In accordance with section 6(2)8 of O. Reg. 53/05, the OEB is required to ensure that OPG recovers the revenue requirement impact of its nuclear waste management and decommissioning liabilities arising from the current approved ONFA reference plan. The proposed revenue requirement in this Application reflects the methodologies that the OEB established for recovery of OPG's nuclear liabilities costs for the prescribed facilities and the Bruce facilities in EB-2007-0905 and has consistently applied in subsequent proceedings. The nuclear liabilities costs in OPG's first Impact Statement (Ex. N1-1-1) reflect the projected accounting impacts of the 2017 Ontario Nuclear Funds Agreement ("ONFA") Reference Plan approved by the Province that reduced the revenue requirement relative to the pre-filed evidence. In addition to these impacts are net ratepayer credits in the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account attributable to changes that occurred after Ex. N1-1-1 was filed and which are explained in Section 9.1.

Common Issues

OPG seeks approval of a deemed capital structure of 49% equity and 51% debt. The proposed capital structure reflects the material increase in OPG's business and financial risks since EB-2013-0321. Both independent experts who evaluated OPG's capital structure agree that these risks have increased materially and the equity percentage should be increased. OPG has applied the proposed capital structure in determining the cost of capital for the nuclear facilities. For the hydroelectric facilities, OPG proposes to establish the Hydroelectric Capital Structure Variance Account to record the revenue requirement impact of the difference between the capital structure approved in this proceeding and the 45% equity and 55% debt capital structure approved in EB-2013-0321, which underpins the proposed hydroelectric payment amounts in this Application.

OPG is proposing a return on equity ("ROE") of 8.78% for the nuclear facilities for 2017. The proposed ROE accords with the latest Cost of Capital Parameters published by the OEB on October 27, 2016. For the subsequent years in the IR term (2018-2021), OPG proposes using the ROE specified annually by the OEB pursuant to the OEB's Cost of Capital Report. OPG proposes to record the revenue requirement impact of the variance between the forecast ROE adopted in this Application and annual ROE that the OEB will specify in future years, in the proposed Nuclear ROE Variance Account. OPG does not propose to update the ROE for the regulated hydroelectric facilities over the IR term because the OEB's IRM policy states that the price cap formula is meant to accommodate changes in ROE.

OPG is seeking approval to retain existing Deferral and Variance ("D&V") Accounts and dispose of their 2015 audited balances, create four new accounts and continue to use the methodologies for recording D&V entries that were approved in prior proceedings. The issue related to the retention of the existing D&V accounts is fully settled. Issues related to the recorded amounts, and the methodologies used to record them have been settled for all existing accounts except the Capacity Refurbishment Variance Account (Nuclear), Nuclear Liability Deferral Account, Bruce Lease Net Revenues Variance Account. Treatment of the Pension & OPEB Cash vs. Accrual Differential Account balances, which OPG does not seek to clear in this Application, is also unsettled. In OPG's submission, the amounts recorded, the methodologies used for recording entries and the balances in the unsettled accounts sought for disposition are appropriate and should be approved. Finally, the proposed new accounts should be authorized because they address circumstances where D&V account treatment is appropriate and satisfy the OEB's eligibility criteria of causation, materiality, and prudence.

Finally, OPG seeks a January 1, 2017 effective date for both the hydroelectric and smoothed nuclear payment amounts. OPG's Application, as filed, complied with the OEB's filing guidelines and previous directions. OPG has worked diligently with all parties and OEB staff to advance the Application in a reasonable and efficient manner while meeting the deadlines established by the OEB's procedural orders.

2.0 GENERAL

2.1 ISSUE 1.1

Secondary: Has OPG responded appropriately to all relevant OEB directions from previous proceedings?

In Ex. A1-11-1, OPG provides a table that identifies the OEB directives from prior proceedings and the exhibit number(s) in this Application where OPG's evidence discusses the responses to the directives. As demonstrated in that table, the referenced exhibits, and the submissions below, OPG has responded to all relevant OEB directions from previous proceedings.

2.2 ISSUE 1.2

Primary: Are OPG's economic and business planning assumptions that impact the nuclear facilities appropriate?

2.2.1 Introduction

The nuclear revenue requirements requested in this Application are based on the forecast costs for the IR term from January 1, 2017 through December 31, 2021 (Ex. A1-3-1), as updated by the First and Second Impact Statements (Ex. N1-1-1 and Ex. N2-1-1).

These forecast costs are based on OPG's 2016-2018 Business Plan, which include financial projections for the 2019-2021 period, developed for all years on the same basis and through a consistent process (Ex. A2-2-1, Attachment 1). This business plan was approved by OPG's Board of Directors in May 2016 and concurred with by the Province (Ex. JT2.1). The 2017-2019 Business Plan that served the basis for OPG's First Impact Statement was similarly developed for the period to 2021 (Ex. N1-1-1, Attachment 1). In OPG's submission, the business plans reflect appropriate economic and planning assumptions, based on OPG's business planning instructions (Ex. A2-2-1, Attachment 2; Ex. L-1.2-1 Staff-103, Attachment 1).

OPG's 2016-2018 Business Plan and 2017-2019 Business Plan reflect the company's focus on the prudent management of costs, achieving safe and reliable operations at the Pickering station through 2024, and successfully executing the DRP, safely, on-schedule and on-budget. The payment amounts and riders resulting from this Application are necessary for OPG to meet its obligation to operate the prescribed assets safely, reliably, and efficiently, for the benefit of the people of Ontario (Ex. A1-3-1), while further challenging and incenting OPG to find additional cost reductions and efficiencies within its operations.

2.2.2 2016-2018 Business Planning and Budgeting

The 2016-2018 Business Plan reflects the significant operational and financial challenges and uncertainties that OPG expects to face during the 2017-2021 period. These challenges include (Ex. A2-2-1, pp. 3-5; Ex. L-1.2-5 CCC-004):

- A high level of DRP-related outages will reduce generation, while the costs of operating the facility remain largely the same;
- Increasing nuclear generation forecast risks associated with the company's aging nuclear plants, DRP, a longer forecast period than prior applications, and the work required to extend operations at the Pickering station; and
- Hiring needs in skilled areas that will need to be addressed during the term of this Application, particularly as workforce demographics continue to result in significant staff attrition, while making appropriate use of other resources (such as overtime, augmented staff and purchased services) to meet work plans and manage total costs (see Section 7.1.2).

The 2016-2018 Business Plan reflects funding and staffing levels aimed at sustaining the performance of the Darlington nuclear generating station and continuing to operate the Pickering nuclear generating station safely and reliably. OPG has eliminated the gap between the company's nuclear staffing and benchmark, as identified by Goodnight Consulting Inc. (Ex. F2-1-1, p. 12), and brought its Total Direct Compensation to market levels (Ex. F4-3-1, p. 18).

OPG's financial priority, as a commercial enterprise, is to consistently achieve a level of financial performance that will ensure its long-term financial sustainability and increase the value of its assets for its Shareholder – the Province of Ontario.

2.2.3 Business Planning Guidelines

The guidelines for OPG's business planning process focus on the company's four key strategic imperatives: (1) Operational Excellence, (2) Project Excellence, (3) Financial Strength, and (4) Social License. Each of the strategic imperatives emphasizes outcomes for OPG's customers – Ontario's electricity consumers (Ex. L-1.2-1 Staff-003 Attachment 1, pp. 3-4):

- The Operational Excellence imperative focuses on the pursuit of business optimization initiatives and seeking out continuous improvement opportunities that aimed at delivering further efficiencies in the company's cost structure.
- The Project Excellence imperative focuses on the need for OPG to deliver projects on-time and on-budget, and specifically on plans to ensure that Darlington operates at industry-leading levels of performance and cost in the post-refurbishment period.
- The Financial Strength imperative drives the company to achieve the outcomes that OPG proposes in its applications to the OEB.
- The Social License imperative reinforces OPG's work to build and maintain partnerships with the people of Ontario, with a corporate culture that focuses on safety, performance excellence, continuous improvement and public trust.

The 2016-2018 Business Plan includes several initiatives intended to drive productivity and continuous improvement during the term of this Application (Ex. A2-2-1, p. 2), including:

- Embedding cost reductions and efficiencies achieved to date in the longer term while identifying and implementing initiatives to further improve OPG's cost structure, without compromising safe and reliable operations;
- Continuing to pursue labour contract negotiations with the objective of facilitating further efficiencies and cost improvements, and supporting the strategy for the end of Pickering commercial operations; and
- Pursuing initiatives to improve operating and financial performance.

OPG's rigorous business planning process will help the company continue to operate the nuclear facilities safely and reliably during 2017-2021. In addition to the challenges described in Section 2.2.2, OPG will be investing increasingly significant amounts of capital in its nuclear facilities, while continuing to respond to evolving public policy, such as the rate smoothing provisions of O. Reg. 53/05. OPG will continue to manage and mitigate these requirements and risks through its nuclear business planning process.

2.3 ISSUE 1.3

Primary: Is the overall increase in nuclear payment amounts including rate riders reasonable given the overall bill impact on customers?

The nuclear payment amounts proposed in this Application are the product of the rate smoothing requirements set out in O. Reg. 53/05, as described in Ex. A1-3-3 and Ex. N3-1-1, and in Section 12.7.

Following the amendments to O. Reg. 53/05 on March 2, 2017, the OEB must determine an amount of nuclear revenue requirement to defer with a view to making the year-over-year changes in OPG's WAPA more stable during the period from 2016 to 2021 (O. Reg. 53/05, s. 6(2)(12)(i)). A more stable WAPA (including riders requested in this Application) will result in more stable bills for customers.

OPG has proposed nuclear deferral amounts that it expects will result in an average year-over-year increase of approximately $0.65 on the typical residential customer's monthly bill over the IR term (Ex. N3-1-1, p. 11). OPG submits that this is a reasonable customer bill impact, given that it will enable the company to proceed with the DRP and Pickering Extended Operations.[1] DRP and Pickering Extended Operations will collectively allow OPG to continue providing low cost, nearly emissions-free electricity for another generation, and OPG's proposed 2.5% WAPA will mitigate the near-term volatility in customer bills.

In addition to smoothing payment amounts, OPG has taken appropriate steps to control costs, improve performance and ultimately to produce value for customers during the IR term. OPG's business plan includes challenging performance initiatives that the company must execute to achieve targeted results for the nuclear business (Ex. A2-2-1, Attachment 1, p. 31; Ex. F2-1-1, pp. 19-21). OPG has also made significant progress in reducing or eliminating benchmarked gaps related to staffing and compensation (Ex. F2-1-1, p. 2, lines 4-5; Ex. F2-1-1, Attachment 2; Ex. F4-3-1, p. 18, lines 10-11; Ex. F4-3-1, Attachment 2). It has also proposed a stretch factor that will reduce the company's nuclear revenue below the nuclear costs forecast in the 2016-2018 Business Plan. The nuclear stretch factor provides

[1] Over half of the forecast revenue deficiency for the nuclear facilities is the result of decreased production, which is primarily driven by units being taken out of service for DRP, and the incremental outage requirements resulting from Pickering Extended Operations between 2017 and 2020 (Ex. A1-3-4, p. 1, lines 20-27).

customers with further, “up-front” savings of over $50M. When combined with the proposed hydroelectric stretch factor,[2] this Application provides customers with incremental benefits of approximately $115M, beyond the targets in the OPG’s business plans.[3]

3.0 RATE BASE

3.1 ISSUE 2.1

Primary: Are the amounts proposed for nuclear rate base (excluding those for the Darlington Refurbishment Program) appropriate?

OPG requests approval of the rate base forecasts set out in Ex. N2-1-1, Table 1. These forecasts are based on the same methodology accepted by the OEB in EB-2007-0905, EB-2010-0008, and EB-2013-0321. Other than for the DRP and ARC, these forecasts were not updated in either the First or Second Impact Statements.

The forecast of total rate base for the nuclear facilities are provided in Chart 3.1. These amounts remain reasonable in light of the actual 2016 in-service additions and consequent impacts on the IR term forecast (Ex. J21.1).

[2] The proposed hydroelectric stretch factor provides a customer benefit of approximately $64M over the 2017-2021 period.
[3] See Issues 11.2, 11.3 and 11.4 in Sections 12.3 and 12.5, for further discussion of the proposed stretch factors.

Chart 3.1

Nuclear Rate Base

Line No.	Rate Base Item	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)
1	Net Plant (Excluding DRP)[1]	1,780.5	1,861.0	1,848.6	1,813.9	1,848.4
2	Net Plant (DRP)[2]	611.9	601.5	586.7	4,699.1	5,154.5
3	Asset Retirement Costs[3]	524.0	446.7	369.5	292.2	249.6
4	Total Nuclear Net Plant	2,916.4	2,909.2	2,804.8	6,805.2	7,252.5
5	Cash Working Capital[4]	11.0	11.0	11.0	11.0	11.0
6	Furl Inventory[4]	251.9	242.2	224.2	210.7	208.6
7	Materials and Supplies[4]	448.7	444.5	436.3	427.0	415.0
8	Total Rate Base[5]	3,627.9	3,606.9	3,476.2	7,453.8	7,887.0

Notes
1 2017 - 2018: Ex, J21.1 Attch 1, Table 1, line 12 minus line 9
2019 - 2021: Ex, J21.1 Attch 1, Table 1, line 19 minus line 16
2 2017 - 2018: Ex, J21.1 Attch 1, Table 1, line 9
2019 - 2021: Ex, J21.1 Attch 1, Table 1, line 16
3 2017 - 2018: Ex, J21.1 Attch 1, Table 1, line 13
2019 - 2021: Ex, J21.1 Attch 1, Table 1, line 20
4 Ex. B3-5-1, Table 1
5 Line 4 plus lines 5, 6, and 7 OR Ex. N2-1-1 Table 1

OPG's forecast of rate base for the IR term is based on a forecast of net fixed/intangible in-service assets (including ARC) and working capital associated with the nuclear facilities. As in OPG's prior rate cases, the net fixed/intangible asset portion of rate base is determined using a mid-year average methodology. For large in-service additions or adjustments, where the in-service addition amount or the amount of an adjustment exceeds $50M, the specific time in which the addition or adjustment is expected is used, instead of a mid-year average, to improve accuracy. The proposed fixed/intangible asset rate base values are based on a 2016-2021 forecast of in-service additions, summarized in Ex. B1-1-1, Chart 1 and discussed in Sections 5.4 and 7.8.5, and a forecast of depreciation expense discussed in Section 7.11.

ARC represents the capitalized costs for nuclear liabilities recorded as an asset retirement obligation ("ARO") on OPG's balance sheet in accordance with US GAAP, as discussed in

Section 9.0. The forecast ARC rate base value reflects a projected year-end 2016 adjustment to ARC and ARO for the prescribed facilities of -$237.9.M on account of the 2017 ONFA Reference Plan update (Ex. N1-1-1, Section 3.2.2) and a year-end 2015 adjustment of -$417.5M related to the impact of changes in nuclear station end-of-life dates on nuclear liabilities (Ex. C2-1-1, Section 5.0), as part of the OEB-approved revenue requirement methodology for recovery of nuclear liabilities costs.

As in OPG's previous payment amounts applications, fixed and intangible assets used by both the regulated and unregulated generating business units continue to be held centrally. These assets are not included in rate base. Instead, all generating business units are charged an asset service fee for the use of these assets, as discussed in Ex. F3-2-1.

The working capital included in rate base consists of cash working capital, fuel inventory and materials and supplies. The fuel inventory and materials and supplies values for rate base continue to be determined using a mid-year average of opening and closing balances during the period. Cash working capital continues to be determined using a lead/lag analysis. All of these approaches are consistent with the methodologies previously approved by the OEB (Ex. B1-1-1, pp. 4-7).

Fuel inventory continues to be valued using the weighted average costing method. Fuel purchases reflect OPG's current target levels for the inventory. This methodology is unchanged from EB-2013-0321 (Ex. B1-1-1, p. 6). Material and supplies continue to be valued at the lower of average cost and market and are forecast based on expected consumption and purchases (Ex. B-1-1, p. 7). Annual targets in 2017 to 2021 have been established to optimize materials and supply inventory levels.

Consistent with regulatory and accounting requirements, OPG has appropriately reflected opening balances (i.e. audited 2015 year-end actual balances) and forecast in-service additions, depreciation expense and other changes to its net fixed/intangible assets in the forecast of rate base for the nuclear facilities over the IR term. Similarly, OPG has calculated the working capital component of rate base for the nuclear facilities appropriately, including use of a lead/lag study and forecasts of fuel inventory and materials and supplies inventory. As a result, OPG submits the rate base forecasts for the IR term should be accepted by the OEB.

3.2 ISSUE 2.2

Oral Hearing: Are the amounts proposed for nuclear rate base for the Darlington Refurbishment Program appropriate?

The forecast of total net plant for the DRP included in the total proposed rate base amounts is $611.9M (2017), $601.5M (2018), $586.7M (2019), $4,699.1M (2020), and $5,154.5M (2021) (Ex. N2-1-1, Chart 3; Ex. J21.1, Attachment 1, Table 1). The same methodology as for the non-DRP net plant values discussed under Issue 2.1 was used to determine these values. The proposed DRP rate base values include in-service additions of $4,800.2M for the planned return to service of the refurbished Darlington Unit 2, consistent with the RQE for the project. Per Ex. N2-1-1, the proposed rate base values were updated to exclude forecast Heavy Water Storage and Drum Handling Facility Project in-service additions.

For the same reasons outlined under Issue 2.1 (Section 3.1) with respect to forecast DRP in-service additions, OPG submits that the DRP rate base forecasts for the IR term should be accepted by the OEB. The revenue requirement impact of variances between actual and forecast DRP rate base values is recorded in the Capacity Refurbishment Variance Account ("CRVA"). D&V accounts are discussed in Section 10.0.

4.0 CAPITAL STRUCTURE AND COST OF CAPITAL

4.1 ISSUE 3.1

Primary: Are OPG's proposed capital structure and rate of return on equity appropriate?

OPG submits that its proposed capital structure and rate of return on equity for the regulated facilities are appropriate and should be approved by the OEB.

4.1.1 Proposed Capital Structure

OPG has applied for the recovery of its cost of capital based on a deemed capital structure of 49% equity and 51% debt. OPG has applied the proposed capital structure in determining the cost of capital for the nuclear facilities in Ex. N2-1-1, Attachment 1.[4] The proposed capital

[4] Nuclear amounts do not include the lesser of average unamortized ARC or unfunded nuclear liabilities. This is consistent with the OEB-approved methodology for determining rate base financed by capital structure, wherein

structure reflects the material increase in OPG's business and financial risks since EB-2013-0321. In that case, the OEB revised downwards OPG's equity ratio from 47% to 45% based on the increase in the proportionate share of rate base related to hydroelectric facilities, which the OEB viewed as less risky than nuclear assets (EB-2013-0321, Decision With Reasons, p. 114).

OPG proposes to establish the Hydroelectric Capital Structure Variance Account to record the revenue requirement impact of the difference between the capital structure approved by the OEB in this proceeding and the capital structure of 45% equity and 55% debt approved by the OEB in EB-2013-0321 that underpins the proposed hydroelectric payment amounts in this IR term. The proposed Hydroelectric Capital Structure Variance Account is described at Ex. H1-1-1, Section 6.4 and in Section 12.2.6 of these submissions. This account is necessary to apply OPG's regulated operations-wide capital structure to the Nuclear and regulated Hydroelectric businesses consistently during the IR term.

4.1.2 Expert Evidence Regarding Capital Structure

The OEB received expert evidence addressing the appropriate capital structure to be applied to OPG's regulated facilities.

Concentric Energy Advisors ("Concentric") was engaged to prepare an independent report as to whether the application of the cost of capital approved by the OEB in EB-2013-0321 is an appropriate basis for setting OPG's Nuclear and Hydroelectric payment amounts in this Application. The Concentric Report was filed as Ex. C1-1-1, Attachment 1.

Messrs. Coyne and Dane testified on behalf of Concentric. Their expertise was unchallenged and they were accepted as experts by the OEB (Tr. Vol. 17, p. 146). In Concentric's opinion, OPG's deemed common equity should, at a minimum, be set at 49%. Concentric concludes that OPG's risk profile has changed, and will continue to change materially over the 2017-2021 period as compared to its risk profile at the time of EB-2013-0321. As the Concentric report states at Ex. C1-1-1, Attachment 1, page 29:

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the weighted average cost of capital is applied to OPG's rate base that does not include the lesser of ARC or UNL.

> Concentric concludes that OPG's overall risk level will increase over the period 2017-2021 from its level as of EB-2013-0321, driven by business risks related to the DRP, pursuit of extended Pickering operation, increasing risks associated with degradation of aging nuclear station components, the implementation of incentive regulation, and changes in the Company's regulatory treatment, among other factors. Increased financial risks, including those arising from OPG's rate-setting proposal for its prescribed nuclear facilities and risks related to future recovery of Pension and OPEB accrual costs will negatively affect the Company's credit metrics, leading to additional financial risks relative to prior risk levels. Concentric's opinion is that an appropriate equity ratio for the Company exceeds the currently deemed ratio of 45% previously set by the Board prior to the EB-2013-0321 rate proceeding.

Concentric further supported its conclusion by analyzing the equity ratios of other utilities (i.e., the proxy group) with risk characteristics comparable to OPG's. As it notes, a review of equity ratios authorized at similarly situated or "proxy" companies is a common and well-accepted approach used in the determination of the cost of capital for regulated utilities. The analysis provides context for where, within a reasonable range, OPG's equity ratio should be set by the OEB (Ex C1-1-1, Attachment 1, pp. 30-31). As Concentric's analysis indicates, OPG's current-approved ratio is low relative to comparable companies despite OPG falling towards the upper end of the spectrum of risk profiles established by those companies, which have a median equity ratio of almost 50%.

In addition to Concentric, Dr. Bente Villadsen of the Brattle Group also testified. Brattle was retained by OEB staff to review the Concentric report and to arrive at its own conclusion as to the appropriate capital structure to apply to OPG regulated facilities. Dr. Villadsen is the President of the Society of Utility Regulatory Financial Analysts and a lead author of Risk and Return for Regulated Industries (published May 1, 2017). Dr. Villadsen's expertise was accepted by the OEB (Tr. Vol. 19, p. 60). The Brattle report is filed as Ex. M3.

In undertaking its analysis, Brattle took an approach comparable to Concentric. As Dr. Villadsen testified in relation to how Brattle approached its engagement (Tr. Vol. 19, p. 66-88):

> First, I reviewed the report submitted by Concentric and [e]valuated where I thought the report could use improvements, and also what I thought generally about their recommendation.

> Second, I went about to look at what would be an appropriate equity percentage for OPG going forward. To do that, I first looked at whether or not the risk of OPG had changed since the last payment amount proceeding, because that would be a threshold for whether we should change to equity structure or not.
>
> Having looked at that, I then did two tasks. One, I looked at the credit metrics of OPG to see whether they could meet the financial integrity standard with the current 45 percent equity, or if we needed to do something differently.
>
> Seeing that that would not be within the range of an appropriate credit metric, I then tried to determine what would be an appropriate capital structure specifically, and to do so I say what would be -- increase be if there should be one. To do so I looked at what I would consider comparable companies…

Brattle agrees with Concentric that OPG's risk has increased materially and that its equity ratio should be increased. As Dr. Villadsen testified:

- The change in the nuclear to hydroelectric asset mix increases risk for OPG (Tr. Vol. 19, p. 88);
- There is an increase in OPG's business risk driven by the DRP (Tr. Vol. 19, p. 63);
- Plans to pursue extended Pickering operations beyond 2020 and the aging of the Pickering plant contribute to an increase in risk (Tr. Vol. 19, pp. 63-64, and p. 88); and
- The move to IR for hydroelectric rate-setting and to long-term rate-setting periods for nuclear operations both increase risk (Tr. Vol. 19, pp. 63-64, and p. 89).

Brattle concludes that OPG's equity ratio should be set at 48%: "I ended up with 48 percent equity recommendation, which I think is in line with what companies that have similar risk have and also in line with a need for an increase in the equity thickness, given that I found that the risks of OPG has increased." (See also Ex. M3, p. 4).

Where Concentric and Brattle differ, slightly, is in relation to the selection of the proxy group of companies and Brattle's preference to look at the market, as opposed to allowed, equity structures of the comparator companies. Brattle also relied on the fact that OPG, unlike some members of the proxy group, has no coal generation. As Brattle says in its report, coal-fired generation has come under pressure, as a result of the significant cost to adhering to environmental legislation (Ex. M3, p. 16; Tr. Vol. 19, pp. 139-140).

In OPG's submission, while the experts substantially agreed with one another, Concentric's opinion should be preferred. At 49%, OPG's proposed equity ratio is the minimum proposed by Concentric. Further, given the recent change in the U.S. political landscape and the desire to unwind U.S. environmental legislation brought about by the previous Obama administration. Brattle's concerns regarding coal have, at least in part, been mitigated.

OPG has applied the proposed capitalization to the rate base for the nuclear facilities as described in Ex. B1-1-1 and updated in Ex. N2-1-1, as adjusted to reflect the application of the lesser of ARC and the unfunded nuclear liability ("UNL") provision applied by the OEB in EB-2007-0905, EB-2010-0008, and EB-2013-0321. OPG proposes to establish the Hydroelectric Capital Structure Variance Account to record the revenue requirement impact of the difference between the capital structure approved by the OEB in this proceeding and the capital structure of 45% equity and 55% debt approved by the OEB in EB-2013-0321 that underpin the proposed hydroelectric payment amounts as described in Ex. H1-1-1, Section 6.4.

4.1.3 Rate of Return on Equity

OPG is proposing an ROE of 8.78% for the nuclear facilities for 2017 (Ex. N1-1-1, p. 20, Chart 3.4).

The proposed ROE for 2017 is in accordance with the latest Cost of Capital Parameter published by the OEB on October 27, 2016 pursuant to the ROE formula set out in the Report of the Board on Cost of Capital for Ontario's Regulated Utilities, December 2009, EB-2009-0084.

OPG proposes to establish the ROE for the Nuclear business for the 2018-2021 period as follows (Ex. C1-1-1, pp. 2-3):

- Use the prevailing ROE specified by the OEB in accordance with the OEB's Cost of Capital Report; and

- Record the revenue requirement impact of the difference between the forecast ROE approved for 2018 to 2021 in this Application and the actual ROE that the OEB will specify annually for 2018 to 2021 in the proposed Nuclear ROE Variance Account, as described at Ex. H1-1-1, Section 6.3.

OPG does not propose to update the ROE for the regulated Hydroelectric business for the 2017-2021 period. In those years OPG's proposed hydroelectric payment amounts would be determined by the price-cap incentive regulated adjustment as set out in Ex. A1-3-2, Section 2.

OPG submits that its proposed rates of ROE and proposed annual updates for ROE for the nuclear facilities are reasonable, consistent with the OEB's approved practice for OPG, and should be approved.

4.2 ISSUE 3.2 (PARTIALLY SETTLED)

Secondary: Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

This issue is partially settled (Ex. O-1-1, p. 8). The parties have agreed that the assumed interest rates used to calculate OPG's proposed debt costs provided in Ex. C1-1-2 and Ex. C1-1-3 are appropriate on the basis of its written evidence. Given that the aggregate debt costs relate to OPG's capital structure and rate base, which are unsettled issues, the parties further agreed that the settlement of this issue was subject to the application of the agreed interest rates to the eventual debt financed component of rate base as determined by the OEB.

5.0 CAPITAL PROJECTS

5.1 ISSUE 4.1

Oral Hearing: Do the costs associated with the nuclear projects that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery meet the requirements of that section?

Section 6(2)4 of O. Reg. 53/05 provides that the OEB shall ensure that OPG recovers capital and non-capital costs and firm financial commitments incurred for the DRP or incurred to increase the output of, refurbish or add operating capacity to a prescribed generation facility if the OEB is satisfied that the costs were prudently incurred and that the financial commitments were prudently made. In EB-2007-0905, the OEB established the CRVA for this purpose.

The projects under OPG's Nuclear Operations that qualify for treatment under Section 6(2)4 of O. Reg. 53/05 are set out in Chart 5.1, which sets out the 2016-2021 forecasts for the non-capital and capital costs reflected in the evidence as well as the actual amounts of these costs for 2015 (Ex. L-4.1-1 Staff-024):

Chart 5.1

Costs Subject To CRVA Treatment

Costs Subject to CRVA Treatment	2015	2016	2017	2018	2019	2020	2021	Total
in millions								
Project OM&A								
Fuel Channel Life Management (FCLM) Project	$ 2.3	$ 0.4						$ 2.7
Fuel Channel Life Extension (FCLE) Project ***	$ 14.9	$ 15.4	$ 13.6	$ 14.4	$ 9.3	$ 1.7		$ 69.3
FLCE-related Ongoing Costs	$ 1.0	$ 0.3	$ 8.0	$ 31.6	$ 57.6	$ 14.4	$ 7.5	$ 120.4
Darlington Spacer Retrieval Tooling Project	$ 4.0	$ 2.2	$ 5.4	$ 1.4				$ 13.0
Less SCFR *					$ (24.0)			$ (24.0)
Total	$ 22.2	$ 18.3	$ 27.0	$ 47.4	$ 42.9	$ 16.1	$ 7.5	$ 181.4
PECO OM&A								
Enabling Costs **	$ -	$ 15.0	$ 25.6	$ 55.3	$ 107.1	$ 104.2	$ -	$ 307.2
Total OM&A Costs	$ 22.2	$ 33.3	$ 52.6	$ 102.7	$ 150.0	$ 120.3	$ 7.5	$ 488.6
Project Capital								
Darlington Spacer Retrieval Tooling Project	$ -	$ 6.2	$ 0.2					$ 6.4

* Single Fuel Channel Replacement (SFCR) included in FCLE Project BCS as contingency/not included in revenue requirement but would be subject to CRVA if incurred
** Includes Fuel Channel Life Assurance (FCLA) Project Costs
*** 2015 for FCLE is Life to Date

These projects and their associated costs meet the requirements of Section 6(2)4 of O. Reg. 53/05 since they serve to increase the output of a prescribed generation station, as further explained below:

- The Fuel Channel Life Management and Fuel Channel Life Extension projects have been previously accepted by the OEB as being subject to Section 6(2)4 and nothing has changed with respect to these projects to alter that treatment (Ex. L-4.1-1 Staff-024); [5]

- The enabling costs associated with Pickering Extended Operations, including the Fuel Channel Life Assurance project, should also be found to be subject to Section 6(2)4, because this work will increase the output of Pickering (Ex. F2-2-3, p. 6, Tr. Vol. 15, p. 93). The proposed treatment of Pickering Extended Operations' enabling costs under Section 6(2)4 would be consistent with the OEB's previously approved treatment of Pickering Continued Operations, including the Fuel Channel Life Management project (EB-2010-0008 Decision with Reasons, p. 52); and

[5] The Fuel Channel Life Management project was completed in June 2016, as indicated in Ex. J15.9.

- The Darlington Spacer Retrieval Tooling Project's capital and OM&A costs qualify for CRVA treatment because that project will support an increase in the output of Darlington by enabling material property testing of selected fuel channel components to assess fitness for service, thereby allowing the Darlington units to operate to their planned service lives in advance of their respective refurbishments (Ex. D2-1-3, Table 2e, line 66; Ex. F2-3-3 Table 2b, line 28).

5.2 ISSUE 4.2

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

5.2.1 OPG Employs a Project Portfolio Management Approach to Oversee the Majority of Capital and OM&A Project Expenditures

The annual actual and forecast totals for both capital and OM&A project expenditures in the nuclear project portfolio are set out in Chart 5.2 (Ex. D2-1-1, p. 2).

Chart 5.2

Nuclear Operations Project Portfolio Expenditures

Line No.	Category	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Project Portfolio - Capital**	190.9	269.8	292.5	322.0	253.0	238.0	248.0	259.0	180.0
2	**Project Portfolio- OM&A**	87.4	80.8	100.7	78.2	98.9	90.4	81.7	83.0	86.8
3	**Total Nuclear Portfolio**	278.3	350.6	393.2	400.2	351.9	328.4	329.7	342.0	266.8

The total average annual portfolio spending in the period 2017-2021 is $323.8M ($32.4M per unit). The average annual capital expenditures and project OM&A increased slightly beyond the range of $25M to $30M per nuclear unit which OPG had historically targeted for project portfolio expenditures. Key drivers of the changes in the Nuclear Operations project portfolio expenditures over the 2013-2021 period are summarized below, as are the various initiatives being undertaken by OPG to improve its project management function. OPG submits that the evidence summarized below demonstrates that the proposed expenditures are reasonable.

When assessing and prioritizing Nuclear Operations projects (both project OM&A and capital), OPG employs an extensive, comprehensive portfolio management approach, as described below and in detail at Ex. D2-1-1, Section 3.

OPG's Board of Directors approves the annual nuclear projects portfolio budget during the business planning process. The annual nuclear projects portfolio budget is administered by the Asset Investment Screening Committee ("AISC") comprised of senior management personnel, including the Chief Nuclear Engineer, Vice President Nuclear Finance, Vice President Projects and Modifications, and the Vice President Project Planning and Controls. The AISC determines project prioritization and allocates portfolio funding to specific projects. The AISC's terms of reference can be found at Ex. J15.4.

The AISC has implemented a gated process, based on industry best practice, to improve the administration of the annual nuclear projects portfolio and determine whether a project can proceed to a subsequent stage of development. Effectively, OPG's gated review and approval process will improve upon prior AISC oversight by establishing standards related to risk, schedule and costing at each project gate. As the project progresses from one phase of a project to the next (e.g., from definition to execution phase), the project is assessed against the criteria established in the gated process, allowing the company to better evaluate the ongoing feasibility of projects at each interval (Ex. L-4.4-15 SEC-043).

As projects progress from an early phase gate through to the execution phase gate, the level of planning increases and the confidence in the project cost and schedule improves. The gated process allows management to assess any changes since the prior gate and determine whether the project should continue. If the project continues, the gate provides management with an opportunity to ensure appropriate plans are in place and that the project is ready to proceed.

This process first was applied to Auxiliary Heating System ("AHS") and Operations Support Building ("OSB") projects (Tr. Vol. 14, pp. 94-95). It was then expanded to other large nuclear projects in 2016 (see Ex. J15.7; Tr. Vol. 15, p. 53) and will apply to all nuclear projects going forward.

As discussed in testimony, OPG's gated process is being augmented in mid-2017 to include independent technical verification of project estimates and schedules at a point in time.[6] The staff performing this independent technical analysis to support the AISC represent a Centre

[6] See Tr. Vol. 15, pp. 16-20 for an in-depth discussion of OPG's gated process and its evolution.

of Excellence for Project Planning and Control (Tr. Vol. 15, p. 19; Ex. J15.3).[7] These adjustments to OPG's gated process are designed to improve project cost and schedule predictability, to enable better class estimates at the time of Full Release business case summary ("BCS"), and to establish common estimating practices for project cost and schedules (Ex. L-4.4-15 SEC-45; Tr. Vol. 15, pp. 16-17, pp. 28-30, and p. 134).

In addition to the nuclear project portfolio, there are other capital and project OM&A expenditures that are managed and approved outside of the project portfolio, including: capital expenditures on minor fixed assets (Ex. D2-1-2); expenditures on special, non-recurring projects that are managed outside of the project portfolio, referred to as "Non-portfolio projects" (e.g., the Fuel Channel Life Extension project and Pickering Extended Operations (Ex. D2-1-2; Ex. F2-3-1; Ex. F2-2-3)); and, capitalization of Darlington new fuel (Ex. F2-5-1, Section 2.0; Ex. L-6.3-1 Staff-111).

5.2.2 OPG's Nuclear Capital Expenditures are Reasonable

OPG nuclear capital projects within the project portfolio are developed to meet regulatory commitments to the CNSC, increase fleet or unit reliability, address fleet obsolescence, or optimize station generation (Ex. D2-1-1, p.1).[8] Capital projects are categorized by OPG into two categories:

- "Portfolio Projects (Allocated)" are projects that have an AISC-approved budget and an approved business case summary. This also includes major capital spares; and
- "Portfolio Projects (Unallocated)" is the difference between the total approved capital budget and the amount of capital allocated to projects in the Portfolio Projects (Allocated) category. In effect, it represents the amount of approved capital that remains available to undertake projects that are currently in the project identification or project initiation phases. A list of the capital projects being considered for funding through the project portfolio is provided in Ex. D2-1-3, Tables 5a and 5b.

OPG's IR term capital expenditures in support of its nuclear operations are $279.0M (2017), $258.0M (2018), $282.4M (2019), $278.5M (2020) and $199.3M (2021) (Ex. D2-1-2, Table

[7] This type of Centre of Excellence has been in place to support the gated process for DRP since the RQE was prepared (Tr. Vol. 15, pp. 22-23). A discussion of the Project Management Centre of Excellence and the Terms of Reference for the overall initiative are provided in Ex. J15.3.

[8] A breakdown and explanation of the Nuclear Operations Capital Project Portfolio budget allocation between these categories (regulatory, system or unit reliability and system obsolescence or optimizing station generation) can be found at Ex. L-4.2-2 AMPCO-29.

1). These amounts primarily consist of project portfolio capital expenditures, but minor fixed assets and capitalized Darlington new fuel are also included (Ex. D2-1-2, Table 2). Planned capital expenditures for DRP are not included in these figures. Discussion of the DRP is presented in Section 5.3.

OPG's 2016 Nuclear Benchmarking Report showed that OPG's nuclear capital expenditures per megawatt ("MW") has benchmarked in the top quartile from 2010 to 2015 (Ex. L-6.2-15 SEC-063, Attachment 3, pp. 81-83).[9]

As mentioned above, OPG's proposed IR term annual capital expenditures in the nuclear project portfolio vary from $238.0M to $259.0M over the 2017-2020 period, before declining to $180.0M in 2021 due to the decrease in unallocated portfolio projects in anticipation of a reduction in capital spending as Pickering begins to approach the end of commercial operations (Exhibit D2-1-2, Table 2). Key drivers of the changes in OPG's Nuclear Operations project portfolio expenditures over the 2013-2021 period (discussed in detail at Ex. D2-1-2, Section 3.1), include:

- Certain projects being reclassified to the Nuclear Operations project portfolio as a result of the RQE review of the appropriate scope for DRP (see Ex. D2-2-10, Section 2.4.4; Ex. D2-1-3, Section 3.0; Ex. L-4.3-1 Staff-071; Ex. L-2.2-1 Staff-008). These projects were determined to be necessary to support Darlington operations before, during and post-refurbishment (for example, AHS and OSB, which are described further below);

- Additional requirements due to regulatory programs such as the Darlington Integrated Implementation Plan ("IIP") and those projects initiated to address the regulatory requirements resulting from the 101 "Fukushima Action Items" assigned by the CNSC;[10]

- Additional capital funding required to replace obsolete and/or life-expired plant equipment at Darlington. This capital spending for Darlington operations is separate and distinct from capital spending on refurbishment, as OPG must replace obsolete and/or life-expired plant equipment to ensure safe and reliable operation before, during, and after refurbishment. The ramp-up in these capital expenditures began in 2014 and is expected to continue until 2020, after which it will decline. The projected level of capital expenditures over the IR term is reasonable, as benchmarking of OPG's capital expenditures against industry peers shows that historically OPG's capital expenditures were below the industry median (Ex. L-6.2-15 SEC-063, Attachment 3, pp. 81-83).

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[9] As the benchmark is $/MW, top quartile performance means that in 2015 OPG spent less per MW on capital than the other nuclear generators in the comparator group.

[10] A detailed list of completed plant modifications and costs, in response to new regulatory requirements imposed by the CNSC in response to the Fukushima disaster is provided at Ex. L-4.2-8 GEC-16.

5.2.1 Improvements to Project Management are Ongoing

As mentioned above, and described in Ex. D2-1-1, Section 3.2, OPG continuously seeks to improve the performance of its project management function. In 2012, OPG implemented an Engineering, Procurement, and Construction ("EPC") contracting strategy for its vendors, establishing a single point of accountability for design, procurement and construction of a designated portion of a project (while OPG retained overall oversight responsibility). The company used a competitive process to select two vendors to enter into Extended Services Master Services Agreements ("ESMSA") for EPC services with the goal of significantly shortening the procurement cycle for executing new contracts covering all or any combination of engineering, procurement or construction work (and subsequently added a third vendor as discussed below). At the same time, OPG commenced an ambitious program to complete major prerequisite projects (Facilities and Infrastructure Projects), managed by OPG's Projects and Modifications ("P&M") organization, in advance of the Darlington Refurbishment Program as discussed in Section 5.5.

As discussed extensively in EB-2013-0321, Ex. D2-2-2, the contracting strategy using the ESMSA agreements for the larger Facilities and Infrastructure Projects proved challenging, pointing to weaknesses in project oversight and to contractor issues related to planning, scope, cost estimating, subcontractor management, and risk management. Some of these projects, including the AHS and OSB, exceeded OPG's original cost estimates and schedules because the project baseline cost estimates and schedules were released before full completion of engineering based on an overstatement of the quality of the cost and schedule estimates (Tr. Vol. 14, p. 61).

