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APPROVALS

In this Application, OPG seeks the following specific approvals:

Revenue Requirement

1. The approval of the following revenue requirements for the nuclear facilities, net of the nuclear stretch factor, as set out in Ex. I1-1-1 and amended by Ex. N1-1-1:

Period	Revenue Requirement
January 1, 2017 through December 31, 2017	$3,201.8M
January 1, 2018 through December 31, 2018	$3,222.5M
January 1, 2019 through December 31, 2019	$3,309.6M
January 1, 2020 through December 31, 2020	$3,824.4M
January 1, 2021 through December 31, 2021	$3,437.8M

Rate Base

2. The approval of the following rate bases for the nuclear facilities, as summarized in Ex. B1-1-1 and amended by Ex. N1-1-1:

Year	Rate Base
2017	$3,868.4M
2018	$3,960.6M
2019	$3,819.3M
2020	$7,786.2M
2021	$8,208.6M

Production Forecasts

3. Approval of the following production forecasts for the nuclear facilities, as presented in Ex. E2-1-1.

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

Cost of Capital

4. Approval of a deemed capital structure of 51 per cent debt and 49 per cent equity and a combined rate of return on rate base to be determined using data available for the three months prior to the effective date of the payment amounts order, in accordance with the OEB's Cost of Capital Report, and currently set by the OEB at 8.78 per cent for 2017 and adjusted annually using the prevailing rate of return on equity specified by the OEB, as presented in Ex. C1-1-1 and amended by Ex. N1-1-1.

Payment Amounts

5. Effective January 1, 2017, $41.71/MWh for the average hourly net energy production (MWh) from the regulated hydroelectric facilities in any given month (the "hourly volume") for each hour of that month. Where production is over or under the hourly volume, regulated hydroelectric incentive revenue payments will be consistent with the OEB's Payment Amounts Order in EB-2013-0321. The calculation of the payment amount for the regulated hydroelectric facilities is set out in Ex. I1-2-1.

6. Approval of the rate-setting formula and related elements for setting payment amounts for the prescribed hydroelectric generating facilities in the period from January 1, 2017 through December 31, 2021, as proposed in Ex. A1-3-2.

7. Approval of the following payment amounts for the nuclear facilities:

Effective Date	Payment Amount
January 1, 2017	$65.81/MWh
January 1, 2018	$73.05/MWh
January 1, 2019	$81.09/MWh
January 1, 2020	$90.01/MWh
January 1, 2021	$99.91/MWh

Rate Smoothing and Mid-term Production Review

8. Approval of the nuclear rate smoothing proposal as set out in Ex. A1-3-3 and amended by Ex. N1-1-1, including the establishment of a rate smoothing deferral account and the portion of the approved nuclear revenue requirement that is to be recorded in that deferral account. Specifically, OPG proposes that annual nuclear base payment amounts reflect a constant 11 per cent per year rate increase during the 2017 to 2021 test period resulting in a deferred revenue requirement of $694M, $412M, $145M, $462M, $(97)M in 2017, 2018, 2019, 2020 and 2021, respectively.

9. Approval of a mid-term production review in the first half of 2019 (i.e., prior to July 1, 2019) for:
   i. an update of the nuclear production forecast and consequential updates to nuclear fuel costs for the final two-and-a-half years of the five-year application period (July 1, 2019 to December 31, 2021); and
   ii. disposal of applicable audited deferral and variance account balances as well as any remaining unamortized portions of previously approved amounts with recovery period extending beyond December 31, 2018.

Deferral and Variance Accounts

10. Approval for recovery of the audited December 31, 2015 balances of the deferral and variance accounts identified in Exhibit H.

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

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

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

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

Project Approvals

15. OPG seeks the following approvals for the Darlington Refurbishment Program:
    i. In-service additions to rate base of: (i) $350.4M in the 2016 Bridge Year; and (ii) for the test period, $374.4M in 2017, $8.9M in 2018, $4,809.2M in 2020, and $0.4M in 2021 on a forecast basis. These amounts reflect the addition to rate base of $4,800.2M related to Unit 2 in-service addition in 2020 and 2021, as well as $743.1M related to Unit Refurbishment Early In-Service Projects, Safety Improvement Opportunities, and Facilities & Infrastructure Projects. If actual additions to rate base are different from

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

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

Interim Payment Amounts

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

RATE-SETTING FRAMEWORK

1. OVERVIEW

This is the first incentive rate-setting ("IR") application for OPG's nuclear and hydroelectric generating facilities. In a letter dated February 17, 2015, the OEB indicated that it expected the company's next payment amounts would be based on the principles outlined in the *Renewed Regulatory Framework for Electricity Distributors* ("RRFE").[1] The OEB further indicated that the application should include an IR mechanism for the company's hydroelectric assets. For OPG's nuclear assets, the OEB set out its view that OPG should take a longer term approach to Custom Incentive Rate-setting ("Custom IR") that focuses on the parameters of a multi-year cost of service application while incorporating elements of IR.[2]

OPG is proposing forms of IR for setting both nuclear and hydroelectric payment amounts. For the company's hydroelectric assets, OPG's proposal is closely aligned to the Fourth Generation IR ("4GIRM") price-cap index method used by most Ontario electricity distributors. For the nuclear assets, OPG's Custom IR proposal includes a benchmarking-based stretch factor to drive continuous improvement in elements of the company's operations that can be implemented without jeopardizing safety, reliability, or the execution of the multi-billion dollar nuclear capital work planned for the application period.

OPG designed this application in direct response to the OEB's letter, and based on input received from stakeholders. This schedule summarizes the ways in which the application reflects the ratemaking approach set out in the RRFE and elsewhere in OEB policy. The schedule is divided between the company's proposed frameworks for hydroelectric and nuclear assets.

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[1] *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012.
[2] Letter re: *Incentive Rate-setting for Ontario Power Generation's Prescribed Generation Assets*, to all participants in EB-2013-0321 and EB-2012-0340, February 17, 2015.

This schedule also reviews OPG's proposed annual performance reporting and the company's customer engagement activities.

1.1. Stakeholder Consultation

In late 2014 and early 2015, OPG held a series of stakeholder information sessions regarding its planned application for 2016 payment amounts. During these information sessions, the company presented OEB Staff and other stakeholders with its proposed rate-setting approach for both hydroelectric and nuclear operations. The consultation consisted of a series of three information sessions during which stakeholders were asked to give feedback on the company's proposed approach. Although OPG ultimately did not file an application for 2016 payment amounts, aspects of the current application were discussed in that stakeholdering process. The agendas for these sessions are provided in Ex. A1-7-1 Attachments 1-3.

OPG also held stakeholder information sessions in connection with the current application on February 8, March 21 and May 19 of 2016. The agendas from these sessions are also provided in Ex. A1-7-1 Attachments 4 -6.

Following the consultations, OPG made a number of changes to the planned application, including:

i. Eliminating the proposal to establish hydro base rates using a 2017 forecast test year cost of service review – instead, the filed application escalates existing hydroelectric payment amounts by the proposed price-cap index;
ii. Eliminating the proposed symmetrical earnings sharing mechanism for nuclear and hydroelectric businesses;
iii. Eliminating the New Cost of Capital Variance Account proposed to record differences in hydro return on equity during the IR term;
iv. Modifying the hydroelectric x-factor, increasing the annual productivity adjustment from -1% (as identified by the independent Total Factor Productivity study) to 0%, reflecting OEB policy in the electric distribution sector;

v. Expanding the application of the nuclear stretch factor applied to include corporate support costs; and

vi. Expanding the proposed performance reporting metrics to include all of the key hydroelectric performance areas filed in OPG's prior payment amounts application (EB-2013-0321, Ex. F1-1-1, Appendix B) and all measures used in annual nuclear benchmarking.