While the AHS and OSB will cost more than originally estimated, this is primarily due to the fact that the project baseline measures were established before completing engineering. The observed cost variances largely relate to inadequate scope in the initial estimates, which were not indicative of the projects' true costs (i.e., had the projects been properly estimated at the correct estimate class initially, the original cost estimate would have been close to the current cost of each project).[11] OPG's experience with the AHS and OSB projects, as well as

[11] This conclusion was reached on the AHS project in the "Supplemental Report to Nuclear Oversight Committee – 2nd Quarter 2014" (see Ex. J15.3, Attachment 1, p. 3; Tr. Vol. 15, p. 131). For the OSB, see Tr. Vol. 12, p. 166, lines 5-21.

others, have provided lessons learned, which have been applied to the ongoing management of these projects and also as input for the continuous improvement initiatives in project management summarized below.

The P&M organization recognized the problems that caused these cost variances early in the process and is actively working to avoid future occurrences. The augmented gated process (discussed above) will add rigour by ensuring that appropriate confidence levels are established for estimates prior to establishing project cost and schedule baselines to use in measuring project performance.

OPG's commitment to continuously improve its project management performance is demonstrated by the five major project management continuous improvement initiatives currently underway.[12] These are:

- Establishing a Centre of Excellence, as discussed above (Ex. L-4.4-15 SEC-43(a); Ex. J15.3);
- Pursuing a variety of contracting strategies depending on the circumstances of each project (Ex. L-4.2-2 AMPCO-19; Tr. Vol. 15, p. 15, lines 4-12);
- Implementing new approaches to improve ESMSA vendor project execution performance, including having added another ESMSA vendor and implementing a Collaborative Front End Planning program (Ex. L-4.4-15 SEC-43(b));
- Improving staff project management and oversight capabilities including through additional training; and
- Improving project cost and schedule predictability via an augmented gated approval process for the Nuclear Operations project portfolio, as discussed above, to enable better class estimates at the time of the Full Release BCS (Ex. L-4.4-15 SEC-45).

OPG submits that the level of proposed test period capital expenditures is appropriate, and that the company's project management process will properly scope, prioritize and execute projects over the IR term. On this basis, OPG respectfully requests that the OEB find the proposed nuclear capital budgets over the IR term as reasonable.

[12] See Ex. D2-1-1, Section 3.2 for additional details.

5.3 ISSUE 4.3

Oral Hearing: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

This issue is covered below in Section 5.5 (Issue 4.5).

5.4 ISSUE 4.4

Primary: Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Program) appropriate?

OPG submits that its forecast Nuclear Operations in-service additions (i.e., excluding DRP) of $389.0M (2017), $315.2M (2018), $239.3M (2019), $300.4M (2020) and $215.6M (2021) are reasonable and should be approved by the OEB (see Ex. D2-1-3, Table 4). The forecast of in-service amounts was developed through OPG's business planning process and reflects in-service dates of the various projects described in Ex. D2-1-3.

In accordance with the OEB filing guidelines, OPG filed detailed business case summaries for "Tier 1" projects with total costs greater than $20M (except for security classified projects),[13] and provided associated in-service amounts.[14] Also in accordance with the OEB filing guidelines, "Tier 2" projects with total project costs between $5M and $20M contributing to in-service additions in the IR term were summarized at Ex. D2-1-3, Tables 2a-2e. "Tier 3" projects with total costs less than $5M were aggregated in Ex. D2-1-3, Table 3. Supplemental in-service amounts (Ex. L-6.9-1 Staff-183) and planned minor fixed asset expenditures can be found at Ex. D2-1-3, Table 4.

As explained at Ex. D2-1-3, Section 4.0, exact forecasting of in-service amounts is challenging due to numerous factors that affect both the amount of capital declared in-service and its timing. In-service amounts vary year-over-year, driven by the level of capital expenditures and the timing of project installations which are frequently tied to specific unit or station outages. Variances can thus arise between forecast and actual in-service amounts due to changes in the level of capital expenditures for specific projects or changes in when projects are brought into service. The steps that OPG is taking to improve project cost and

[13] While business case summaries are not provided for security-related projects, Ex. D2-1-3, Attachment 1 provides a brief description of security-related projects included in Ex. D2-1-3, Table 1.
[14] See Ex. D2-1-3, Table 1, with the business case summaries provided in Ex. D2-1-3, Attachment 1.

schedule predictability (described in Section 5.2.1) are expected to help address this challenge.

In-service amounts are also directly affected by the portfolio management process (described in Section 5.2.1) depending on organizational priorities and constraints as well as project-specific circumstances. For example, the AISC may defer or cancel a project as part of the portfolio management process so that a higher priority alternative project can be pursued.

With respect to project timing, if a project that is forecast for completion in a particular year is delayed into the following year, there will be a significant impact on in-service amounts for both years (Tr. Vol. 14, pp. 90-92). For example, the lower 2016 actual nuclear in-service capital amounts compared to the 2016 budget reflects project delays and deferrals that moved some planned in-service declarations beyond 2016. However, as of Q1 2017, $70.3M of in-service capital that was planned for 2016 has been placed in-service in 2017. This shift reduced the in-service amount for 2016 relative to 2016 budget, but is expected to result in a positive in-service amount variance in 2017 relative to the 2017 forecast (Ex. J14.1, Attachment 1; Ex. J21.1, Attachment 2).

This shift of in-service amounts from one year to the next is not unusual and can be seen in the variances between historical forecast and actual amounts from 2013 to 2016 (Ex. J14.1, Attachment 1). Of the four years, two years yielded positive variances and two years yielded negative variances, in a cyclical pattern. As noted above, this pattern is expected to continue in 2017. More broadly, over the 2016-2021 period, the current view of in-service additions (for Nuclear Operations and Support Services combined) as presented in Ex. J21.1 is virtually the same as the forecast provided in the pre-filed evidence. For these reasons, OPG submits that a prudent approach would be to assess in-service forecasts and variances over the five-year period rather than on an annual basis (Ex. J21.1).

Shifts in the declaration of in-service capital also need to be considered in the context of their impact on net plant rate base. As noted in Ex. J21.1, OPG's overall current view of 2016-2021 net plant rate base associated with Nuclear Operations and Support Services capital in-service amounts is substantially unchanged relative to the pre-filed evidence, despite the variance between forecast and actual in-service amounts in 2016.

OPG submits that the OEB should find that the proposed forecast of nuclear in-service additions is appropriate and approve it.

5.5 ISSUE 4.5

Oral Hearing: Are the proposed test period in-service additions for the Darlington Refurbishment Program appropriate?

5.5.1 Approvals

The DRP is a multi-year, multi-phase mega-program that will enable the Darlington Generating Station ("Darlington") to continue safe and reliable operation until approximately 2055. The Program includes the replacement of life-limiting critical components, the completion of upgrades to meet applicable regulatory requirements, and the rehabilitation of components at Darlington's four units.

OPG seeks approval from the OEB for the DRP rate base values as set out in Issue 2.2, including the following in-service additions to rate base over the period of 2016-2021, on a forecast basis: (i) $350.4M in the 2016 Bridge Year; and (ii) for the IR term, $8.5M in 2017, $8.9M in 2018, $4,809.2M in 2020, and $0.4M in 2021.

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 ("SIO"), and Facilities & Infrastructure Projects ("F&IP"). The Unit 2 in-service estimate includes capital costs incurred in the Definition Phase. As these expenditures are necessary to the refurbishment of Unit 2, in accordance with regulatory accounting principles and financial accounting principles (i.e., US GAAP) they are included in the amounts being added to rate base.

5.5.2 DRP Overview

OPG has embarked on the Execution Phase of the DRP after 10 years of work completing the Initiation and Definition Phases. In the Initiation Phase, OPG evaluated the feasibility of the DRP and received approval from the OPG Board of Directors to proceed with the program. In the Definition Phase, all major contracts required to execute the DRP were awarded, and OPG undertook extensive and rigorous planning to determine the Program's proper scope and develop its cost and schedule. OPG has employed best in class industry standards for planning and implementing mega-projects and mega-programs.

To successfully complete the DRP on time and on budget, OPG has put in place a number of elements that are essential for Program development, execution and completion. Key among those elements is an appropriate structure, both to manage OPG's relationship with the contractors who will execute the major DRP work programs and to perform OPG's Program oversight function. This structure helps ensure the appropriate allocation of risk and cost responsibility and an effective and functioning working relationship between OPG, the Program owner, and its contractors. OPG has established procedures and oversight that require its contractors to execute the major work bundles in an efficient and cost effective manner, and to ensure OPG conducts itself likewise in its capacity as owner. OPG completed engineering for each Unit 2 design modification package covering all committed DRP scope. Based upon this work, OPG prepared a detailed high confidence four-unit budget and schedule also known as the Release Quality Estimate.

Significant effort went into developing the RQE. OPG has a high level of confidence in the overall DRP cost estimate of $12.8B and in the Unit 2 estimate of $4.8B, which were both developed as part of the RQE. The OPG Board of Directors reviewed and approved the RQE on November 13, 2015. For Unit 2, the estimate in the RQE was further developed in the Unit 2 Execution Estimate that was approved by OPG's Board of Directors in August 2016 (Ex. L-4.3-1 Staff-055, Attachment 1). The RQE establishes a four-unit, program-level control budget that serves as the baseline against which the success of the DRP will be measured.

The submissions that follow demonstrate the following:

- Section 5.5.3: The regulatory framework supports OPG's requested approvals.
- Section 5.5.4: OPG has established an efficient program structure that will allow OPG to effectively perform its overall management role over the DRP.
- Section 5.5.5: OPG has adopted appropriate commercial strategy and contracting strategies, and applied them to the contracts for each major work bundle.
- Section 5.5.6: OPG has used its program structure and organization, in conjunction with its contractors, to undertake extensive planning that applied lessons learned, defined the scope, and planned the schedule of the Program.

- Section 5.5.7: OPG has prepared a high-quality cost estimate for the Program, which has been reviewed and validated by multiple experts.
- Section 5.5.8: OPG has established the contingency included in the Program using a comprehensive and robust risk management system.
- Section 5.5.9: OPG has put in place the appropriate measures to ensure that the Program is executed safely, on time, and on budget.
- Section 5.5.10: The capital in-service amounts for the Early In-Service Projects, F&IP and SIO are reasonable.

As such, OPG submits that the incurred and forecast in-service amounts are reasonable and prudent and should be added to rate base over the IR term as requested above.

5.5.3 Regulatory Framework

The regulatory regime that informs the OEB's consideration of the DRP has three components: (i) the applicable provisions under Ontario Regulation 53/05; (ii) the standard of reasonableness and prudence; and (iii) the manner in which that standard is typically applied by the OEB.

O. Reg. 53/05 Amendments

Ontario Regulation 53/05, *Payments Under Section 78.1 of the Ontario Energy Board Act* ("O. Reg. 53/05") was amended to include additional provisions that deal with nuclear refurbishment costs and define the scope of the OEB's jurisdiction in considering this Application. The need for the DRP was established by the regulation. As set out in the regulation, in setting nuclear payment amounts during the period from January 1, 2017 to the end of the DRP, the OEB "shall accept the need for the Darlington Refurbishment Project in light of the [2013 Long Term Energy Plan] and the related policy of the Minister endorsing the need for nuclear refurbishment."[15] The Long Term Energy Plan ("LTEP") sets out a number of principles with respect to the nuclear refurbishment process. As shown in Ex. D2-2-1, Attachment 2, OPG's planning and execution of the DRP align with each of the LTEP principles.

[15] O. Reg. 53/05, s. 6(2)(12)(v).

Reasonableness and Prudence

In setting just and reasonable payment amounts, the OEB typically conducts a forward looking assessment of the reasonableness of future test year costs, and a backward looking assessment of the prudence of costs already incurred. As OPG is requesting the inclusion of in-service amounts for DRP over the five-year IR term, these amounts are subject to OEB review on the basis of reasonableness.

In practical terms, “prudence” and “reasonableness” are essentially synonymous unless otherwise prescribed by statute. As Justice Rothstein wrote for the Supreme Court of Canada in *ATCO Gas Pipelines Ltd. v. Alberta Utilities Commission*:

> In the context of utilities regulation, I do not find any difference between the ordinary meaning of a ‘prudent’ cost and a cost that could be said to be reasonable. It would not be imprudent to incur a reasonable cost, nor would it be prudent to incur an unreasonable cost.[16]

Approval of Forecast In-service Amounts for the DRP

The approval, in this Application, of forecast DRP in-service additions that will occur during the IR term is consistent with past OEB practice and appropriately balances the interest of ratepayers and OPG.

The record provides ample evidence to approve the in-service amounts proposed to be added to rate base over the IR term. OPG has provided extensive evidence to validate its cost and schedule estimates, as is discussed in the sections that follow. As is appropriate for a program the size, scope and cost of the DRP, this material far exceeds the information that is typically provided by applicants seeking the approval of future in-service amounts.

It is not at all unusual for utilities to apply for, and the OEB to approve, the reasonableness of future in-service amounts on a forward test-year basis. For example, in the proceeding relating to Hydro One Networks Inc.’s 2011-2012 transmission revenue requirement (EB-2010-0002), the OEB accepted Hydro One’s capital spending plan for 2011 and 2012, which included amounts relating to projects that were anticipated to come into service during the

[16] [2015] 3 SCR 219, at para. 35.

test years.[17] The forecast in-service additions for 2011 and 2012 were $859.2M and $1.42B[18] respectively, with the significant increase being partly due to the forecast addition of the Bruce to Milton transmission project in rate base. Despite the concern expressed by some intervenors that Hydro One had in prior years under-spent its OEB-approved capital budget, the OEB was satisfied that Hydro One's capital spending plan was reasonable.

The OEB also has taken steps to limit customer risks if large forecast in-service additions are delayed. For example, in EB-2010-0002, the OEB approved a variance account that would track the change in Hydro One's 2012 revenue requirement if the Bruce to Milton project did not close to rate base by 2012. The approach was adopted to address intervenor concerns about the potential for Hydro One Networks Inc. to under-spend its forecast capital. In authorizing this account, the OEB emphasized that it does not normally require this type of mechanism to ensure the alignment between projected rate base and matching revenues. However, the OEB found that the variance account was warranted in this case given the uncertainty around project completion and the quantum of revenue requirement impact.[19]

The CRVA provides a similar mechanism for OPG. It will reconcile the revenue requirement impact of any differences between forecast and actual in-service additions for the DRP. If any differences arise, they will be recorded in the CRVA for future disposition, with the recovery of any additions greater than forecast subject to a prudence review in a future proceeding.

On this basis, OPG respectfully submits that it is fully within the OEB's jurisdiction to determine the reasonableness of OPG's forecast DRP in-service additions in this proceeding and that to do so is the appropriate regulatory approach.

5.5.4 Program Structure

The DRP is a complex undertaking, made up of numerous individual projects carried out by multiple contractors. In addition, the Program is taking place within a nuclear power plant that continues to produce power from two or three of its four units during execution of the DRP.

[17] EB-2010-0002 Decision with Reasons dated December 23, 2010, p. 27.
[18] Excluding Green Energy Plan in-service capital additions.
[19] EB-2010-0002 Decision with Reasons dated December 23, 2010, p. 28.

To ensure that the DRP is completed safely, on time, on budget, and with quality, OPG, as the owner, is retaining overall responsibility for the DRP's deliverables, costs, schedule, and design (Ex. D2-2-2, p. 1).

Consistent with recommendations from the Project Management Institute ("PMI") to subdivide project work into manageable, related scopes of work, OPG divided the DRP into five major work bundles, each consisting of numerous individual projects:

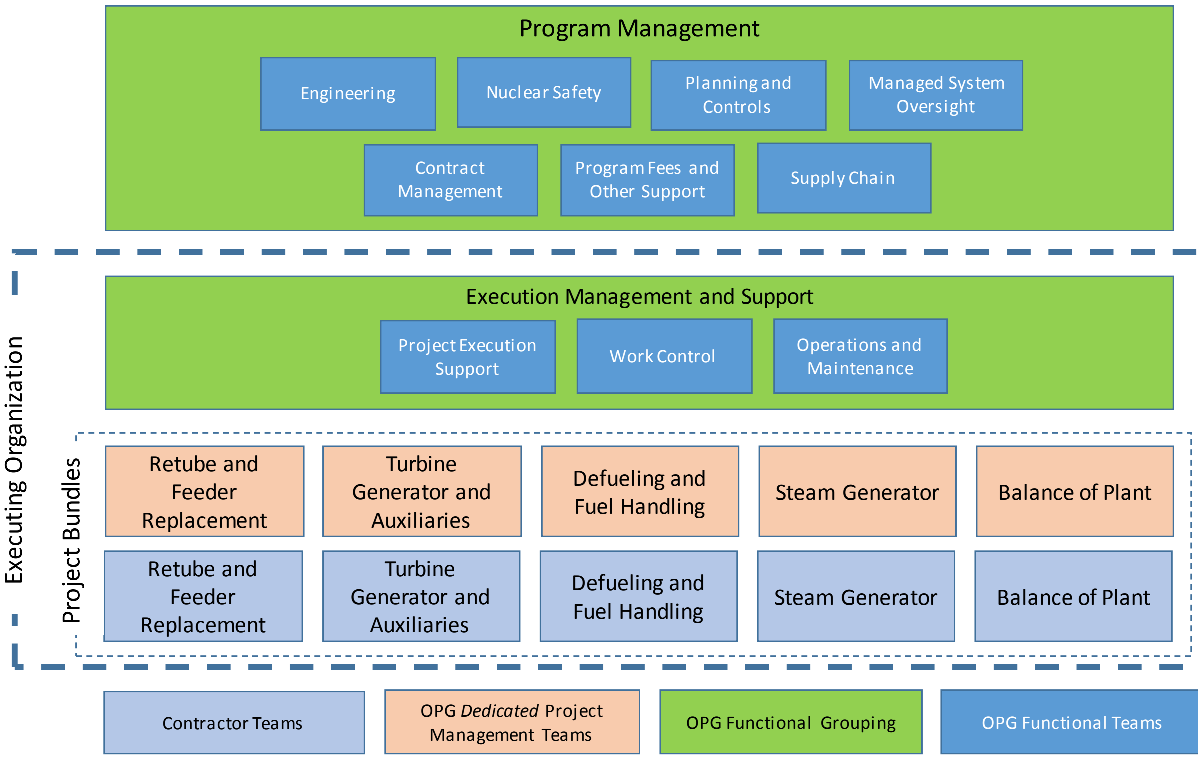
- Retube and Feeder Replacement ("RFR");
- Turbine Generator;
- Balance of Plant;
- Fuel Handling and Defueling; and
- Steam Generator.

Detailed description of each work bundle can be found in Ex. D2-2-3, pages 1-2.

To effectively perform its overall management role over each major work bundle and the Program as a whole, OPG has established an organizational structure dedicated to overseeing the DRP. As illustrated in Figure 5.1 below, the DRP organizational structure is divided into two areas: Program Management and the Executing Organization.

Figure 5.1

DRP Organizational Structure



Within this structure, OPG has established functional support groups ("Functions") dedicated to performing specific types of work to support the major work bundles and their integration into the overall Program. The Functions contained within the Program Management level illustrated in Figure 5.1 are accountable for the overall delivery of the program, including planning, oversight, monitoring, reporting, and contract management. The Functions within the Executing Organization are responsible for day-to-day execution support. In addition, OPG established project management teams that are responsible for ensuring effective planning and successful execution of each major work bundle. This responsibility includes working with each contractor to support the delivery of contracted services safely, to the requisite quality standard, on time, and on budget. Detailed description of the roles of each group can be found in Ex. D2-2-2, pages 4-10.

OPG has also recognized that change is inherent in a program the size, scope and duration of the DRP and has equipped the DRP organization with an effective and adaptive change management process. A key principle that guides OPG's change management process is that change is managed at the lowest authorized level of the organization at all times. Thus, the Executing Organization is always the first to attempt to mitigate the impact of any change. A clear and flexible change management process is in place to ensure that change management requests only escalate to higher authorities to review and approve when required. OPG's change management process is set out in Ex. D2-2-9, Attachment 1; Ex. L-4.3-6 EP-11; and Ex. L-4.3-15 SEC-38; and the thresholds for escalating cost and schedule changes are set out in Ex. L-4.3-1 Staff-58.

Dr. Patricia Galloway of Pegasus-Global Holdings, Inc. ("Pegasus-Global") reviewed several aspects of OPG's execution approach. In her independent expert assessment, Dr. Galloway found that:

- OPG is using a strong matrix organization comprised of full-time project managers with considerable authority and full-time functional support staff, which she considered appropriate.
- The content and scope of OPG's program and project management plans is consistent with industry best practices and other megaprojects and mega-programs she has reviewed.
- OPG sought to find the most qualified individuals in the industry to manage the Program and she found that the individuals assigned to the Program are qualified and competent.
- The Program Management Organization and Staff decisions were reasonable and in accordance with good utility practice. (Ex. D2-2-11, Attachment 3, pp. 15 and 44).

With respect to OPG's policies and procedures, Pegasus-Global found that OPG's policies and procedures are "exemplary":

> In reviewing OPG's policies and procedures, both from an organizational and program-specific standpoint, I found they are exemplary in their thoroughness and alignment with other individual policies and procedures providing OPG with a comprehensive tool from which it can properly execute the Program. In addition to reflecting corporate standards and expectations, the policies and procedures support OPG's adherence to its regulatory requirements. Each policy and procedure was written in a way that aligns with industry best practices, as applicable, as prescribed by leading project management organizations such as PMI and AACE. (emphasis added) (Ex. D2-2-11, Attachment 3, p. 48).

5.5.5 Contracting

OPG employed an overall commercial strategy for the DRP and distinct contracting strategies for each major work bundle to ensure that the DRP is completed as planned. For each of the major work bundles, the contracting strategy informed the contract model and terms that OPG adopted. The sections that follow provide the commercial and contracting strategies employed for the DRP, as well as an overview of the individual contracts.

Commercial and Contracting Strategies

The DRP's overall commercial strategy is based on a "multi-prime contractor" model, which involves multiple prime contractors working on the major work bundles that comprise the DRP. Under this model, OPG has a separate contract with each prime contractor to complete a specified scope of work. The key benefit of this model is that while the contractors are responsible for the completion of their work, OPG, as owner, retains overall control and ultimate responsibility for the deliverables, costs and schedule (Ex. D2-2-2, pp. 1-2). In EB-2013-0321, OPG provided an independent expert report from Concentric that validated OPG's overall commercial strategy, noting that OPG "has acted prudently in selecting the multi-prime contractor model strategy", and that this model "provides Ontario Power Generation with the necessary control over the design and planning of the Project and allows Ontario Power Generation to utilize the expertise of specialty vendors in a cost effective manner" (Ex. D2-2-2, Attachment 1, p. 2).

For each of the DRP's major work bundles, OPG has developed and implemented distinct "contracting strategies" based on the nature and scope of the work, the vendor marketplace, and any potential long term commercial arrangements. Each contracting strategy balances the need and ability of OPG to transfer risk to its contractors against the benefit of achieving a lower contract price. High levels of complexity and uncertainty in certain work packages (such as RFR) made it commercially impractical to transfer significant pricing risk to the contractor (Ex. D2-2-3, pp. 4-5). As OPG's President and CEO, Jeff Lyash, testified:

> Mitigating risk does not equate to establishing a fixed-price contract and paying a high premium for someone else to take that risk. Mitigating risk is a much broader topic than that that gets mitigated through planning, completion

> of engineering, procurement and delivering in advance of all spare parts, development and testing of tooling, training and qualification of workforce.
>
> So there -- identification of risks and specific mitigation of them, so there's a much broader risk mitigation strategy implied and asked for in the [LTEP] than just contracting strategy, although contracting strategy is certainly an element of that risk. <u>And in developing a contract strategy, it takes careful evaluation of who is best in a position to identify, characterize, mitigate, and control the risk, and setting up a structure where that party is charged with that responsibility, and that helps drive the notion of what the target price, what the fixed price or firm price, and what to do as cost plus. And that is embedded in this overall strategy to minimize risk to the company and ultimately to the customer</u>. (<u>emphasis added</u>) (Tr. Vol 1, p. 162).

Concentric reports filed in EB-2013-0321 evaluated OPG's contracting strategies for each major work bundle. In each case, Concentric noted that the strategies OPG is employing are "appropriate and reasonable and meet the regulatory standard of prudence."[20]

Schiff Hardin also confirmed that OPG's contracting strategy meets industry standards (Ex. M1, p. 34). In addition, Schiff Hardin reached the following conclusion on OPG's contracting strategy:

> The applicable EPC [Engineering, Procurement and Construction] contractor will be responsible for its island of work. As to the particular island of work, OPG has appropriately attempted to shift the risk of island-specific performance to qualified contractors to perform the riskiest portions of the work. Because OPG does not routinely self-perform work on mega-projects the size of DRP, OPG, by hiring contractors with qualified personnel, is able to mitigate some of the risks related to hiring qualified staff for a multi-prime project with potentially hundreds of contractors.
>
> … Moreover, under OPG's mini-EPC contracts, OPG has tried, to the extent possible, to shift the financial risk for the applicable islands of work through various fixed, target, and cost-plus price structures and by using contract incentives and disincentives (Ex. M1, p. 35).

Schiff Hardin also found that OPG's contracting strategies, contract terms, and contractual risk allocation are consistent with best practices (Ex. M1, pp. 7, 38-39, 44 and 46; Tr. Vol. 7, pp. 55-56).

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[20] For RFR, see: Ex. D2-2-2, Attachment 1; for Turbine Generator, see: Ex. L-4.3-15 SEC-16, Attachment 2; for Fuel Handling, see: Ex. JT1.3, Attachment 1; for Steam Generator, see: Ex. JT1.3, Attachment 2; and for Balance of Plant, see: Ex. JT1.3, Attachment 3).

Contracts Overview

As summarized in Ex. D2-2-3, Chart 2, there were three main contracting models employed for the major work bundles: (1) Engineering, Procurement and Construction, (2) Engineering Support and Equipment Supply, and (3) Extended Services Master Services Agreement ("ESMSA"). Depending on the complexity of the work and the need, ability and cost effectiveness of transferring risk for the work to the contractor, OPG's contracts also incorporated a mixture of three pricing models: (1) Target Price, (2) Fixed/Firm Price, and (3) Reimbursable Costs or Cost Plus Mark-up. The pricing models are explained at Ex. D2-2-3, pages 4-5.

OPG negotiated a number of contract terms and conditions that added project controls across all of the DRP work bundles, including:

- *Project Change Directives* – The major work bundle contracts limit the ability of the contractors to initiate project change directives, except in certain circumstances (e.g., force majeure). The limitation on contractor initiated project change directives reduces OPG's risk exposure to changes in target costs, target schedules or fixed fees.
- *Warranty Provisions* – The warranty periods are sufficiently long for OPG to identify any potential defects with work performed by the contractors or in owner-specified materials supplied by the contractors.
- *"Open Book" Approach and OPG Audit Rights* – OPG may review, audit and dispute invoiced costs.
- *Termination for Convenience* – OPG may terminate the contracts for convenience at any time, providing an important off-ramp to OPG.
- *Suspension of the Work* – OPG has the option to suspend the work at any point during the contract. This provides an important cost-saving measure in the event of a delay in execution. (Ex. D2-2-3, pp. 6-7).

In Ex. D2-2-3, OPG reviewed each of the major contracts and set out its respective contracting strategy, contracting model and pricing model. Given that the RFR major work bundle represents the largest share of the Unit 2 refurbishment costs, and also because it incorporates all three pricing models, OPG elaborates on its structure below. In addition, the ESMSA is highlighted below given its unique pricing and performance incentives relative to those found in the other DRP contracting models.

<u>RFR Contract</u>

For the RFR, OPG employed an EPC arrangement that combines all three pricing models:

- fixed/firm pricing for known or highly definable tasks and that are within the control of the contractor (e.g., construction of the mock-up and tooling largely constructed within the contractor's facility);
- reimbursable costs or cost plus mark-up for procurement of owner specified materials, goods and commissioning work; and
- target cost for the remaining scope of RFR where work is difficult to define and the execution of the work is less controllable (e.g., tube replacement execution within OPG's operating plant) (Ex. D2-2-3, p. 7).

This contractual framework has allowed OPG to establish an appropriate allocation of risk and cost.

For the target cost components of work, the RFR contract also includes direct and effective incentives and disincentives to execute the DRP on time and on budget. OPG and the contractor, a joint venture between SNC-Lavalin Nuclear Inc. and Aecon Industrial, a division of Aecon Construction Group Inc. ("SNC/AECON JV"), will jointly share in any cost savings or overruns based on percentages specified in the contract (Ex. D2-2-3, pp. 7-8). The incentives and disincentives are triggered when costs surpass a negotiated neutral band around the target price.

The incentive/disincentive mechanism is also tied to the contractually negotiated "Fixed Fee." The Fixed Fee is a specified amount set out in the contract comprised of the contractor's profit, overhead and a risk amount. In the event a contractor's performance warrants a cost disincentive, OPG may receive payments equivalent of up to 48% of the contractor's Fixed Fee. In this scenario, although the contractor would still be reimbursed for its actual (allowed) costs, it is effectively losing a share of its profit, overhead and risk amount for its work on the DRP (Ex. D2-2-3, p. 8). In addition, since the contractually negotiated Fixed Fee does not change and was not set assuming that extra work would be required, the contractor in effect does not receive any profit, overhead or risk amount for any extra work it has to complete. The disincentive mechanism therefore has a direct and significant impact on the contractor. Lost profit and reduced overhead recovery hit the contractor's bottom line. Financial disincentives are also imposed for failure to complete unit outages within the agreed schedule. In aggregate, schedule and cost disincentives together can cost a contractor up to 80% of its Fixed Fee.

The contractor is also motivated to complete the work *under* budget and *ahead* of schedule in order to maximize its profits under the contract. Incentives under the contract for cost and schedule savings, in aggregate, could result in incentive payments of up to 40% of the contractor's Fixed Fee (Ex. D2-2-3, p. 8).

Given that the RFR work bundle is on the critical path, OPG recognized that schedule efficiency gains in the RFR segment are vital to the success of the DRP. Accordingly, the RFR contract "hardwires" set percentage reductions in schedule duration for each subsequent unit to reflect productivity gains and experienced-based schedule adjustments (Ex. L-4.3-15 SEC-023).

In this proceeding, given the significant size of the RFR bundle of work, OPG again engaged Concentric to independently assess whether the final RFR contract is reasonable. Following their review, Concentric confirmed the reasonableness of the contract for the RFR work package as well as the target price and risk allocation within the contract (Ex. D2-2-11, Attachment 1, p. 8). Specifically, Concentric concluded:

- The terms of the final Retube & Feeder Replacement contract are consistent with what Concentric would expect for a project of this scale and nature.
- The parties have agreed on a reasonable allocation and apportionment of risks that holds each party responsible for those risks over which it has the most control.
- The review and validation process Ontario Power Generation followed to arrive at a target price estimate was both comprehensive and prudent.
- The contract provides a reasonable structure by which the Joint Venture has incentives to meet and outperform the cost and schedule budgets (and is penalized for exceeding those budgets). (Ex. D2-2-11, p. 8)

<u>Extended Services Master Services Agreement</u>

For the majority of the Balance of Plant work bundle, as well as for the F&IP and SIO, OPG utilized the ESMSA contracting model. The ESMSA model establishes terms and conditions in advance with each pre-qualified contractor to facilitate a competitive bidding process for discrete projects in the areas covered by the contract. This enables OPG to significantly shorten the procurement cycle for obtaining engineering, procurement, or construction services, or any combination of the three types of services, as required (Ex. D2-2-3, p. 19).

OPG has achieved significant benefits by using a competitive process to enter into substantially similar agreements with its three ESMSA contractors. These benefits include favourable pricing and terms and conditions, as well as flexibility. The ESMSA contracts also allow OPG to retain overall control of the work. The key contract features and benefits are highlighted on pages 19-21 of Ex. D2-2-3.

In particular, OPG retains the flexibility to adopt different pricing models for each purchase order awarded under the ESMSAs. Except with respect to fixed price work and any flow-through amounts, each ESMSA contractor's application for payment is then subject to the performance fee pool mechanism. This mechanism withholds a percentage of every applicable invoice pending a review of each contractor's performance scorecard, which is comprised of safety, human performance, cost and schedule indicators (Ex. J17.1). This mechanism therefore aligns each contractor's incentives with OPG's interests in terms of ongoing performance improvement, ensuring that the contractors are motivated to perform safely, on time, on budget, and with quality on every project.

5.5.6 Extensive Planning

The DRP has three phases: Initiation, Definition and Execution.[21] The Initiation Phase, commenced in 2007, was successfully completed at the end of 2009 when the OPG's Board of Directors granted approval to proceed with the DRP. The Definition Phase commenced in 2010 to plan and prepare for the start and execution of the Unit 2 refurbishment. In the Definition Phase, and in anticipation of the start of the Execution Phase, OPG made a significant investment to develop a robust cost estimate and schedule. Program expenditures for the Definition Phase are $2.2B inclusive of interest and escalation (Ex. D2-2-4, p. 1). As this section will show, OPG has undertaken a significant amount of work over the last 10

[21] Detailed descriptions of the phases are set out in Ex. D2-2-2, Attachment 1.

years to plan and prepare for the DRP. Independent experts have verified that the work that OPG has undertaken is uniformly consistent with industry standards and best practices.

To ensure successful execution of the DRP, OPG undertook vigorous and extensive planning during the Definition Phase. The degree of planning undertaken has enabled OPG to establish detailed scope and a high-confidence schedule and cost estimate. OPG's investments in detailed planning will also minimize the risk of scope creep, schedule delays and resulting increases in cost.

The RQE was the culmination of the Definition Phase work. The RQE successfully satisfied the following key Definition Phase milestones: (1) Scope Definition, (2) Lessons Learned, (3) Engineering, (4) Reactor Mock-up and Tool Development, testing, and time trials, and (5) Scheduling.[22]

- ***Scope Definition****:* The DRP is based on a clear, well-defined program scope, which provides the proper basis for establishing high confidence estimates of the budget and schedule.

  The work scope definition process for DRP commenced in 2008 with a number of scope assessments for the major components within the nuclear plant, including the reactor components, steam generators, turbine generator sets and other nuclear and conventional components. OPG performed nearly 3,000 component condition assessments and reviewed numerous other sources in order to determine all scope related to life extension of the Darlington units. In making decisions about what scope should be performed in the DRP outages, OPG primarily considered whether the proposed scope had to be completed during the DRP or if it could be performed through normal station work processes (or if it was required at all) (Ex. D2-2-5, p. 3). This was a lesson learned from prior refurbishments in order to minimize project risk.

  The scoping process also included: (i) finalizing the regulatory requirements for extending the life of Darlington in conjunction with CNSC staff (see section 4 of Ex. D2-2-1 for discussion of regulatory requirements); and (ii) a detailed review of all scope requests by the Darlington Nuclear Refurbishment Scope Review Panel (also referred to as the "Blue Ribbon Task Force") (Ex. D2-2-5, p. 4). There have been no major scope changes since the RQE was finalized (Ex. J2.7).

  Approximately 80% of the DRP scope is driven directly by regulatory requirements, with the remainder being related to non-nuclear systems and/or scope that is required to be in place to support the refurbishment. OPG's Global Assessment Report and Integrated

[22] The key Definition Phase milestones also included "Cost Estimation", which is discussed in relation to the RQE, in Section 5.5.7 of these submissions.

Implementation Plan were accepted by the CNSC in December 2015, thereby confirming the regulatory scope for the DRP (Ex. D2-2-5, pp. 1-4).

- ***Lessons Learned****:* The DRP is the product of a planning process that incorporates past operating experience and lessons learned from prior refurbishments and other mega-projects or programs. The lessons learned incorporated into the DRP planning process influenced OPG's approach to the development of contracts, engineering completion, procurement, and project controls, among others. As well, OPG worked with its contractors to ensure lessons learned from reviewed projects relating to contractor safety, quality, cost and schedule were integrated into the DRP major work bundles.

In its review, Pegasus-Global concluded that OPG's Program planning "appropriately identified lessons learned" from a variety of sources, and applied them to the Program:

> Through my review and in interviews with OPG personnel, I found that OPG captured operating experience and lessons learned from Darlington projects, past nuclear refurbishments on other units, and other large projects involving CANDU reactors. OPG identified lessons learned from previous refurbishments and megaprojects at other nuclear stations such as Pickering Nuclear Station, Point Lepreau Nuclear Generating Station, Bruce Nuclear Station, Vogtle Electric Generating Plant, and Watts Bar Nuclear Generating Station and have taken specific actions in the DRP to incorporate those lessons learned. OPG also identified lessons learned from non-nuclear megaprograms including the London Olympics and the Heathrow International Airport. Some of those lessons learned include lack of management and contractor oversight, lack of intrusive performance assessments, and performance assurance independent assessment. …. <u>Through interviews with OPG personnel, I found that OPG appropriately identified lessons learned and took appropriate actions to apply these lessons learned to OPG's operating environment and implement into the contractors' plans. In addition, I found that OPG continues to work in a collaborative manner with Bruce Power to share lessons learned identified during both companies' overlapping refurbishments.</u> (<u>emphasis added</u>) (Ex. D2-2-11, Attachment 3, pp. 69-70).

Schiff Hardin also confirmed that OPG's level of effort for applying lessons learned met best practices:

> MR. ROBERTS: Yeah, the only caveat I'd use to that, though, is you can look at industry best practices, in this sense means, did you have a robust planning period? Do you have a well-defined schedule? Have you done a robust analysis on your costs, you know, have you gone out and done lessons learned? And there are some companies -- I just want to -- there are some companies that just check that box. They make a phone call to other companies that have done similar projects, and it's a 30-minute phone call. That's not industry best practice.

> OPG went out and looked at the different sites, had those interviews. Again, their level of effort is -- that's when I would say they're meeting best level of practice. (emphasis added) (Tr. Vol. 7, pp. 47-48).

- ***Engineering:*** OPG completed design engineering for all DRP related Unit 2 scope and modifications. Because all major contracts required to execute the DRP scope were awarded during the Definition Phase, OPG worked with the contractors to complete the detailed engineering for DRP. The completion of engineering provided OPG's contractors with the ability to develop accurate estimates and schedules for the work and the basis for purchasing materials (Ex. D2-2-4, pp. 6-7). As Mr. Reiner, OPG's Senior Vice President Nuclear Projects, explained, the importance of engineering completion was a key lesson learned from the F&IP and SIO projects that OPG applied to planning for Unit 2:

> Another key lesson is the completion of a certain amount of engineering work to inform the execution and specifically the types of methods and risks that you would encounter when you're actually in the construction phase. So there is an element of engineering that is required to inform that. In an ideal world, when you have time to execute the projects and you're not time constrained, there is a sequential method of going through this. And we factored that into the planning by beginning planning relatively early for the Darlington refurbishment so we could complete design engineering (Tr. Vol. 4, p. 45).

- ***Reactor Mock-up and Tool Development***: OPG built a full scale reactor mock-up and undertook RFR tooling development and testing in the mock-up to inform schedule task durations and train staff. This enabled staff to come up the significant learning curve associated with work procedures and equipment before the Execution Phase. The DRP required a substantial number of customized tools that OPG developed and tested for use on the mock-up before the Execution Phase. As a result of this training and tool testing, OPG was better able to determine the level of effort required for and the expected duration of critical path activities. This information improved the sequencing of tasks and the optimizing of project schedules. Consequently, OPG has a high degree of confidence in its schedule for the RFR work bundle (Ex. D2-2-4, pp. 5-6).

- ***Scheduling:*** Establishing an accurate, integrated, and realistic schedule is critical to the successful execution of the DRP. The schedule reflects the sum total of the estimated duration of the individual tasks included within the Program scope. Based on recommended practices, OPG has used a multi-level scheduling approach for the DRP. The levels increase in detail, ranging from Level "0", which contains the Program milestones managed by OPG and identifies the major deliverables and timelines for the overall DRP to Level "3", which contains the individual work components at the task level (Ex. D2-2-6, pp. 2-4). According to Pegasus-Global, "OPG has the plans and processes in place to effectively develop, manage, and control the schedule in full alignment with industry standards and best practices" (Ex. D2-2-11, Attachment 3, p. 66).

  OPG project teams have broken down the Program work based on specific deliverables. This breakdown encompasses 100 per cent of the work, identified down to the individual work components that make up a bundle (also referred to as “work packages”). The work breakdown reflects the corresponding contracting strategies so that work scope, budgets and responsibilities are clearly allocated (Ex. D2-2-6, pp. 1-4).

The schedule provided in Ex. D2-2-6, Attachment 1, reflects the critical path for the refurbishment of Unit 2, including all contractor schedules. OPG will manage day-to-day performance using this schedule, which reflects the planned outage duration at Darlington. OPG will also use the schedule to determine contractor incentives and disincentives, where applicable. Development of a fully integrated, detailed, multi-level schedule is another example of applying key lessons learned during the planning phases of the DRP.

Both Pegasus-Global and Schiff Hardin agree that, overall, the robust, extensive planning methodologies used by OPG are world-class, and that the time and effort put into the planning stage goes beyond what is seen in most other mega-projects (Ex. D2-2-11, Attachment 3, pp. 56, 77 and Tr. Vol. 7, p. 46). Both experts agree that the planning conducted by OPG is consistent with industry standards and/or best practices.[23] A summary of the particular elements of OPG’s planning that Pegasus-Global or Schiff Hardin found to meet industry standards and/or best practices are set out in the Chart 5.3 below:

[23] Schiff Hardin explained that for the purposes of its report, the term “industry standards” is interchangeable with “best practices” (Ex. M1 SEC-7, lines 21-27).