2. HYDROELECTRIC FACILITIES RATE-SETTING PROPOSAL

2.1. Summary of Hydroelectric Rate-setting Proposal

OPG proposes a price-cap index rate-making methodology for the company's regulated hydroelectric generation assets, modelled closely on 4GIRM method set out in the RRFE. Of the three rate-making methods in the RRFE, OPG believes that a price-cap index is best suited to the circumstances of the company's hydroelectric generation facilities.

Consistent with the price-cap index methodology in the RRFE, OPG has proposed I- and X-factors to establish the annual price cap adjustment for 2017 to 2021. Consistent with the RRFE, the productivity and stretch factors that comprise the proposed X-factor are based on independent Total Factor Productivity ("TFP") and total-cost benchmarking studies.

As set out below in Chart 1, the structure of OPG's hydroelectric ratemaking proposal is largely identical to 4GIRM:

Chart 1 – Summary of Hydroelectric Ratemaking Proposal

Ratemaking Element	4GIRM	OPG Proposal
"Going-In" Rates	Determined in a forward test year cost of service review	Determined in cost of service review of 2014/2015 test year (EB-2013-0321)
Form	Price-cap Index	Price-cap Index
Coverage	Comprehensive (capital and OM&A)	Comprehensive (capital and OM&A)
Annual Adjustment Mechanism	1+(I-X) **Inflation**: Composite Index. Distribution Industry weighted Labour Index (Ontario AWE) and Non-Labour index (GDP-IPI-FDD) **X-factor**: Peer group X-factors comprised of: 1. Distribution industry TFP growth potential; and 2. a Stretch Factor	1+(I-X) **Inflation**: Composite Index. Generation Industry weighted Labour Index (Ontario AWE) and Non-Labour index (GDP-IPI-FDD) **X-factor**: Peer group X-factors comprised of: 1. Hydroelectric generation industry TFP growth potential; and 2. a Stretch Factor
Role of Benchmarking	1. Assess reasonableness of test year cost forecasts 2. Determine stretch factor	1. Test year review completed in EB-2013-0321 2. Determine stretch factor
Sharing of Benefits	Stretch factor of between 0% and 0.6% based on benchmarking	Stretch factor of between 0% and 0.6% based on benchmarking OPG proposes a stretch factor of 0.3% for the application term, based on the company's hydroelectric benchmarking

Ratemaking Element	4GIRM	OPG Proposal
Term	Five years	Five years
Incremental and Advance Capital Modules	Available on application	Available on application OPG is not proposing an Advance Capital Module
Treatment of Unforeseen Events	Per OEB policy (*Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, EB-2007-0673)	Per OEB policy (*Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, EB-2007-0673), with OPG-specific materiality threshold of $10M
Treatment of Deferral and Variance Accounts	Status quo	Status quo, with addition of a variance account to account for the impact of OEB's decision on OPG's request to adjust the common equity ratio
Performance Reporting / Monitoring and Off-ramps	Annual performance reporting A regulatory review may be initiated if a distributor's annual reporting shows performance outside of the ±300 basis points ROE dead band, or if performance erodes to unacceptable measures	Annual performance reporting A regulatory review may be initiated if OPG's annual reporting shows performance outside of the ±300 basis points ROE dead band, or if performance erodes to unacceptable measures

2.2. OEB & Stakeholder Guidance

2.2.1. OEB Policy

With the Niagara Tunnel Project now in service, OPG's regulated hydroelectric generation facilities are in a relatively stable, steady state that is conceptually consistent with a price-cap index form of IR. The company believes that, of the three options set out in the RRFE, the 4GIRM approach is best suited to the state of its regulated hydroelectric generation facilities.

As the RRFE is aimed at rate-making for electricity distributors in Ontario, it is not directly applicable to generators. However, OPG recognizes that many of the objectives and principles addressed in the RRFE can be applied to the generation sector.