Chart 5.3

DRP Meeting or Exceeding Industry Standards/Best Practices

Expert	Industry Standard/Best Practice	Reference
Pegasus	Earned value	Tr. Vol. 6, pp. 95-96.
	Estimating process and basis of estimate	Ex. D2-2-11 Attachment 3, p. 7, lines 22-24; p. 52, lines 10-14; pp. 53-54, lines 22-25 and 1-8; p. 56, lines 5-22.
	Cost and schedule contingency development	Ex. D2-2-11, Attachment 3, p. 9, lines 19-23; p. 70, lines 9-17.
	Measurement of progress	Ex. D2-2-11, Attachment 3, p. 10, lines 6-8; p. 74, lines 18-20. Tr. Vol. 6, p. 96, lines 8-9.
	Policies and procedures	Ex. D2-2-11 Attachment 3, p. 7, lines 16-17; p. 48, lines 8-15; p. 77, lines 19-23.
	Program and project management	Ex. D2-2-11, Attachment 3, p. 7, lines 4-6; p. 44, lines 14-20.
	Project control systems and tools (cost and schedule management)	Ex. D2-02-11, Attachment 3, p. 8, lines 10-11; p. 9, lines 3-5; pp. 58-59, lines 20-25 and 1-2; p. 63-66; p. 77, lines 19-23.
	Risk management processes	Ex. D2-2-11, Attachment 3, p. 9, lines 24-26; p. 72, lines 1-16; p. 77, lines 19-23. Tr. Vol. 5, p. 142, lines 17-20.
	Organizational structure	Ex. D2-2-11, Attachment 3, p. 7, lines 13-14; p. 46, lines 2-6. Tr. Vol. 5, p. 142, lines 21-25.
Schiff Hardin	DRP	Ex. M1 PWU-002, part (a), Ex. M1 SEC-007.
	Audit and oversight	Ex. M1, p. 28. Tr. Vol. 7, pp. 37, lines 18-21.
	Project planning	Ex. M1, p. 7. Tr. Vol. 7, p. 14, lines 16-24.
	Cost and schedule estimating and development	Ex. M1, pp. 19, 21, 23-24.
	Contracting strategy, contract terms, contractual risk allocation	Ex. M1, pp. 7, 38-39; 46. Tr. Vol. 7, p. 55, lines 17-20; p. 58, lines 7-9.
	Incorporation of lessons learned	Ex. M1 AMPCO-005, part (a). Tr. Vol. 7, p. 47-48.

	Policies and procedures	Ex. M1, p. 7.
	Processes and procedures to manage the project	Ex. M1, p. 29.
	Program and project management plans	Ex. M1, pp. 7, 25. Tr. Vol. 7, p. 76, lines 8-12.
	Project controls systems and tools (cost and schedule management)	Ex. M1, pp. 7, 16, 18-19, 21-23; Ex. M1 EP-008, part (a).
	Risk assessment and management (including development of risk register)	Ex. M1, pp. 7, 12-14; Ex. M1 AMPCO-004, part (b). Tr. Vol. 7, pp. 60-61.
	Use of P90	Tr. Vol. 7, pp. 60, lines 11-14.

5.5.7 Cost Estimate

The RQE reflects a high confidence cost estimate, prepared using the estimate accuracy classification standards established by the Association for the Advancement of Cost Engineering ("AACE"), a non-profit association that is a recognized authority in project and program cost and schedule management. As described below, multiple independent experts have reviewed various elements of the estimating methodology used to develop the RQE and uniformly found them to be appropriate.

OPG established its estimate and underlying assumptions for all major cost elements within the Program in accordance with the requirements for a Class 3 estimate. As defined by AACE, a Class 3 estimate provides an expected accuracy range of -10% to -20% on the low end and +10% to +30% on the high end and is typically used for "Budget authorization or control." (Ex. D2-2-8, p. 3, Chart 1). The RQE is a program control budget. 90% of the estimated completion costs meet or exceed Class 3 estimate standards (Ex. D2-2-8, p. 3). Moreover, the RFR work bundle, the largest component of the DRP, is a Class 2 estimate that was established after a rigorous vetting process (Ex. D2-2-8, pp 1-3).[24]

In their final oversight report to the OPG Board of Directors, BMcD/Modus concluded:

[24] By implementing the RFR procurement process early in the Definition Phase, OPG and the SNC/AECON JV have been able to work together, on an open book basis, to develop the engineering, refine the schedule and budget estimates, and to jointly identify, monitor and address risks as they arise. Burns & McDonnell Canada Ltd. and Modus Strategic, ("BMcD/Modus") assessed the SNC/AECON JV's development of cost estimates for the RFR contract and OPG's vetting of these estimates and concluded that the results are appropriate (Ex. D2-2-8, Attachment 2, p. 19).

> Based on our nearly three years of oversight of the DR Project's planning, BMcD/Modus believes the process used for developing the control budget and critical path schedule that form the basis for RQE meets or exceeds industry thresholds. The control budget is based, most notably, on well-defined scope and detailed engineering, which has sufficiently matured to allow classification using the AACE International guidelines in the manner OPG intended for RQE. In addition, the level of detail in the RQE control budget is in line with our experience for projects of this nature and should form the basis for a robust project controls regime that will be used to track progress against the control budget (Ex. D2-2-8, Attachment 2, p. 5).

OPG also engaged KPMG to provide an independent review that consisted of (1) a governance and process assessment, and (2) a "cross-cutting vertical slice review"[25] of the estimates. KPMG found that OPG's estimating governance and processes were particularly strong in: (1) their alignment with AACE's estimate classification system, (2) integration and consideration of historical knowledge of risks, opportunities and lessons learned from other projects, (3) the risk management framework that has been developed and implemented using best practice tools, and (4) design and implementation of processes for challenging and performing quality reviews of vendor estimates in alignment with AACE guidelines and best estimating practices (Ex. D2-2-8, Attachment 3).

KPMG found that the vertical slices it reviewed were generally well organized, complete, and traceable to estimate detail and source data. KPMG also found that the level of detail in the estimate packages is generally acceptable and sufficient when compared to other similar projects and best industry practices (Ex. D2-2-8, pp. 4-5, and Attachment 3).

CALM Management Consulting Inc., ("CALM"), the previous Independent Advisor to the Ontario Minister of Energy, also recognized the efforts OPG undertook to determine the RQE value, and the work undertaken to arrive at a 90% confidence level, noting that:

> From the start of the refurbishment program, OPG was committed to have the RQE follow the Association for the Advancement of Cost Engineering International Recommended Practice (AACE IRP). This results in an estimate for cost (including contingency) and duration that has been based on sufficient planning and engineering to be considered reliable to a 90% confidence level

[25] This portion of KPMG's work was to review OPG's estimate documentation, based on three different vertical-slices of the DRP: 1) Re-tube and Feeder Replacement ("RFR"); 2) Balance of Plant ("BOP"); and 3) Operations and Maintenance ("O&M"). The term "cross-cutting vertical slice" refers to the review of three separate areas (Ex. D2-2-8, p. 6).

> (Class 3 estimate using the AACE classification terminology). The AACE-IRP is considered the best practice for the development of estimates for mega projects, such as the Darlington Refurbishment Project. (emphasis added) (Ex. L-4.3-1 Staff-072, Attachment 27, p. 6).

After reviewing the process OPG used to come to the RQE value, scope, outage duration, and risk management approach, CALM concluded that:

> Based upon observations of the RQE development process, the associated management oversight and the third party assessment, it is believed that the RQE is appropriate and provides confidence that the Darlington Refurbishment Project can be completed within OPG's cost and duration estimates. The contingency included in the project estimate is sound and developed on a basis of a rigorous risk management program. (emphasis added) (Ex. L-4.3-1 Staff-072, p. 9).

5.5.8 Contingency

Contingency is an important tool for managing uncertainty and risk throughout the life of a project. It refers to amounts that OPG anticipates spending because there are risk items and uncertainties that will occur and cannot be entirely mitigated or avoided. Contingency is included as a cost component of a project estimate just like any other component of a project. It is not an extra amount that will not be spent if the project goes as planned, nor is it a tool to compensate for an underdeveloped project plan. It is a necessary, legitimate and thoughtfully developed part of the estimated project cost based on residual (post-mitigation) risk and uncertainty[26] (Ex. D2-2-7, pp. 1-2).

OPG established the contingency included in RQE through a comprehensive and robust risk management system. OPG undertook a detailed evaluation of cost and schedule uncertainties and discrete risks to determine the appropriate amount of contingency to include in the RQE. This amount, $1.7B (2015$), consists of project contingency and

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[26] AACE defines "contingency" as an amount that is added to an estimate to allow for items, conditions or events, for which the state, occurrence or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs. In addition, the AACE definition states that "contingency is generally included in most estimates, and is expected to be expended." ("Cost Engineering Terminology", Recommended Practice 10S-90, AACE International, WV, rev. 2007). Similarly, the Project Management Institute, a leading professional membership association for the project, program and portfolio management profession, explains that contingency allowances are part of the funding requirements for a project, necessary to account for cost uncertainty (Project Management Institute, *Guide to the Project Management Body of Knowledge (PMBOK Guide)*, 4th ed., 2008, Section 7.1.2.6 at p. 173).

program contingency. Of the total $1.7B in DRP contingency, $694.1M is attributed specifically to the Unit 2 refurbishment and forms part of its forecast cost.

OPG developed the DRP estimate in accordance with industry best practices using AACE's recommended practices for estimate classification. OPG used both qualitative and quantitative methods, including an integrated Monte Carlo simulation of the Program's cost and schedule, representing execution of the entire Program on a four-unit basis. The simulation produces thousands of iterations, each using a different set of random values from the probability functions. The intent is to simulate the outcome of DRP risk and uncertainty variables thousands of times and integrate these results to determine the confidence levels associated with project cost estimates, including contingency (Ex. D2-2-7, pp. 2 and 5).

OPG engaged Palisade Corporation ("Palisade") to assist with developing the RQE contingency calculation model for the DRP. OPG also retained a risk modeling subject matter expert from Palisade to assist in the developing the architecture of the model used to oversee the simulation and evaluating whether the model was robust. In its final report, Palisade observed that:

> <u>The model that both OPG and Palisade designed and constructed contains all the elements included in risk management's best practices</u> such as: disaggregating uncertainty and risk events, including Correlation Matrices (one for each unit's execution section), defining a contingency percentile and obviously refining the input sheets with many iterations with project managers and subject matter experts, and extensive use of ranges (3 points estimate) for risk probability (occurrence and reoccurrence), risk impacts, number of risk reoccurrence, schedule duration impacts and burn rates.
>
> <u>It also contains a well-defined methodology as its foundation, and the collaboration of a team of risk experts that interfaced with several teams of Project Managers and experts which during many weeks translated their knowledge about risks and poured into this placeholder</u>.
>
> Generating a quantitative model that orchestrates all these elements in an organized manner, and at the same time respects the process is much more complex application and generates a much more robust and dependable outcome than a simple one-dimensional model.
>
> This model also enable OPG to use it as a monitoring tool for the execution of the program, applying the same methodology and recalculating the contingency as the project advances. <u>It represents a very strong risk management tool supporting risk analysts and decision making during Nuclear</u>

Refurbishment Project Execution. (emphasis added) (Ex. L-4.3-15 SEC-26, p. 13).

OPG also retained KPMG to provide an independent review of the risk management and contingency development process used by OPG to develop the RQE. Based on its review, KPMG found OPG's governance, methodology and approach to be aligned with AACE guidelines and industry best practices in terms of identifying and classifying risks and using an integrated Monte Carlo-based risk analysis (Ex. D2-2-7, Attachment 1, pp. 5-8). KPMG found that such use of a risk modelling subject matter expert is considered a best practice for infrastructure projects of a similar nature and scale (Ex. D2-2-7, Attachment 1, p. 7).

OPG also evaluated risks and uncertainties for each segment of the schedule, and determined the amount of schedule contingency required to deliver the Unit 2 refurbishment. This resulted in the production of a schedule that includes contingency for certain schedule risks that may be encountered during the execution of the refurbishment outages. KPMG considers the practice of identifying and modeling the integrated effects of risk and uncertainty on schedule to be best practice (Ex. D2-2-7, pp. 3-5). KPMG also found that OPG's use of statistical correlations for the schedule analysis to simulate the interdependence of related activities is considered to be best practice.

BMcD/Modus reached a similar conclusion, finding, "the process OPG has utilized for developing contingency to be sufficiently robust to support RQE" (Ex. D2-2-8, Attachment 2, p. 21). After acknowledging that OPG's DRP team utilized a number of AACE recommended practices for contingency development and supplemented them with the expert opinion and judgment of OPG's Nuclear Projects Executive Team, BMcD/Modus concluded that, "The [DRP] Contingency development process is rigorous and reasonably conforms to good industry practices" (Ex. D2-2-8, Attachment 2, p. 31).

The Use of P90 Estimate

RQE is an estimate of cost with contingency based on extensive planning and detailed estimating that is reliable to a 90% confidence level; otherwise referred to as a "P90" estimate. A P90 estimate means that there is a 90% chance that the actual project cost will not exceed the estimated amount (Ex. M1-4.3 AMPCO-9).

Independent experts have confirmed that a P90 estimate is a reasonable basis for estimating DRP costs. Pegasus-Global stated that:

> By performing a detailed cost estimate and schedule based on a thorough and robust probabilistic risk assessment of the Program, OPG has established a P90 confidence level of the cost to complete the Program and established an appropriate level of contingency, which in my opinion, is a reasonable cost estimate. (emphasis added) (Ex. D2-2-11, Attachment 3, p. 14).

And:

> Although no specific confidence level is considered a best practice, using a P90 confidence level provides OPG with a high probability that the Program will be completed within the budget. Using a lower confidence level, such as a P50 confidence level, may not adequately address the complexities and risks inherent with the execution of a megaprogram (particularly the extended duration of execution as compared to a typical project), thus increasing the risk of a cost overrun. (Ex. D2-2-11, Attachment 3, p. 56)

With specific reference to the Unit 2 schedule, Pegasus-Global again concludes that OPG's selection of a P90 confidence level is reasonable:

> While there is no prescribed standard for use of a particular confidence schedule over another, OPG, by selecting the P90 schedule for Unit 2, has demonstrated its risk tolerance preference for a high-confidence schedule (aligning with its use of a P90 estimate) to limit the likelihood of schedule overruns. I find OPG's selection of a P90 confidence level for the Unit 2 schedule to be reasonable and in accordance with the robust risk analyses that were performed. (emphasis added) (Ex. D2-2-11, Attachment 3, p. 62).

Schiff Hardin has also confirmed that the use of a P90 estimate is well within industry standards (Tr. Vol. 7, p. 60).

Both Schiff Hardin and Pegasus-Global further confirm that the selection of a P90 is a reasonable choice for all stakeholders involved, providing an estimate that creates a reasonable expectation that a project can come in on its schedule and budget (Tr. Vol. 5, pp. 154-155 and Tr. Vol. 7, p. 98). Schiff Hardin additionally notes that, "The vast majority of large capital improvement projects simply don't have the luxury of time, [or] the resources to develop a P90 before they go out", and that "OPG has taken advantage, has by design made sure that they had that luxury of time and effort to develop that P90" (Tr. Vol. 7, p. 98). During the hearing, in response to a question regarding the amount of contingency embedded within the P90 estimate, Schiff Hardin also noted:

> I don't -- I can't answer that, because that question presupposes that the P90 contingency is excessive, and I don't have any basis at this stage to make that statement. In fact, I mean, I think that on the process and procedure part of it, using a P90 in and of itself is a prudent, you know, decision. It's certainly, you know, something that I think anybody in the industry would say gives you a higher probability you're going to hit budget and schedule (emphasis added) (Tr. Vol. 7, pp. 51-52).

Furthermore, on the issue of the RFR contingency amount, BMcD/Modus confirmed that it is appropriate for OPG to hold additional contingency above the contractor's P50 amount to reach P90. BMcD/Modus noted, "…taking into account the level of planning and engineering performed to date, offset by the track record of prior CANDU refurbishments, the work performed to identify performance risks and the overall importance of RFR to the work, this level of contingency appears, at this stage, to be appropriate all from a process perspective" (Ex. D2-2-8, Attachment 2, p. 19). This conclusion was repeated in BMcD/Modus' final quarterly oversight report to the OPG Board of Directors (Ex. D2-2-9, Attachment 2, p. 10).

Finally, Concentric opined that a request for approval of P90 estimate is reasonable:

> I think it's prudent, from a company standpoint, to tighten that band as much as possible. It will have to show amounts above that estimate as being prudent before it would be able to file for inclusion in rates in the future.
>
> And as we know, and I think the record is established in this proceeding, there are a lot of ways that costs can vary from estimates even for the best planned projects of this type. So I don't find it unusual that the company would be looking for that type of a band in that regard, because even with that band, I think the risks are still substantial.
>
> …
>
> the project is ultimately for the benefit of ratepayers. This is going to be producing long-term power for Ontario consumers for 30 years post refurbishment. So the benefits and the costs should move in parallel with each other. (emphasis added) (Tr. Vol. 19, pp. 11-12).

In sum, all the experts in this proceeding have confirmed that it is reasonable and prudent for OPG to use a P90 amount based on the work that OPG has already completed to develop the robust RQE cost and schedule estimate.

5.5.9 Effective Management

A central focus of the DRP is to bring Unit 2 into service on time and on budget and with the quality required to support safe and reliable operation after refurbishment. To do so, building on OPG's rigorous planning effort, OPG has put in place effective measures to ensure the execution of the DRP as planned. These measures encompass a number of interrelated key features, including: (i) execution management, (ii) direct incentives for OPG, (iii) multiple layers of independent oversight, and (iv) appropriate reporting to stakeholders.

Execution Management

Execution management refers to the methods that OPG as the Program owner will use to manage the delivery of all DRP work safely, on time, on budget, and to the required quality. The functional groups responsible for execution management and support will enable OPG to ensure that: (i) interface with EPC contractors is effective and efficient; (ii) work is controlled and all changes are tracked using the integrated schedule and cost performance and monitoring tools; (iii) worker protection, conventional and nuclear safety, environmental safety, and plant safety requirements are met; (iv) all quality requirements are achieved; (v) risks are appropriately managed; and (vi) reporting, and internal and external oversight are appropriate.

Pegasus-Global examined OPG's execution management efforts and described them as follows:

> My assessment found that project controls are managed from both a program and project-level with the Project Planning and Controls (PP&C) group being accountable for the overall program- level scope, cost and schedule management, estimating, forecasting, risk management, and major milestone management. As such, PP&C has responsibility for establishing the project controls standards and tools that are used on the Program. I found that OPG has a dedicated program management plan for its intended use during planning and execution of the Program. This document provides an overview of the project controls functions as well as the roles and accountability of key personnel in the Program as it pertains to project controls. My review of the Program record and interviews with OPG personnel determined that the project controls systems in place on the Program include: Primavera P6 (schedule management); Ecosys (cost management); RMO (risk management and oversight); and an integrated database (used for reporting program/project metrics). (emphasis added) (Ex. D2-2-11, Attachment 3, p. 49).

To measure cost control and schedule compliance during execution, OPG has adopted an "earned value" methodology (Ex. D2-2-9, pp. 7-9). Earned value is a method to summarize many hundreds or even thousands of detailed schedule activities into simple time and cost indices. It allows the OPG project team to find the root cause of cost increases or schedule delays. This information helps mitigate adverse trends and improve forecasts of work completion (Ex. M1, pp. 21-22).

In Schiff Hardin's view, earned value is an extremely useful tool for tracking large volumes of work and forecasting contractor performance (Ex. M1, p. 21 and Tr. Vol. 7, p. 85). According to Schiff Hardin, "by effectively utilizing this tool during the Execution Phase, OPG has the opportunity to understand where problems are with the DRP's major contractors and will have the opportunity, with timely decision making, to develop appropriate problem-solving strategies utilizing that information" (Ex. M1, p. 23).

Similarly, Pegasus-Global opined that OPG has exceeded expectations in its use of earned value metrics:

> I think in, for instance, the way that they're looking at earned value, they're more granular than I have seen other utilities look at relative to the detail of the level of progress, the level of the actual budgets and costs that they are looking at in capturing.
>
> Some utilities roll those numbers up and do it at a more macro level. Darlington seems to be doing it at a much more lower level within the system and the program of those metrics which, in our view allows for earlier detection of issues that go to cost and schedule (Tr. Vol. 6, pp. 95-96).

Pegasus-Global also concluded that OPG has in place the necessary cost management procedures to monitor expenditures against RQE:

> Through my review of the Program project controls and OPG's management of costs, I identified aspects of OPG's cost controls to include:
>
> - Using standard project reporting to monitor cost performance;
> - Reporting and communicating cost trends, performance, and any corrective actions;
> - Developing sufficient cost detail to allow for effective cost monitoring, including alignment of the WBS and the cost accounts;

> - Ensuring proper project cost or control accounts are set up in OPG's cost management systems;
>
> - Ensuring planned value (or budget) is accurately allocated, and that actual cost is collected in the cost or control accounts to support measuring cost performance;
>
> - Ensuring accrual is captured in actual costs;
>
> - Identifying incorrect, inappropriate, or unauthorized charges and implementing corrective actions to rectify;
>
> - Performing cost trend analyses and forecasting the Estimate at Completion and cash flows; and,
>
> - Evaluating cost impacts of changing conditions and issues on the project budget and cash flow.
>
> These activities align with the program financial monitoring and control activities prescribed by PMI in its *The Standard for Program Management* (Ex. D2-2-11, Attachment 3, p. 57).

Throughout the Execution Phase, OPG's risk management process will continue to ensure that risks are identified, evaluated and acted upon. As the DRP progresses, OPG maintains and updates risk registers at both the program level and at the individual project level. The program risk register contains risks that apply to the entire DRP and risks that are related to DRP functions (e.g. supply chain, planning and control, etc.). The project risk registers are maintained for each individual work bundle and contain risks that apply to project work within the given bundle (e.g. balance of plant, fuel handling, etc.).

As stated by Pegasus-Global:

> I determined through my review of the Program record and interviews with OPG personnel that risks are reported as part of the monthly reporting cycle, including top risks from each bundle and function and key DRP program risks. The type of information included in the risk reporting includes a description of the risk, response strategy and status, current risk score, post-risk response risk score, and target date for reaching post-risk response score.
>
> The risk scores measure the probability of occurrence, schedule impact, and financial impact of a given risk and assists those inside and outside the project in quickly identifying the biggest risks to the project at a given point in time.

> … It is my opinion that OPG has, through a reasonable and prudent process, identified those risks that could potentially impact the Program's cost and schedule and has instituted practices in accordance with industry standards that will allow OPG early identification should any of those risks emerge, allowing OPG to quickly implement the mitigation plans, thereby either avoiding or minimizing the impact of that risk. (Ex. D2-2-11, Attachment 3, pp. 71-72).

OPG Incentives

OPG has extensive incentives in place to deliver the project safely, on time, on or under budget and to the requisite quality level. As Mr. Lyash indicated:

> What incentive does OPG have to come in under budget? I think there is a layered set of incentives that we have, beginning with the fact that we're an Ontario business corporation, so, as part of that, we have an obligation, a fiduciary obligation, to run the company in a certain manner, and as part of that, our long-term objective is to satisfy our customers so that we're rewarded with net income and return on equity. Successfully completing this project on or under budget, on or under schedule, we believe substantially increases the company's potential to be successful in the long run.
>
> The second incentive I point out to you is that, in regard to Darlington, we're a regulated generating company, and part of the compact for being a regulated generating company is to deliver value to the customer. And that's at the heart of the value proposition for a regulated utility. It is for OPG. And so delivering projects ahead of schedule and under budget in a way that lowers the customer's price is part of our core objectives.
>
> The third element, I think, that provides us an incentive is that our shareholder in this case, unlike most other companies, are the citizens of Ontario. And so they, through the provincial government, own the company. And so, in defining what shareholder value we're delivering, ahead of schedule, under budget, and lowest customer price is what our shareholder demands, and they exercise that through the Minister of Energy, and he has made that very clear.
>
> Another significant element here is that this is a destiny project for the company, and it is, frankly, a destiny project for the nuclear industry, and we're all very clear that meeting or exceeding expectations has tremendous value for the company and the industry in the long-term. This is also tied directly to management compensation, delivering not only the project but reliable and cost-effective operation of the units post-refurbishment.
>
> And then lastly -- and I would ask Mr. Reiner to comment on this -- we have built incentives down through the project management team and the contracts that we've structured" (Tr. Vol 1, pp. 37-40).

All of these incentives are very real and tangible for OPG (Tr. Vol 1, p. 122). OPG takes these incentives very seriously, and has described in detail how management compensation is tied to the success of the DRP through the corporate scorecard (Tr. Vol. 2, pp. 179-182 and Tr. Vol. 4, pp. 93-99). OPG has taken every opportunity to ensure that the incentives do, in fact, appropriately motivate the company to continually seek to improve its execution performance.

Oversight

Oversight is key to the successful execution of the DRP. Its purpose is to shine a light on the program to see which aspects need attention. Oversight works in tandem with risk management, which enables OPG to identify potential issues while oversight will direct attention to the issue and the need for action. Specifically, oversight will help to ensure that the DRP meets safety, quality, cost and schedule expectations; that issues are identified and resolved expeditiously; and that complete and accurate information flows up to the Board of Directors. As Mr. Reiner indicated:

> Well, so oversight will always identify problems. That's what oversight is there for. We don't bring in oversight to tell us that everything is going good. The idea is: Are there blind spots that the management team isn't seeing? We ask -- we ask them to be -- you know, these aren't -- these reports aren't about, "Tell us the good news." We want to understand everything that you, in your independent role, see as an issue. Identify it for us.
>
> The Refurbishment Construction Review Board is the same thing. You're always going to see reports with issues. The importance of that is: What is the project management team doing about those? What is OPG doing about the issues to rectify them to ensure there isn't a cost and schedule impact?
>
> Now, in the ideal world, all problems go away, and we never have another problem again, but there are going to be ebbs and flows in this. There are going to be issues. The issues will get identified, and we are going to address them in the course of execution, and it's going to be this way throughout the project (Tr. Vol. 3, pp. 116-117).

OPG has developed and implemented an assurance plan that features several layers of oversight. This tiered oversight is provided by program staff, external contractors, program leadership, enterprise leadership and external advisors. The oversight and assurance plan ensures appropriate oversight during the Execution Phase with a focus on key risk areas.

The plan will allow OPG to see issues early and to respond quickly. Key aspects of OPG's DRP oversight include:

- *Project-specific oversight processes and practices* based on risk management, operating experience, contract requirements, scope of work and reviews of contractor performance by each of the Project Management Teams, as well as by the Project Execution Support Function (Ex. D2-2-2, section 3.2.1);

- *Oversight of the Executing Organization* (see Section 5.5.4 above) by the DRP leadership team and by program functions, including the:

    - *Managed Systems Oversight Function,* which provides programmatic oversight based on risks and themes emerging from operational experience, project oversight data, and program and project risks (see section 3.2.6 of Ex. D2-2-2). Through the Program Assurance Group, the Managed Systems Oversight Function conducts surveillances across the projects focused on identifying emerging problems and opportunities in time to address them, including: process improvement, lessons learned and providing coaching and assistance to the project team and contractors as part of an effective risk management culture; and

    - *Planning and Controls Function,* which ensures cost and schedule compliance including forecasting, change management, and milestone adherence, effective risk management, and complete and accurate metric and progress reports.

- *OPG's Internal Audit group,* which provides oversight in a broad range of areas such as scheduling, cost estimates, contractor procurement, quality assurance, cost management, contractor time keeping and EPC contracts. OPG's Internal Audit group has functional independence from management. The Internal Audit group publishes the results of audits in a report and requires management actions be assigned, and tracked to completion. The results of all audits are presented to OPG's Chief Executive Officer and the OPG Board of Directors;

- *The Refurbishment Construction Review Board* ("RCRB"), which supports Program-level oversight by the Chief Nuclear Officer and the Chief Executive Officer. The RCRB provides independent assessments of DRP progress, estimates and schedules for early intervention and correction of any shortfalls in execution. The RCRB is comprised of approximately six external members with expertise in nuclear plant operations, mega-projects and relevant regulatory requirements, typically with support from one internal OPG member. It meets quarterly and reports directly to OPG's Chief Executive Officer and its Chief Nuclear Officer. The RCRB will also provide the OPG Board of Directors with an annual report on the scope and execution of the DRP; and

- *The Darlington Refurbishment Committee of OPG's Board of Directors,* which supports Program level oversight by OPG's Board of Directors. During the Definition Phase, OPG's Board of Directors engaged BMcD/Modus to provide oversight support. A copy of the final quarterly oversight report from BMcD/Modus to OPG's Board of Directors on the Definition Phase is provided in Ex. D2-2-8 Attachment 2. OPG's Board of Directors has re-engaged BMcD, with Modus as subcontractors, to provide independent oversight services during the Execution Phase. BMcD will validate the accuracy and completeness of reports from the DRP to the Darlington Refurbishment Committee and validate that DRP assurance processes at the program level are healthy, robust, and reviewing the right areas.

- *Infrastructure Ontario Advisor,* who provides independent oversight of DRP to the Ministry of Energy. The advisor sits as an observer on the Darlington Refurbishment Committee, and reports to the Minister of Energy on the status, performance and risks of the project following each quarterly meeting of the Darlington Refurbishment Committee (Ex. L-4.3-1 Staff-222).

As demonstrated by the many oversight reports (for example, Ex. L-4.3-1 Staff-72 and Ex. L-4.3-15 SEC-37) as well as the recommendations tracking logs (for example, Ex. L-4.3-15 SEC-32, Ex. JT1.8 and Ex. JT1.15) filed in this Application, OPG has treated issues identified by oversight very seriously and taken immediate action to remedy them.

Both Pegasus-Global and Schiff Hardin have opined that OPG has appropriate oversight in place over the DRP. Pegasus-Global indicated that, "OPG has efficient oversight in place, including senior and executive management and a Board of Directors (Board) with a focus on important process/progress issues; participation in strategic decisions; and, active in issue resolution" (Ex. D2-2-11, Attachment 3, p. 7). Schiff Hardin noted that, "OPG's project management plans including the use of audit and oversight is within industry standard practices" (Ex. M1, p. 28).

Reporting

The following information, while relevant to Issue 4.5, is also responsive to Issue 10.4.

For a program the size, complexity and duration of the DRP with significant impacts on a variety of diverse stakeholders, there are numerous reporting streams provided. These include internal reporting metrics, reporting between OPG's contractors and OPG, OPG's corporate reporting to the public, and the reporting OPG makes to the OEB for regulatory compliance. Furthermore, information and reports are generated at varying intervals, including daily, weekly, monthly, quarterly, and annually.

While more information is always available, depending on the audience for the reports, granularity on reporting can send mixed messages and raise more questions than answers

(Tr. Vol. 1, p. 100). Therefore, it is important on a project the size and complexity of the DRP that the information provided be accessible to the specific audience to which it is directed.

For regulatory reporting to the OEB, OPG proposes to file annual status reports for the duration of the Program. Chart 5.4 below illustrates the measures that OPG has committed to providing to the OEB for the duration of the DRP.

Chart 5.4

Proposed Content/Metrics for Reporting to the OEB
(Set out in Ex. D2-2-9 and Ex. L-4.3-12 OAPPA-2)

Category	**Measure**
Progress	• Key Achievements • % Complete
Safety	• All Injury Rate
Quality	• # of Significant Field Rework Events
Cost	• Cost Performance Index • Life-to-date cost • Forecast to Complete • Estimate at Complete
Schedule	• Schedule Performance Index • Status of Key Milestones • Critical Path Progress • Forecasted Completion Dates

OPG submits that the information listed above is the most relevant, important and helpful information to provide the OEB with an understanding of the DRP's progress and assist the OEB in exercising effective oversight over the Program.

Throughout this proceeding, OPG has additionally agreed to provide the public with a number of other measures on both a monthly and quarterly basis through the DRP's dedicated website on opg.com (Ex. JT1.18). OPG's communication plan to the public will necessarily evolve over time based on the activities and needs of the DRP and public response.

5.5.10 Early In-Service, F&IP and SIO

Early In-Service Projects, SIO and F&IP are projects that are a fundamental and pre-requisite part of the DRP. With the exception of the Heavy Water Storage and Drum Handling Facility ("D2O Project") that was removed from the approvals requested in this proceeding (Ex. N2-1-1), these projects have, for the most part, been completed.

Early In-Service Projects are capital work performed for the refurbishment that will be placed in service and included in rate base prior to the completion of Unit 2 refurbishment, because these projects provide immediate benefit to the nuclear station ahead of the Unit 2 return to service. The material Early In-Service Projects are:

- Tooling for Removal Activities;[27]
- Irradiated Fuel Bay Heat Exchanger Plate Replacement;
- Negative Pressure Containment;
- Heavy Water Islanding Modifications; and
- Low Pressure Service Water.

Descriptions for the Early-In Service Projects can be found on pages 2-4 of Ex. D2-2-10.

Safety Improvement Opportunities are initiatives which OPG committed to complete in the Environmental Assessment for the DRP that was approved by the CNSC. To meet required in-service dates, OPG commenced execution of SIO work early in the Definition Phase of the Program. The SIO are useful to OPG's current and future nuclear operations independent of whether the DRP is completed (Ex. D2-2-10, p. 4). The material SIO projects are:

- Third Emergency Power Generator;
- Containment Filtered Venting System;
- Powerhouse Steam Venting System Improvements;

[27] The tooling used exclusively for removal activities for the four units are placed in service ahead of completion of Unit 2 refurbishment and is being depreciated over its useful life, which is approximated by the feeder removal time periods for the four units. The unique treatment of these tools is consistent with the treatment of removal costs which, in accordance with US GAAP, are being expensed to OM&A in the period in which they are incurred (Ex. D2-2-10, p. 2; Ex. D4-1-1; Ex. L-6.4-1 Staff-113(a)).

- Shield Tank Overpressure Protection; and
- Replacement of Emergency Service Water Buried Services Line 60.

Descriptions of the SIO projects can be found on pages 4 to 7 of Ex. D2-2-10.

Facilities & Infrastructure Projects are necessary to enable execution of the unit refurbishments. A number of the F&IP involve upgrades to Darlington site infrastructure to ensure it can effectively support continued operations for 30 or more years. Other F&IP involve facilities that are needed to support DRP activities during the life of the program. To meet required in-service dates, OPG commenced the F&IP work early in the Definition Phase of the Program. The F&IP are expected to remain useful to OPG's current and future nuclear operations independent of whether the DRP is completed. The material F&IP projects are:

- Retube and Feeder Replacement Island Support Annex;
- Refurbishment Project Office;
- Water and Sewer Project; and
- Electrical Power Distribution Project.

Descriptions for the F&IP can be found on pages 7-22 of Ex. D2-2-10.

As noted above, OPG seeks approval of DRP rate base values as asset out under Issue 2.2, including the following forecast in-service additions over the 2016-2021 period: (i) $350.4M in the 2016 bridge year, (ii) $8.5M in 2017, (iii) $8.9M in 2018, (iv) $4,809.2M in 2020, and (v) $0.4M in 2021 (Ex. J21.1, Attachment 1, Tables 2 and 3, and Attachment 2, Table 1). The amounts reflect the in-service amounts sought after the removal of the D2O Project from this proceeding as described in Ex. N2-1-1, but do not reflect any further updates to forecast in-service dates or amounts from those in the pre-filed evidence. OPG is not updating its overall capital in-service forecast for the IR term (Ex. J21.1). The breakdown of the forecast capital in-service amounts for each project can be found in Tables 2 to 5 of Ex. D2-2-10.

5.5.11 Conclusion

As demonstrated above, OPG has undertaken prudent and reasonable steps to plan and execute the DRP and related Early In-Service projects, F&IP and SIO initiatives. The material that OPG has filed summarizes and explains 10 years of planning and preparation. OPG is well past the initial stages of the DRP. As Mr. Lyash explained:

> In fact, we're ten years into the project. So we've been through the initiation; we've been through the development stage. We have put tremendous effort into building up a cost, the schedule, a risk register, and a contingency. We've completed a long set of activities: tooling development, mock-up construction, processes, benchmarks. So we believe we have created enough work and work of a quality that it supports the estimate and schedule that we've laid out as reasonable.
>
> And given that we're essentially $2.9 billion into the project, now there is an adequate basis to evaluate and make a conclusion. And we think, by doing so, it supports execution of the project (Tr. Vol. 1, p. 67).

The DRP is an integrated mega-program that has been developed based upon industry best practices. OPG has completed extensive planning to drive high confidence cost and schedule baselines. The program and project management structures that OPG has implanted are designed to drive cost and schedule performance, provide necessary oversight and manage change. OPG’s effort has all been aimed at enabling the effective execution of the DRP, safely, on-time, on-budget and at the requisite quality. As Mr. Lyash summarized the matter:

> …we believe what we've done in terms of building a detailed cost, a detailed schedule, a detailed risk register, and the foundation we put this on demonstrates that the company has taken every reasonable action to deliver the project for 4.8, and that if we deliver it at 4.8, that should be a primary measure of prudence (Tr. Vol. 2, pp. 99-100).

On the basis of the evidence presented in this proceeding, including that of numerous experts who have confirmed the quality of OPG’s planning and preparation and its approach to project execution, OPG respectfully requests that OEB approve the forecast DRP in-service amounts and resulting rate base values.

6.0 PRODUCTION FORECASTS

6.1 ISSUE 5.1

Primary: Is the proposed nuclear production forecast appropriate?

OPG is seeking approval of the nuclear production forecast shown in Chart 6.1 (Ex. E2-1-1, Table 1). As discussed below, this represents a challenging production forecast for OPG's nuclear facilities during a period of unprecedented change in OPG's Nuclear Operations due to the DRP and Pickering Extended Operations.

Chart 6.1

Production Forecast

(TWh)	2017	2018	2019	2020	2021
Production Forecast	38.1	38.5	39.0	37.4	35.4

6.1.1 OPG Has Developed A Detailed Nuclear Production Forecast Using A Rigorous Methodology

OPG's nuclear production planning process establishes annual production forecasts for its individual nuclear units, an aggregated forecast for each station, and an overall corporate forecast (Ex. J12.9; Ex. E2-1-2, Table 1). Nuclear facilities are designed to operate continuously at full power as base load generators. Therefore, the annual nuclear production forecast is equal to the sum of the generating units' capacity multiplied by the number of hours in a year, less the number of hours for planned outages and forced production losses (i.e., unplanned outages and derates) as adjusted for sources of generation losses (i.e., lake temperature, grid losses and consumption (station service)) (Ex. E2-1-1, p. 5). As such, the production planning process is focused on establishing annual planned outage schedules and on estimating forced production losses (Ex. E2-1-1, pp. 6-10).

OPG's planned outage schedule identifies the number of days required for inspections and maintenance activities to ensure continued safe, reliable and long-term operation (Ex. E2-1-

1, p. 6). Outage durations are determined based on the scope of work defined for each outage while considering recent benchmarking efforts, industry best practices and the Nuclear business' commitment to continuous improvement (Ex. E2-1-1 p. 5).

Forced production losses reflect the fact that all generating units face the risk of unscheduled equipment problems that may require unplanned shutdowns or a derating of the generating unit (Ex. E2-1-1, p. 8). Accordingly, OPG develops challenging FLR targets that reflect the risk of such forced production losses for all units in the station. The FLR targets are based on the plants' historical performance, any known improvements or plant material condition issues, and initiatives to improve equipment reliability.

In EB-2013-0321, OPG changed its approach in developing its nuclear production forecast. This change entailed increased scrutiny to more fully and realistically recognize the scope, risks and complexity of work performed during outages, and where possible, basing the forecast on actual experience with similar work performed in the past at OPG and other organizations. In EB-2013-0321 the OEB accepted OPG's approach. The methodology used to develop OPG's 2017-2021 nuclear production forecast maintains the approach set out in EB-2013-0321.

6.1.2 Factors Influencing The IR Term Production Forecast

The major factors influencing the IR term production forecast are:

- The DRP with Darlington Unit 2 being taken out of service in 2016, followed by Unit 3 in 2020 and Unit 1 in 2021. Each unit refurbishment project will take more than three years to complete. Two post-refurbishment mini-outages have been scheduled for Unit 2 to address equipment reliability issues that are expected to emerge post-refurbishment. The need for these post-refurbishment outages is based on operating experience at other nuclear facilities that underwent major refurbishment. The first mini "warranty" outage of 55 days duration is scheduled for Unit 2 in 2020, within six months of completing refurbishment. This duration will allow sufficient time for anticipated equipment repair for newly installed components as well as repairs to laid up existing systems that may experience reduced reliability as a result of returning to service after a three-year shutdown (Ex. L-5.1-1 Staff-082). The second mini "warranty" outage of 31 days is scheduled in 2021, within 18 months of completing refurbishment. The shorter duration is due to an expectation that the majority of scope required to be addressed post-refurbishment will be completed during the first post-refurbishment outage in 2020 (Ex. L-5.1-1 Staff-082; Ex. JT2.17).

- Seven mini-outages of approximately 20 days duration at Darlington over the period 2017-2021 are required to replace the primary heat transport ("PHT") pump motors, which have a high risk of failure (Tr. Vol. 15, pp. 123-126). There are 16 operating PHT pump motors (four per unit) at Darlington. Failure of any one of the operating motors will result in a forced outage and could result in an extended outage, depending on availability of spare motors (Ex. L-5.1-12 OAPPA-006; Ex. JT2.21).