The proposed hydroelectric IR framework deviates from 4GIRM only as is necessary to incorporate material differences between the distribution and hydroelectric generation industries and to transition OPG to IR for the first time.[3] Specifically, OPG's proposed model incorporates the following modifications to the 4GIRM methodology:

1. **Inflation factor**: OPG proposed using the same input sub-indices as the OEB's 4GIRM I-factor; however the I-factor is weighted appropriately to reflect the input costs of the hydroelectric generation industry (i.e., not the electric distribution industry) as determined independently by London Economics International LLC ("LEI"));
2. **Productivity Growth**: The independent Total Factor Productivity ("TFP") study reflects growth potential of the hydroelectric generation industry. However, notwithstanding the negative productivity factor identified by the LEI TFP study, OPG is proposing a productivity factor of zero; and
3. **Stretch factor**: Set once at the beginning of the IR plan term (i.e., not revised annually) to place OPG's hydroelectric benchmarking performance in the context of the OEB's 0% to 0.6% stretch factor range.

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[3] Reflects an adjustment to the hydroelectric base rate to remove a 2015 nuclear tax loss (discussed in Section 2.3.2) and a new deferral account to reflect the OEB's decision on common equity (discussed in Section 2.6).

The RRFE requires an X-Factor to be based on industry TFP growth potential and a stretch factor. In its letter of February 17, 2015, the OEB noted its expectation that OPG's hydroelectric incentive rate-making framework would take into consideration the independent productivity study performed by LEI and filed with the OEB on December 19, 2014. That productivity study reflected information for the 2002 to 2012 period. An updated version of the study including data for 2013 and 2014 is filed as Attachment 1 to this schedule. The TFP study results were substantially the same, as demonstrated in Chart 2:

Chart 2 – Summary of Hydroelectric TFP Results

Approach	2002-2012 Information	2013-2014 Update
Average Index	(1.02)	(1.01)
Trend Regression Index	(1.00)	(1.19)

Although LEI's TFP study concludes that a -1% productivity factor is appropriate for OPG's regulated hydroelectric facilities, OPG recognizes that the OEB has declined to accept a negative productivity factor in the context of electricity distribution. OPG therefore proposes a 0% productivity factor for the 2017-2021 IR period. This increase to the productivity factor essentially creates an additional 1% stretch factor for OPG's hydroelectric facilities during each year of the IR period, relative to the industry trend identified in the TFP study.

Total cost benchmarking is an important component of each rate-setting model in the RRFE and plays an important role in OPG's proposed IR frameworks for both hydroelectric and nuclear assets. Under the 4GIRM method, which OPG's hydroelectric IR proposal is based upon, an applicant's benchmark performance is used to determine the stretch factor in the distributor's price-cap index. Similarly, OPG proposes that the hydroelectric stretch factor be determined based on the hydroelectric total cost benchmarking study conducted by Navigant Energy Consulting Inc. ("Navigant"), which is filed as Attachment 2 to this schedule.

As discussed in section 2.3 below, the proposed 0.3% stretch factor is based on the company's hydroelectric benchmarking performance. In determining the value of the stretch factor, OPG has adopted the same 0% to 0.6% range applied under the RRFE. As OPG's benchmarking results will be submitted and reviewed in this proceeding and not updated over the IRM term, OPG proposes that the stretch factor set in this proceeding remain in effect for the five-year IRM term.

2.2.2. Filing Guidelines

The OEB's Filing Guidelines for OPG's prescribed generation facilities are based on a cost of service methodology and are therefore not applicable to a price-cap-based application. OPG has structured the hydroelectric payment amounts evidence on the OEB's 4GIRM Filing Requirements.[4]

OPG has applied the Filing Requirements as appropriate for the generation industry, as set out in Ex. A1-3-1 Attachment 1. For example, since OPG's payment amounts do not include pass-though amounts, many of the sheets in the OEB's IRM Rate Generator, such as those relating to Retail Transmission Service Rates, are not applicable to OPG. OPG has incorporated the applicable elements of the IRM Rate Generator in Ex. I1-2-1.

2.3. Annual Adjustment Mechanism

OPG proposes that the company's existing hydroelectric payment amounts be adjusted annually according to a mechanistic price-cap adjustment according to the same formula as used in 4GIRM:

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[4] *Filing Requirements for Electricity Distribution Rate Applications – 2015 Edition for 2016 Rate Applications – Chapter 3: Incentive Rate-Setting Applications*, dated July 16, 2015.

Base Rates x (1 + I – X)

In this formula:

(i) **"I"** represents generation-industry inflation, determined annually based on a composite inflation index recommended LEI, using the same indices that the OEB uses to adjust rates for electricity distributors. As in 4GIRM, OPG proposes that the I-factor value would be adjusted mechanistically as part of an annual payment amounts adjustment application.

LEI has calculated a current I-factor value of 1.8% using the most recent Statistics Canada data.[5]

(ii) **"X"** is the sum of:

a) a productivity factor, and

b) a stretch factor determined by total-cost benchmarking of OPG's hydroelectric generation facilities.

As described in greater detail below in section 2.3.3.1, the TFP studies conducted by LEI concluded that a -1% productivity factor would be appropriate, based on productivity trends in the North American hydroelectric generation industry. However, in deference to OEB policy, OPG has increased the proposed productivity factor to zero.

Based on a total-cost benchmarking study of OPG's regulated hydroelectric generation assets by Navigant, OPG proposes a hydroelectric stretch factor of 0.3%, consistent with the range of stretch factors applied by the OEB under 4GIRM.

[5] Derived from sub-index values as of March 31, 2016.

The X-factor would remain consistent over the five-year term of the application. The derivation of the inflation factor and X-factor values are discussed in greater detail in subsections 2.3.1 and 2.3.2, respectively.

2.3.1. Inflation Factor

OPG retained LEI to recommend an appropriate inflation factor for the company's hydroelectric price-cap framework. LEI recommended a composite index using the same sub-indices that the OEB uses when determining the inflation factor for electricity distributors under 4GIRM:

(i) Canadian Gross Domestic Product Implicit Price Index – Final Domestic Demand ("GDP-IPI FDD") from Statistics Canada; and
(ii) Average Weekly Earnings for Ontario – Industrial Aggregate ("Ontario AWE") from Statistics Canada.

LEI further recommended applying the sub-indices above to the same cost components that the OEB uses when determining the inflation factor for electricity distributors under 4GIRM:

(i) GDP-IPI FDD is applied to capital costs and non-labour O&M costs; and
(ii) Ontario AWE is applied to labour costs.

LEI's inflation factor analysis was presented to stakeholders during OPG's stakeholder consultation in late 2014 and early 2015. As discussed at the stakeholder consultation, LEI considered other sub-indices that were more relevant to the capital costs OPG would incur. However, LEI found that these alternative indices were historically less stable. Information presented by LEI on the inflation factor at the stakeholder consultations is provided in Attachment 3.

LEI recommended that OPG's inflation factor follow a 4GIRM-like composite index approach for several reasons:

(i) It is representative of the various basic categories of inputs that affect OPG (labour and non-labour).

(ii) It captures labour costs that are specific to the Ontario industrial sector.

(iii) Since it represents inflation trends across many firms and industries, it is exogenous to OPG.

(iv) It is based on data that is readily available from Statistics Canada.

(v) It can be calculated simply and transparently.

(vi) It has historically been very stable, leading to more predictable rates.

OPG expects that the proposed approach will result in more stable payment amounts. Given the relative size of the capital for the generation industry (81%) the capital sub-index has a significant impact on the I-factor, and therefore would result in less stable rates. OPG believes that its customers prefer and the public interest favours more stable rates.

OPG asked LEI to identify the appropriate weighting between capital, labour, and non-labour costs for the hydroelectric generation industry and specifically for OPG. LEI used the weighting of capital, labour, and non-labour indices that was suggested by its TFP study.