- Darlington forecast FLR of 1.0% for 2016 through 2019, 4.2% for 2020 and 3.0% for 2021. A Darlington FLR of 1.0 is extremely challenging - Darlington has never achieved a three-year rolling average FLR of less than 1% (Ex. L-6.2-15 SEC-063, Attachment 3, p. 53). The increase in FLR in 2020 and 2021 reflects the return to service of Darlington Unit 2 from its refurbishment outage and is consistent with industry operating experience. In particular, Unit 2's FLR is forecast to be 12% in 2020 and 6% in 2021 (Ex. L-5.1-1 Staff-081). Pickering's annual FLR is forecast to be stable at 5% for the period 2017 through 2021, reflecting expectations of reduced volatility in performance as a result of equipment reliability and fuel handling improvement initiatives (Ex. L-5.1-1 Staff-083).

- Undertaking 637 incremental planned outage days in 2016-2020 to enable the completion of various work activities required for Pickering Extended Operations as well as restoring normal planned outages and durations in 2020 (Ex. E2-1-1, p. 4; Ex. J12.11).

- Maintaining a three-year outage cycle for Darlington and a two-year outage cycle for Pickering. Continuation of using mid-cycle planned outages on Pickering Units 1 and 4 each year to focus on preventive maintenance to maintain reliability and lessen the risk of forced outages (Ex. J12.12). Planned outage durations include production allowances, consistent with the approach adopted in EB-2013-0321, to reflect the risk of generation loss due to forced extensions to planned outages. These allowances more fully and realistically recognize the scope and complexity of planned outages that will be undertaken in 2017-2021 to address equipment reliability, equipment aging and parts obsolescence on OPG's aging reactors at Darlington and Pickering (Ex. E2-1-1, pp. 7-8).

- A six unit Pickering Vacuum Building Outage ("VBO") is scheduled for 2021 (Ex. L-5.1-1 Staff-087(c)).

6.1.3 Production Forecast Risk

OPG's projected planned outage days, FLR, and generation losses during the IR term reflect challenging targets. While any production forecast is subject to unplanned outcomes, OPG continues to be subject to unanticipated production disruptions due to events such as an unbudgeted planned outage in 2015 to replace PHT pump motors at Darlington. Key risks to achieving the production forecast are discussed at Ex. L-5.1-1 Staff-085(c).

OPG has experienced significant revenue shortfalls due to variances between the nuclear production forecasts that underpin OEB approved nuclear rates and actual generation. As shown on Ex. E2-1-1, Chart 2, the average annual production shortfall over the 2008-2015 period was 3.2 TWh. This resulted in an average negative revenue impact of $154.0M borne each year by OPG's shareholder. In 2016, OPG's production was 1.2 TWh lower than the amount of production forecast in OPG's 2016-2018 Business Plan, which is the source of the production forecast used in this Application (Ex. J12.7).

In OPG's previous applications, a two-year production forecast was used to set OPG's payment amounts. In the current five-year Application, OPG has proposed a Mid-term Production Review that would allow OPG to update the nuclear production forecast (and consequential updates to nuclear fuel costs underpinning the payment amounts) for the final two-and-a-half years of the five-year period (i.e., July 1, 2019 to December 31, 2021) (Ex. A1-3-3). Even with the Mid-Term Production Review, OPG would be subject to a greater period of production forecast risk in this Application (30 months) than it was in its previous applications (24 months).

In its Decision with Reasons for EB-2007-0905, the OEB noted at page 174 that it believes "OPG should be fully incented to produce as accurate a forecast of nuclear production as possible and should be at risk if actual output falls short of forecast." While OPG will be challenged to meet the IR term nuclear production plan filed in this Application, it represents OPG's most complete and accurate forecast for the IR term and, therefore, should be approved.

7.0 OPERATING COSTS

7.1 ISSUE 6.1

Oral Hearing: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities (excluding that for the Darlington Refurbishment Program) appropriate?

7.1.1 Introduction

This section presents OPG's forecast nuclear OM&A costs, which constitute the OM&A expenditures necessary to safely, reliably and efficiently operate and maintain OPG's nuclear stations over the test period. As Chart 7.1 below demonstrates, OPG's nuclear OM&A costs are relatively flat over the five year test period (Ex. J14.2, Attachment 1). The maximum annual increase is 2% between 2018 and 2019 and the maximum annual decrease is 5%

between 2020 and 2021. Overall, OM&A costs decline over the period. While actual 2016 expenditures were below budget (Ex. J14.2), OPG continues to believe that the IR term forecast for base, project and outage OM&A are required to execute necessary additional work as explained below in Sections 7.1.2, 7.1.3 and 7.1.4, respectively.

Chart 7.1

Test Period Nuclear OM&A ($M)

	2016 Actual	**2017 Plan**	**2018 Plan**	**2019 Plan**	**2020 Plan**	**2021 Plan**
Base OM&A	1,182.4	1,210.6	1,226.0	1,248.4	1,264.7	1,276.3
Project OM&A	89.3	113.7	109.1	100.1	100.2	86.8
Outage OM&A	306.7	394.6	393.8	415.3	394.4	308.5
Total	**1,578.3**	**1,718.9**	**1,728.9**	**1,763.8**	**1,759.4**	**1,671.6**

7.1.2 Base OM&A

Base OM&A provides the main source of funding for operating and maintaining the nuclear facilities to ensure they operate safely, meet all applicable regulatory standards, achieve targeted levels of production, and maintain and improve their reliability (Ex. F2-2-1, p. 1). Base OM&A also funds regular labour for planned outages, the cost of all forced outages and derates and the indirect costs of commercial activities such as the provision of inspection and maintenance services to OPG facilities.

As shown in Chart 7.1, OPG's base OM&A funding request demonstrates the company's commitment to cost control. Even before applying the 0.3% stretch factor to base OM&A (see Section 12.2.5), the forecast average annual increase during the IR term is about 1.3% with the yearly increases ranging from a high of 1.8% to a low of 0.9%. Including the stretch factor, the IR term average increase falls to 1.0% and the corresponding range becomes 1.5% to 0.6%. These modest increases in the face of labour and material cost escalation reflect OPG's continued focus on controlling cost and incorporate the planned results from OPG's various value for money, fleet wide and site initiatives to reduce costs as part of its focus on continuous improvement.

The 2017 base OM&A forecast represents a 2.4% increase over 2016 actual expenditures. This increase is due in part to actual 2016 expenditures being below plan primarily because of greater than anticipated attrition and the lag in filling vacancies in 2016 (Ex. J15.12). This lag is being addressed through the new hiring processes OPG implemented during 2016 (Ex. L-11.4-1 Staff-255 (a) (i)).

OPG's planning identified specific objectives and focus areas that impact base OM&A costs. Several of the initiatives discussed in Ex. F2-1-1, Section 3.5, including Human Performance, Equipment Reliability, Outage Performance, Parts Improvement, Inventory Reduction and Workforce Planning and Resourcing use base OM&A resources to achieve nuclear performance targets for safety, reliability, value for money and human performance. Base OM&A resources will also be employed for inspection and maintenance and project support to address life cycle aging of equipment at Darlington to ensure safe and reliable operation before, during, and after refurbishment, as well as similar support at Pickering as part of OPG's plan to operate Pickering until 2022/2024 (Ex. F2-2-1, pp. 4-5).

The work encompassed by base OM&A is primarily accomplished through the use of OPG labour, which comprises about 70% of base OM&A cost in the IR term (Ex. F2-2-1, Table 2). As noted in testimony, however, OPG uses a variety of resources to accomplish its base OM&A activities as circumstances require and makes tradeoffs among regular labour, overtime, augmented staff and purchased services depending on the cost and availability of these resources and the timeframe within which specific tasks need to be accomplished (Tr. Vol. 14, pp. 8-9). This flexibility is a key attribute of OPG's resourcing strategy and is required to maximize responsiveness and manage total costs (see also Section 7.7.3).

The modest increase in forecast base OM&A costs over the IR term demonstrates that OPG has embraced the culture of cost control and the forecast should be approved as requested.

7.1.3 Project OM&A

As shown in Chart 7.1, OPG is requesting approval of forecast project OM&A expenditures during the IR term of \$113.7M (2017), \$109.1M (2018), \$100.1M (2019), \$100.2M (2020) and \$86.8M (2021).

OPG defines a project (whether capital or OM&A) as a temporary, unique endeavor undertaken outside the routine base activities of the normal work program. Project OM&A funds are expended on activities that meet the criteria for categorization as a project, but do not meet the criteria for capitalization. The final decision on whether work will be classified as a nuclear project is made by the AISC having regard to the complexity and materiality of the work (Ex. F2-3-1, p. 1). A description of the initiation, review and approval process for nuclear projects, including OM&A projects, is provided above under Issue 4.2 (see Section 5.2).

The forecast project OM&A expenditures include both portfolio and non-portfolio projects (Ex. F2-3-1, p. 2). Portfolio project costs are those included in the budget managed by the AISC and come in three types:

- Allocated Portfolio Projects, which are AISC-approved projects that have an approved business case summary;
- Unallocated Portfolio Projects, which represent work that is progressing through the review and approval process but does not yet have an AISC-approved budget; and
- Infrastructure, which includes project management costs, project initiation costs for conceptual design work, minor modifications (projects less than $200k), and project cancellation costs (Ex. F2-3-1, p. 2).

Non-portfolio projects are major undertakings managed outside the AISC process due to their extraordinary nature. There are two non-portfolio projects with expenditures during the IR term: the Fuel Channel Life Extension Project, and Pickering Extended Operations. The Fuel Channel Life Extension Project supports the high confidence that the fuel channels in Pickering can operate to 261,000 Equivalent Full Power Hours ("EFPH") and those in Darlington can operate to 235,000 EFPH (Ex. F2-3-3, Attachment 1, Tab 4). This project is jointly funded with Bruce Power (Ex. F2-3-1, p. 3). Pickering Extended Operations is discussed under Issue 6.5 (See Section 7.5).

The level of project OM&A expenditures reflects forecasted work program demands. Project OM&A spending is forecast to increase in 2017 primarily due to increased expenditures at Pickering to address life cycle aging of equipment and regulatory requirements resulting from the decision to operate Pickering until 2022/2024, as well as increased infrastructure spending at Pickering and Darlington for minor modifications. Actual 2016 project OM&A was slightly below 2016 budget (Ex. J14.2, Attachment 1). The slight decreases in spending between 2017 and 2018 to 2020 reflects end of the Fuel Channel Life Extension Project in 2017. This decrease is partially offset by increased spending for Pickering Extended Operations over the IR term (see Ex. F2-3-1, p. 1). The reduction in 2021 reflects reductions in spending at Pickering due to the completion of Pickering Extended Operations enabling costs in 2020 (*Id.*). As discussed under Issue 6.5 (see Section 7.5), over the period 2016-2020, $61.6M in project OM&A is included in the $307M of Pickering Extended Operations enabling costs (Ex. F2-3-1, p. 2).

Nuclear project OM&A expenditures are categorized as regulatory, sustaining or value enhancing/strategic (Ex. F2-3-1, Table 2). The overwhelming majority of identified OM&A project expenditures relate to sustaining projects required to operate safely and maintain unit reliability. The remainder of the identified projects are regulatory, but the spending on identified regulatory projects declines over the IR term as projects required in the wake of Fukushima are completed.

The evidence in this proceeding demonstrates that OPG has a robust and well managed process for selecting and executing projects. Based on this evidence, OPG's project OM&A budget is reasonable and should be approved.

7.1.4 Outage OM&A

Outage OM&A includes the expenditures on the incremental labour (e.g., overtime, temporary staff and external contractors), services and materials necessary to complete OPG's planned outages along with Inspection and Maintenance Services ("IMS") regular staff labour (Ex. F2-4-1, pp. 1-3). As shown in Chart 7.1, the IR term outage OM&A expense is $394.6M (2017), $393.8M (2018), $415.3M (2019), $394.4M (2020) and $308.5M (2021). Outage OM&A costs vary year over year depending on the number and scope of outages undertaken in each year and therefore do not demonstrate a consistent trend over time. Chart 7.2 shows the types of nuclear outages planned for the 2017 to 2021 period (Ex. F2-4-1, p. 2).

Chart 7.2

Outage Type and Frequency 2017-2021

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Darlington Unit Outages [1]	Unit 1	Unit 3	Unit 4	Unit 1	None
Darlington Station Outages	None	None	None	None	None
Darlington Refurbishment Outages	Unit 2	Unit 2	Unit 2	Unit 2; Unit 3	Unit 3; Unit 1
Darlington PHT Pump Replacement Mini Outages	Unit 3; Unit 4	Unit 1; Unit 4	Unit 1	Unit 4	Unit 4
Darlington Post-Refurbishment Outages	None	None	None	Unit 2	Unit 2
Pickering Unit Outages	Unit 1,5,6	Unit 4,7,8	Unit 1,5,6	Unit 4,7,8 [2]	Unit 1,5,6
Pickering Station Outages	None	None	None	VBO Preparation	Units 1-8 VBO
Pickering Mid-Cycle Outages	Unit 4	Unit 1	Unit 4	Unit 1	None

[1] Unit 2 will be subject to inspection and maintenance activities over the period 2017-2019 associated with a planned outage in accordance with OPG's aging and life cycle management programs, in addition to and separate from the refurbishment of the units.
[2] The scope for the Unit 7 outage in 2020 is limited as it is solely for Pickering Extended Operations and therefore excludes "typical" planned outage.

OPG develops its forecast of outage OM&A expenses as part of its business planning process. The outage planning process begins with a refresh and challenge of major scope required to be completed in each outage during the planning period. This typically defines the duration and flow of each outage. Each outage plan is unique and is updated periodically based on scope changes that arise from inspection programs, component aging management and system health analysis, and discovery work. OPG then estimates the hours required to complete the defined scope and develops a resource plan that provides the required mix of regular, non-regular, augmented staff, other purchased services and overtime necessary to accomplish the planned outage work. However, the selection of which option to employ is an ongoing resource optimization process of available fleet resources and depends on the specific circumstances of each outage (Ex. F2-4-1, pp. 4-5). Finally, OPG solicits Request for Interest quotations for contractor work and estimates the cost of materials required based on the amount of work in the outage overlaid with major materials purchases (Ex. L-6.1-5 CCC-026).

Outage OM&A spending in 2017 is significantly higher than 2016 budgeted amounts, which were higher than actual 2016 spending (Ex. F2-1-1, Table 1; Ex. J14.2). The increase in the forecast for 2017 is primarily due to additional work at Darlington related to routine station inspection and maintenance work required on Unit 2 during the Unit 2 refurbishment outage. Darlington is also forecasting increased outage scope related to generator and transformer work and Single Fuel Channel Replacement. For Pickering, additional work is required for Extended Operations, as discussed under Issue 6.5 (Section 7.5). From 2017 to 2020, forecast outage OM&A expenditures are fairly stable before dropping significantly in 2021 primarily because there is no scheduled Darlington planned outage (except for a short post-refurbishment outage for Unit 2) and because outage OM&A associated with Pickering Extended Operations is expected to be completed in 2020, partially offset by a planned Pickering VBO in 2021.

OPG's forecast outage OM&A spending is necessary to properly inspect and maintain the prescribed nuclear facilities and should be approved.

7.2 ISSUE 6.2

Oral Hearing: Is the nuclear benchmarking methodology reasonable? Are the benchmarking results and targets flowing from OPG's nuclear benchmarking reasonable?

7.2.1 Introduction

This section discusses OPG's nuclear benchmarking and the top-down gap-based nuclear business planning process first implemented in 2009 based on the methodology developed by ScottMadden Management Consultants ("ScottMadden") (Ex. F2-1-1, p. 3). OPG submits that its continued reliance on the benchmarking and gap-based nuclear business planning methodology, which consists of four steps (benchmarking, target setting, gap closure and resource planning), is a reasonable method of evaluating nuclear performance against other operators and working to improve it. Furthermore, the benchmarking results and the targets chosen by OPG are appropriate and have been accepted by the OEB in previous proceedings as reasonable (see, e.g., EB-2013-0321, Decision with Reasons, November 20, 2014, p. 45). Consistent with the OEB's decision in EB-2013-0321, OPG produced and filed annual nuclear benchmarking reports using the methodology developed previously by ScottMadden (*Id.*).

While benchmarking provides insight into relative cost and performance, it is not a precise tool because of the inherent technological and regulatory differences between OPG and the comparators and the aggregate nature of the data used in benchmarking (Ex. F2-1-1, p. 3). Comparison of OPG's CANDU units to industry benchmarks is further complicated by differences that exist between Darlington and Pickering (e.g., unit size, technology and design) (Ex. F2-1-1, pp.3-4). Thus, OPG believes that benchmarking results are directional and need to be interpreted in context (Tr. Vol. 13, p. 8, line 23 - p. 9, line 3). Based on these factors, benchmarking results should not be used as a prescriptive tool for setting appropriate cost levels.

This Application covers a period of significant change in OPG's nuclear operations. Executing both the DRP and Pickering Extended Operations poses unique challenges in terms of business planning and benchmarking, as generators in the comparator group are unlikely to be undergoing changes of this magnitude (Tr. Vol. 13, p. 42). In this environment, the OEB's prior finding that: "[b]enchmarking serves as a guide only" is particularly applicable (EB-2013-0321, Decision with Reasons, November 20, 2014, p. 46).

7.2.2 2015 and 2016 Benchmarking Reports

In 2015, OPG prepared a 2015 Nuclear Benchmarking Report, based on 2014 data, that benchmarks OPG's performance against industry peers using 20 indicators aligned with the cornerstone values of Safety, Reliability, Value for Money and Human Performance (Ex. F2-1-1, Attachment 1). In 2015, ScottMadden conducted an independent review and validated the ongoing appropriateness of OPG's application of the benchmarking methodology (Ex. F2-1-1 Attachment 3).

OPG conducted a 2016 Nuclear Benchmarking Report using 2015 data and filed it upon completion (Ex. L-6.2-15 SEC-063, Attachment 3).[28] This report uses the same indicators, methodology and comparators as the 2015 Nuclear Benchmarking Report.

OPG's 2016 Benchmarking Report demonstrates strong safety performance at both of its nuclear stations. The 2016 Report shows that OPG's overall reliability performance declined in 2015. While Pickering's reliability performance improved, this improvement was insufficient to offset the decline in Darlington performance as discussed below. The decrease in overall reliability contributed to the decline in the Total Generation Cost per MWh ("TGC/MWh") benchmark. In 2015 OPG improved in the area of Human Performance due to an increased focus on initiatives to drive performance (Ex. L-6.2-15 SEC-063, Attachment 3, pp. 6-8).

The 2016 Benchmarking Report shows that Pickering's TGC/MWh improved slightly in 2015. Since 2010, Pickering has been able to maintain a stable TGC/MWh, thereby improving its relative performance against the Value for Money benchmark, reflecting the fact that industry costs are escalating as demonstrated by the increase in the top quartile and median TGC/MWh values (Ex. L-6.2-15 SEC-063, Attachment 3, p. 70). During the 2010 to 2015 period, Pickering's TGC/MWh was relatively flat with an annual compound growth rate of 0.5%, whereas the industry top quartile and median experienced compound annual growth rates of 3.4% and 2.1% per year, respectively, over the same period (Ex. L-6.2-15 SEC-063, Attachment 3, p. 71). Nevertheless, Pickering's TGC/MWh metric remains in the 4th quartile due to its smaller unit size, first generation CANDU technology and low capability factor attributable to the extensive planned outage program that is required to extend the life of Pickering (Ex. F2-1-1, p. 3; Tr. Vol. 13, p. 15, lines 14-27).

Darlington has been recognized by the World Association of Nuclear Operators ("WANO") as being among the best performing nuclear plants in the world (Tr. Vol. 13, p. 28; Tr. Vol. 15, p.150). In contrast to Pickering, Darlington's larger unit size, third generation CANDU technology improvements and lower fuel costs have enabled it to compete favourably against comparable Pressurized Water Reactors ("PWR") and Boiling Water Reactors ("BWR") reactors in the United States despite the technology related cost difference (Ex. F2-1-1, p. 4).

[28] The 2014 Nuclear Benchmarking Report, which uses 2013 data, was also filed at Ex. L-6.2-15 SEC-063, Attachment 1.

Historically, Darlington has benchmarked very well on the TGC/MWh metric, being in the top quartile between 2011 and 2014 (Ex. K12.4, p. 18). This performance reflected OPG's cost management and strong generation performance (Ex. F2-1-1, p. 9).

In 2015, Darlington's TGC/MWh moved from first quartile into second quartile. This change in quartile ranking was driven by the VBO that required the shutdown of all Darlington units in 2015 (a requirement only once every 12 years),[29] an increased forced loss rate, partially attributable to PHT pump-related outages, and capital investments required to achieve strong reliability and operating performance post-DRP (Tr. Vol. 13, p. 24, line 26 - p. 25, line 17, p. 28, lines 10-20). Darlington had 234 more outage days in 2015 than in 2014 mainly due to the 2015 VBO (Ex. L-6.2-15 SEC-063, Attachment 3, p. 71). Increased outage costs associated with the VBO were also a key driver of increased 2015 OM&A costs. Finally, Darlington's capital costs continued to increase in 2015 due to aging plant equipment, refurbishment support and regulatory requirements for extended life at Darlington (Ex. L-6.2-15 SEC-063 Attachment 3, pp. 71-72, Tr. Vol. 13, p. 30 lines 10-18).

With the exception of OPG and Bruce Power, all of the comparators in the ScottMadden Benchmarking for TGC/MWh are U.S. PWR and BWR reactors (Ex. L-6.2-15 SEC-063, Attachment 3, p. 103). The Goodnight Consulting Nuclear Staffing Study ("Goodnight") (discussed further below) shows that technology, design and regulatory differences exist between CANDU and PWR units and that these factors result in higher staffing levels for CANDU plants (Ex. F2-1-1, p. 4). As staffing costs represent a significant per cent of nuclear base OM&A costs (Ex. F2-2-1, Table 2), these factors contribute to Darlington's and Pickering's TGC/MWh performance relative to benchmark.

Despite the inherent limitations of benchmarking noted above, OPG continues to believe that benchmarking is a useful tool to evaluate OPG's high level operating and financial performance compared to other operators in the nuclear generation industry. The major operator results indicate that OPG's nuclear business performs well across a broad range of

[29] For Darlington, prior to 2015 a station-wide four unit VBO was required every 12 years and a Station Containment Outage ("SCO") every six years. A SCO also requires that all four units be shut down, but for a shorter duration. However, OPG was successful in obtaining CNSC consent to implement a 12-year VBO/SCO cycle versus continuing with a 12-year VBO/6-year SCO cycle. In 2015, the Darlington VBO that was scheduled for 2021 was brought forward and combined with the SCO, which moved it out of the refurbishment window (Ex. F2-4-1, pp. 7-8).

industry operational measures and improvement in some areas has been achieved to-date. OPG has taken a prudent and reasonable approach in response to the benchmarking results by setting business plan targets that will allow OPG to narrow the identified performance gaps at a pace consistent with continuing safe operation.

In addition, OPG's Custom IR proposal in this Application (discussed in Section 12.5) includes a benchmarking-based stretch factor to drive continuous improvement. By 2021, the proposed stretch factor will require that OPG find savings across Nuclear Operations equal to 0.9% of its total forecast nuclear OM&A costs in that year (Ex. A1-3-2, p. 33).

7.2.3 Goodnight Nuclear Staffing Study Results

Since the last payment amounts proceeding, OPG continued to examine staffing levels as part of its benchmarking studies. In 2016, OPG determined that the staffing benchmark gap to industry peers shown in the 2014 Goodnight Study had been eliminated and OPG staffing was less than benchmark (Ex. F2-1-1, p. 11; Ex. L-6.2-19 SEP-003(a); Tr. Vol. 14, p. 44, line 15-26, p. 45, lines 7-17). OPG FTEs during 2017-2021 are expected to continue to remain at or below the 2014 Goodnight benchmark (Ex. L-6.2-19 SEP-003(b)).

OPG first engaged Goodnight in 2011 to undertake a nuclear staffing benchmarking analysis in response to the OEB direction in EB-2010-0008 to examine its nuclear staffing levels. Goodnight benchmarked the staff supporting steady state operations, including regular and non-regular staff, augmented staff, and contractor labour in the "other purchased services" category. The initial Goodnight study conducted in 2011 indicated that OPG Nuclear was 17% above its industry peers (normalized for CANDU technology differences).[30] Two subsequent updates by Goodnight demonstrated that OPG was successful in reducing the gap to 8% by 2013 and further to four percent by the latest analysis conducted in 2014. The 2014 Goodnight study concluded that reductions were largely due to initiatives undertaken by OPG, including the centre-led initiative (i.e., Business Transformation) and the Pickering station amalgamation, that have allowed OPG to manage staff resources primarily through attrition. The industry peer benchmark showed modest increases during this period (Ex. F2-1-1, Attachment 2, p. 34).

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[30] This report, dated February 2012, is filed at EB-2013-0321, Ex. F5-1-1, Part a.

OPG has been successful in achieving Business Transformation targets through attrition (Tr. Vol. 13, p. 22, lines 4-15). Using the same approach as the Goodnight study, OPG has determined that its 2016 staffing level was below the 2014 Goodnight staffing benchmark (Ex. L-6.2-19 SEP-003(a)). Over the IR term, OPG staffing is expected to continue to remain at or below the 2014 Goodnight benchmark (Ex. L-6.2-19 SEP-003(b)).

7.2.4 OPG's Response to the Goodnight Nuclear Staffing Studies

OPG has accepted the methodology and observations of the Goodnight studies as reasonable for the purpose of benchmarking staff levels (in total and by function) between OPG CANDU units and U.S. PWR units. OPG agrees with the conclusion from the application of the Goodnight methodology that technology/design/regulatory differences exist between CANDU and PWR units and that such factors drive differences in staffing levels (Ex. F2-1-1, pp. 12-13).

Since 2011, OPG has implemented nuclear staffing plans in response to the conclusions of the Goodnight studies that OPG nuclear staffing was above comparable benchmark. Achieving the business plan targets for staff numbers required continuous monitoring, controls and initiative development and implementation to streamline processes and find efficiencies to offset the staff reductions that occurred through attrition (Ex. F2-1-1, p. 13).

In 2015 and 2016, actual FTEs were below budgeted FTEs primarily due to higher than planned attrition and delays in hiring Nuclear Operations regular staff (Ex. F2-1-1, p. 13; Tr. Vol. 13, p. 49, lines 10-14). The planned increase in FTEs in 2017 reflects completion of hiring to the level required to sustain Nuclear Operations, undertake Extended Operations at Pickering and increase staffing for DRP. The planned hiring in 2017 would restore staffing to a sustainable level, but would not move OPG above benchmark (Ex. F2-1-1, p. 13; Tr. Vol. 13, p. 50, lines 14-21).

Nuclear Operations staffing trends downward reflecting continuous monitoring and controls as well as development and implementation of initiatives to streamline processes and identify efficiencies to accommodate expected staff attrition (Ex. F2-1-1, p. 13; Ex. J14.6).

OPG has pursued a measured approach in Nuclear staff management. This has allowed OPG to undertake ongoing initiatives to improve reliability and implement industry best practices, while maintaining safe and reliable operations as its top priority.

7.2.5 Gap Based Business Planning: Target Setting

Top-down targets are designed to close performance gaps and significantly drive OPG's Nuclear Operations performance over the business plan. The top-down approach establishes operational, financial, generation and staff targets set by reference to historical performance, targets established in the prior years, and updated benchmarking results (Ex. F2-1-1, p. 14).

OPG's projected targets for the 2017-2021 period are shown at Chart 4 and Chart 5 of Ex. F2-1-1, pp. 15, 17. These targets are challenging, but achievable. They were set on the basis that Darlington and Pickering will require significant investment and operational excellence to achieve the desired outcome of low cost, safe and reliable generation (Ex. F2-1-1, p. 14).

For the Safety cornerstone, OPG is targeting either best quartile performance or maximum nuclear performance index ("NPI") points at both stations with a focus on improving Collective Radiation Exposure at Pickering and the Fuel Reliability Index at Darlington (Ex. F2-1-1, p. 16).

For the Reliability cornerstone, OPG is targeting best quartile FLR (1%) at Darlington on units not undergoing refurbishment over the test period.[31] OPG is targeting a 5% FLR at Pickering over the IR term, which compares favourably to the average Pickering FLR of 8.5% over the period 2010-2015 (Ex. E2-1-1, Section 3.1.2). OPG is targeting a lower FLR at Pickering based on past and expected future improvements in equipment reliability. Both Pickering and Darlington are targeting reductions in Online Deficient and Corrective Maintenance backlogs. However, due to the extensive additional planned outage days for Pickering Extended Operations, Pickering's unit capability factor is targeted to be lower than current levels (Ex. F2-1-1, p. 16). OPG's production forecast is based on these targets as discussed above in Section 6.1.

[31] Darlington's FLR in 2020 and 2021 is impacted by the assumed FLR for refurbished Unit 2 returning to service and is consistent with the assumptions that underpin the Darlington Refurbishment Execution Phase Business Case (Ex. D2-2-8, Attachment 1). This issue is discussed in Section 6.1.2 above.

For the Human Performance cornerstone, OPG expects to realize improved performance at Darlington by targeting reductions in the human performance error rate (“HPER”) over the 2016-2018 business planning period. Pickering’s HPER is targeted to remain unchanged over this period, in line with the median benchmark level (Ex. F2-1-1, p. 17; Ex. L-6.2-19 SEP-004).

For the Value for Money cornerstone, Pickering’s TGC/MWh is expected to remain in the fourth quartile for reasons noted above (i.e., its smaller unit sizes, first generation CANDU technology and low unit capability factor resulting from the extensive planned outage program associated with Pickering Extended Operations).

The TGC/MWh targets for Darlington have been calculated on a normalized and non-normalized basis to account for the impact of reduced unit output during Darlington Refurbishment (Ex. L-6.2-1 Staff-101(a) and (b); Ex. JT2.09). The denominator in TGC/MWh, i.e., MWh, declines because units are being refurbished but there is not a corresponding decline in the numerator, as support costs and station costs are largely fixed (Ex. L-6.1-2 AMPCO-092; Ex. L-6.2-1 Staff-101, Attachment 1, p. 6). The net impact will be to temporarily skew these metrics higher than would otherwise be the case. Nuclear Operations has set internal performance targets for TGC/MWh on a non-normalized basis, but for benchmarking against industry peers, will compare Darlington’s performance using a normalized TGC/MWh metric. ScottMadden evaluated OPG's approach to normalizing TGC/MWh during DRP and ScottMadden found that while it was unique to OPG, it was logical, reasonable, and easy to understand (Ex. L-6.2-1 Staff-101, Attachment 1).

Darlington’s normalized TGC/MWh is expected to increase until 2020 and is not expected to be at top quartile during this period given the need for capital investment to support operations after refurbishment is complete and maintain strong reliability, and not as a result of a decrease in the station’s fundamental performance (Tr. Vol. 14, p. 22 line 23 - p. 25 line 3).

OPG has a comprehensive plan to perform non-refurbishment inspection and maintenance work on the Darlington unit that is offline for refurbishment (Ex. F2-4-1, p. 1). This work includes preventative and corrective maintenance and outage inspections that would normally be done as part of OPG’s aging and lifecycle management programs during scheduled outages (Ex. L-6.1-1 Staff-096). Instead, it will be accomplished while the unit is undergoing refurbishment (Tr. Vol. 13, p. 68, lines 7-26). OPG is planning to do work on equipment that cannot be done when the unit is operating, including working on equipment for the first time since the unit began operating. This approach ensures that the units will return to service positioned to achieve strong reliability and safety performance post-Refurbishment (Tr. Vol. 14, p. 23, line 15 – p. 24, line 10). Incremental investments are also needed over the rate-setting period to address specific reliability matters (e.g., PHT pump motors, as discussed at Ex. F2-4-1, p. 7).

The anticipated improvement in Darlington's normalized TGC/MWh in 2021 is largely attributable to the planned refurbishment of two units in 2021 (Ex. F2-1-1, p. 17). As there is no planned outage at Darlington in 2021, except for a short post-refurbishment outage for Unit 2, outage OM&A is forecast to be significantly lower in that year (Ex. F2-1-1, p. 17).

7.3 ISSUE 6.3 (PARTIALLY SETTLED)

Secondary: Is the forecast of nuclear fuel costs appropriate?

7.3.1 Introduction

This issue was partially settled as part of the approved Settlement Agreement (Ex. O-1-1, pp. 9-10; Tr. Vol. 9, p.1). As described at Ex. O-1-1, p. 9, the Parties have agreed to a 2% downward adjustment to the nuclear fuel bundle unit cost forecast in each year of the IR term relative to the forecast in the Application at Ex. F2-5-1, Table 1, line 4, resulting in fuel bundle unit costs as follows: $4.18/MWh (2017), $4.14/MWh (2018), $4.07/MWh (2019), $4.39/MWh (2020), and $4.19/MWh (2021).

Nuclear fuel costs consist of the weighted average cost of manufactured uranium fuel bundles loaded into a reactor ("nuclear fuel bundle cost"), used nuclear fuel storage and disposal costs, and fuel oil costs (Ex. F2-5-1, p.1). As indicated in Ex. F2-5-2, actual nuclear fuel bundle costs are driven by total energy production, unit cost of new fuel loaded, and fuel utilization efficiency.

The unsettled aspects of this issue, as discussed in the next section, are:

- The impact of the approved production forecast on annual nuclear fuel bundle cost;

- All components of used nuclear fuel costs; and
- Fuel oil costs.

7.3.2 Unsettled Components of OPG's Fuel Costs Forecast

OPG's nuclear production forecast (Issue 5.1) is discussed above at Section 6.1 and in Ex. E2-1-1. OPG is seeking approval of the nuclear production forecast shown in Chart 6.1 in Section 6.1 above. The approved nuclear production forecast will be combined with the agreed upon nuclear fuel bundle unit cost to determine the annual nuclear fuel bundle cost included in the revenue requirement.

Used nuclear fuel storage and disposal variable costs (Issue 8.2) are covered in Section 9.1 and in Ex. C2-1-1, Ex. C2-1-2 and Ex. N1-1-1.

Fuel oil is used to run stand-by generators at OPG's nuclear stations. OPG's fuel oil forecast ranges between $4.3M and $4.7M over the IR term. These amounts are less than the 2015 actual spending of $5.1M (Ex. F2-5-1, Table 1, line 6). OPG submits that the proposed fuel oil cost forecast is appropriate and should be approved.

7.4 ISSUE 6.4

Oral Hearing: Is the test period Operations, Maintenance and Administration budget for the Darlington Refurbishment Program appropriate?

While the vast majority of the DRP expenditures are capitalized, the DRP RQE does include expenditures for removal costs and the variable expenses related to the disposal of low and intermediate level waste ("L&IL") that are properly expensed as OM&A (Ex. D2-2-1, p. 3, ft. nt. 2; Ex. F2-7-1, p. 1). A breakdown of requested DRP OM&A costs is provided below in Chart 7.3 (Ex. L-6.4-20 VECC 28). About 90% of the forecast expenditures shown in Chart 7.3 are removal costs, which are charged to OM&A in accordance with US GAAP, as in previous proceedings (Ex. L-6.4-1 Staff-113(a)). These costs are subject to CRVA treatment.

Chart 7.3

DRP OM&A Costs

(M$)	2017	2018	2019	2020	2021
Removal Costs					
Retube and Feeder Replacement	24.7	2.8	0.6	30.3	11.8
Turbine Generator	1.0	-	-	1.0	1.0
Balance of Plant	2.8	-	-	3.0	3.1
Fuel Handling	10.4	8.7	-	11.1	-
Total Removal Costs	**39.0**	**11.6**	**0.6**	**45.4**	**15.8**
L&ILW costs	2.5	2.1	2.8	2.9	3.8
Contingency	0.1	0.1	0.1	0.1	0.1
Total DRP OM&A Costs	**41.5**	**13.8**	**3.5**	**48.4**	**19.7**

OPG respectfully submits that these costs are reasonable and necessary expenditures for DRP and should be approved.

7.5 ISSUE 6.5

Oral Hearing: Are the test period expenditures related to extended operations for Pickering appropriate?

7.5.1 Introduction

OPG's plan for Extended Operations, as approved by the Province of Ontario, has all six units at Pickering operating until 2022, at which point two units would be shut down and the remaining four units would operate until 2024. Under this plan, Pickering is expected to produce approximately 62 TWh of incremental generation (Ex. L-6.5-1 Staff-126). Achievement of this plan is subject to the results of certain ongoing technical investigations and requires CNSC approval. Based on results to date, including completion of the Fuel Channel Life Assurance Project and majority of component condition assessments, OPG is confident that the remaining technical issues are being resolved and is optimistic that the CNSC will approve the planned operation (Tr. Vol. 13, p. 177, 187-88).

The cost of the activities necessary to enable Extended Operations is $307M over 2016-2020, including $292M to be spent during the IR term (Ex. F2-2-3, p. 6). Under this issue, OPG discusses these enabling costs and the other OM&A and capital costs necessary to operate Pickering during the IR term. This request is consistent with the OEB's finding in its Decision and Order on Motion Filed by Environmental Defence (February 16, 2017, p. 4), which states: "The scope of the OEB's review in issue 6.5 is to assess the appropriateness of the expenditures related to PEO."

7.5.2 The Province Has Approved OPG's Plan to Extend Pickering's Operation

Before moving to the substance of this issue, the costs of Extended Operations, OPG first addresses as an initial matter the suggestion by some parties that OPG's shareholder, the Minister of Energy, has not approved OPG's plan to pursue Extended Operations. In OPG's respectful submission, this suggestion is wrong and ignores the evidence on the record.

The Province of Ontario, as represented by the Minister of Energy, is OPG's sole shareholder (Ex. A1-4-1, Attachment 2, p. 3). The Minister of Energy is also Ontario's electricity System Planner and is responsible for the issuance of the Long Term Energy Plan (LTEP) (*Electricity Act, 1998,* Section 25.29). On January 11, 2016, the then Minister of Energy travelled to Darlington to announce the Province's approval of OPG's plans to refurbish Darlington and pursue Pickering Extended Operations. Following the event, the Ministry of Energy issued a press release which states:

> The Province has also approved OPG's plan to pursue continued operation of the Pickering Generating Station beyond 2020 up to 2024, which would protect 4,500 jobs across the Durham region, avoid 8 million tonnes of greenhouse gas emissions, and save Ontario electricity consumers up to $600 million. OPG will engage with the Canadian Nuclear Safety Commission and the Ontario Energy Board to seek approvals required for the continued operation of Pickering Generating Station.[32]

While the above quote acknowledges the reality that OPG must obtain CNSC approval to operate Pickering and OEB approval in order to recover the costs of operating Pickering, it is unambiguous in stating that: "The Province has also approved OPG's plan."

Every subsequent action by the Minister of Energy, whether in his role as OPG's shareholder or in his role as System Planner confirms the Province's support for Pickering Extended Operations. As the shareholder, the Minister concurred with OPG's 2016-2018

[32] See Ex. L-6.5-1 Staff-115, Attachment 1.

Business Plan that is explicitly based on Pickering Extended Operations (Tr. Tech. Conf. Vol. 2, pp. 12-13; Ex. JT2.1). As the System Planner he issued a discussion guide for the 2017 LTEP consultation that reads as follows: "Keeping Pickering running until 2024 will ensure the province has a reliable source of GHG-free baseload electricity to carry it through the refurbishment of the Darlington and the initial Bruce units." (OPG Reply to Motions, December 13. 2016, p. 5).

The Province also expressed its approval of OPG's plans for Pickering Extended Operations in other ways. The 2016 Provincial Budget contains a section entitled Energy Infrastructure - Smart Investments in Energy Infrastructure for Today and Tomorrow that states (2016 Ontario Budget, Chapter I, p. 84; see also Ex. L-3.1-20 VECC-009):

> Ontario Power Generation is also pursuing continued operation of the Pickering Generating Station beyond 2020 up to 2024, which would protect 4,500 jobs across the Durham region, avoid eight million tonnes of greenhouse gas (GHG) emissions, and save Ontario electricity consumers up to $600 million. Ontario Power Generation will engage with the Canadian Nuclear Safety Commission and the Ontario Energy Board to seek approvals required for the continued operation of the Pickering Generating Station.

All of these sources support a single conclusion: the Province has approved OPG's pursuit of Pickering Extended Operations.

7.5.3 The IESO's Analysis Supports Pickering Extended Operations

Before determining whether to approve OPG's plan for Extended Operations, the Government asked the IESO to conduct an independent assessment of the integrated power system impacts of various Pickering Life Extension scenarios (Ex. F2-2-3, Attachment 1, p. 2). The IESO's analysis was completed in March 2015. In April 2015, the Government convened a working group consisting of personnel from the Ministry of Energy, the IESO and OPG to develop a work plan for an updated economic analysis (*Id.*). The IESO then prepared an updated "evaluation of the merits of Pickering extension with focus on the extension to 2022/24 option in particular…" (*Id.*). This analysis was completed in October 2015. OPG filed both IESO analyses with its Application.

The IESO examined a number of sensitivities, but ultimately concluded that the:

> IESO's updated assessment indicates, on balance, Pickering extension to 2022/2024 is an option worth continuing to explore on the basis of:
>
> - Defers timing of need and the supply/transmission investments that would otherwise be required
> - Defers procurement decisions with respect to new resources, providing more time in exercising options while reducing risk of over investment during a period of supply/demand uncertainty
> - Provides insurance supply in some years in case of nuclear refurbishment delays
> - Defers Pickering decommissioning and severance costs
> - Offsets production from natural gas-fired resources
> - Increases export revenues and reduces carbon emissions (Ex. F2-2-3, Attachment 1, p. 9).

The testimony of Mr. Andrew Pietrewicz, Director of Resource Integration, Demand Forecasting, and Conservation Planning at the IESO, further explained the IESO's analysis and the basis for its conclusion (Tr. Vol. 8, pp. 38-139; Tr. Vol. 12, pp. 1-116). His testimony emphasized that beyond the potential economic benefits, which can vary depending on both Pickering's costs and those of alternative generation resources as well as other supply and demand factors, the IESO sees substantial benefit in having Pickering available at a time when the generation resources that supply the electricity system are going through unprecedented changes (Tr. Vol. 8, pp. 86-92).

7.5.4 The Costs of Pickering Extended Operations are Reasonable

OPG seeks to recover three types of costs associated with Pickering Extended Operations:

1. Enabling costs are the OM&A costs for the technical and regulatory work necessary to demonstrate that Pickering can safely operate to 2022/24.

2. When Pickering was expected to shutdown in 2020, ongoing operations and their costs were set to decline starting in 2017. The cost category "Restoration of Normal Operating Costs" covers the OM&A and capital costs that will be incurred between 2017 and 2020 to reverse previously anticipated spending reductions.

3. 2021 operating costs are the normal OM&A and capital costs necessary to fund Pickering operations in that year. When Pickering was expected to close in 2020, these operating costs were not budgeted, but once OPG adopted Pickering operation to 2022/24 as its

planning assumption, these costs were included in the 2016-2018 Business Plan (Tr. Tech. Conf. Vol. 2, pp. 12-13).[33]

The projected costs are based on OPG's 2016-2018 Business Plan. As explained in Ex. JT2.5, these costs are consistent with those used in the BCS for Pickering Extended Operations, which was approved by the OPG Board of Directors in November 2015 and supported the request for approval of a partial funding release for Pickering Extended Operations (Ex. F2-2-3, Attachment 2, pp. 1- 8). The BCS demonstrates that Extended Operations has economic, technical and environmental benefits including reducing OPG's nuclear payment amounts (Ex. F2-2-3, Attachment 2, pp. 16-19).

Chart 7.4 shows the amount that OPG seeks to recover for each type of costs.

Chart 7.4

Costs Associated with Pickering Extended Operations ($M)

	2016	2017	2018	2019	2020	2021	Total
Enabling Costs	15	26	55	107	104	0	**307**
Restoration of Normal Operating Costs	0	15	32	56	147	0	**250**
2021 Operating Costs	0	0	0	0	0	1,395	**1,395**

Source: Ex. L-6.5-1 Staff-116

As shown in Chart 7.4, the "Enabling Costs" for Extended Operations are forecast to be $307M from 2016 to 2020. These costs include those to complete the Periodic Safety Review, the Fuel Channel Life Assurance project, component condition assessments, incremental outage inspections and maintenance programs and potential modifications that are required to demonstrate fitness-for-service beyond 2020, and to maintain safe, reliable operations (Ex. F2-2-3, p. 3)**.**

The total for "Restoration of Normal Operating Costs" is forecast to be $250M from 2017 to 2020 as shown in Chart 7.4. With shutdown previously anticipated in 2020, ongoing

[33] Instead, OPG would have expected to incur shutdown and severance costs in 2021. A discussion of these costs is provided later in this section.

operations and their costs were set to decline starting in 2017. With Extended Operations, OPG needs to restore on-going operating and maintenance programs to normal levels for the 2017 to 2020 period. For example, outage requirements previously set to decline will now need to be reinstated. As well, project work needs to be funded at the levels required to continue to operate safely for four additional years and to maintain or improve plant reliability during that time. Exhibit L-6.5-1 Staff-118(a)-(b) provide additional details on Restoration of Normal Operating Costs.

The normal 2021 operating costs for Pickering are discussed extensively in the base, project and outage OM&A exhibits (Ex. F2-2-1, Ex. F2-3-1 and Ex. F2-4-1), as well as in the project capital descriptions (Ex. D2-1-3). When Pickering was expected to shut down in 2020, there were no operating or capital costs for Pickering anticipated for 2021. The $1,395M in "2021 Operating Costs" shown in Chart 7.4 comprises the fully allocated forecast OM&A and capital costs necessary to fund Pickering operations in 2021. As shown in Ex. F2-2-3, Chart 1, the 2021 operating costs are very much in line with the costs forecast for the other years in the IR term.[34]

All three types of costs for Pickering Extended Operations (Enabling costs, Restoration of Normal Operating Costs and 2021 Operating Costs) shown above are included in the nuclear base, project and outage OM&A exhibits for recovery through the proposed payment amounts. There is no additional cost request associated with Pickering Extended Operations. In OPG's submission, the Enabling Costs are subject to CRVA treatment under O. Reg. 53/05, consistent with the previously approved approach for the Pickering Continued Operations (see Section 5.1).

It is important to note that if Pickering were to shut down in 2020 not all of the 2021 operating costs could be avoided. With regard to costs that would not be avoided, OPG explained:

> In the event that plant life was not extended beyond 2020, these costs could also be reduced but not fully eliminated. As described in EB-2013-0321 Ex. F2-2-3 Attachment 1 p. 19, it is OPG's assessment that as the nuclear fleet shrinks, losses of economies of scale will result in an effective increase in the cost of providing nuclear support services and corporate support services. As

[34] See Ex L-6.5-1 Staff-116 for the specific dollar amounts underpinning Ex. F2-2-3, Chart 1.

a result, these services and any fixed overheads would need to be reallocated across the remaining, smaller fleet. (Ex. L-6.5-1 Staff-118(c) ii).

In addition, a Pickering shut down in 2020 would cause OPG to incur about $700M in incremental costs in 2021 related mainly to severance and associated costs (Ex. L-6.5-1 Staff-118(d), Table 2). Even when these additional costs are offset by reductions in other cost items like fuel, IESO non-energy charges and depreciation, the net incremental cost of these items is $475M (Ex. L-6.5-1 Staff-118(d), Table 2).

In conclusion, the evidence establishes that Pickering provides a reliable and cost effective source of economic base load generation. The IESO's analyses and the testimony of the IESO witness confirm that the IESO sees value in having Pickering continue to operate during the period of nuclear refurbishment at Darlington and Bruce. The Province has approved OPG's plans to pursue Pickering operations to 2022/24. Based on these factors, OPG respectfully requests that under this issue, the OEB approve the costs of Pickering Extended Operations.

7.6 CORPORATE COSTS

7.7 ISSUE 6.6

Oral Hearing: Are the test period human resource related costs for the nuclear facilities (including wages, salaries, payments under contractual work arrangements, benefits, incentive payments, overtime, FTEs and pension costs, etc.) appropriate?

7.7.1 Introduction

This section discusses OPG's workforce and the cost of the wages, pension and other benefits (together "compensation and benefits") that they receive. It demonstrates that OPG has made substantial progress in addressing the compensation and benefit issues that the OEB has identified in previous applications. Chart 7.5 provides a summary of OPG's IR term compensation and benefits cost for its regulated facilities.[35] The costs presented in Chart 7.5 are equivalent to almost 50% of OPG's forecast 2017 nuclear revenue requirement,

[35] Total regulated costs includes base salary and wages, overtime, incentive pay and total benefits (comprised of statutory benefits, non-statutory benefits, and current pension and other post employment benefits service cost).

reflecting the vital role OPG employees play in producing electricity for Ontario.[36] As Chart 7.5 shows, OPG's forecast compensation and benefits costs are relatively flat over the IR term. In fact, compensation and benefit costs are forecast to be lower in the last two years of the IR term (2020 and 2021), than in the first year (2017).

Chart 7.5

Nuclear Compensation and Benefit Costs

	2016 Budget	**2017 Plan**	**2018 Plan**	**2019 Plan**	**2020 Plan**	**2021 Plan**
Pensions & Benefits (M$)[37]	397	407	400	405	404	405
Overtime (M$)	112	117	116	119	102	81
Base Salaries & Incentives(M$)	1,046	1,082	1,095	1,099	1,097	1,096
Total Compensation (M$)	1,554	1,606	1,611	1,623	1,603	1,582

Source: Ex. F4-3-1, p. 6, Figure 3.

Almost 90% of OPG nuclear employees are unionized with about two thirds represented by the Power Workers' Union ("PWU") and the remainder by the Society of Energy Professionals ("Society") (Ex. F4-3-1, p. 3). PWU employees hold positions like operators, maintainers and skilled and semi-skilled trades-people. Society employees are employed as engineers, finance professionals, supervisors and operations support personnel (Ex. F4-3-1, p. 4). Wages and benefits for represented employees are determined through collective bargaining.

Approximately 10% of OPG employees are in Management Group. This group includes managers, executives and their assistants, and some clerical workers. OPG's Board of Directors sets Management Group compensation and benefits, including base salary ranges and pay for performance programs.

[36] On average, compensation costs reflected in OM&A expenses comprise approximately 40% of the proposed 2017-2021 nuclear revenue requirements. (L-6.6-2 AMPCO-123)

[37] As discussed in Section 7.7.4, these costs represent current service costs that are presented on an accrual basis in OPG's evidence, but OPG is proposing to continue the approach the OEB adopted in EB-2013-0321 (i.e., using cash amounts to set the payment amounts), pending a resolution of this issue in the OEB generic proceeding on Pension and Other Post Employment Benefits (EB-2015-0040).

OPG uses a mix of various types of labour resources and purchased services to accomplish the necessary work at its nuclear facilities. This mix includes regular and non-regular labour (i.e., individuals employed directly by OPG), overtime, augmented staff and other purchased services as discussed in Section 7.7.3 (Ex. F2-2-1, p. 3). Flexibility to address changing work requirements by adjusting the mix of labour resource types and purchased services is essential if OPG is to accomplish the work required to maintain and operate its nuclear facilities efficiently and cost-effectively.

OPG's Application included a Compensation Benchmarking Study prepared by Willis Towers Watson ("Towers") (Ex. F4-3-1, Attachment 2). This study shows that overall OPG's Total Direct Compensation ("TDC")[38] benchmarks within 5% of the target median value. Towers defines results within a band of +/- 10% of the target market positioning as being aligned with the competitive market ("at market") (Ex. F4-3-1, Attachment 2, p. 11). While Pension and Benefits, excluding time off with pay, continue to benchmark higher than median, OPG has made significant progress in negotiating increased pension contributions and changes in plan provisions with both the PWU and Society and has adopted similar changes for Management as discussed in Section 7.7.4.

In OPG's submission, its evidence in this Application clearly demonstrates that the company has made significant progress in addressing the compensation and benefit issues from prior proceedings. Moreover, as shown in Chart 7.5, OPG is forecasting an overall decline in nuclear compensation and benefit costs over the IR term. On this basis, OPG requests that the OEB find its compensation and benefits are appropriate for a business with the scope and complexity of OPG's nuclear operations and approve them as proposed.

7.7.2 OPG's Workforce and Staff Levels

At the end of 2015, OPG had approximately 9,247 regular employees. Of this total, approximately 7,294 employees work directly in, or in support of, OPG's nuclear facilities (Ex. F4-3-1, p. 3). In order to operate OPG's complex nuclear generation facilities, staff must possess a wide array of skills and backgrounds. In particular, these employees require extensive knowledge, adherence to very detailed procedures, particular skills and

[38] Total Direct Compensation is the cash compensation paid to employees, excluding overtime. It includes base salaries and pay at risk incentives.

comprehensive training, much of which is unique to the nuclear industry. OPG's workforce is comprised of engineers, scientists, other professional staff, nuclear operators, and skilled trades people. These highly skilled employees are in demand across the country, and OPG must compete for these employees with Bruce Power and other private generators and energy service organizations, as well as the general marketplace.

OPG has a mature and experienced workforce. Based on OPG's 2015 year-end employee population, approximately 20% of active employees were expected to be eligible to retire with an undiscounted pension by the end of 2016, with an additional 4% of employees becoming eligible each year thereafter (Ex. F4-3-1, p. 5).

OPG has used this demographic profile to support its objectives of transforming the business to a more cost effective and sustainable model. As part of Business Transformation, OPG changed its structure to a centre-led matrix organization that allowed it to reduce its regular headcount company wide by nearly 2,700 positions between 2011 and 2015. By managing staffing reductions through retirements and putting in place vacancy controls (see Ex. L-6.6-2 AMPCO-129), OPG was able to avoid costly severance packages and minimize disruptions associated with the redeployment of staff.

In 2015, nuclear attrition was at its highest level in years, with over 300 retirements.[39] This represents a 20% increase in the number of retirements in Nuclear compared to 2014, and represented a higher percentage of employee retirements than OPG experienced in recent history (Ex. L-6.6-19 SEP-013). Over two thirds of the 2015 retirements were in critical operations, maintenance, engineering and technical roles and will need to be replaced. To address staffing related to the DRP, and, to a lesser extent, Pickering Extended Operations,[40] and shortages in certain skilled positions, OPG had set a challenging target of increasing its total staffing for the nuclear operations by over 600 FTEs in 2016 (Ex. F4-3-1, p. 6; Ex. L-6.6-1 Staff-138; Ex. L-6.6-1 Staff-143). Although OPG hired more staff into the

[39] This figure includes only retirements of staff reporting directly to the nuclear organization directly; retirement of staff supporting the nuclear facilities is not reflected in this number.

[40] To address the anticipated staff redeployment and involuntary terminations after Pickering is shut down, OPG negotiated a new employee category, called "Term Employees," with the PWU for the current collective agreement period. In general, Term Employees may be hired to avoid adding regular staff in circumstances where additional regular employees are likely to be laid off as a result of Pickering's end of commercial operations (Ex. F4-3-1, p. 7).

Nuclear organization in 2016 than in any other year since 2008 (Ex. L-6.6-2 AMPCO-127), OPG fell short of this target and was only able to increase its staffing by less than half this number of FTEs in 2016 (Ex. K16.2, p. 16, line 9). In this circumstance, OPG relies on overtime and purchased services to supplement its workforce and complete priority work programs in a cost effective manner (Tr. Vol. 13, p. 106; J15.12; J17.3). Enhancements to the hiring process during 2016 are expected to enable OPG to fill the remaining vacancies in 2017 (Tr. Vol. 16, pp. 151-52; Ex. L-11.4-1 Staff-255(a)). OPG's nuclear staffing forecast shows staff levels peaking in 2017 before declining by over 500 FTEs by the last year of the IR term, as shown in Chart 7.6 (Ex. J14.6).

Chart 7.6

Nuclear Staffing

Line No.	Group	2013 Actual[2]	2014 Actual	2015 Actual	2016 Actual	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	NUCLEAR OPERATIONS:									
1	**Regular Staff**	5,870.7	5,626.7	5,430.4	5,341.1	5,710.8	5,666.2	5,602.1	5,504.1	5,394.7
2	**Non-Regular Staff**	496.9	578.1	670.0	843.8	614.4	646.6	632.2	526.8	420.4
3	**Subtotal Nuclear Operations**	6,367.6	6,204.8	6,100.4	6,184.9	6,325.2	6,312.8	6,234.3	6,030.9	5,815.1
	DARLINGTON REFURBISHMENT:									
4	**Regular Staff**	282.0	307.2	329.7	422.6	587.2	599.9	620.5	589.5	597.8
5	**Non-Regular Staff**	24.6	35.3	60.7	112.7	153.2	152.2	137.4	157.7	230.1
6	**Subtotal Nuclear Generation Development**	306.6	342.5	390.4	535.3	740.4	752.1	757.9	747.2	827.9
7	**Total Nuclear Direct**	6,674.2	6,547.3	6,490.8	6,720.2	7,065.6	7,064.9	6,992.2	6,778.1	6,643.0
8	**NUCLEAR ALLOCATED[3]**	1,919.5	1,884.4	1,628.9	1,659.8	1,742.8	1,703.7	1,679.8	1,659.0	1,656.2
9	**Total Nuclear[4]**	8,593.7	8,431.7	8,119.7	8,380.0	8,808.4	8,768.6	8,672.0	8,437.1	8,299.2

1 Nuclear Operations and Darlington Refurbishment FTEs are aligned to where costs related to the FTEs are incurred.
2 The 2013 actual FTEs shown are adjusted from those provided in EB-2013-0321, Ex. J7.3, Attachment 1. The adjustment increases the number of FTEs by excluding the impact of banked overtime (overtime taken as time off rather than pay) and shows the 2013 actual FTEs on a consistent basis with the remaining years in the table.
3 Ex. F4-3-1, Attachment 1 updated for 2016 actual FTEs.
4 Does not include adjustment discussed in Ex. L-6.6-1 Staff-139(a).

7.7.3 Non-Regular Staff, Overtime and Contract Staff

While the work necessary to support OPG's nuclear operations is overwhelmingly delivered by regular staff working their normal hours (see Ex. F2-2-1, Table 2), OPG's Nuclear Business does use other types of labour as well as purchased services, where appropriate and cost-effective. These include:

- Non-regular staff "hired for a fixed period of time with a start and end date. Non-regular employees include students and other employees hired directly by OPG or through a trade union hall for a limited duration. Non-regular employees are paid through OPG payroll." (Ex. L-6.6-1 Staff-136(b)).[41]

- Overtime for both regular and non-regular represented staff working beyond their normal working hours (Ex. F2-2-1, p. 3).

- Augmented staff (a form of purchased services) who are "external personnel providing specialized expertise (e.g., engineering) to supplement internal capability and/or to fill temporary vacancies." (Ex. F2-2-1, p. 3). These staff are not OPG employees and are not paid through OPG payroll.

In addition, OPG may purchase services to accomplish certain tasks. Purchased services typically include both labour and a mix of other items (e.g., equipment) necessary to deliver the required service (Tr. Vol. 16, pp. 144-46).

While OPG may plan to use a particular mix of labour resources to deliver a work program, the circumstances encountered in a given year may necessitate a different mix. As Ms. Carmichael noted in testimony:

> if you do look at our base OM&A picture, we plan in various categories, but they don't always happen in each of the categories, so labour, overtime, aug staff, purchased service, there's a mix. So sometimes the actuals don't always agree with the way it was planned. But from an overall perspective, we have a steady state base OM&A budget (Tr. Vol. 14, pp. 8-9).

A comparison of OPG's budgeted and actual 2016 base OM&A spending by resource type bears out this point (compare Ex. F2-2-1, Table 2 to Ex. J14.3), and while there were changes in virtually all categories of base OM&A, actual base OM&A spending in 2016 was within 1.6% of the 2016 budget.

OPG respectfully submits that it must be allowed the flexibility to address changing work requirements through a mix of staff, overtime, augmented staff and other purchased services if it is to accomplish its operational, outage and project work efficiently and cost-effectively. While a variety of labour sources is used for all aspects of the Nuclear business, flexibility is

[41] OPG negotiated a new category of non-regular employees called "Term Employees" in its most recent PWU contract (Ex. F4-3-1, p. 7; Ex. L6.6-2 AMPCO 132). Term employees may be used to avoid adding regular staff in circumstances where additional regular employees are likely to be laid off when Pickering's ends commercial operations (Id.).

particularly important for outage work, where the peaking nature and critical timelines associated with the work often makes it more cost-effective to use overtime, temporary staff or purchased services (i.e., contractors) rather than maintaining permanent outage staff (Ex. F2-4-1, p. 5). The value of the flexibility to make cost-effective use of non-OPG resources is underscored by the savings attached to collective agreement provisions that provide for such flexibility, as discussed below.

PWU and Society

Given the high degree of unionization, collective bargaining plays a dominant role in determining OPG's compensation costs. Collective bargaining directly affects the wages, overtime rates and incentives paid to unionized employees, as well as their pensions and benefits. In 2015 OPG negotiated three-year collective agreements with both the PWU and Society that provide for a 1% wage increase each year. The PWU agreement runs from April 1, 2015 to March 31, 2018 and the Society agreement runs from January 1, 2016 to December 31, 2018. Based on OPG's 2016-2018 Business Plan, the Application makes reasonable assumptions relating to wages for the remainder of the IR term after the expiry of the collective agreements (Ex. L-6.6-15 SEC 70).

The current collective agreements were negotiated with the direct involvement and support of the Government (Ex. F4-3-1, p. 8). In both the PWU and Society negotiations, which were conducted separately, a representative of the Province led a centralized bargaining table that addressed wages and pension benefits on behalf of OPG and Hydro One (Ex. L-6.6-15 SEC-077). OPG and Hydro One each had separate local bargaining tables (Tr. Vol. 16, p. 11, lines 1-7).

The Government also established a mandate for OPG that included obtaining a multi-year agreement in which any wage increases were neutral to Ontario taxpayers and electricity ratepayers, and which included longer term solutions to help address pension sustainability (Ex. F4-3-1, p. 15; Ex. L-6.6-1 Staff-147, Attachment 1). The mandate required that at the local table OPG negotiate operational savings sufficient to offset the modest wage increases (1% annually) negotiated at the central table so that the overall cost of the agreement represents a “net neutral” outcome for electricity customers. The Government’s mandate explicitly precluded the use of pension plan cost savings to offset the wage increases (*Id.*).

OPG was successful in negotiating such offsets with both unions, and the Government was satisfied that OPG had met the mandate (Tr. Vol. 16, p. 15). Offsetting savings negotiated at the local table relate predominantly to labour staffing options that provide OPG with greater flexibility in the use of various types of non-regular resources. (Ex. L-6.6-2 AMPCO-122; Ex. L-6.6-15 SEC-072)

In addition to the 1% annual wages increase, the collective agreements negotiated with the PWU and Society included pension reforms. In exchange for increased pension contributions and changes to pension eligibility rules applicable to all current and future represented employees, PWU and Society employees received lump sum payments and eligible existing employees received Hydro One share grants for a defined period, as more fully discussed in Section 7.7.4.

Management Group

Between 2011 and 2015, OPG’s Management employees received no annual base salary increase. This freeze has resulted in overall management salaries that benchmark below market as discussed in Section 7.7.5. Salary restraint measures have created the following issues regarding internal equity and the ability to attract talent:

1. Approximately 250 managers earn less than the staff they supervise, making it difficult to attract qualified represented staff into Management positions.

2. The prospect of a long term salary freeze for Management is a concern for represented staff when recruiting qualified internal personnel into Management positions. This has led to the use of temporary and acting assignments to fill some of the Management roles. This situation was cited in a recent World Association of Nuclear Operators review of OPG Nuclear facility operations and noted as an area for improvement.

3. OPG’s compensation relative to market negatively impacts its ability to attract and retain senior Management staff. (Ex F4-3-1, pp. 11-12).

The ability to attract and retain Management talent is recognized in OPG’s business plan as one of the top risks facing the company. (Ex. A2-2-1, Attachment 1, p. 2)

To address these issues, OPG obtained Board of Directors approval to reinstate an annual base pay increase program for Management staff below the Vice President level in 2016 (Ex. F4-3-1, p. 12). Under this program, salary increases are performance based, linked to external labour markets in line with the benchmarking results discussed in Section 7.7.5, and enable some compression issues to be addressed, where appropriate. Headcount reductions in later years and other means will be used to offset the cost of these salary increases. OPG forecasts the cost of management compensation to be virtually flat over the IR term (Ex. F4-3-1, Attachment 1).[42]

Recently enacted regulations permit salary increases to employees at the Vice President level and above based on the development and posting of a compliant executive compensation program.[43] OPG has developed a compliant executive compensation program that became effective January 1, 2017, but has not modified its request in this Application to account for any incremental compensation costs pursuant to this program (Tr. Vol. 17, pp. 113-14).

7.7.4 Pension and Benefits

Pension and Benefits costs represent approximately 25% of OPG's total nuclear compensation costs over the IR term and include current service costs for pension and other post employment benefits ("OPEB") and current employee benefits (Ex. F4-3-1, p 14). OPG has proposed limiting the recovery of pension and OPEB costs to cash amounts during the IR term, subject to the outcome of the OEB's generic proceeding on pension and OPEB costs (EB-2015-0040). OPG also has proposed to continue recording the difference between actual accrual and actual cash amounts for pension and OPEB in the Pension & OPEB Cash Versus Accrual Differential Deferral Account, for both the nuclear and hydroelectric facilities (Ex. F4-3-2, p. 6). Consistent with the OEB's findings in EB-2013-0321 (Decision with Reasons, pp. 88-89), OPG proposes that the future consideration of recovery of the difference between accrual costs and cash amounts for the IR term be limited to the outcome of the EB-2015-0040 proceeding and not be subject to a future prudence review beyond the proceeding for this Application. (Ex. F4-3-2, p. 2)

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[42] Exhibit F4-3-1, Attachment 1, shows that Management compensation rises slightly in the early years of the IR term (a maximum annual increase of less than 1%) before declining over the final two years of the IR term.
[43] See the *Broader Public Sector Executive Compensation Act, 2014*, O. Reg. 304/16.

OPG's Pension and Benefits Programs

OPG's pension and OPEB programs consist of a registered pension plan ("RPP"), a supplementary pension plan, other post-retirement benefits such as group life insurance and health and dental care for pensioners and their dependants, as well as long-term disability benefits for current employees. Recent changes to OPG's pension plan are discussed in the next section. OPG's evidence presents pension and OPEB costs on an accrual basis, as that is how they are calculated for planning, accounting and reporting purposes and reflected in OPG's business plans approved by the Board of Directors (Ex. F4-3-2, p. 7).

The amount and calculation of pension and OPEB costs are described in Ex. F4-3-2, as updated by the Ex. N1 Impact Statement. Exhibit N1, Charts 3.1.1A and 3.1.1B (Ex. N1-1-1, pp. 7-8) show the total cash amounts that OPG is seeking to recover in this Application.[44] Although OPG's pension and OPEB proposal in this Application aligns with the OEB's EB-2013-0321 Decision, OPG continues to be of the view that it is appropriate for OPG to recover its accrual pension and OPEB costs, as set out in OPG's September 22, 2016 submission in the EB-2015-0040 generic consultation and as summarized in Ex. F4-3-2.

The RPP amounts included in the revenue requirement reflect OPG's minimum required contributions to the pension plan for the 2016-2018 period according to the latest actuarial valuation for funding purposes, as of January 1, 2016, filed with the Financial Services Commission of Ontario in September 2016 (Ex. L-6.6-1 Staff-156). The valuation was prepared by OPG's independent actuary, Aon Hewitt, in line with the requirements of the *Pension Benefits Act* (Ontario). The revenue requirement request also includes Aon Hewitt's projected results of the next funding valuation as of the latest permitted date of January 1, 2019, which would set OPG's minimum funding requirements for 2019 to 2021 (Ex. N1-1-1, pp. 6-9). All of the above amounts reflect the negotiated changes in pension plan provisions, discussed in the next section. The pension cash amounts over the 2016-2021 period are lower than the actual amounts for 2014 and 2015, which were based on the previously funding valuation, as of January 1, 2014. (Ex. F4-3-2, Chart 1 and pp. 9, 10 and 15). The approach to determining RPP contribution amounts is discussed at Ex. F4-3-2, pages 7-12.

[44] In order to reflect the cash amounts in the revenue requirement, OPG adjusts the amount of centrally-held pension and OPEB accrual costs by the difference between cash and accrual amounts (Ex. F4-3-2, p. 7 and Ex. F4-4-1, p. 2)

OPEB cash amounts were also projected by Aon Hewitt and represent forecast benefit payments to retirees and dependants in accordance with the provisions of the plans, based on estimated future cash flows used to project the corresponding benefit obligations. As expected under the cash basis of recovery, the OPEB cash amounts are increasing gradually over the IR term, reflecting the growing retiree population and expected increases in medical and other costs in the market. (Ex. N1-1-1, p. 9; Ex. F4-3-2, p. 12)

Aon Hewitt's report in support of the forecast amounts proposed in the revenue requirement can be found in Ex. N1-1-1, Attachment 2. The forecast amounts will be subject to the Pension & OPEB Cash Payment Variance Account, which will continue pursuant to the Settlement Agreement (see Issue 9.6). The account will record variances between actual and forecast cash amounts for pension and OPEB for both the Nuclear and Hydroelectric businesses.

Current benefits include the cost of OPG's Health, Dental and Group Life Insurance benefits for employees while on payroll, as well as statutory requirements such as the Employer Health Tax, Canada Pension Plan, Employment Insurance and Workers Compensation. These costs are recognized and included in the revenue requirement as benefits are paid to employees. OPG outsources claims administration to Sun Life Financial and has a number of plan management and adjudication mechanisms in place to control benefit costs. These include the mandatory substitution of generic drugs, maximizing coordination of benefit opportunities, and a requirement for prior approval for certain drug and treatment therapies (Ex. F4-3-1, p. 14, lines 10-27). Current employee benefit costs are expected to remain relatively stable over the IR term.

Recently Negotiated Changes to OPG's Pension Plan Provisions

As part of the recent collective agreements with the PWU and Society, OPG with the assistance of the Government, was able to negotiate significant changes to its pension plan provisions, as follows (Ex. F4-3-1, pp. 15-16):

Employee Contributions Increases

OPG was able to negotiate increased employee pension contributions as shown in Chart 7.7. These changes came into effect beginning April 1, 2015 for PWU employees, and January 1, 2016 for Society employees. Chart 7.7 also includes the comparable changes OPG made for Management employees starting January 1, 2016.

Chart 7.7

Employee Pension Contributions	% of Pensionable Earnings Contributed by Employees (% below / above YMPE)			Contribution Ratio (Employee/Employer)
	MG	PWU	Society	
2014	7 / 7	5 / 7	7 / 7	24% / 76%
2015	7 / 7	6 / 8	7 / 7	
2016	7.3 / 8.25	7 / 9	8 / 8	
2017	7.6 / 9.5	7.5 / 10	9 / 9	35% / 65%

Earnings Basis for Pension

OPG negotiated changes to the basis for determining pension benefits. Previously, the calculation basis was an employee's highest three consecutive years. This was increased to the highest five consecutive years for future service beginning March 31, 2025 for both the PWU and Society. This change applies to both current employees and new hires.

Retirement Eligibility for an Undiscounted Pension

OPG successfully negotiated a change in the retirement eligibility formula. Currently, PWU and Society employees can retire with an undiscounted pension when their age plus years of service equal 82; this is referred to as the Rule of 82. For service after March 31, 2025, the eligibility will be based on the Rule of 85. The retirement eligibility formula of age plus service was also changed for Management employees from Rule of 84 to Rule of 90. This change is effective July 1, 2014 for new Management employees, and effective for future service beginning January 1, 2025 for existing employees.

In exchange for these pension reforms, existing PWU and Society employees contributing to the pension plan will receive the following (Ex. F4-3-1, pp. 16-18):

Lump Sum Payment

Both the PWU and Society represented employees received non-pensionable lump sum payments of 1% of salary in the first year of the agreement and 2% of salary in the second year of the agreement.

Share Performance Plan

PWU and Society represented employees who were contributing to the pension plan on April 1, 2015 (PWU) and January 1, 2016 (Society) and had less than 35 years of pensionable service as of those dates will be granted Hydro One Limited shares awards at the start of the third year of the current agreement term (April 1, 2017 for PWU and January 1, 2018 for Society). Eligible employees will continue to receive shares annually for up to 15 years subject to the following two conditions:

1. The number of shares to be awarded annually will be based on a set percentage of salary at the beginning of the agreement term (2.75% of salary as of April 1, 2015 for PWU and 2.0% of salary as of January 1, 2016 for Society).

2. Shares will be granted annually to active employees with less than 35 years of pensionable service on April 1 of the corresponding year for the PWU and January 1 for the Society. The last share award will be granted on April 1, 2031 for eligible PWU employees and January 1, 2032 for eligible Society employees.

In 2016, OPG acquired nine million Hydro One shares at a price per share of $23.65, as a risk management strategy against future fluctuations in the price of the shares. OPG expects to be able to satisfy its share award obligations to eligible PWU and Society employees during the IR term by using the shares it acquired in 2016. Forecast compensation costs included in the nuclear revenue requirement represent the cost of the shares expected to be awarded during each year of the IR term valued at OPG's purchase price (i.e., $23.65 per share) (Ex. L-6.6-15 SEC-078(c)). As such, ratepayers are protected from fluctuations in the market price of the shares. The investment in the shares is not included in the regulated rate base (Ex. L-6.6-20 VECC-032).

Over the IR term, the costs associated with the lump sum payments and the share performance plan largely equal the cost savings from the higher pension contributions, but the pension savings will continue to grow over time while the number of employees eligible for share awards will decline (Ex. L-6.6-1 Staff-147(d), (g); Ex. L-6.6-15 SEC 78(a)). For example, the number of PWU employees eligible for share awards is forecast to decline by over 900 between 2017 and 2021 (Ex. L-6.6-15 SEC-078(a)). Over the longer-term, the savings from higher employee contributions will significantly exceed the costs associated with the Share Performance Plan lump sum payments (Ex. L-6.6-1 Staff 147(g)).[45]

Pension and Benefit Costs

As Chart 7.5 (Nuclear Compensation and Benefits) shows, OPG's pension and benefits costs are quite stable over the IR term. This is consistent with stable level of pension and OPEB current service costs over this period, as shown in Ex. F4-3-2, Chart 7. These cost levels reflect the negotiated pension changes described above and changes that OPG has initiated to control benefit costs such as outsourcing claims administration through a competitive procurement process, the mandatory substitution of generic drugs in prescriptions, maximizing coordination of benefit opportunities, and a requirement for prior approval for certain drugs and treatments (Ex. F4-3-1, p 14; Ex. 6.6-1 Staff 157).

7.7.5 Benchmarking Shows that OPG's Overall Compensation is "At Market"

Towers conducted a comprehensive benchmarking survey that compared a wide range of OPG positions to corresponding positions in the comparator organizations (Ex. F4-3-1, Attachment 2). This benchmarking was both more rigorous and extensive than was done in the last application (Tr. Vol. 16, pp. 69-71; Ex. L-6.6-1 Staff-149(b)). Based on their study, Towers concludes that OPG's Total Direct Compensation is at market (Ex. F4-3-1, Attachment 2, p.11).

The Study Methodology

[45] In addition, while the favourable cost impacts of changes in contribution levels have been credited to the Pension & OPEB Cash Payment Variance Account and Pension & OPEB Cash Versus Accrual Differential Deferral Account starting in 2015/2016, costs of the lump sum payments incurred in those years were not recoverable from ratepayers.

In assessing OPG's compensation relative to external labour markets, OPG's positions were categorized into three segments: Utility, Nuclear Authorized, and General Industry. The characteristics of each segment and the proportion of OPG jobs it represents are shown in Chart 7.8.

Chart 7.8

Benchmarking Segments

Segment	Description	Percentage of Total OPG Positions
Utility	"Requires specific education and knowledge in a unique discipline related to the theories, principles and methods associated with the generation, regulation or trading of nuclear or non-nuclear energy. The requirement to apply this professional body of knowledge represents a significant portion of the job."	69%
Nuclear Authorized	"Requires federal licensing, specific education and in-depth knowledge in a unique discipline related to the theories, principles and methods associated with the generation, regulation or training [*sic "trading"*] of nuclear energy. The requirement to apply this professional body of knowledge represents a significant portion of the job."	4%
General Industry	"- Roles that do not meet the Utilities and Nuclear segment definition criteria. - These roles may require formal education and/or in-depth knowledge of a professional body of knowledge; however, this body of knowledge is not specific to energy generation. - Previous industry experience may support faster contextual understanding, however this can be learned 'on the job'."	27%

Source: Ex. F4-3-1, Attachment 2, p. 5

OPG's compensation for jobs in each of these segments was compared to the compensation provided by other companies for comparable jobs (called "roles" in the study) (Ex. F4-3-1, Attachment 2, p. 7). The process for matching jobs is described by Towers as follows:

> Based on job content information from OPG, each OPG role was matched to benchmark role functional specialities and levels of accountability within the Willis Towers Watson's 2015 Compensation databases where a suitable match was available. In total, 78% of incumbents matched to over 250 survey roles are included

in the analysis. This encompasses roles across all OPG job families, employee groups and pay bands. For non-authorized roles residing in nuclear plants, no direct matches were available, however it is recognized that comparable skill sets reside within energy and utilities organizations. As such, jobs were matched to non-nuclear comparators based on similar skills and level of accountability (Ex. F4-3-1, Attachment 2, p. 7).

Towers specifically noted that "78% of OPG incumbents are in roles covered by this benchmark review. In our experience, this is a strong representative sample." (Ex. F4-3-1, Attachment 2, p. 3).

The companies selected for comparison (called "comparator organizations" in the study) in the various segments are:

- A mix of Canadian public and private companies that represent both publically and privately owned utilities for the Utility Segment;
- Nuclear generators for the Nuclear Authorized Segment; and
- A 50/50 weighting of public and private employers requiring a large range of skill sets and emphasizing large Ontario employers for the General Industry Segment (Ex. F4-3-1, Attachment 2, p. 6).

A listing of the comparator organizations for each segment is provided (Ex. F4-3-1, Attachment 2, pp. 29-32).

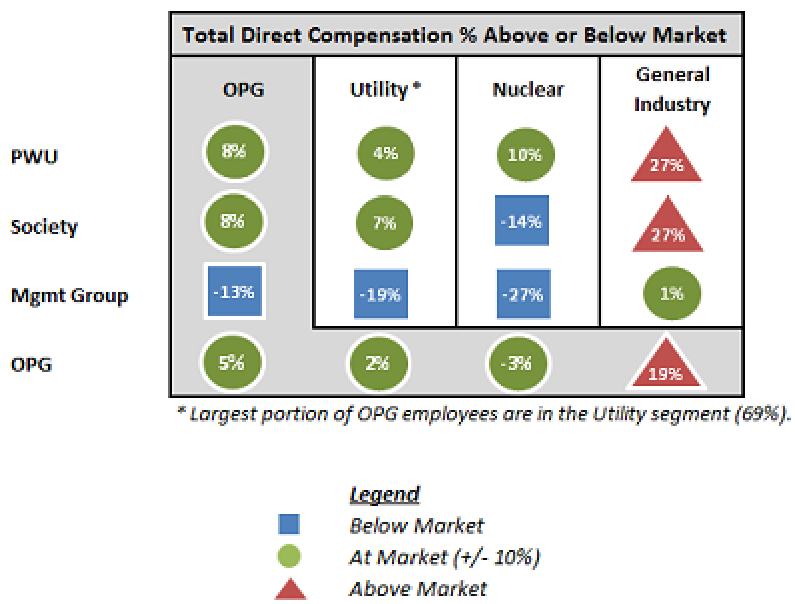
This assessment included reviewing OPG's base salaries, Total Direct Compensation, as well as Pensions and Benefits. Total Direct Compensation reflects the cash compensation paid to employees, excluding overtime. It includes base salaries and pay at risk incentives (Ex. F4-3-1, Attachment 2, p. 8).

Towers considers compensation benchmarking results to be at market if they are within +/- 10% of the target market positioning. OPG's target market positioning is the 50th percentile for positions in the Utility and General Industry segments, and 75th percentile for the Nuclear Authorized segment (Ex. F4-3-1, Attachment 2, p. 11).

The Study Results

Chart 7.9 depicts the results of the Towers study. These results are shown by industry segment and union representation, capturing whether OPG's Total Direct Compensation is above, at, or below market. Overall, OPG is 5% higher than market. In the largest segment, Utility, which represents 69% of the OPG positions, OPG is within 2% of the target market at the 50^{th} percentile. For the Nuclear Authorized segment, with 4% of OPG positions, the results show that OPG is actually 3% lower than the 75^{th} percentile.[46] For the General Industry Segment, with 27% of OPG positions, OPG is 19% above the target market at the 50^{th} percentile.

Chart 7.9



OPG respectfully submits that the most important conclusion of the Towers study is that overall Total Direct Compensation is within 5% of the target market (Ex. F4-3-1, Attachment 2, p. 11). Moreover, these results show improvement from those filed in the last application (Ex. F4-3-1, p. 19, Figure 11). While OPG is both above and below market for individual segments and employee groups, these individual results do not detract from the study's central conclusion that OPG's overall compensation is at market.

[46] Nuclear Authorized positions are targeted at the 75^{th} percentile except for senior executives in this segment which are target at the 50^{th} percentile (Ex. F4-3-1, Attachment 1, p. 11). OPG targets the 75^{th} percentile to recognize the greater scope and complexity of these jobs at OPG (Tr. Vol. 16, pp. 56-58; JT2.33; Ex. L-6.6-1 Staff-153(b)).

Pension and Benefit Benchmarking

Towers also undertook a Pension and Benefits benchmarking analysis (Ex. F4-3-1, Attachment 2, pp. 26-27). This benchmarking compares the value of OPG's pension and benefits program, excluding time off with pay, as a percentage of OPG's base salary to the value of the pension and benefit plans currently offered by the comparator companies, which are also expressed as a percentage of OPG's base salary (Ex. J16.5, lines 22-24, lines 39-40). The comparator companies are a 50/50 mix of private and public sector organizations (Ex. F4-3-1, Attachment 2, p. 26).

Value benchmarking is used to compare the value of pension and benefit plans and is not intended to be an analysis of their costs (Ex. L-6.6-15 SEC-083). The benchmarking uses a common set of actuarial assumptions to determine the employer-provided value of both OPG and comparator organizations' plan provisions. These actuarial assumptions are not specific to OPG or any other organization. In contrast, the pension and benefits costs a company incurs are affected by both plan provisions and by factors such as provider costs, plan utilization, funding policies, and other actuarial assumptions that vary among organizations (J16.5, p.2).

The value-based approach followed by Towers to benchmark pension and benefits follows prevailing industry practice. In this regard, the Towers approach is conceptually similar to the previous benchmarking study prepared for OPG by AON Hewitt (J16.5, p. 2, lines 16-17; Ex. L-6.6-15 SEC-083, p. 2).

Based on this approach, Towers calculated the aggregate average value of OPG's pension and benefits expressed as a percentage of base salary at OPG to be approximately 30%. The estimated value of the median market plan value was then expressed as a percentage of base salary at OPG, yielding a value of about 20%.

The objective of Pension and Benefits benchmarking is to be a directional tool to help OPG understand market competitive practice with respect to the current pension and benefits plan offerings of comparator organizations (Ex. L-6.6-1 Staff-154, part b). While OPG recognizes that its Pension and Benefits remain above market at this time, further significant changes to plan offerings can only be made through the collective bargaining process. OPG will attempt to continue building on the success achieved in the last round of collective bargaining as discussed above in Section 7.7.4.

Benchmarking Bruce Power Wages

Towers also compared OPG's and Bruce Power wages (Ex. F4-3-1, Attachment 3). Bruce Power is the closest single comparator to OPG because it:

- Operates in the same market;
- Competes for the same labour;
- Has equivalent positions;
- Uses similar technology; and
- Negotiates with the same unions.

Towers comparison demonstrates that Bruce Power's unionized wages are 16% higher for PWU positions and 2% higher for Society positions (Ex. F4-3-1, p. 21).

OPG's analysis is consistent with the Towers results. OPG compared its negotiated PWU and Society wage increases to those of Bruce Power (Ex. F4-3-1, pp. 8-9). In both recent years and cumulatively since 2001, OPG has negotiated lower wage increases than Bruce Power for both the PWU and Society (Ex. F4-3-1, pp. 8-9, Figures 5-8).

7.8 ISSUE 6.7

Oral Hearing: Are the corporate costs allocated to the nuclear business appropriate?

7.8.1 Introduction

This section discusses the corporate support services costs ("Support Services") and corporate allocations that form part of the nuclear revenue requirement. Support Services presented in the Application comprise of Business and Administrative Services, Finance, People and Culture, Commercial Operations and Environment, and Corporate Centre (Ex. F3-1-1, p. 1). As centre-led organizations in OPG, Support Services provide support to the Nuclear business. The costs attributed to the Nuclear business cover the centralized activities necessary to operate OPG's nuclear facilities.

Support Services costs assigned and allocated to the Nuclear business unit over the IR term are \$448.9M (2017), \$437.2M (2018), \$442.7M (2019), \$445.0M (2020), and \$454.1M (2021) as presented in Ex. F3-1-1, Table 3. Actual 2016 Support Services costs assigned and allocated to the Nuclear business were \$426.2M (Ex. J14.2, Attachment 1). These costs continue to be calculated based on the cost allocation methodology that was independently reviewed by cost allocation experts HSG Group Inc. in EB-2013-0321 and accepted by the OEB in that proceeding and in prior proceedings (see EB-2010-0008, Decision with Reasons, p. 94).

OPG submits that the corporate support costs attributed to the Nuclear business are reasonable. The level of these costs is consistent over the IR term. Support Services costs show a slight decrease between 2017 and 2020. The costs in the final year (2021) are about 1% higher than the costs in the initial year (2017).

In the EB-2013-0321 Decision (p. 95), OPG was directed to undertake an independent benchmarking study of corporate support functions and costs given the significant changes resulting from the Business Transformation initiative. The Hackett Group ("Hackett") carried out an independent benchmarking study ("Hackett Study") in response to that direction, which was filed as Ex. F3-1-1, Attachment 1.

As discussed in the next section, the Hackett Study shows that OPG's benchmarking performance for Support Services costs improved between 2010 and 2014. Moreover, in aggregate the cost of OPG's Support Services is calculated to be below the 2014 median benchmark over the IR term (Ex. J20.3).

For these reasons, as explained more fully in the sections that follow, OPG respectfully submits that the Support Services costs allocated to the Nuclear business should be approved.

7.8.2 Support Services Benchmarking

The Hackett Study benchmarked OPG against peers in 2010 (before the start of the Business Transformation initiative) and in 2014 to show results in a manner that facilitates a transparent comparison before and after the Business Transformation initiative. Both assigned and allocated Support Costs were included in the scope of the Hackett Study. The study uses Hackett's independent benchmark methodology to compare OPG's corporate support functions and costs against peers on an equivalent basis (Ex. F3-1-1, Attachment 1, p. 3).

The Hackett Study found that OPG's regulated corporate function costs declined 10% from 2010 to 2014 while total regulated OPG headcount declined 11% (Ex. F3-1-1, Attachment 1, p. 3). It also found that OPG's overall cost benchmark performance at the functional level improved between 2010 and 2014 in all areas, but the degree of improvement varied among the individual factions, as shown in Figure 7.1 (Ex. F3-1-1, Attachment 1, pp. 11-15).

Figure 7.1

Summary of Corporate Cost Benchmarking Results

Line No.	Corporate Function	OPG 2010	OPG 2014	Peer	OPG Improvement 2010 - 2014 (%)
		(a)	(b)	(c)	(d)
1	IT Cost per End User	$12,015	$9,541	$14,995	21%
2	HR Cost per Employee	$3,400	$3,375	$3,350	1%
3	Finance Cost as a Percent of Revenue	1.02%	0.75%	0.66%	26%
4	ECS Cost as a Percent of Revenue	3.39%	2.75%	1.07%	19%

Exhibit L-6.7-1 Staff-169, Attachment 1 shows the results of the Hackett Study for both 2010 and 2014 by quartile. Overall, the IT function benchmarks near the top of the first quartile in 2014. HR benchmarks about at median in 2014. Finance moved from the top of the fourth quartile in 2010 to the middle of the third quartile in 2014. The most significant variance to median is in the ECS function. While showing significant improvement between 2010 and 2014, the ECS function remained below the fourth quartile in 2014.

In response to Undertaking J.20.3, OPG provided a chart that shows the mathematical calculation of the estimated nuclear revenue requirement impact if all the cost categories in the Hackett Study were adjusted to achieve the 2014 median result (Ex. J20.13, Chart 1). As the chart shows, adjusting all cost categories to meet 2014 median performance would increase the IR term revenue requirement by $95M. While the response clearly states OPG's view that using benchmarking in this way is inappropriate, Exhibit J20.3 does show that if this approach were taken on a consistent basis, it would demonstrate that OPG's performance in total is better than median (Ex. J20.3, p. 2).

Risk Management and Environment, Health and Safety; Procurement; and Real Estate and Facilities Management are the ECS areas where OPG's costs were most significant and where the differences between OPG and peers was greatest (Ex. F3-1-1, Attachment 1, p. 16). In its evidence and during cross examination, OPG explained the reasons for these differences. OPG's costs associated with Risk Management and Environment, Health and Safety, Procurement and Real Estate continue to be driven by unique nuclear requirements that are not common to the peer group, which only includes five nuclear generators out of 19 companies (Ex. F3-1-1, pp. 15-16; Tr. Vol. 21, pp. 127-28).

In the Environment, Health and Safety area OPG's commitment to adherence to strict CNSC regulations and its robust safety and environmental programs are examples of key cost drivers (Ex. F3-1-1, p. 15). As Mr. Mauti stated (Tr. Vol. 21, pp. 127-28):

> I think if I was a ratepayer I would want to make sure that OPG was properly protecting the environment and ensuring public and employee safety, so I think there has to be an understanding and appreciation for a Nuclear generating fleet that some of these things will result necessarily in higher than the median for the group of companies that we look at, especially since only five of the 19 are nuclear generators, and as I mentioned yesterday, of those five I don't believe any are as highly dependent and focused on Nuclear as OPG would be in terms of its overall corporate structure, so I think that would have to be taken into account.

OPG's Procurement function must address the significant quality requirements for materials that are used in nuclear facilities. In addition, the cost of Procurement activities is affected by aging assets, parts obsolescence and the limited market availability of nuclear qualified suppliers. The majority of the utilities included in OPG's peer benchmarking group were not nuclear power producers and therefore do not have the same breadth of requirements as OPG in these areas (Ex. F3-1-1, p. 15).

OPG's Real Estate and Facilities Management costs continue to be driven by business requirements associated with the large number of facilities and the geographic spread of facilities across the province. As the Hackett Study notes, OPG's Real Estate and Facilities

Management costs included all facility costs associated with its corporate regulated operations, including facility costs associated with IT, HR and Finance functions (Ex. F3-1-1, Attachment 1, p. 16). Such facility costs were embedded in each particular function for OPG's peers. This limitation had an unfavourable impact on OPG's Real Estate and Facilities Management performance (Ex. F3-1-1, pp. 15-16).

On balance, the Hackett Study demonstrates that OPG has made significant improvements in controlling Support Services costs since 2010. While OPG recognizes that its ECS costs did not benchmark well, as shown above, there are specific factors necessitating additional costs given the scope of OPG's nuclear operations relative to the comparators. On this basis, the Support Services costs requested above are reasonable overall and should be approved.

7.8.3 Corporate Cost Allocation Methodology

The cost allocation methodology is the same as was previously accepted by the OEB in EB-2013-0321, EB-2010-0008 and EB-2007-0905. In 2013, OPG's allocation methodology was independently evaluated by HSG Group Inc. and the report was filed to the OEB as part of EB-2013-0321.

The cost allocation methodology uses two methods to distribute costs among the business units: direct assignment and allocation (Ex. F3-1-1, p. 16). Direct assignment is used when the specific resources used by a particular business unit can be reasonably established by showing a direct relationship between the costs incurred by a support group and the business unit that causes the costs to be incurred. Allocations are used when more than one business unit uses a resource, but the portions of the resource that each uses cannot be directly established. In these cases, a cost driver is used to allocate the costs of the resource. A cost driver is a formula for sharing the cost of a resource among those who caused the cost to be incurred (Ex. F3-1-1, p. 17). Over 80% of corporate support costs attributed to the nuclear facilities are directly assigned (Ex. L-6.7-6 EP-026 Attachment 1, Table 1).

No party questioned OPG's cost allocation methodology in the proceeding. OPG respectfully submits that the cost allocation method used in this Application remains appropriate and should be approved here, as it was in prior applications.

7.8.4 Procurement and Support Services Purchased Services

OPG's procurement process for Nuclear and Support Services begins when the need for a service or item is identified. A requisition is created and approved by the appropriate authority as per OPG's Organizational Authority Register ("OAR") (Ex. J15.2). If no existing agreement is in place that can satisfy the need for the service or item, Supply Chain, in consultation with the requesting group, seeks quotations or proposals using an open competitive process for all contracts valued at $100K and above. For smaller contracts, OPG may invite pre-qualified suppliers to submit quotations or proposals on a competitive basis (Ex. F3-3-1, p. 1). Sole source exceptions to competitive procurement are allowed under certain circumstances with appropriate justification and approval.

Exhibit F3-3-2 provides information on the purchases of OM&A services and products by Support Services that are above the OEB threshold of 1% of total OM&A expense before taxes (about $6M). Two vendors met the threshold: New Horizons System Solution, which provides OPG with information technology services, and ARI Financial Services Inc., which provides transport and work equipment leasing (Ex. F3-3-2, Chart 1).

OPG respectfully submits that its procurement policies are appropriate, and its Support Services purchased service amounts are reasonable.

7.8.5 Support Services Capital

Exhibit D3-1-1 presents capital expenditures of Support Services groups that form part of rate base or are recovered through the asset service fee. Capital expenditures average about $25M over the IR term, which is significantly less than the actual amounts (about $40M) spent in 2014 and 2015 (Ex. D3-1-1, Table 1). The associated forecast capital in-service amounts of $8.1M (2017), $18.0M (2018), $5.0M (2019), $5.0M (2020), and $5.0M (2021) are reflected in the requested nuclear rate base are set out in Ex. B1-1-1, Chart 1. The capital expenditures by OPG's Support Services groups, in support of the regulated facilities, fund work in the Information Technology ("IT") and Real Estate groups within the Business and Administrative Services ("BAS") business unit.

These projects follow OPG governance and processes as set out in Ex. A2-2-1, Attachment 4. The capital budget available for a given period is established through the business planning process. It is based on an assessment of the needs of the business units in order to sustain the reliability, availability, and performance of existing assets and services, as well as to meet changing regulatory requirements, and to improve overall business value.

OPG respectfully submits that the capital expenditures and associated in-service additions of the Support Services group are reasonable and should be approved.

7.9 ISSUE 6.8

Oral Hearing: Are the centrally held costs allocated to the nuclear business appropriate?

Centrally-held costs are an integral part of the costs of operating OPG's generation facilities. They are company-wide costs that are recorded centrally for a variety of reasons, such as achieving record-keeping efficiency and maintaining proper oversight (Ex. F4-4-1, p. 1).

The amounts included in the nuclear revenue requirements are $94.1M (2017), $131.1M (2018), $156.7M (2019), $166.6M (2020) and $155.0M (2021), comprised of several largely unrelated cost categories.[47] The main cost categories are discussed in the next section. OPG submits that these amounts are reasonable and should be approved.

Centrally-held costs are directly assigned or allocated to OPG's regulated operations using the same methodology as in EB-2010-0008 and EB-2013-0321. The methodology was previously reviewed and found to be appropriate by Black & Veatch Corporation in EB-2010-0008. The methodology was similarly found to be appropriate as part of the independent review of OPG's cost allocation methodology by HSG Group Inc. in EB-2013-0321, Ex. F5-5-1. Excluding the Pension/OPEB Adjustment for Test Period Cash to Accrual Differences, at least 90% of the centrally-held costs attributed to the nuclear facilities over the IR term are directly assigned (Ex. L-6.8-6 EP-027 Attachment 1, Table 1).

7.9.1 Pension and OPEB-related Costs

Certain components of pension and OPEB-related accrual costs for all of OPG's employees and retirees continue to be included in centrally-held costs (Ex. F4-4-1, pp. 2-3). These cost components continue to include interest costs on the obligations, the expected return on

[47] Ex. F4-4-1, Table 3 plus updates to Pension and OPEB Cash Amounts at Ex. N1-1-1, Page 4, Chart 2, line 1.

pension plan assets, amounts in respect of past service costs, actuarial gains and losses, and variances from the forecast current service costs reflected in the standard labour rates. These components are further described at Ex. F4-3-2, pp. 13-16 and p. 18. As in EB-2013-0321 and EB-2010-0008, the pension and OPEB-related accrual costs that are centrally-held are directly assigned and allocated to business units in proportion to the pension and OPEB costs directly charged to the business units.

The nuclear portion of centrally-held pension and OPEB-related accrual costs underpinning the 2016-2018 Business Plan costs are shown at Ex. F4-4-1, Table 3, line 1 and Ex. F4-3-2, Chart 6.

Similar to the approach applied in the EB-2013-0321 payment amounts order process to implement the OEB's decision to reflect cash amounts in the revenue requirement, centrally-held costs in this proceeding include an adjustment for the difference between forecast accrual costs, in part embedded throughout other elements of the revenue requirement, and forecast cash amounts for pension and OPEB (Ex. F4-4-1, Table 3, line 2).

The resulting net pension and OPEB amounts (i.e. Ex. F4-4-1, Table 3, line 1 plus line 2) included in the proposed nuclear revenue requirement through the centrally-held costs for the 2017-2021 IR term are -$19.7M (2017), $2.1M (2018), $37.2M (2019), $41.7M (2020) and $46.3M (2021).[48] Section 7.7, Ex. F4-3-2, and Ex. N1-1-1 provide further information on OPG's pension and OPEB plans and costs.

7.9.2 Insurance

OPG's insurance costs include the cost of the company-wide insurance program and the additional nuclear-specific insurance program. The company-wide program covers commercial general liability, directors and officers and fiduciary liability, all property, boiler and machinery breakdown, including statutory boiler and pressure vessel inspections, and business interruption (Ex. F4-4-1, p. 3).

[48] Ex. F4-4-1, Table 3, line 1 plus line 2, plus updates to pension and OPEB cash amounts at Ex. N1-1-1, Chart 2.0, line 1.

As in EB-2013-0321 and EB-2010-0008, the costs of this program are assigned to the business units based on the applicability of each type of insurance coverage and the asset replacement cost of the generation facilities.

The nuclear-specific insurance program relates to liability insurance associated with nuclear operations and additional property insurance for damage to the nuclear portions of OPG's nuclear generating stations, which complements the conventional property insurance program. This portion of insurance costs continues to be directly assigned to the nuclear facilities.

The company-wide insurance costs for the nuclear facilities are generally stable over the IR term, with period-over-period fluctuations attributable mainly to insurance premium increases and changes related to appraised asset replacement cost values. The increasing trend in nuclear insurance costs starting in 2016 is due to higher statutory nuclear liability insurance limits being phased in accordance with the provisions of the new federal legislation, the *Nuclear Liability and Compensation Act* (Ex. F4-4-1, p. 4). The requested company-wide and nuclear insurance costs are found at Ex. F4-4-2, Table 2, lines 12 and 20.

7.9.3 Performance Incentives

Centrally held costs include performance incentives for OPG's management employees. Performance incentive costs continue to be attributed to the business units based on the distribution of past performance incentive payments. Performance incentive costs are projected assuming overall corporate target performance, set by annual corporate scorecards, is achieved on plan (Ex. F4-4-1, p. 4; Tr. Vol. 17, p. 12, lines 5-6). This results in generally stable performance incentive costs over the IR term (Ex. F4-4-2, Table 2, lines 13 and 21).

The overall corporate performance sets the envelope for total incentive payments, recognizing that individual performance within the envelope varies based on personal performance reviews (Tr. Vol. 17, p. 121, lines 23-28, p. 122, lines 1-18). Historically, these costs have fluctuated reflecting varying levels of actual corporate performance, being either above or below plan (Tr. Vol. 17, p. 12, lines 14-20, p. 15, lines 4-13).

7.9.4 IESO Non-Energy Charges

IESO non-energy costs are charges that are applied to withdrawals of energy from the IESO controlled grid. These charges are not discretionary and apply to all energy withdrawals from the IESO-controlled grid. These charges are directly assigned to the specific regulated facilities. The fluctuations in the costs over the 2013 to 2021 period, seen at Ex. F4-4-2, Table 2, lines 14 and 22, are primarily due to the variability in Global Adjustment rates (Ex. F4-4-1, p. 5).

7.9.5 Other Centrally Held Costs

Other centrally-held costs consist of a number of relatively smaller items. In the IR term, these are comprised primarily of labour-related costs and the annual ONFA guarantee fee. The labour-related costs include the fiscal calendar and labour balancing adjustments, as well as the vacation accrual, and are the primary driver of fluctuations in the Other costs of the IR term (Ex. F4-4-1, pp. 5-6). The proposed Other costs are found at Ex. F4-4-2, Table 2, lines 15 and 23.

The annual ONFA guarantee fee is the amount payable to the Province of Ontario pursuant to the ONFA. In exchange for the fee, the Province of Ontario supports financial guarantees to the CNSC by providing a guarantee relating to OPG's nuclear decommissioning and waste management liabilities and nuclear segregated funds pursuant to the ONFA (Ex. F4-4-1, p. 8).

7.10 DEPRECIATION

7.11 ISSUE 6.9

Primary: Is the proposed test period nuclear depreciation expense appropriate?

OPG seeks approval of test period revenue requirements that include depreciation and amortization expense of $367.0M (2017), $395.0M (2018), $400.3M (2019), $541.5M (2020) and $316.7M (2021) for the nuclear facilities, as shown in Ex. N2-1-1, Table 1 (historical and bridge year expenses are also provided in Ex. F4-1-1, Table 2). OPG continues to determine depreciation and amortization expense in the same manner as presented in EB-2013-0321. OPG submits that these amounts are reasonable and should be approved.

The depreciation and amortization expense for the prescribed nuclear facilities increases moderately from 2013 to 2019, with year-over-year increases largely due to the impact of in-service additions at the Darlington and Pickering stations and for the Darlington Refurbishment Project (discussed in detail at Ex. D2-1-2 and Ex. D2-2-1). OPG's 2016 Nuclear Benchmarking Report showed that OPG's nuclear capital expenditures per MW were lower than the comparators from 2010 to 2015 (Ex. L-6.2-15 SEC-063 Attachment 3, pp. 82-83). Exhibit D2-1-3, Table 4 shows there is a decline in the level of capital in-service additions for Pickering over the IR term. As discussed in Section 5.2.2, the reduction in capital spending toward the end of the IR term is the result of Pickering approaching its end of commercial operations.

The projected increase in depreciation and amortization expense in 2016, compared to 2015, is net of a reduction in prescribed facilities' ARC depreciation as a result of the changes in station end-of-life ("EOL") dates discussed in Ex. F4-1-1, Section 3.2,[49] as well as the related year-end 2015 adjustments in the ARO and ARC balances. These changes in EOL dates were anticipated in EB-2015-0374, a proceeding for OPG's accounting order application initiated pursuant to requirements of the EB-2012-0002 and EB-2013-0321 payment amount orders (EB-2012-0002, Payment Amounts Order, p. 7; EB-2013-0321, Payment Amounts Order, p.9). The year-end 2015 ARO and ARC adjustments and related revenue requirement impacts are discussed in Ex. C2-1-1, Section 5.0.

Nuclear depreciation and amortization expense is forecast to increase in 2020 when rate base increases as a result of the Darlington Unit 2's planned return to service in February 2020 (Ex. F4-1-1, p.7). The expense declines significantly in 2021, compared to 2020, as the current assumed Pickering EOL date of 2020, discussed below, is reached (also see Ex. L-6.9-1 Staff-177).

Allocation of depreciation and amortization expense is not required to attribute depreciation and amortization expense to the regulated facilities. Approximately 99% of OPG's in-service fixed and intangible assets are associated with specific generation facilities or plant groups (Ex. F4-1-1, p.1). The remaining in-service fixed and intangible assets, such as information

[49] The EOL dates for depreciation purposes for the prescribed nuclear facilities and the Bruce stations are also summarized at Ex. F4-1-1, pp. 2-3.

technology assets, continue to be either directly associated with a business unit or to be held centrally for use by both regulated and unregulated generation business units. For the use of assets held centrally, generating business units (both regulated and unregulated) continue to be charged an asset service fee for the use of these assets. This charge continues to be reported as an OM&A cost (Ex. F2-1-1, Table 1, line 9). The asset service fees are described in Ex. F3-2-1 and were fully settled as part of the settlement agreement (Ex. O1-1-1, p. 10).

Depreciation and amortization rates for the various classes of OPG's in-service fixed and intangible assets continue to be based on estimated service lives. The service life of an asset class is limited by the service life of the station(s) to which it relates. An average EOL date is established for depreciation purposes for all units at a particular station, which is typically based on estimated EOL dates for each operating unit of the station. The determination of the station EOL dates for depreciation purposes involves an assessment of the condition and expected remaining life of certain key components (referred to as life-limiting components), in conjunction with an estimate of the expected operation of the station, which includes economic viability considerations. For the nuclear stations, the life-limiting components are: fuel channels, steam generators, feeder pipes and reactor components (Ex. F4-1-1, p. 2).

As part of its due diligence process, OPG continues to convene an internal Depreciation Review Committee ("DRC") to examine the service lives of fixed and intangible assets and therefore the calculation of depreciation and amortization expense. The DRC is comprised of business unit representatives as well as staff from the Finance and Regulatory Affairs functions. The DRC considers available engineering, technical, operational and financial assessments/information as part of its regular review.

The DRC conducts a regular review of the service lives of generating stations (including the Bruce stations) and a selection of asset classes with the general objective of reviewing all significant asset classes for the regulated assets over a five-year cycle.[50] Periodic independent reviews of the service life estimates of significant asset classes for the regulated assets are also performed periodically. The DRC's scope and recommendations continue to

[50] The DRC recommended, and the Approvals Committee approved, changes to the nuclear station EOL dates effective December 31, 2015 (recommendations are found at Ex. F4-1-1, Attachment 1). The revenue requirement impact of these changes and associated Impact Resulting from Changes in Station End-of-Life Dates (2015) Deferral Account established in EB-2015-0374 are discussed at Ex. F4-1-1, p.4 and Ex. H1-1-1.

be submitted for approval to OPG's senior executives, including the Chief Financial Officer and the business unit leader of the nuclear operations. Approved DRC recommendations are used to calculate the depreciation and amortization expense that is reflected in OPG's financial statements and business plan. OPG's DRC review process was found by Gannett Fleming Canada ULC ("Gannett Fleming") to be procedurally sound and to meet generally accepted regulatory objectives regarding depreciation (Ex. F4-1-1, pp. 3-4).

Exhibit F4-1-1, Section 3.2 discusses changes in the nuclear station EOL dates since EB-2013-0321.[51] As discussed on page 6 of that exhibit, OPG has adopted an average EOL date, for accounting purposes, of December 31, 2020 for all four Pickering units 5 to 8.[52] As discussed in Ex. F2-2-3, OPG is undertaking a set of initiatives to extend Pickering operation beyond 2020, which will require the CNSC's approval. The December 31, 2020 accounting EOL date for the Pickering units is expected to be reassessed in the future when further technical work confirms, with the necessary high confidence, that the units would be fit to operate beyond 2020. OPG will seek the OEB's approval of an accounting order related to any future changes to the Pickering EOL date based on the same requirements that underpinned OPG's EB-2015-0374 application (Ex. F4-1-1, p.6; Ex. L-6.9-1 Staff-178(b)).

OPG last commissioned an independent assessment of its nuclear asset service life estimates for the EB-2013-0321 proceeding, based on year-end 2012 net book values (EB-2013-0321, Ex. F5-3-1). The results of the study, performed by Gannett Fleming, were accepted by the OEB in that proceeding (EB-2013-0321, Decision with Reasons, p. 98). As discussed in Ex. L-6.9-1 Staff-175, OPG plans to conduct the next independent study after refurbished Darlington Unit 2 is scheduled to return to service in February 2020. This would allow the substantial in-service addition associated with the Unit 2 return to service to be reviewed and overall more recent information to be provided to the rate-setting process for OPG's next IR term starting in 2022.

Differences between forecast DRP depreciation expense reflected in the approved nuclear revenue requirement and such actual expense will continue to be subject to the CRVA during the IR term.

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[51] EOL assumptions in relation to the Bruce Nuclear Generating Station are discussed in Section 8.4.

[52] This matches the previously approved December 31, 2020 EOL dates for Pickering Units 1 & 4 (Ex. F4-1-1, p.3).

7.12 INCOME AND PROPERTY TAXES

7.13 ISSUE 6.10

Primary: Are the amounts proposed to be included in the test period nuclear revenue requirement for income and property taxes appropriate?

7.13.1 Income Taxes

OPG is seeking approval of nuclear income tax expense of $-6.7M (2017), $-18.4M (2018), $-18.4M (2019), $59.2M (2020) and $-5.0M (2021), as presented in Ex. N2-1-1, Table 1.[53] OPG submits that these amounts are reasonable and should be approved.

For all prescribed facilities tax matters addressed in Ex. F4-2-1, OPG applied the same principles and methodology as in EB-2013-0321. OPG continues to use the taxes payable method for determining regulatory income taxes for its prescribed assets. Under the taxes payable method, only the current income tax expense is reflected in the revenue requirement.

Regulatory income taxes are determined by applying the statutory tax rates to the regulatory taxable income of the prescribed facilities and reducing the resulting amount by recognized investment tax credits ("ITCs") for qualifying Scientific Research and Experimental Development ("SR&ED") expenditures.[54] There have been no changes in the statutory income tax rates in the historic period and none are forecast in the bridge year or over the IR term.

As in EB-2013-0321, regulatory income taxes for the historical and bridge years continue to be determined by applying statutory tax rates to the regulatory taxable income of the combined prescribed nuclear and hydroelectric facilities, less SR&ED ITCs. Total regulatory income taxes are then allocated based on each business' regulatory taxable income, while SR&ED ITCs are predominantly directly attributed to each business unit based on the underlying expenditures giving rise to the ITCs (Ex. JT3.13).

[53] OPG's 2013-2016 regulatory income tax expense calculations are shown in Ex. F4-2-1, Table 3, and 2017-2021 calculations (for the nuclear facilities) are found at Ex. N2-1-1, Table 2.

[54] The approach to SR&ED ITCs is discussed in detail at Ex. F4-2-1, Section 3.4, Ex. L-6.10-1 Staff-189, and Tr. Vol. 21, pp. 131-132.

For nuclear ratemaking purposes for 2017 to 2021, the forecast regulatory income tax is presented for the prescribed nuclear facilities only, and is determined by applying statutory tax rates to the forecast regulatory taxable income of these facilities, less corresponding forecast SR&ED ITCs. In a situation where a tax loss is forecast for the nuclear business unit in a given year of the IR term, the loss is applied (carried back or carried forward) to reduce the nuclear business unit's taxable income in other years of the IR term (Ex. N2-1-1, Table 2, line 21).

Regulatory taxable income is computed by making additions and deductions to regulatory earnings before tax for items affected by differences in regulatory accounting treatment and tax treatment reflecting applicable requirements of the tax legislation. These additions and deductions are described in Ex. F4-2-1, Section 3.2, and are detailed in the calculation of regulatory income taxes in Ex. F4-2-1, Table 3 for 2013 to 2016 and Ex. N2-1-1, Table 2 for 2017 to 2021.

The negative tax expense shown for 2017 to 2019 and for 2021 is largely the result of the forecast amount of SR&ED ITCs attributed to the nuclear facilities in those years and reflects the carryover of projected regulatory tax losses arising in 2018 and 2019. The losses of $18.0M projected in 2018 and $16.4M in 2019 are carried back to reduce the regulatory taxable income for 2017 to $46.7M (Ex. N2-1-1, Table 2, lines 20-22).

The decrease in regulatory taxable income over the 2017-2019 period is driven primarily by forecast capital cost allowance deductions, primarily on account of DRP expenditures (Ex. L-6.10-1 Staff-194), and deductions for internally funded cash expenditures for nuclear waste management and decommissioning (see Issues 8.1 and 8.2). The increase in regulatory taxable income in 2020 reflects higher earnings before tax and higher depreciation expense, both due to the increase in rate base associated with the return to service of Darlington Unit 2 (see Issues 2.2 and 6.9). The decrease in 2021 taxable income is largely due to a reduction in depreciation and amortization expense related to the Pickering station (see Issue 6.9 in Section 7.11).

7.13.2 Property Taxes

OPG is seeking approval of property tax expense of $14.6M (2017), $14.9M (2018), $15.3M (2019), $15.7M (2020) and $17.0M (2021) as presented in Ex. F4-2-1, Table 2. OPG submits that these amounts are reasonable and should be approved.

The nature, basis, and components of OPG's property tax expense are unchanged from the evidence presented in EB-2013-0321 and EB-2010-0008. OPG remains responsible for both the payment of municipal property taxes and a payment in lieu of property tax to the Ontario Electricity Financial Corporation. The total of these two payments is intended to represent what a commercial generating company would pay as property tax, based on full Current Value Assessment, and constitutes OPG's property tax expense. Municipal property taxes and payment in lieu of property tax are described at Ex. F4-2-1, pp. 14-15.

OPG's property tax expense for the regulated nuclear facilities is presented in Ex. F4-2-1, Table 2, for the historical and bridge periods and the IR term. Municipal property taxes paid by OPG for properties that are not directly associated with specific generation business units and are held centrally continue to form part of the asset service fee, as discussed in Ex. F3-2-1. Property taxes associated with the Bruce assets are presented separately in Ex. G2-2-1, as part of Bruce Lease net revenues.

7.14 OTHER COSTS

7.15 ISSUE 6.11 (SETTLED)

Secondary: Are the asset service fee amounts charged to the nuclear business appropriate?

This issue has been settled.

8.0 OTHER REVENUES

8.1 NUCLEAR

8.2 ISSUE 7.1 (SETTLED)

Secondary: Are the forecasts of nuclear business non-energy revenues appropriate?

This issue was fully settled as part of the Settlement Agreement approved by the OEB (Ex. O1-1-1, pp. 10-11; Tr. Vol. 9, p. 1). As set out in Ex. O-1-1, p. 11:

> The Parties have agreed that OPG's forecast amounts of nuclear non-energy revenues are appropriate, subject to the following increases to OPG's net revenue forecast for heavy water sales for each year of the IR term (totaling a $12.2M increase over the IR term), relative to the forecast in the Application at Ex. G2-1-1, Table 1, line 1:
>
> - 2017: $6.1M
> - 2018: $1.3M
> - 2019: $1.5M
> - 2020: $1.6M
> - 2021: $1.7M
>
> These amounts represent increases at 100% of net revenues for heavy water sales, prior to the 50/50 sharing arrangement.

8.3 BRUCE NUCLEAR GENERATING STATION

8.4 ISSUE 7.2

Primary: Are the test period costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease appropriate?

OPG leases the Bruce A (Units 1-4) and Bruce B (Units 5-8) Nuclear Generating Stations and associated lands and facilities to Bruce Power L.P. ("Bruce Power"). The Bruce lease agreement sets out the main terms and conditions of the lease arrangement between OPG and Bruce Power, including lease payments.

In addition, OPG and Bruce Power have entered into a number of associated agreements for the provision of services by OPG to Bruce Power or by Bruce Power to OPG. These agreements include the Amended and Restated Used Fuel Waste and Cobalt-60 Agreement ("Used Fuel Agreement"), the Amended and Restated Low and Intermediate Level Waste Agreement ("L&ILW Agreement"), and the Amended and Restated Bruce Site Services Agreement.

The proposed net amounts of Bruce Lease revenues and costs for the purposes of setting the revenue requirement for the IR term are -$16.9M (2017), -$17.1M (2018), -$27.4M (2019), -$23.8M (2020) and -$38.1M (2021), as shown in Ex. N1-1-1, Table 7, line 30. These values reflect the projected impact of the 2017 ONFA Reference Plan based on OPG's 2017-

2018 Business Plan provided in OPG's First Impact Statement (Ex. N1-1-1). In accordance with O. Reg. 53/05 and the OEB's previous findings, these net amounts are applied towards the nuclear revenue requirement (i.e. negative net revenues increase the nuclear revenue requirement). Specifically, sections 6(2)9 and 6(2)10 of O. Reg. 53/05 provide that the OEB shall ensure that OPG recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations, and that any revenues earned from the Bruce Lease in excess of costs be used to offset the nuclear payment amounts.

As discussed further under Section 9.1.1, OPG filed updated evidence subsequent to Ex. N1-1-1 (namely, updated Ex. C2-1-2) to reflect the approval of the 2017 ONFA Contribution Schedule on February 28, 2017 and actual year-end 2016 financial information in line with OPG's audited financial statements filed on March 10, 2017. That evidence included summary level impacts of these items on Bruce Lease net revenues relative to Ex. N1-1-1, which, given that these changes became evidence at a late stage in the proceeding, OPG has proposed be recorded in the Bruce Lease Net Revenues Account. (Ex. C2-1-2) As OPG indicated during the hearing, however, another option would be to reflect these impacts in the revenue requirement, along with any other flow through impacts, through the Payment Amounts Order process for this proceeding (Tr. Vol. 21, p. 42). Taking into account these late changes, the forecast Bruce Lease net revenues over the IR term would be -$5.3M (2017), -$7.3M (2018), -$20.6M (2019), -$20.0M (2020) and -$40.3M (2021), as shown in Ex. J21.2, Attachment 1, Table 1.

On December 3, 2015, the Province announced that an updated contract had been executed between the IESO and Bruce Power to enable the refurbishment of Bruce Units 3-8 (the Amended and Restated Bruce Power Refurbishment Implementation Agreement or "ARBPRIA").[55] In support of these planned refurbishments, an amended Bruce lease agreement was executed by OPG and Bruce Power on December 4, 2015 ("2015 Amendment") that extended the lease period in line with the estimated post-refurbishment EOL dates of the Bruce units contained in the ARBPRIA.

The 2015 Amendment resulted from negotiations undertaken by OPG and Bruce Power in the context of the IESO and the Province's need to fully consider the economics of Bruce

[55] https://news.ontario.ca/mei/en/2015/12/ontario-commits-to-future-in-nuclear-energy.html

Power's proposed refurbishment of the Bruce units. These negotiations provided an opportunity to reassess certain aspects of the lease arrangements between OPG and Bruce Power. These negotiated amendments cover other areas including base rent, supplemental rent, low and intermediate level waste ("L&ILW") management fees, and related provisions that serve to limit OPG's financial risk exposure over the term of the lease.

Key changes to the Bruce Lease resulting from the negotiations included:

- Extension of the lease renewal term by approximately 20 years, with higher renewal term base rent payments that are now subject to CPI escalation, starting in 2019;
- Elimination of the derivative liability embedded in the lease agreement, leading to the reversal of the derivative liability in December 2015 of approximately $299M (approximately $224M after tax) that OPG expects otherwise would have been payable by ratepayers over 2016 to 2019;
- Effective in 2016, changes in the supplemental rent and L&ILW management fees to align them more closely with the costs of managing used fuel and L&ILW generated by the Bruce units as determined under the ONFA; and
- Provisions that serve to limit OPG's financial risk exposure over the term of the lease related to changes in nuclear used fuel and waste management costs arising from future updates to the ONFA reference plan.

These changes are discussed more fully in Ex. G2-2-1, pp. 4-6 and Ex. JT3.10.

As in EB-2014-0370, EB-2013-0321, EB-2012-0002 and EB-2010-0008, the treatment of revenues and costs associated with the Bruce lease agreement and associated agreements follows the OEB's decision in EB-2007-0905, based on O. Reg. 53/05 requirements. Namely, these revenues and costs are calculated in accordance with generally accepted accounting principles for unregulated businesses. (Ex. G2-2-1, p. 3) The EB-2007-0905 Decision with Reasons with respect to the treatment of Bruce Lease net revenues is further discussed under Issues 8.1 and 8.2.

The nature of, and the methodology for assigning and allocating revenues and costs to the Bruce facilities and under the Bruce Lease also is unchanged from that applied in EB-2013-0321 and EB-2010-0008, and reflected in EB-2014-0370 and EB-2012-0002 through the disposition of the Bruce Lease Net Revenues Variance Account. The vast majority of the revenue and costs items continues be directly assigned. As discussed in EB-2010-0008, this methodology was previously independently reviewed and found to be appropriate by Black & Veatch Corporation Inc. (Ex. G2-2-1, p. 3; Ex. L-7.2-1 Staff-202).[56]

In addition to the accounting impact on nuclear liabilities of the 2017 ONFA Reference Plan update, Bruce Lease net revenues over the 2016-2021 period reflect the accounting impact on the nuclear liabilities of extending the EOL dates of the Bruce units, effective December 31, 2015, as anticipated in EB-2015-0040 (Ex. F4-1-1, p. 5). These extended EOL dates match the post-refurbishment EOL dates in the ARBPRIA (*Id*.). The resulting changes in ARO and ARC are discussed under Issues 8.1 and 8.2.Future changes arising from subsequent ONFA reference plans, including the impact of the funded status of the ONFA segregated funds and associated earnings discussed in Ex. C2-1-2, will impact the Bruce Lease net revenues over the remaining lease term to the early 2060s, such that future amounts of net revenues may be positive or negative (Ex. L-7.1-12 OAPPA-004(a); Ex. L-7.2-20 VECC-040).

OPG submits that the forecast net revenue amounts are appropriate for the IR term, but, in any event, these forecast amounts will be tracked against actual revenues and costs and trued up via the Bruce Lease Net Revenues Variance Account, based on O. Reg. 53/05 requirements, as discussed in Ex. H1-1-1, pp. 24-27.

9.0 NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

9.1 ISSUE 8.1 AND ISSUE 8.2

Primary: Is the revenue requirement methodology for recovering nuclear liabilities in relation to nuclear waste management and decommissioning costs appropriate? If not, what alternative methodology should be considered?

Primary: Is the revenue requirement impact of the nuclear liabilities appropriately determined?

This section discusses OPG's forecast of liabilities for nuclear waste management and decommissioning costs and how the treatment of those liabilities impacts OPG's revenue requirement.

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[56] See EB-2010-0008 Ex .G2-2-1, Section 3.0. The changes resulting from the 2015 Amendment do not affect the allocation of revenues and costs in the determination of Bruce Lease Net Revenues, as discussed in Ex. L-7.2-20, VECC-039.

OPG is seeking recovery of $1,808M over the IR term for nuclear liabilities (Ex. C2-1-2, Chart 1, line 11), comprised of $786.4M for the prescribed facilities and $1,021.6M for the Bruce facilities (Ex. C2-1-2, Chart 1, lines 5 and 8, respectively). This reflects the First Impact Statement filed by OPG in December 2016 (Ex. N1-1-1). Partly offsetting this impact are net ratepayer credits of approximately $295M that OPG proposes to reflect in the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account over the IR term. These credits arose from events that occurred or information that became available subsequent to the filing of the First Impact Statement (Ex. N1-1-1).[57]

9.1.1 Background to Evidence

On December 20, 2016, the Province approved the 2017 to 2021 ONFA Reference Plan, effective January 1, 2017 (the "2017 ONFA Reference Plan"). The 2017 ONFA Reference Plan resulted in an overall reduction in OPG's nuclear liabilities and, through the subsequent approval by the Province of a contribution schedule, a reduction in overall segregated fund contributions relative to OPG's pre-filed evidence. This reduction in the liabilities was mainly attributable to a proposed new, more cost effective container design and engineered barrier concept to house used nuclear fuel for disposal, as well as a later planned in-service date for Canada's proposed used fuel deep geologic repository. The projected impact of the 2017 ONFA Reference Plan based on OPG's 2017-2019 Business Plan was included in Ex. N1-1-1.

On February 14, 2017, OPG filed Ex. C2-1-2 to provide supplementary information on the nuclear liabilities pursuant to the OEB's Procedural Order No. 6, including information on the funded status of the Decommissioning Segregated Fund ("DF") and the Used Fuel Segregated Fund ("UFF"). That evidence included Chart 1 that outlined the revenue requirement impact of the nuclear liabilities over the IR term, based on Ex. N1-1-1. OPG subsequently updated Ex. C2-1-2 to reflect the approval of the 2017 ONFA Contribution Schedule on February 28, 2017 and actual year-end 2016 financial information in line with

[57] The $295M credit relative to the impacts reflected in the First Impact Statement is made up of a net credit of $119.7M shown at Ex. C2-1-2, Chart 1A, line 10 from the approval of 2017 ONFA Contribution Schedule on February 28, 2017, and $95M shown at Ex. C2-1-2, p. 5, line 12 for the prescribed facilities and $80M shown at Ex. C2-1-2, p. 5, line 13 for the Bruce facilities from the use of the actual year-end 2016 asset retirement obligation adjustment and discount rate.

OPG's audited financial statements filed on March 10, 2017, including summary level impacts (a net ratepayer credit) of these items relative to Ex. N1-1-1 (see footnote 57).

As part of Ex. J21.2, OPG updated Ex. C2-1-2, Chart 1 to incorporate these summary level impacts to produce the overall revenue requirement impact of the nuclear liabilities (for both prescribed and Bruce facilities) over the IR term based on current best available information.[58,59]

Given that these changes happened at a late stage in the proceeding and were filed during the oral hearing portion, OPG has proposed that the nuclear liabilities revenue requirement changes subsequent to the Exhibit N1 Impact Statement be recorded in the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account (Ex. C2-1-2). As OPG indicated during the hearing, however, another option would be to reflect these impacts in the revenue requirement, along with any other flow through impacts, through the Payment Amounts Order process (Tr. Vol. 21, p. 42).

9.1.2 OPG's Obligation for Nuclear Waste and Decommissioning

OPG is responsible for the ongoing and long-term management of radioactive wastes, including used nuclear fuel and less radioactive material, categorized as low-level and intermediate-level waste ("L&ILW") and for the decommissioning of its nuclear generating and waste management facilities after their shutdown. These obligations include used fuel and L&ILW generated at the Bruce stations and the decommissioning of the Bruce stations. The five programs used to track the obligation are described in Ex. C2-1-1, Section 3.1.1. OPG typically performs a comprehensive update of the cost estimates for the nuclear liabilities every five years, through the ONFA reference plan update process outlined in Ex. C2-1-1, Section 3.1.2. Given the long duration of the nuclear liabilities programs and the

[58] The difference between the total revenue requirement impact per Ex. J21.2, Chart 1, line 11 and Ex. C2-1-2, Chart 1, line 11 is $304.7M. This amount corresponds to the $295M credit detailed in footnote 57, plus the regulatory income tax impact of about $10M (at 25% tax rate, grossed-up) on the net reduction in Bruce Lease net revenues impact of about $29M. This amount is not included in the $295M credit because the Bruce Lease Net Revenues Variance Account does not record the regulatory income tax impact associated with variances in Bruce Lease net revenues. Rather, as in previous proceedings, these tax amounts are typically settled with ratepayers through the regulatory income tax calculation reflected in payment amounts, on disposition of the Bruce Lease Net Revenues Variance Account (Ex. F4-2-1, p. 9, line 14-25).

[59] Ex. J21.2 also provided, in Table 1, the corresponding update to the forecast Bruce Lease net revenues, reflecting the nuclear liabilities revenue requirement impact in Ex. J21.1, Chart 1.

evolving technology to handle nuclear waste, there is inherent uncertainty surrounding the cost estimates and economic indices underpinning the nuclear liabilities, which may increase or decrease over time as plans and assumptions are refined and economic conditions change.

In accordance with US GAAP, OPG recognizes an accounting obligation for its nuclear liabilities on the balance sheet, known as an asset retirement obligation ("ARO"). The ARO represents the present value of the committed portion of the costs for OPG's nuclear liabilities. The committed costs include the fixed cost components of the five programs referenced above as well as the lifetime variable costs for waste generated to date. The baseline cost estimates underpinning these costs are those developed through the ONFA reference plan update process.

An overall objective of the financial accounting treatment of AROs is to reflect the costs in the periods they are incurred, by matching them to the benefits derived from the asset. ARO costs are typically capitalized as a component of property, plant and equipment on the balance sheet and depreciated over the useful life of the stations, in order to match the incurrence of these costs to the generation output of the station. The capitalized costs are known as asset retirement costs ("ARC"). As such, a change in the ARO as a result of changes in baseline cost estimates or assumptions typically results in an equal amount being recorded as an increase or decrease to the property, plant and equipment balances for the corresponding stations, to be depreciated over their remaining useful lives.

The initial value and each subsequent adjustment to the ARO are known as tranches. As required by US GAAP, each tranche is calculated using a discount rate determined at the time of the adjustment and is not revalued for subsequent changes in the discount rate. Each upward revision in the amount of undiscounted estimated cash flow underlying the ARO is required to be discounted using a credit-adjusted risk free rate determined as of the date of revision. For OPG, this rate is based on the Province of Ontario long-term bond yield rate (Ex. L-8.2-1 Staff-207). Each downward revision in the amount of undiscounted estimated cash flows is required to be calculated using the weighted average discount rate of the existing tranches.

Quantities of used fuel and L&ILW produced over time give rise to incremental committed costs, which are recorded as increases to the ARO. These costs, expressed in present value terms, are known as used fuel variable and L&ILW variable expenses, and are charged to the income statement as incurred, in the period the additional used fuel and L&ILW is generated.[60]

Being a present value obligation, the ARO increases due to the passage of time, which gives rise to accretion expense recognized in OPG's income statement.

The difference between the ARO and the segregated fund assets recorded on OPG's balance sheet represents the unfunded nuclear liability ("UNL"), as defined under the OEB-approved revenue requirement methodology for the prescribed facilities. The method for recovering the revenue requirement impact of nuclear liabilities is discussed in Section 9.0.

9.1.3 Ontario Nuclear Funds Agreement

The ONFA sets out OPG's funding obligations for the long-term programs of lifecycle nuclear liabilities, through contributions to the DF and the UFF. These funds are set aside in segregated accounts for the express purpose of funding the future costs of the underlying obligations. The Province established the ONFA as the funding mechanism for OPG's nuclear liabilities consistent with a growing trend around the world to place money aside for the long-term management of nuclear liabilities, in recognition of the fact that these liabilities will be discharged many years after the nuclear generating stations have closed. The DF was established to fund the lifecycle costs of nuclear decommissioning and long-term L&ILW management. The UFF was established to fund the lifecycle costs of long-term nuclear used fuel management.[61]

The costs for used fuel management and L&ILW storage costs incurred during the stations' operating lives are not funded under the ONFA and cannot be drawn from the segregated funds. As these costs, referred to as "internally funded," are part of OPG's legal obligation for nuclear waste, they are included in the ARO and are funded from OPG's operating cash flow.

[60] See Ex. N1-1-1, p. 17, footnote 14 for the determination of the discount rate applied to calculate variable expenses.

[61] Ex. C2-1-1, p. 5, footnote 1 details the specific definition of the funding boundaries for each of the segregated funds.

OPG's station-level quarterly contributions to the segregated funds are determined periodically, with reference to the funding liabilities contained in an approved ONFA reference plan in effect and corresponding segregated fund balances. Prescribed funding formulae and rules set out in the ONFA are applied to calculate the contribution amounts based on the difference between the funding liabilities and fund balances. The discount rate used to calculate the funding liabilities is determined in accordance with the ONFA, at the time of each approved of ONFA reference plan, as the 3.25% real rate of return prescribed by the ONFA plus the long-term change in the Ontario consumer price index. The resulting rate also establishes the long-term target rate of return on the ONFA segregated funds. ONFA reference plans, including all underlying cost estimates and assumptions, are required to be updated every five years or whenever there is a significant change as determined under the ONFA. The funded status of the funds at any point in time represents the difference between the funding obligations per an approved ONFA reference plan then in effect and the value of the segregated funds.

Cost estimates and underlying operational, economic and other planning assumptions reflected in the ONFA funding liabilities are determined through a comprehensive process that draws from a variety of sources, including the use of independent third party experts in different fields. Cost estimates and underlying assumptions are reviewed by the Province and their technical consultants prior to approving ONFA reference plans. In addition to the funding liabilities for ONFA-funded costs, an approved ONFA reference plan contains cost estimates for internally funded costs, which are also subject to review by the Province.

The ONFA contains several specific features designed to reduce risk for future generations of Ontarians, by ensuring that sufficient funds are available to pay for nuclear liabilities. First, the segregated funds are held in third-party custodial accounts, externally administered and subject to extensive reporting controls. Second, OPG cannot withdraw monies from the funds, unless the withdrawal reimburses OPG for an eligible incurred expenditure related to nuclear waste management and decommissioning activities as specifically defined by the ONFA. These disbursements are subject to a detailed review and approval process by the Province. OPG does not have other rights to withdraw the funds, including on the agreement’s termination, as discussed below. Third, specific funding formulae and rules contained in the ONFA have been structured such that OPG has been required to fund a substantial portion of the underlying used fuel liabilities early as a form of funding conservatism (Ex. C2-1-2, p. 11).

Upon the termination of the ONFA, only the Province has a right to any excess funds in the UFF and DF, and the ONFA does not allow inter-fund transfers from the UFF to the DF. If there is a surplus in the UFF such that the funding liability per the most recently approved ONFA reference plan is at least 110 percent funded, the Province has the right to access the surplus amount greater than 110 percent at any time.[62] For the DF, OPG has the right to direct, when a new or amended ONFA reference plan is approved, up to 50% of the excess, if any, above 120% to the UFF,[63] with the Province entitled to receive the other 50%.[64]

In accordance GAAP, segregated funds are recognized as assets on OPG's balance sheet to the extent that OPG has a right to access the monies based on the ONFA terms specified above. For the UFF, this means limiting the asset recognized to the funding liability per the approved ONFA Reference Plan in effect. For the DF, this means recording an asset equal to the underlying funding liability, plus 50% of surplus funding above the 120% threshold up to the amount of the underfunding, if any, in the UFF. The portion of any surplus not recognized as an asset is recorded as "Due to Province" in OPG's financial statements. OPG has consistently applied this accounting treatment to the segregated funds in the current and previous proceedings, including EB-2013-0321. The OEB addressed the matter of the Due to Province amounts related to the segregated funds in EB-2013-0321 (see EB-2013-0321, Decision with Reasons, p.110).

Based on the 2017 ONFA Reference Plan, both the UFF and the DF were determined to be overfunded. The UFF was marginally overfunded at less than 1%, for the first time since its inception, while the DF was overfunded at approximately 21%, as of year-end 2016. The DF has been in an overfunded position every time a new ONFA contribution schedule has been established. The overfunded status of the DF was noted in EB-2007-0905 Decision with Reasons (p. 66) and the EB-2031-0321 Decision with Reasons (p. 108).

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[62] The UFF has never experienced a surplus amount greater than 110%. The Province does not have a right to withdraw, at its own discretion, any portion of the excess amounts in the DF until the termination of the ONFA.
[63] OPG has not directed any portion of the DF surplus to the UFF since the funds' inception.
[64] OPG and Province's respective rights of access to the UFF and the DF are also outlined in OPG's annual audited consolidated financial statements, including for the 2015 year-end found at Ex. A2-1-1, Attachment 3, pp. 143-144. Further details also can be found in Ex. L-8.1-2 AMPCO-147 and EB-2013-0321, Ex. J11.8.

As noted above, the long-term nature of the required funding for nuclear liabilities lends itself to periods of under-earning or over-earning relative to the long-term target rate of return, which, along with changes in underlying cost estimates, can lead to fluctuations in the funded position of the funds. Either or both of the funds may be in an underfunded position in the future, either as a result of changes in the liabilities or due to below target fund asset performance.

9.1.4 OEB Approved Revenue Requirement Methodology

For the IR term, OPG proposes to continue to maintain the OEB-approved revenue requirement methodology first established in EB-2007-0905 and applied in each subsequent proceeding.

In accordance with section 6(2)8 of O. Reg. 53/05, the OEB is required to ensure that OPG recovers the revenue requirement impact of its nuclear waste management and decommissioning liabilities arising from the current approved ONFA reference plan. The OEB established the methodologies for recovery of OPG's nuclear liabilities costs in OPG's first payment amounts proceeding, EB-2007-0905 with different methodologies being established for the prescribed facilities and the Bruce facilities, as discussed below.

In establishing the revenue requirement methodologies in EB-2007-0905, the OEB recognized that nuclear liabilities were an integral, material element of OPG's costs to operate the nuclear stations, stating the following:

> In the Board's view, there is no doubt that the cost of nuclear liabilities should be included in the revenue requirement for the prescribed facilities. Managing nuclear waste, and decommissioning the plants at the end of their lives, is an integral part of operating the Pickering and Darlington plants (EB-2007-0905, Decision with Reasons, p. 88).
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> For OPG, the issue is both real and material (EB-2007-0905, Decision with Reasons, p. 91).

The revenue requirement methodologies established by the OEB were largely based on accounting values determined in accordance with GAAP. The main difference between the methodology for the prescribed facilities and the Bruce facilities is the application of a return on rate base, a regulatory construct, to the prescribed facilities, as opposed to including the net amount of ARO accretion expense and segregated fund earnings for the Bruce facilities.

Approved Revenue Requirement Methodology for Prescribed Facilities

For the prescribed facilities, OPG recovers the following amounts for nuclear liabilities, based on values determined in accordance with GAAP, as described in more detail in Ex. C2-1-1, Section 3.2:

- Depreciation expense on the ARC balance;
- Used fuel and L&ILW variable expenses;
- Return at the ARO weighted average accretion rate on the lesser of the average unamortized ARC and the average UNL; and
- Return at the weighted average cost of capital on the portion, if any, of average unamortized ARC in excess of average UNL.

The return component of the prescribed facilities' methodology effectively replaces the net amount of ARO accretion expense and segregated fund earnings recorded (or forecasted to be recorded) in relation to these stations for financial accounting purposes.

With respect to the inclusion of ARC depreciation expense in the revenue requirement, the OEB stated the following in EB-2007-0905:

> The Board will accept inclusion in the revenue requirement of depreciation expense for the nuclear plants computed in accordance with GAAP, as proposed by OPG. Under GAAP, ARC included in the net book value of fixed assets is depreciated like any other fixed asset cost. It appears as an expense in OPG's income statement. The Board finds that this approach results in a rational allocation of cost. (EB-2007-0905, Decision with Reasons, pp. 88-89)

Through the calculation of regulatory income taxes for the prescribed facilities, OPG's revenue requirement also includes income tax impacts associated with the above cost elements, as well as the tax impacts of the prescribed facilities' contributions to the segregated funds, expenditures on nuclear liabilities and disbursements from the segregated funds (see Ex. F4-2-1, Sections 3.2.1, 3.2.2, 3.2.3, 3.2.4 and 3.2.6).[65]

O. Reg. 53/05 Section 5.2(1) establishes the Nuclear Liability Deferral Account, which records the revenue requirement impact for the prescribed facilities of any change in the nuclear liabilities arising from an approved ONFA reference plan. Section 6(2)7 states that the Board shall ensure recovery of the balance in the account over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirements impacts are accurately recorded, based on the following items as reflected in OPG's audited consolidated financial statements: (i) return on rate base; (ii) depreciation expense; (iii) income and capital taxes;[66] (iv) fuel expense. These items correspond to the components of the revenue requirement methodology established in EB-2007-0905. This account is covered in Section 10.1 (see also Ex. H1-1-1, Section 5.13).

Approved Revenue Requirement Methodology for Bruce Facilities

For the Bruce facilities, the OEB determined, by reference to sections 6(2)9 and 6(2)10 of O. Reg. 53/05, that it was appropriate to calculate OPG's revenues and costs, including the costs of the nuclear liabilities, using GAAP applicable to unregulated entities. Section 6(2)9 requires that the OEB ensure that OPG recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations. Section 6(2)10 requires that the excess of OPG's revenues over costs related to its lease of these stations be applied to reduce the payment amounts for the prescribed nuclear facilities.

Specifically, the Board found the following in EB-2007-0905:

> The Board finds that the appropriate method to calculate OPG's test period revenues and costs related to the Bruce stations is to use amounts calculated in accordance with GAAP. OPG's investment in Bruce is not rate regulated. In the Board's view, it would be not be a reasonable interpretation of Section 6(2)9 and 6(2)10 to find that

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[65] The tax benefit of nuclear liabilities expenditures less segregated fund disbursements is shown in Ex. N1-1-1 Chart 3.2.1, lines 9-18, Ex. C2-1-2 Chart 1, line 4 and Ex. J21.2 Chart 1, line 4, but not in Ex. C2-1-1. All of these exhibits include the tax gross-up related to the revenue requirement cost components and the tax benefit of the segregated fund contributions. All of the above tax impacts, including for the nuclear liabilities expenditures and segregated fund disbursements, are appropriately included in the calculation of regulatory income taxes (Ex. F4-2-1 Table 3a, as updated in Ex. N1-1-1 Table 8 and Ex. N2-1-1 Table 2).

[66] Capital tax was eliminated effective in 2010.

> OPG should use an accounting method to determine revenues and costs that an unregulated business would otherwise never use (EB-2007-0905, Decision with Reasons, p. 109).
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> …
>
> OPG should base its calculation of costs on GAAP. The costs should include all items that would be recognized as expenses under GAAP, including accretion expense on the nuclear liabilities. Forecast earnings on the segregated funds related to the Bruce liabilities should be included as a reduction of costs (EB-2007-0905, Decision with Reasons, p. 110).
>
> …
>
> When OPG earns a profit (measured in accordance with GAAP) on its Bruce activities, the Board's approach calls for all of that profit to be used to reduce payment amounts for Pickering and Darlington. […] If OPG were to include a loss on its Bruce activities, which could happen if there are significant increases in the Bruce nuclear liabilities in the future, that loss would increase the payment amounts for the prescribed assets under the Board's approach (EB-2007-0905, Decision with Reasons, p. 111)

OPG recovers the following amounts for the Bruce facilities' portion of the nuclear liabilities, as components of Bruce Lease net revenues, as described in more detail in Ex. C2-1-1, Section 3.3:

- Depreciation expense on the ARC balance
- Used fuel and L&ILW variable expenses
- Accretion expense on the ARO balance

less

- Earnings on the segregated funds

The calculation of Bruce Lease net revenues also includes the income tax expense associated with the above items, including deferred income taxes in accordance with GAAP. As part of Bruce Lease net revenues, segregated fund contributions and expenditures on nuclear liabilities (net of disbursements from the segregated funds), as tax deductible items, reduce the current income tax expense but also attract an equal and offsetting deferred income tax cost, with no net effect.[67] The income tax expense components of Bruce Lease net revenues are discussed further in Ex. G2-2-1, Sections 5.8 and 5.9. Bruce Lease net revenues amounts are subject to regulatory income tax treatment through their impact on regulatory earnings before tax for the prescribed facilities.[68]

To give effect to O. Reg. 53/05 requirements, in EB-2007-0905 the OEB established the Bruce Lease Net Revenues Variance Account, which captures the difference between forecast and actual Bruce Lease net revenues, including nuclear liabilities costs.[69] The Bruce Lease Net Revenues Variance Account is discussed in Section 10.1 (see also Ex. H1-1-1, Section 5.15).

9.1.5 Revenue Requirement Impact

For the prescribed facilities, OPG is seeking recovery of a total pre-tax amount of $750.5M in respect of the nuclear liabilities (Ex. C2-1-2, Chart 1, line 1). The associated regulatory income tax impact is $36.0M (Ex. C2-1-2, Chart 1, lines 2 and 4). For the Bruce facilities, OPG is seeking recovery of $766.2M as part of Bruce Lease net revenues (Ex. C2-1-2, Chart 1, line 6) The associated regulatory income tax impact is $255.4M (Ex. C2-1-2, Chart 1, line 7).[70] These impacts do not include credit amounts OPG proposes to reflect in the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account, using the methodologies previously applied to these accounts as discussed above in Section 9.1.1.

The impacts proposed for inclusion in the revenue requirement reflect the projected accounting impacts of the 2017 ONFA Reference Plan approved by the Province, based on OPG's 2017-2019 Business Plan. These impacts include a year-end 2016 projected adjustment to reduce the carrying value of the ARO and ARC by $1,529.7M, comprising $237.9M for the prescribed facilities and $1,291.8M for the Bruce facilities.[71] This adjustment

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[67] As the net tax effect is nil, these items were not explicitly identified in the calculation of the income tax component of Bruce Lease net revenues at Ex. C2-1-1, Table 1a, footnote 3, as updated in Ex. N1-1-1, Table 2a, footnote 3.
[68] As shown at Ex. C2-1-1, Table 1, line 16, as updated at Ex. N1-1-1, Table 2, line 16 and Ex. C2-1-2, Chart 1, line 7, and as further updated in Ex. J21.2, Chart 1, line 7.
[69] See EB-2007-0905, Decision with Reasons, p. 112.
[70] The components of the proposed revenue requirement impact for the prescribed and Bruce facilities are detailed among Ex. N1-1-1, Table 2 and Ex. N1-1-1, Chart 3.2.1. Supporting continuities of ARO, segregated fund and ARC balances for the period are shown Ex. N1-1-1, Tables 3 and 4.
[71] Ex. N1-1-1, p. 16, lines 5-8 and footnote 13.

is detailed, by station and program, in Ex. N1-1-1, Table 5. As the projected year-end 2016 ARO adjustment represented an overall downward revision in the undiscounted cash flows underlying the obligation, it was calculated using the weighted average discount rate of existing tranches, at 4.95%. (Ex. N1-1-1 p. 16, lines 11-18; Ex. J21.1) The projected discount rate used to calculate used fuel variable and L&ILW variable expenses is 2.63% (Ex. N1-1-1, p. 17, lines 19-24).

The nuclear liabilities amounts proposed for inclusion in the revenue requirement also reflect current accounting end-of-life assumptions for OPG's nuclear stations (Ex. F4-1-1, pp. 2-3) and the impacts of changes in these assumptions effective December 31, 2015, as discussed in EB-2015-0374 and Ex. C2-1-1, Section 5.0.[72]

Based on the extensive evidence addressing nuclear liabilities in this Application, OPG submits that the amounts proposed for recovery using methodologies previously approved by the OEB are appropriate. Consistent with the requirements of O. Reg. 53/05, they should be approved.

10.0 DEFERRAL AND VARIANCE ACCOUNTS

10.1 ISSUE 9.1 (PARTIALLY SETTLED)

Primary: Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

This issue is partially settled. In the OEB-approved settlement agreement (Ex. O1-1-1, p.12; Tr. Vol. 9, p. 1), parties agreed that the nature and type of costs recorded by OPG in the year-end 2015 audited balances of deferral and variance accounts were appropriate on the basis of OPG's evidence, with the exception of the Capacity Refurbishment Variance Account (Nuclear), Nuclear Liability Deferral Account, and Bruce Lease Net Revenues Variance Account.

In OPG's submission, the nature and type of costs recorded in the unsettled deferral and variance accounts are appropriate. With respect to all existing accounts, OPG submits that

[72] Details on the corresponding year-end 2015 ARO and ARC adjustment can be found in Ex. C2-1-1, Table 4.

the nature and type of costs recorded going forward, as described in Ex. H1-1-1 are appropriate.

Entries into the unsettled accounts for 2015 have been calculated in accordance with the applicable OEB decisions and orders in EB-2013-0321 and EB-2014-0370. The December 31, 2014 balances in all authorized accounts were approved by the OEB for recovery in EB-2014-0370.

Variances recorded in the Capacity Refurbishment Variance Account (Nuclear) in 2015 pertain to the same eligible projects and initiatives that were captured in the December 31, 2014 balance of the account, including DRP and Pickering Continued Operations. The Bruce Lease Net Revenues Variance Account captured variances in the same type of items that comprise the OEB-approved forecast of Bruce Lease net revenues, determined in accordance with GAAP as described under Issue 7.2. The balance for recovery in the Nuclear Liability Deferral Account is nil as there was no new ONFA Reference Plan approved in 2015.

OPG submits that the nature and type of costs recorded in the unsettled deferral and variance accounts comply with O. Reg. 53/05 and appropriate.

10.2 ISSUE 9.2 (PARTIALLY SETTLED)

Primary: Are the methodologies for recording costs in the deferral and variance accounts appropriate?

This issue is partially settled. In the OEB-approved settlement agreement (Tr. Vol. 9, p. 1; Ex. O1-1-1, p.12-13), parties agreed that the methodologies for recording costs in OPG's existing deferral and variance accounts through December 31, 2015 were appropriate on the basis of OPG's evidence, except for the Capacity Refurbishment Variance Account (Nuclear), the Nuclear Liability Deferral Account, and the Bruce Lease Net Revenues Variance Account.

The methodologies used to record costs through December 31, 2015 in the three unsettled accounts as described in Ex. H1-1-1 follow the EB-2013-0321 and EB-2014-0370 payment amounts orders and are appropriate. The same methodologies were used to record amounts in these accounts as the OEB approved in previous proceedings, including, most recently, EB-2014-0370.

For the existing nuclear accounts, OPG submits that the methodologies used for recording amounts post-2015 as described in Ex. H1-1-1 are appropriate. The proposed methodologies for the existing accounts post-2015 for the nuclear facilities have been well established through OPG's previous proceedings and, where applicable, achieve results necessary to implement O. Reg. 53/05.

Similarly, for the regulated hydroelectric facilities, most aspects of the proposed methodologies for the existing accounts post-2015 are consistent with those approved and applied in previous proceedings. OPG proposes to continue using the previously approved reference amounts in EB-2013-0321 for these accounts over the IR term. OPG's proposed treatment of the CRVA under the hydroelectric price-cap IRM is discussed in Section 12.2.6.

10.3 ISSUE 9.3 (PARTIALLY SETTLED)

Secondary: Are the balances for recovery in each of the deferral and variance accounts appropriate?

This issue is partially settled. In the OEB-approved settlement agreement (Ex. O1-1-1, p.13-14; Tr. Vol. 9, p. 1), parties agreed that the December 31, 2015 balances for recovery in each of the deferral and variance were appropriate on the basis of OPG's evidence, except for the Capacity Refurbishment Variance Account (Nuclear), the Nuclear Liability Deferral Account, the Bruce Lease Net Revenues Variance Account, and the Pension & OPEB Cash Versus Accrual Differential Deferral Account (which is subject to the OEB's generic proceeding).

The year-end 2015 balances in all accounts, including additions to these accounts during 2015, are shown in Ex. H1-1-1, Table 1a. The total year-end 2015 debit balances are $255.5M for the regulated hydroelectric facilities and $1,433.4M for the nuclear facilities. To arrive at the balances presented for recovery in this Application, these balances are adjusted as follows:

- Remove 2016 amortization amounts approved in EB-2014-0370;

- Exclude the Pension & OPEB Cash to Accrual Differential Deferral Account not proposed for clearance pending the outcome of the EB-2015-0040 consultation; and
- Remove the unamortized portion of the Pension and OPEB Cost Variance Account previously approved for recovery over periods extending beyond December 31, 2018 in EB-2012-0002 and EB-2014-0370.

The resulting debit balances presented for recovery from ratepayers are $86.8M[73] for the regulated hydroelectric facilities and $217.9M[74] for the nuclear facilities, largely relating to the previously approved 2017/2018 recoveries of the unamortized portions of the Pension and OPEB Cost Variance Account over periods extending beyond December 31, 2016.

The total amounts requested for disposition for the unsettled Capacity Refurbishment Variance Account (Nuclear), the Nuclear Liability Deferral Account, the Bruce Lease Net Revenues Variance Account is a credit of $117.2M pertaining to the nuclear facilities. [75]

The December 31, 2015 balances in the deferral and variance accounts, including the unsettled accounts, have been audited by Ernst & Young LLP, as shown in Ex. H1-1-1, Attachments 1 and 2.

OPG submits that the amounts recorded in the unsettled accounts are in accordance with O. Reg. 53/05, appropriate and should be approved.

10.4 ISSUE 9.4

Secondary: Are the proposed disposition amounts appropriate?

OPG proposes to clear the audited December 31, 2015 balances in the deferral and variances accounts as provided in Ex. H1-1-1, Table 1, consistent with the OEB's expectation that "all accounts should be reviewed and disposed of in a cost of service proceeding unless there is a compelling reason to not do so" (EB-2013-0321 Decision with Reasons, p. 125).

The balances in all accounts, including additions and interest recorded during 2015, are shown in Ex. H1-1-1, Table 1a. As discussed under Issue 9.3, the balances presented for

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73 Ex. H1-2-1, Table 1, col. G, Line 12
74 Ex. H1-2-1, Table 2, col. G, Line 16
75 Ex. H1-2-1, Table 2, col. G, Lines 1 and 4 through 8

clearance, over the period from January 1, 2017 to December 31, 2018, are a debit of $86.8M[76] for the regulated hydroelectric facilities and a debit of $217.9M[77] for the nuclear facilities.

For the Pension and OPEB Cost Variance Account, these balances reflect the clearance schedules previously approved in EB-2012-0002 and EB-2014-0370. The remaining accounts reflect a 24-month amortization period (January 1, 2017 to December 31, 2018) for the year-end 2015 balances, adjusted for 2016 amortization amounts approved in EB-2014-0370. OPG submits that this proposed disposition period, combined with the balances discussed under Issue 9.3, results in appropriate disposition amounts.

OPG submits that a 24-month disposition period is reasonable, taking into account the relatively small net debit balance in the accounts other than Pension and OPEB Cost Variance Account (a debit of $72.9M[78] for regulated hydroelectric facilities and a credit of $51.2M[79] for the nuclear facilities). The proposed disposition period is consistent with the periods approved in previous proceedings for most of OPG's accounts, and aligns the end date of the resulting riders with the timing of the proposed mid-term review application that OPG expects would include disposition of year-end 2018 balances in the accounts (Ex. H1-1-1, p. 2).

10.5 ISSUE 9.5

Primary: Is the disposition methodology appropriate?

OPG submits that the proposed disposition methodology is appropriate. Under this methodology, OPG proposes to calculate separate hydroelectric and nuclear payment riders for the period from January 1, 2017 to December 31, 2018 in the form of $/MWh rates consistent with the OEB's decisions and Payment Amounts Orders in EB-2012-0002, EB-2010-0008, EB-2013-0321, and EB-2014-0370.

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[76] Ex. H1-2-1, Table 1, col. G, Line 12
[77] Ex. H1-2-1, Table 2, col. G, Line 16
[78] Ex. H1-2-1, Table 1, column g, line 12 minus lines 7 and 8
[79] Ex. H1-2-1, Table 2, column g, line 16 minus lines 10 and 11

Consistent with the methodology applied in the above noted proceedings, OPG proposes that the hydroelectric and nuclear payment riders be calculated separately, on the following basis:

- Use the audited balance in each of the accounts less any amortization already approved (see Issue 9.3);
- Establish a recovery period for each account to be cleared (see Issue 9.4); and
- Use the proposed energy production amount to establish riders:
    - For the nuclear facilities use the 2017 and 2018 production forecast; and
    - For the regulated hydroelectricity facilities use the 2015 actual production (divided by 12 months and multiplied by 24 months) (Ex. H1-2-1, p. 2).

The resulting proposed riders are $1.44/MWh for hydroelectric and $2.85/MWh for nuclear (Ex. H1-2-1, Table 1 and 2), for the period from January 1, 2017 to December 31, 2018. OPG requests approval of these riders.

10.6 ISSUE 9.6 (SETTLED)

Secondary: Is the proposed continuation of deferral and variance accounts appropriate?

This issue is settled (Ex. O1-1-1, p.14-15; Tr. Vol. 9, p. 1).

10.7 ISSUE 9.7

Primary: Is the rate smoothing deferral account in respect of the nuclear facilities that OPG proposes to establish consistent with O. Reg. 53/05 and appropriate?

10.7.1 OPG's Proposal

Nuclear rate smoothing is a requirement of O. Reg. 53/05, as amended. OPG's rate smoothing proposal, as discussed in detail in Ex. N3-1-1 and Ex. A1-3-3, responds to the regulation. OPG is proposing that effective January 1, 2017, the Rate Smoothing Deferral Account ("RSDA") would record the difference between: (i) the total annual nuclear revenue requirement approved by the OEB; and, (ii) the portion of the approved revenue requirement that is used to set the nuclear payment amounts in each year (the "annual deferral amount").

According to O. Reg. 53/05, the annual deferral amount will be recorded in this account from January 1, 2017 until the DRP ends (the “deferral period”). The regulation requires the OEB to determine the revenue requirement for OPG’s nuclear facilities on a five-year basis for the first 10 years of the deferral period and, thereafter, on such periodic basis as the OEB determines. The regulation also requires the OEB to determine the annual deferral amount with a view to making the year-over-year changes in the WAPA more stable.

OPG proposes to set the annual deferral amount to achieve annual smoothed WAPA increases of 2.5% over the January 1, 2017 to December 31, 2021 period. Each month, OPG will record 1/12th of the annual deferral amount in the Rate Smoothing Deferral Account.

Relative to the alternatives illustrated by OPG in Ex. N3-1-1, Chart 3, a 2.5% year-over-year increase in WAPA best satisfies the six considerations that OPG identified to assess smoothing scenarios. These were (Ex. N3-1-1, pp. 12-14):

Financial Viability (Leverage and Cash Flow Impacts): Higher values for the FFO Adjusted Interest Coverage ratio and lower values for the Debt to EBITDA credit metric reduce financial risk to OPG. OPG’s assessment was based on at least one of the two metrics cited above being within threshold at all times during each of the two 5-year deferral periods (i.e., 2017 to 2021 and 2022 to 2026).

Rate Stability: OPG focused on maintaining a constant year-over-year change in WAPA within the two halves of the deferral period and within the recovery period. While the year-over-year change in WAPA may vary between the two halves of the deferral period, and again at the beginning of the recovery period, lower variances at each of these points was considered better.

Long-Term Perspective: The assessment was based on the size of the average year-over-year change in WAPA during the recovery period (closer to 0 per cent is better).

Post-Recovery Transition: The assessment was based on the size of the change in the nuclear payment amount at the end of the recovery period (smaller is better) to the forecast post-transition payment amount of approximately $120/MWh.

Intergenerational Equity: The assessment was based on the ratio of total interest costs to total amounts deferred (total interest / total amounts deferred). A lower ratio implies a lower cost of deferring revenue. Intergenerational equity involves striking a balance between the benefits of deferring revenue and the costs of the deferral; therefore, OPG’s assessment placed value on a ratio that best reflects this balance (i.e., neither the highest nor the lowest ratio).

Customer Bill Impact: Each scenario was assessed based on the resulting average year-over-year change in a typical residential customer's monthly bill, both in the 2017-2021 period and over the full deferral and recovery periods.

While a number of possible scenarios were reviewed (see Ex. N3-1-1, Chart 3) and others could be imagined, in OPG's view, its proposal (Ex. N3-1-1, Chart 3, Scenario B), results in the best overall balance of the above considerations. As set out above, OPG proposes that WAPA reflect a constant 2.5% per year rate increase over the IR term, resulting in the deferral of $1,005M of nuclear revenue requirement (Ex. N3-1-1, Chart 4).

10.7.2 Implementation of Rate Smoothing

The OEB's findings on the proposed nuclear revenue requirements, nuclear production forecast, hydroelectric and nuclear payment riders and the hydroelectric IRM formula will necessarily impact the 2017-2021 nuclear payment amounts, the annual deferred nuclear revenue requirement, and the resulting WAPA.

Nuclear rate smoothing is unique in terms of the magnitude of the proposed deferred amounts, and the number of interrelated decisions required. To the extent the OEB's decision changes the rate smoothing inputs, it may be efficient for the OEB to decide the annual nuclear revenue requirements and the inputs (steps 2 and 3 of the chart at Ex. N3-1-1, p. 5), and withhold its final decision on the "outputs" (i.e., the annual change in WAPA, the resulting nuclear payment amount, and the amount to be deferred in the RSDA) until the Payment Amounts Order approval process (steps 4, 5 and 6 of the chart at Ex. N3-1-1, p. 5).

If the OEB defers its determination of the outputs to the Payment Amounts Order approval process, OPG could apply the OEB's findings on the inputs and provide options for the nuclear payment amounts, the annual nuclear deferred revenue requirement and the resulting WAPA in the same format and level of detail as Chart 3 at Ex. A1-3-3, p. 8.

As a final matter, the regulation stipulates that the OEB shall ensure that OPG recovers the balance recorded in the deferral account and shall authorize recovery of the account balance on a straight line basis over a period not to exceed 10 years commencing at the end of the deferral period. The regulation also stipulates that the deferral account shall record interest on the balance of the account at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB from time to time, compounded annually.[80] OPG will record interest based on the monthly opening balance in the account on this basis.

10.8 ISSUE 9.8

Primary: Should any newly proposed deferral and variance accounts be approved by the OEB?

As set out in detail in Ex. H1-1-1, Section 6, OPG seeks approval of four new deferral and variance accounts.[81] OPG submits that each account is required by regulation or appropriately addresses a proposed change in regulatory approach. Each account proposed satisfies the OEB's deferral and variance account eligibility criteria of causation, materiality, and prudence. On this basis, OPG requests that the proposed accounts be established.

10.8.1 Rate Smoothing Deferral Account

The proposed new RSDA is mandated by O. Reg. 53/05 as amended and should be approved by the OEB. The account is discussed in further detail in Section 10.7 under Issue 9.7.

10.8.2 Mid-term Nuclear Production Variance Account

As set out in detail in Ex. A1-3-3, Section 3, OPG seeks approval to file an application in the first half of 2019 to review and update the nuclear production forecast and corresponding fuel costs for the July 1, 2019 to December 31, 2021 period.[82] To effect this proposal, OPG proposes establishing the Mid-term Nuclear Production Variance Account to record the impact of the production variance from July 1, 2019 to December 31, 2021. This account is proposed to take effect on July 1, 2019.

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[80] The current OEB-approved long-term debt rates would be those accepted by the parties for the purposes of settling Issue 3.2.

[81] Exhibit L-9.8-1 Staff-218 provides detail on the entries that would be used to record additions in each of the proposed accounts.

[82] The mid-term review application will also seek disposal of applicable audited deferral and variance account balances (most accounts will reflect amounts accumulated over the period January 1, 2016 to December 31, 2018) as well as any remaining unamortized portions of previously approved amounts with recovery periods extending beyond December 31, 2018, currently the Pension and OPEB Cost Variance Account. OPG does not propose to re-open any other elements of the revenue requirement or other aspects of this Application in the mid-term review.

The production variance will be based on the difference between: (i) the nuclear production forecast approved in this Application and, (ii) the nuclear production forecast approved in the mid-term review application. To determine the entries into the account, the monthly production variance will be multiplied by the approved smoothed nuclear payment amount. The resulting amount would then be adjusted by changes in nuclear fuel costs, calculated as the monthly production variance multiplied by the average nuclear fuel cost reflected in the approved revenue requirement for the applicable year (Ex. L-11.5-1 Staff-259; Ex. H1-1-1, pp. 30-31).

As described in Ex. A1-3-3, Section 3, the purpose of the Mid-term Nuclear Production Variance Account is to mitigate the significant production risk associated with setting nuclear payment amounts over the five-year term of this Application. OPG's 2017-2021 nuclear production forecast is presented in Section 6.1 (Issue 5.1) and Ex. E2-1-1. The production risk is expected to increase during the second half of the five-year term due to the DRP and the work required to enable Pickering Extended Operations and the inherent inaccuracy of forecasting further into the future (Tr. Vol. 15, p. 77; Ex. A1-3-3, p. 13).

The Mid-term Nuclear Production Variance Account provides symmetrical protection to customers and to OPG irrespective of whether the approved mid-term review nuclear production forecast is higher or lower than the nuclear production forecast approved in this Application (Tr. Vol. 15, p.78). If production is higher than currently forecast, the higher production would result in a credit balance in the account, to be refunded to customers. If production is lower than forecast, the debit balance in the account would be recovered from customers. The Mid-term Nuclear Production Variance Account is necessary to record the impacts of adopting a more accurate production forecast for the second half of the IR term, which benefits both customers and the company.

10.8.3 Nuclear ROE Variance Account

OPG proposes to establish the Nuclear ROE Variance Account to record the nuclear revenue requirement impact of the difference between (i) the approved ROE for the nuclear business in 2018 to 2021 in this proceeding and (ii) the actual ROE that the OEB will specify for each year in its future prescribed ROE determinations. This account is proposed to take effect on January 1, 2018.

This Application incorporates an ROE of 8.78% for each year of the IR term for the nuclear business (Ex. N1-1-1 Chart 3.4, line 6), as this is the latest rate published by the OEB. The OEB's cost of capital parameters, including prescribed ROE, are updated on an annual basis. For the period January 1, 2018 to December 31, 2021, entries into this account would record the annual nuclear revenue requirement impact of the difference between the OEB's annually updated prescribed ROE and the annual ROE incorporated into the 2018 to 2021 annual revenue requirements approved by the OEB.

For purposes of calculating the annual nuclear revenue requirement impact of the ROE difference, OPG proposes to multiply the difference in ROE in each of the years 2018 to 2021 by the forecast nuclear rate base financed by capital structure for each year in 2018 to 2021 as approved by the OEB in this Application.

OPG's ROE proposal is described at Ex. C1-1-1. This account is necessary to reduce the significant risk associated with otherwise relying on long-term forecasts of ROE, which protects both customers and OPG symmetrically. This type of account has been approved by the OEB in previous proceedings (e.g. in EB-2013-0416/EB-2014-0247 (Hydro One)).

10.8.4 Hydroelectric Capital Structure Variance Account

OPG proposes establishing the Hydroelectric Capital Structure Variance Account to record the hydroelectric revenue requirement impact of the difference between the capital structure approved by the OEB in this proceeding and the capital structure approved by the OEB in EB-2013-0321 that underpins the hydroelectric payment amounts in this proceeding for 2017 to 2021. This account is proposed to take effect on January 1, 2017.

OPG's proposed application of a price-cap IR formula (described in Ex. A1-3-2) to 2014-2015 hydroelectric payment amounts implicitly incorporates the capital structure of 45% equity and 55% debt that was approved by the OEB in EB-2013-0321. This capital structure would form the basis for the proposed hydroelectric payment amounts in the IR term. In this Application, however, OPG is proposing a capital structure of 49% equity and 51% debt, as described in Ex. C1-1-1. As of the effective date of the payment amounts order in this proceeding, entries into this account would record the annual hydroelectric revenue requirement impact of the difference between the 45% equity/55% debt capital structure approved by the OEB in EB-2013-0321 and the capital structure approved in this proceeding.

For purposes of calculating the annual hydroelectric revenue requirement impact of the difference, OPG proposes to multiply the difference in capital structure each year by the average 2014-2015 regulated hydroelectric rate base forecast approved by the OEB in EB-2013-0321 (Ex. L-9.8-1 Staff-217).

OPG's capital structure proposal is described at Ex. C1-1-1. This account is necessary to apply the OPG-wide regulated capital structure approved in this application to the hydroelectric payment amounts that will be in effect during the IR term.

11.0 REPORTING AND RECORD KEEPING REQUIREMENTS

11.1 ISSUE 10.1

Secondary: Are the proposed reporting and record keeping requirements appropriate?

OPG proposes to continue to report as previously directed by the OEB (EB-2010-0008, Decision with Reasons, March 10, 2011, p. 151). This reporting includes achieved regulatory ROE which is a factor in assessing the financial viability outcome identified in the *Renewed Regulatory Framework for Electricity Distributors* ("RRFE").

In addition, OPG proposes to provide a suite of measures to reflect OPG's performance on key company outcomes, as discussed below in Issue 10.2 (hydroelectric performance reporting) and in Issue 10.3 (nuclear performance reporting). The proposed performance measures focus on Operational Effectiveness outcome identified in the RRFE. They include measures of the company's cost performance, system reliability, and service quality such as safety and environmental performance. Reporting on the DRP (Issue 10.4) is discussed in Section 5.3.

11.2 ISSUE 10.2

Primary: Is the monitoring and reporting of performance proposed by OPG for the regulated hydroelectric facilities appropriate?

OPG submits that the proposed hydroelectric performance measures proposed are appropriate (Ex. A1-3-2, p. 41). The proposed performance measures are identical to the key performance measures proposed in the previous payment amounts application (EB-2013-0321, Ex. F1-1-1, pp. 26-27). They are key metrics by which OPG measures the company's safety, reliability and cost-effectiveness outcomes. OPG has consistently measured and reported its performance on these metrics, allowing it to gauge its relative effectiveness over time.

Beginning in 2017, OPG proposes to file an updated set of performance measures with the OEB annually. The updated measures would include the prior year's actual performance as well as targets for the then current year for each measure (Ex. A1-3-2, p. 43).

11.3 ISSUE 10.3

Primary: Is the monitoring and reporting of performance proposed by OPG for the nuclear facilities appropriate?

OPG proposes to report the key performance measures that are used in its annual nuclear benchmarking report. The proposed nuclear performance measures are listed in Ex. A1-3-2, p. 42.

OPG proposes to report on these metrics in the same manner and level of detail provided in Ex. F2-1-1, Attachment 1, p. 6, Table 2, which summarizes OPG's nuclear performance compared to benchmark results. Table 2 provides best quartile and median information. OPG proposes to provide separate performance metrics for the Darlington and Pickering stations (Ex. L-10.3-1 Staff-221).

OPG's 2016-2018 Business Plan (Ex. A2-2-1, Attachment 1) and 2017-2019 Business Plan (Ex. N1-1-1, Attachment 1) reflect operational and financial targets developed for the specific years reflected in the above business plans as part of OPG's gap-based business planning process at the nuclear facilities (Ex. F2-1-1, p. 14). The annual performance targets on eight key operational metrics are provided separately in Ex. N1-1-1, Attachment 1, p. 24 for each nuclear facility. OPG proposes to provide an annual performance report including actual results relative to those targets, including Total Generating Cost per MWh on a normalized and non-normalized basis using the methodology described by ScottMadden (Ex. L-6.2-1 Staff-101, Attachment 1), as well as updated targets for the subsequent year.

11.4 ISSUE 10.4

Primary: Is the proposed reporting for the Darlington Refurbishment Program appropriate?

Please see submissions on Issue 4.5 in Section 5.5.

12.0 METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

12.1 HYDROELECTRIC

12.2 ISSUE 11.1

Primary: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

12.2.1 Introduction

Using the hydroelectric payment amounts approved in EB-2013-0321 as a starting point, OPG is proposing to apply a price-cap index based closely on the elements and approach in the 4GIRM to the prescribed hydroelectric facilities. OPG has developed an inflation factor that is based on the 4GIRM indices, appropriately weighted by the capital and non-capital costs of the hydroelectric generation industry. Based on a TFP study of North American hydroelectric generation by LEI, which found a negative TFP value, OPG is proposing to set the IRM formula's productivity factor at zero, consistent with prior OEB determinations for electricity distributors. Finally, OPG is proposing a stretch factor that uses the 4GIRM methodology and incorporates the relative performance of OPG's hydroelectric facilities as determined through benchmarking conducted by Navigant Energy Consulting Inc. ("Navigant").

OPG's submissions on this issue are divided into the following sub-sections:

- 12.2.2: Consistency with the RRFE and OEB Guidance
- 12.2.3: Inflation Factor
- 12.2.4: Industry Productivity Factor
- 12.2.5: Stretch Factor
- 12.2.6: Function of the Hydroelectric CRVA Under Incentive Regulation

12.2.2 Consistency with the RRFE and OEB Guidance

OPG closely modelled the proposed hydroelectric incentive rate-setting framework on the 4GIRM method set out in the RRFE (Ex. A1-3-2, p. 8). OPG understands that the 4GIRM method is suited for utilities that are generally in a steady state, subject to some incremental investment needs (RRFE, p. 14).

The 4GIRM method fits the state of OPG’s prescribed hydroelectric facilities: since the Niagara Tunnel Project entered service in 2013, the prescribed hydroelectric facilities have been in a comparatively steady state. Although the company does expect to make incremental capital investments during the 2017-2021 period (Ex. L-11.1-15 SEC-095), it believes that the hydroelectric rate-setting framework proposed in this application will allow it to operate safely and reliably during the IR term.

The proposed hydroelectric incentive rate-setting framework varies from 4GIRM only where necessary to reflect the reality of OPG’s regulated hydroelectric generating facilities. OPG has proposed the following four adjustments to the 4GIRM method:

1. Rather than adopting the OEB’s inflation index (which was developed to reflect the Ontario electric distribution industry), OPG has proposed an inflation adjustment (or “I-factor”) based on the same two sub-indices used by the OEB, adjusted appropriately reflect the weighting of capital and non-capital costs for the hydroelectric generation industry (Ex. A1-3-2, p. 8, lines 14-18). Since hydroelectric generation is a more capital-intensive business than distribution, the effect of OPG’s proposed weighting is to reduce the I-factor, relative to the OEB’s inflation adjustment for electric distributors.

2. OPG has developed a hydroelectric industry productivity factor based on the historic TFP of the North American hydroelectric generation industry (Ex. A1-3-2, p. 8, lines 19-22).

3. The proposed stretch factor is based on the range of stretch factors set out in the RRFE, but determined according to the performance of the prescribed hydroelectric facilities relative to their peers, as determined by an independent benchmarking study conducted by Navigant (Ex. A1-3-2, Attachment 2).

4. An adjustment to the “going in” rates to account for the one-time allocation of nuclear tax losses to the hydroelectric business. This issue was settled (as discussed in Section 12.3 of these submissions).[83]

Like 4GIRM, OPG proposes that unforeseen events affecting the prescribed hydroelectric facilities be treated according to OEB policy, subject to the $10M regulatory materiality threshold that has historically applied to OPG (Ex. A1-3-2, p. 22).

[83] While OPG is not proposing to adjust the “going-in” rates to reflect proposed changes in the OPG-wide capital structure, OPG is proposing to capture these changes in a variance account as discussed in Section 10.8.4.

12.2.3 Inflation Factor

OPG has proposed an I-factor that is structurally and substantively consistent with the composite index used to adjust electric distribution rates under 4GIRM (Ex. A1-3-2, p. 12, lines 7-19):

1. **Structural consistency**: The proposed I-factor is divided into the same three cost categories as the OEB's electric distribution I-factor: capital, labour, and non-labour.
2. **Substantive consistency**: The value of the proposed I-factor is calculated based on the same two Statistics Canada sub-indices that the OEB uses to determine the electric distribution I-factor:
   a. for capital and non-labour O&M costs: the Canadian Gross Domestic Product Implicit Price Index – Final Domestic Demand ("GDP-IPI FDD"), and
   b. for labour costs, the Average Weekly Earnings for Ontario – Industrial Aggregate ("Ontario AWE").

The only adjustment that OPG has made to the proposed hydroelectric I-factor, relative to the composite index used to adjust rates for electric distributors, is to adjust the weighting between capital, labour, and non-labour to appropriately reflect the hydroelectric generation industry, as independently determined by LEI (Ex. A1-3-2, p. 13, lines 15-17).

For 2017, OPG has proposed an inflationary adjustment of 1.8% (Ex. A1-3-2, p. 14). The annual I-factor and resulting payment amounts will vary with changes in the sub-indices, as determined by the OEB during annual adjustment applications during subsequent years of the IR term (2018-2021).

12.2.4 Industry Productivity Factor

Under 4GIRM and under OPG's proposed hydroelectric IR framework, the productivity factor represents the total factor productivity growth of the regulated industry (in this case, the hydroelectric generation industry). In the rate-setting formula, the productivity factor is an external benchmark that the applicant is expected to achieve.[84]

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84 Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, p. 17. [RRFE]

Consistent with the 4GIRM rate-setting method, OPG has proposed a productivity factor as part of the price-cap index to be used to determine the company's hydroelectric payment amounts during the 2017-2021 period. Although LEI's evidence indicates that the industry productivity trend is -1%, OPG has proposed a productivity factor of zero, consistent with the OEB's prior decisions on negative productivity factors (Ex. A1-3-2, p. 19).

Extensive expert evidence has been filed on measuring the productivity trend of the hydroelectric generation industry:

- OPG's pre-filed evidence included a Total Factor Productivity ("TFP") study of the North American hydroelectric generation industry prepared by Julia Frayer of LEI (Ex. A1-3-2, Attachment 1). LEI concluded that productivity industry is declining by 1% annually (Ex. A1-3-2, Attachment 1, p. 8).
- OEB Staff filed a study by Mark Lowry and David Hovde of Pacific Economics Group Research LLC ("PEG"), which concluded that industry productivity was increasing by 0.29% annually (Ex. M2).
- OPG filed supplemental evidence from LEI, responding to the PEG Report (Ex. A1-3-2, Attachment 6).
- OEB Staff filed sur-reply evidence from PEG (Ex. M2, Attachment 1).
- Significant volumes of interrogatory responses were filed by both LEI and PEG on their respective evidence.

OPG believes that the -1% productivity growth rate found by LEI accurately reflects the industry productivity trend, meaning that the proposed zero-percent productivity factor creates an additional 1% stretch factor for the prescribed hydroelectric facilities, relative to the industry's actual productivity trend.

12.2.4.1 Purpose of a TFP Study

At the highest level, an industry TFP study measures the total quantity of outputs that a group of companies produces relative to the quantity of inputs it takes to achieve that production. It is a backward-looking exercise that illustrates the historic trend (positive or negative) in the relationship between inputs and outputs of the industry being studied. It is not intended to assess the relative efficiency of the companies in the industry – that is the role of a benchmarking study (Ex. A1-3-2, Attachment 1, p. 7).

As Ms. Frayer testified, the selection of appropriate input and output measures is specific to the industry being studied. Designing a TFP study is not a “one size fits all” exercise – it requires professional judgment and knowledge about the industry (Tr. Vol. 9, p. 39, lines 12-20).

The record shows that, while the LEI and PEG productivity studies agree on many aspects, they disagree on several key points. In OPG’s submission, the two most critical areas of disagreement are the appropriate capital input measure and the appropriate output measure, which are discussed below.

LEI Used the Most Appropriate Capital Input Measures

LEI’s study broke down the hydroelectric generation industry’s “inputs” into two measures:

1. Physical capital, measured in MW, and
2. Operations and maintenance (“O&M”) costs measured in dollars and deflated to isolate productivity trends (Ex. A1-3-2, Attachment 1, p. 8).

The choice of capital input measure is a major difference between LEI and PEG’s studies. By measuring the actual, physical capacity of each generator, LEI is able to accurately reflect the entirety of the capital deployed by the industry.

LEI’s approach to measuring capital input quantities has several advantages, including the following:

1. **No assumptions or conversions are required.** LEI does not need to make any assumptions or convert the capital input data it uses. Under other approaches (including the monetary approach used by PEG), a researcher must convert financial data into capital quantities. That conversion process must necessarily be based on certain assumptions about the underlying capital assets (such as the appropriate depreciation profile) (Tr. Vol. 9, p. 26, lines 3-17).

   In contrast, PEG’s approach relies on a series of assumptions to calculate a monetary proxy for the capital input quantities. A central assumption required by PEG’s approach is the appropriate depreciation profile to apply to a hydroelectric generator. PEG’s study assumes a “geometric decay” depreciation profile, meaning a constant rate of decline in productive capability each year (Ex. A1-3-2, Attachment 6, p. 6). However, hydroelectric generating facilities are long-lived assets that do not decline at anything close to a geometric decay pattern (Ex. A1-3-2, Attachment 6, pp. 5-9).

2. **LEI's measure is comprehensive and current.** A plant's capacity reflects all the capital assets used to generate electricity – from the concrete in the dams to the windings in the turbines. Since OPG routinely revisits capacity ratings as reported to the IESO, they represent a current, accurate measure of capital in use (Tr. Vol. 9, p. 25, lines 22-28; p. 26, lines 1-2).

3. **The data is universally available.** Since capacity data is universally available and comparable between hydroelectric generators, LEI is able to use a direct measure of the capital employed by each generator in the peer group (Tr. Vol. 9, p. 25, lines 15-28).

4. **LEI's input measure produces conservative results.** Using a physical measure of capital input quantities may understate the costs of certain types of capital-related efficiency improvements, such as capital investments that do not increase production (since the capacity would not change as a result of projects, like the Niagara Tunnel Project, that only increase energy production). To the extent that such projects occur, LEI's approach would result in a conservative productivity factor value (i.e., the productivity growth rate would be more negative if such projects were captured by the input measure) (Tr. Vol. 10, p. 42, lines. 5-6).

LEI Used the Most Appropriate Output Measure

LEI's TFP study measures the output of hydroelectric generators by their product: the quantity of electricity (MWh) produced and purchased by customers (Ex. A1-3-2, Attachment 1, pp. 18-20). In contrast, PEG's study uses generators' installed capacity (the maximum possible production) to measure the industry's output (Ex. M2, p. 5).

There are several reasons that electricity production (in MWh) is the superior measure of a hydroelectric generator's output, for the purpose of assessing productivity:

1. Production is How Generators (including OPG) are Paid

OPG is paid for its production. Effectively, this means that OPG's sole hydroelectric billing determinant is production.

OPG is not paid for its installed capacity. As Ms. Frayer testified, all hydroelectric generators are paid on the basis of MWh. While some generators are also paid for other services, those payments are a very small portion of their total revenues (Tr. Vol. 9., p. 27, lines 5-9), and apply to only a few deregulated wholesale markets that have a centralized capacity market (Ex. L-11.1-1 Staff-235, p. 1, lines 39-40). There is currently no market for capacity in Ontario.

PEG's own evidence reinforces the importance of setting an X-factor that is consistent with the industry's actual billing determinants. As PEG noted in their initial report, "the calibration of the X-factor for a price cap index should consider the trend in billing determinants. The generation volume [MWh] is by far the most important billing determinant in OPG's hydroelectric generation invoicing" (Ex. M2, p. 29).

2. Most Hydroelectric Productivity Improvement Projects are Undertaken to Increase Production

Ms. Frayer testified that MWh is "the metric by which hydroelectric operators and system planners look to find efficiency improvements that they could undertake. They look to expand their megawatt-hours of output" (Tr. Vol. 9., p. 27, lines 11-14).

In contrast, PEG's measure of generators' output – capacity (in MW) – would have excluded the majority of the hydroelectric efficiency projects that have been implemented at OPG (Ex. A1-3-2, Attachment 6, p. 18). The increased production from the Niagara Tunnel Project is an example of a project that would not be captured by PEG's output measure.

3. Consistency with All Hydroelectric Productivity Studies Reviewed by Both Experts

All 32 of the studies reviewed by both LEI and by PEG used production (in MWh) as the output measure (Tr. Vol. 9, p. 28, lines 11-14; Ex. M2-11.1-OPG-003; Ex. L-11.2-20 VECC-045). While consistency with other studies does not dictate the appropriate output measure for OPG's hydroelectric facilities, it is worth noting that all other studies reviewed by the experts have measured generators' productivity relative to the product they create for consumers: MWh.

4. OPG's Key Corporate Performance Metrics are Measured Relative to Production

OPG's key cost-effectiveness measures relate to MWh, and it has proposed to report the company's hydroelectric cost-effectiveness to the OEB reporting through the OM&A Unit Energy Cost metric, which is measured in dollars per MWh (Ex. A1-3-2, p. 41).

Correcting for Variability in Production

LEI appropriately used production data that had been corrected to address potential volatility in production. LEI took three major steps to address potential volatility in production:

1. Excluding utilities from its study that had experienced unusual water conditions during the study timeframe;
2. Using a timeframe that averaged out year-over-year variations in output; and
3. Using a trend-regression method to remove any bias that could have been introduced by the specific conditions in the first or last year of the study (Ex. A1-3-2, Attachment 6, p. 18).

These steps allowed LEI to use the best measure of the industry's output while avoiding potential concerns due to year-over-year variations in production.

LEI reviewed the peer group used in its study for abnormal hydrological conditions, and ultimately determined that it was necessary to remove only one company that had experienced abnormal drought conditions (Tr. Vol. 9, p. 54, lines 8-11).

12.2.5 Stretch Factor

OPG has proposed a hydroelectric stretch factor that reflects the incremental, challenging productivity gains that it could reasonably expect to achieve at the prescribed hydroelectric facilities during the 2017-2021 IR term. Based on the results of a comprehensive benchmarking study conducted by Navigant, OPG has proposed that the hydroelectric stretch factor be set at 0.3% throughout the IR term (Ex. A1-3-2, p. 22).

OPG's approach to calculating the appropriate stretch factor value was based on the OEB's approach as set out in the RRFE. In the 4GIRM method, a stretch factor reflects the "incremental productivity gains that the [utility] is expected to achieve", determined by the relative efficiency of the utility at the outset of the IR term (RRFE, p. 17).

The best, independent evidence of the relative efficiency of the prescribed hydroelectric facilities is the Navigant cost benchmarking study (Ex. A1-3-2, Attachment 2). As required by the OEB's Decision with Reasons in EB-2013-0321, OPG retained Navigant to conduct a "fully independent benchmarking study [of its] hydroelectric operations" (EB-2013-0321, Decision with Reasons, p. 18).

OPG relied on Navigant's expertise and depth of knowledge to develop a robust benchmarking methodology and to identify the appropriate performance metrics. Navigant identified the appropriate functions to benchmark, the relevant peer groups for comparison, and the accurate key metrics and quartiles to employ (Ex. A1-3-2, Attachment 2, p. 3). Navigant also adjusted for regional differences in purchase prices and accounting differences (Ex. A1-3-2, Attachment 2, p. 9). Navigant then reviewed all of OPG's regulated hydroelectric costs and determined that approximately 92% could be benchmarked (Ex. A1-3-2, Attachment 2, p. 3).

Navigant benchmarked the performance of OPG's prescribed hydroelectric facilities on two bases: Total Function Cost and Partial Function Cost (Ex. A1-3-2, Attachment 2, p. 4). Based on its knowledge of the industry and expert judgment, Navigant determined that the Partial Function Cost metric is "the key cost metric for benchmarking purposes because it includes the functions that are regularly performed at all hydro plants" (Ex. A1-3-2, Attachment 2, p. 4).

Navigant concluded that the prescribed hydroelectric facilities are essentially at the median for the hydroelectric generation industry on the Partial Function Cost metric (Ex. A1-3-2, Attachment 2, p. 4). Using the range of stretch factors applied in the 4GIRM method, OPG's median performance would effectively land in the middle of the third quintile, resulting in the proposed 0.3% stretch factor.

12.2.6 Function of the Hydroelectric CRVA Under Incentive Regulation

OPG proposes that the CRVA should continue to serve the same purpose under incentive rate-setting framework as it has under cost of service-based rate-setting: recording the revenue requirement impact of variances in costs and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to the prescribed hydroelectric generation facilities relative to forecast (Ex. H1-1-1, pp. 12-14). The OEB established the CRVA to implement the requirements of O. Reg. 53/05 (O. Reg. 53/05, s. 6(2), para. 4).

OPG does not propose that the CRVA should allow the company to be paid twice for the same work (Ex. H1-1-2, p. 5, lines 15-17). As it would with any other variance account, the OEB would determine whether amounts recorded should be recovered from (or credited to) customers in a subsequent proceeding, if OPG proposes to recover or refund a balance in the account. OPG has filed supplemental evidence to illustrate how it proposes to establish that it will not "double recover" costs for CRVA-eligible projects (Ex. H1-1-2). If OPG's total prudent capital in-service additions (both CRVA-eligible and non-CRVA eligible) for the prescribed hydroelectric facilities do not exceed the implied capital funding, OPG would not seek to recover any balance in the CRVA, since the costs of any such CRVA-eligible projects would effectively have been funded through base payment amounts (Ex. H1-1-2, p. 5, lines 2-8).

12.3 ISSUE 11.2 (SETTLED)

Secondary: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

This issue is settled (Ex. O1-1-1, p.15-16; Tr. Vol. 9, p. 1**)**.

12.4 NUCLEAR

12.5 ISSUES 11.3 AND 11.4

Primary: Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?

Primary: Does the Custom IR application adequately include expectations for productivity and efficiency gains relative to benchmarks and establish an appropriately structured incentive-based rate framework?

12.5.1 Introduction

OPG has proposed a Custom IR framework for the company's nuclear facilities that is consistent with OEB policy, recognizes that both Darlington and Pickering are undergoing significant changes during the IR term and supports the continued safe and reliable operation of these facilities. OPG's Custom IR proposal adds a stretch factor which will reduce the cost of nuclear base OM&A and Corporate Support OM&A below the amounts forecast in the Application. The cumulative reductions produced by the stretch factor mean that over the IR term, OPG is committing to provide customers with over $50M in up-front cost reductions, whether or not the company is able to achieve these savings.

The proposed nuclear Custom IR framework is layered on top of a nuclear rate structure that necessarily creates a strong incentive for OPG to continually improve its productivity and cost-efficiency. OPG's nuclear payments are 100% variable, meaning that the company's revenues vary directly with the amount of electricity it produces from the nuclear facilities. Even without the proposed nuclear stretch factor, OPG has a very strong financial incentive to operate as efficiently as possible, since any decrease in reliability or increase in cost directly reduces the company's net income (Ex. A1-3-2, Section 3.4).

In addition to the incentives in the nuclear Custom IR framework, OPG remains subject to significant risk associated with forecast levels of nuclear production. Historically, OPG's actual nuclear production has been significantly below the forecasts approved by the OEB. As discussed in Section 6.1.3, nuclear production shortfalls over the 2008-2015 period have resulted in average negative revenue impacts of $154.0M each year (Ex. E2-1-1, p. 3). These shortfalls are borne by OPG's shareholder. This risk creates a further incentive for OPG to continuously improve efficiency and productivity of the nuclear facilities.

OPG's submissions on these issues are divided into the following sub-sections:

- 12.5.2: Consistency with the RRFE and OEB Guidance
- 12.5.3: Calculating the Nuclear Stretch Factor
- 12.5.4: Applying the Nuclear Stretch Factor

12.5.2 Consistency with the RRFE and OEB Guidance

OPG has developed a nuclear Custom IR framework based on the principles of the RRFE and the OEB's specific guidance on what the company's first nuclear incentive rate-setting regime should (and should not) include.

Following the EB-2012-0340 consultation, the OEB issued a report entitled, *Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets* (the "IR Report") on

March 28, 2014. In the IR Report, the OEB was clear that it would not be appropriate for OPG to adopt a "pure IR" regime for the nuclear facilities, based on TFP with input cost indices and other features of a price-cap IR framework until the DRP and Pickering closure were complete (IR Report, pp. 8-9). The OEB confirmed that it expected OPG to set rates using "multi-year CoS principles" for the immediate future (IR Report, p. 9).

The OEB also stated that:

> The Board accepts that introducing an IR regime for the nuclear generation assets will be <u>a longer-term process</u> than is the case for the hydroelectric assets <u>given the greater degree of uncertainty and risk inherent in the nuclear capital investment program.</u> (<u>emphasis added</u>) (IR Report, pp. 8-9).

Collectively, OPG takes these statements to support the form of Custom IR proposed in this application: one that is based on specific forecast costs from a challenging business plan, further reduced by a benchmark-based stretch factor. In effect, OPG has proposed that its nuclear payment amounts be set relative to the forecast costs and production in its challenging business plan, and then further reduced to account for additional, yet-to-be-defined incremental performance improvements across the Nuclear business.

OEB policy and O. Reg. 53/05 require that nuclear payment be set for a five-year term, as proposed in this application:

- The RRFE specifies that Custom IR applications set rates on a five-year forecast of revenue requirement and production (RRFE, p. 18).
- The OEB's letter of February 17, 2015 confirmed that OPG would file a five-year application for the company's nuclear assets (Letter re: *Incentive Rate-setting for Ontario Power Generation's Prescribed Generation Assets*, to all participants in EB-2013-0321 and EB-2012-0340, p. 2).
- O. Reg. 53/05 requires that the OEB approve nuclear revenue requirement on a five-year basis for the first 10 years of the DRP (O. Reg. 53/05, Section 6(2)(12)(ii)).

OPG proposes that unforeseen events affecting the nuclear business be addressed through an accounting order process, as they have been historically, subject to the $10M regulatory materiality threshold that has historically applied to OPG (Ex. J8.2).

OPG's proposed nuclear Custom IR framework was based on, and is directly responsive to, the OEB's guidance on OPG's initial transition toward incentive rate-setting, which recognized the impacts of the DRP and changes to Pickering's operation.

12.5.3 Calculating the Nuclear Stretch Factor

OPG has proposed a stretch factor of 0.3% based on the Total Generating Cost per MWh ("TGC") benchmark performance of the Darlington and Pickering generating stations (Ex. A1-3-2, p. 29).

TGC/MWh is the best available metric to establish a nuclear stretch factor for OPG's nuclear facilities. It is a key measure in the nuclear benchmarking reports that the OEB expects OPG to file.[85] TGC/MWh is an "all-in" measure of the cost of operating the nuclear facilities. The 2015 Nuclear Benchmarking Report describes nuclear TGC/MWh performance as the "best overall financial comparison metric for OPG facilities." (Ex. F2-1-1, Attachment 1, p. 66).

TGC/MWh is particularly well-suited to determining a stretch factor since it is measured relative to the units of production (MWh) that customers ultimately pay for. Since MWh are the ultimate output for which OPG is paid, improvement on this measure reflects a benefit to customers. If OPG is able to improve productivity at the nuclear stations, TGC/MWh will necessarily reflect those improvements. Since TGC/MWh performance is a measure of the value that customers receive from OPG's nuclear facilities, it is appropriate that the nuclear stretch factor be tied to TGC performance.

OPG calculated the nuclear stretch factor value using the weighted-average TGC/MWh performance of both nuclear stations, based on the three-year rolling average of the facilities' performance between 2012 and 2014, as reported in the 2015 Nuclear Benchmarking Report (Ex. F2-1-1, Attachment 1). OPG then applied the range of stretch factor values used in the RRFE to the stations' performance, resulting in a stretch factor value of 0.3%.

The proposed stretch factor reflects the performance of the Darlington station in a comparatively steady-state. Historically, Darlington has benchmarked very well on the TGC/MWh metric. The station was ranked in the top quartile between 2011 and 2014 (Ex.

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[85] EB-2013-0321, Decision with Reasons, p. 45.

K12.4, p. 18), consistent with the 2015 Nuclear Benchmarking Report. Several unique events impacted the station's performance in 2015, including (i) a one-in-twelve-year vacuum building outage, (ii) a ramp-up in capital spending required to achieve strong reliability and operating performance post-DRP, and (iii) an increase in the station's FLR rate, partially attributed to PHT pump-related outages (Section 7.2.2; Tr. Vol. 6, p. 126, lines 4-25).

OPG determined a stretch factor for each station based on the reported quartiles in the 2015 Nuclear Benchmarking Report and then combined the results into a single, weighted average value applicable to the combined nuclear fleet (Ex. L-11.4-1 Staff-256, p. 2).

As discussed in detail in this application and in prior proceedings (see Section 7.2 addressing Issue 6.2), the Darlington and Pickering stations face different challenges. The two stations have different designs and are in different stages of their life cycles. Pickering's fourth quartile performance on TGC/MWh is a function of the size of its units, its first-generation CANDU design, and the reduction in capability factor due to outages that will be required to extend operations at the station (Ex. F2-1-1, pp. 5 and 9). A 0.3% stretch factor, applied as proposed, reflects a challenging-but-realistic level of incremental productivity improvement across OPG's nuclear fleet.

12.5.4 Applying the Nuclear Stretch Factor

OPG submits that a stretch factor must be achievable. In establishing the 3GIRM regime for electricity distributors, the OEB has stated that a stretch factor "is intended to reflect the incremental productivity gains that firms <u>are expected to achieve</u> under IR."[86] In OPG's view, a stretch factor should be applied to cost categories where it is reasonable to expect a company to continuously improve its productivity or efficiency during the IR term.

OPG submits that a stretch factor be applied to the elements of its nuclear costs where it is reasonable to expect the company to make incremental performance improvements during the IR term: base OM&A and Corporate Support OM&A. These costs generally reflect recurring costs that are susceptible to incremental efficiency improvements (Tr. Vol. 6, p.

[86] *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, July 14, 2008, p. 12.

137, lines 23-26). These cost categories comprise approximately 75% of the company's nuclear OM&A during the term of the application (Ex. A1-3-2, pp. 30-31).

While controlling costs is always an important element of OPG's business planning, other types of OM&A (i.e., Project OM&A and Outage OM&A) cover unique endeavours that do not present opportunities for recurring efficiency gains (Ex. L-11.3-20 VECC-049, p.1, lines 33-38). Similarly, OPG's nuclear capital investments are discrete, unique projects (Tr. Vol. 6, p. 138, lines 22-26). OPG has strong incentives to execute planned capital work as cost-efficiently as possible, but the nature of the work is inconsistent with a formulaic stretch factor (Tr. Vol. 6, p. 139, lines 1-12).

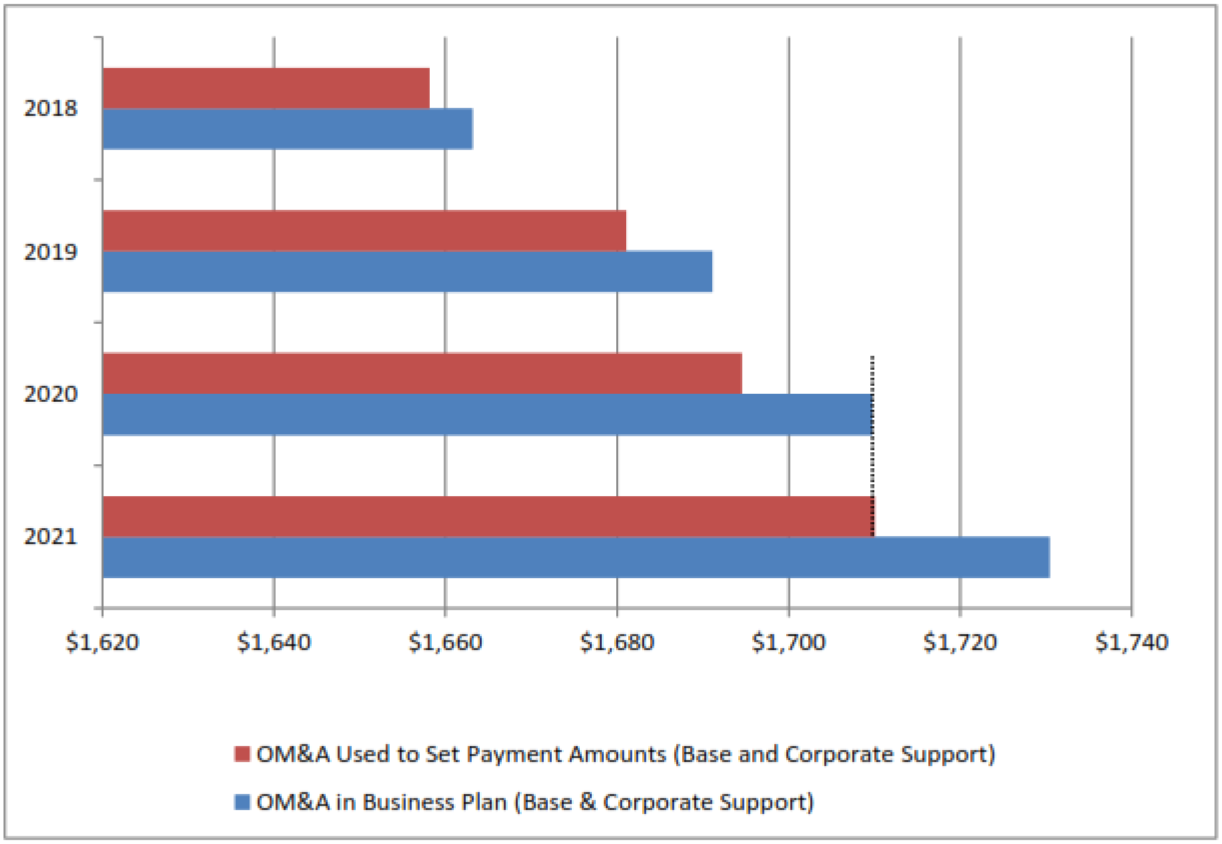
Even within the base OM&A and Corporate Support OM&A categories where OPG proposes to apply the stretch factor, there are functions whose costs cannot be reduced, such as those related to safety, and regulatory and legislated requirements applicable to nuclear operators (Ex. A1-3-2, p. 30). To the extent that the base OM&A and Corporate Support OM&A costs contain functions that cannot be reduced, OPG will experience additional pressure to find efficiencies in other areas (Ex. L-11.3-20 VECC-049, p. 2).

The proposed nuclear stretch factor creates a meaningful incentive for OPG to seek out new efficiencies during the term of this application, in addition to efficiencies and performance improvements within the company's business plan (Ex. A1-3-2, p. 32; Technical Conference Tr. Vol. 2, p. 86, lines 17-26). The stretch factor grows each year, requiring OPG to continuously and sustainably improve its productivity throughout the IR term (Ex. A1-3-2, p. 29). As shown in Figure 12.1, by the last year of the IR term, the stretch factor effectively eliminates the annual increases in nuclear base OM&A and Corporate Support OM&A costs that are forecast under the 2016-2018 Business Plan (Ex. A1-3-2, p. 29). The stretch factor reduction in 2021 constitutes a 1.2% reduction to that year's stretch-eligible OM&A, or a 0.9% reduction to total nuclear OM&A (Ex. A1-3-2, p. 33).

Achieving the stretch factor reductions will be challenging, especially since the 2016-2018 Business Plan limits the average annual increase in total nuclear operations OM&A to 0.9% per year over the 2015-2021 period, before the stretch factor is applied (Ex. F2-1-1, p. 5, line 25).

Figure 12.1

Nuclear Stretch Factor Reductions ($ M) (Ex. A1-3-2, p. 30)



OPG submits that the proposed Custom IR framework strikes the appropriate balance between driving continuous improvement, while still representing an achievable target in the context of the major work that the nuclear facilities will undergo over the IR term.

12.6 ISSUE 11.5

Primary: Is OPG's proposed mid-term review appropriate?

Please see submissions on Issue 9.8 above in Section 10.8.

12.7 ISSUE 11.6

Primary: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

OPG has proposed that the company's nuclear payment amounts be smoothed in accordance with the requirements of O. Reg. 53/05, as amended on March 2, 2017. Under this proposal, the OEB would defer recovery of approximately $1B of the approved 2017-2021 nuclear revenue requirement. In accordance with the regulation, the deferred amounts would be recovered over a period not to exceed 10 years following the end of the DRP. The proposed deferral will limit the year-over-year increase in OPG's weighted average payment amounts ("WAPA") during the IR term to 2.5%. OPG's proposal reflects a reasonable balance among the following considerations: rate stability, OPG financial viability, intergenerational equity, transition impacts after the recovery period, and overall cost to customers.[87] OPG's approach to rate smoothing is fully discussed in Section 10.7 under Issue 9.7.

12.8 ISSUE 11.7

Primary: Is OPG's proposed off-ramp appropriate?

OPG proposes that the same financial off-ramp apply to the company's regulated business as applies under the RRFE.

All three of the rate setting methods in the RRFE provide that a "regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels" (RRFE, p. 11). No other off-ramps are provided in the RRFE, and no other off-ramps are proposed by OPG. OPG submits that the off-ramp provision in the RRFE should be equally applicable to OPG.

By June 30 of each year, OPG is required to file an analysis of the actual annual regulatory return for the regulated business (EB-2010-0008 Decision with Reasons, p. 151). This analysis includes a comparison of the total regulated business's achieved ROE against the approved ROE included in the payment amounts. OPG submits that this reporting requirement be used as the basis for determining if the actual ROE of the regulated business is outside the ±300 basis point trigger established by the RRFE for determining whether the OEB may initiate a regulatory review (Ex. A1-3-2, p. 23, Section 2.7; RRFE, p. 11).

[87] O. Reg. 53/05, s. 0.1(1) defines the formula used to calculate OPG's WAPA.

As necessary, OPG expects that it would submit additional information to enable an assessment of its ROE performance to the OEB as part of its reporting, as well as a proposal on what corrective action, if any, may be required under off-ramp provisions.

13.0 IMPLEMENTATION

13.1 ISSUE 12.1

Primary: Are the effective dates for new payment amounts and riders appropriate?

OPG requests an effective date of January 1, 2017, in respect of the payment amounts associated with the prescribed hydroelectric and nuclear facilities (Ex. A1-2-1, p.1-2). Moreover, OPG requests recovery, by way of rate riders, of the difference between existing payment amounts and the payment amounts sought in this Application from the effective date to the implementation date.

The general IESO settlement process is described in Chapter Nine of the Market Rules. OPG understands that in order for revised payment amounts and riders to be implemented on the first of a given month, a final rate order establishing new payment amounts and riders would have to be issued by the 20th of the second month prior to the implementation month in order for the IESO to update its systems (Ex. I1-4-1).

In OPG's submission, the requested effective date for new payment amounts and rate riders are appropriate and should be approved by the OEB. As filed, the Application complied in all material respects with the OEB's filing guidelines and any directions provided in OPG's last payment amounts proceeding. On August 12, 2016, the OEB issued Procedural Order No. #1. Since then, OPG has met the deadlines established by the OEB and has worked diligently with all parties and OEB Staff to advance the Application in a reasonable and efficient manner, including reaching a settlement on a subset of issues (Ex. O1-1-1). OPG has done so while responding to over one thousand interrogatories and undertakings, and while marshalling evidence to support its requests from dozens of witnesses from across the company and, where appropriate, third party independent experts.