LEI's analysis produced the following weightings between capital and OM&A costs in Chart 3:

Chart 3 – Summary of Hydroelectric I-Factor Weighting

Sub-index	**Weight Assigned**	
	Industry	**OPG-specific**
Capital	81%	88%
OM&A - Non-labour	7%	4%
Total (GDP-IPI FDD)	**88%**	**92%**
OM&A - Labour	12%	8%
Total (Ontario AWE)	**12%**	**8%**

In the electricity distribution context, the OEB adopted a weighting of distribution industry sub-indices that was a "reasonable representation for the industry as a whole."[6] Similarly, OPG's proposed annual adjustment mechanism uses generation industry weighting to determine the annual inflation factor adjustment.

Based on labour and non-labour sub-index values as of March 31, 2016, LEI calculated an I-factor of 1.8%. The derivation of this value is set out in Chart 4:

Chart 4 – Summary of Hydroelectric I-Factor Sub-indices, Q1 2016

Inputs and Assumptions											
Year	Non-Labour GDP-IPI-FDD - National							Labour AWE - All Employees - Ontario			Composite index
	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Annual % Change
2014	112.5	113.2	113.7	114.1	113.375			938.27			
2015	114.3	114.9	115.8	116.2	115.3	**1.7%**	**88%**	962.73	**2.6%**	**12%**	1.8%

OPG proposes to make annual adjustments for inflation on the same basis as the OEB does when setting rates for electricity distributors under 4GIRM. As under 4GIRM, OPG's inflation factor would be updated annually to account for the most current sub-index values. The sub-indices and their weighting would remain constant in each year; only the value of each sub-index would change (i.e., the value of GDP-IPI FDD and Ontario AWE would be updated with the latest Statistics Canada data).

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[6] EB-2010-0379, *Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, corrected on December 4, 2013, p. 9.

OPG expects to file annual price-cap adjustment applications in the fall of each year to set the next year's rate. For example, OPG expects to file an application in the fall of 2017 to determine 2018 rates. That 2018 payment amounts adjustment would be based on the values for the GDP-IPI (FDD) and Ontario AWE at the time of those applications.

2.3.2. "Going in" Rates

OPG proposes that the company's current hydroelectric payment amounts as approved in EB-2013-0321 be used as the "going in" rates for the 2017-2021 period, adjusted to correct for the one-time allocation of nuclear tax losses to the hydroelectric business in the prior application. The current payment amounts reflect the OEB's findings in EB-2013-0321 to only allow OPG to recover its cash requirements for pensions and other post employment benefits[7] .

In its treatment of tax losses in the EB-2013-0321 proceeding, OPG applied the 2015 forecast nuclear tax loss to reduce the 2014 and 2015 nuclear taxable income to $0. OPG then allocated the remaining unused nuclear tax loss of $86.7M to the hydroelectric business.[8] This allowed OPG to reduce hydroelectric payment amounts, giving customers the benefit of the nuclear tax losses immediately, rather than carrying the losses forward to offset future nuclear taxable income.

To establish the "going-in" rate for IR, the current hydroelectric payment amounts must be adjusted to remove the impact of applying the 2015 nuclear tax loss to the 2015 hydroelectric revenue requirement. Removal of the nuclear tax loss from the approved hydroelectric rate as illustrated in Ex. I1-2-1 Tables 2 and 2a results in a revised "going-in" hydroelectric rate of $41.09/MWh as derived in Ex. I1-2-1 Table 1a.

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[7] EB-2013-0321 Decision With Reasons, Page 87.
[8] EB-2013-0321, OPG Response to Intervenor Comments on the Draft Payment Amounts Order, December 12, 2014, page 4.

The allocation of specific tax losses from the nuclear to the hydroelectric business unit for ratemaking purposes is necessarily a one-time adjustment to payment amounts intended to provide customers the benefit of the nuclear tax loss sooner than would be the case if they were carried forward within the nuclear business unit. Absent the allocation, the OEB approved hydroelectric base rate in EB-2013-0321 would have been the $41.09/MWh discussed above, and the $86.7M would be applied to reduce the nuclear revenue requirements in this application. As customers have received the benefit of the tax losses, these losses are no longer available to reduce nuclear payment amounts in this application.[9] OPG has therefore adjusted the "going in" hydroelectric rates to remove these tax losses.

2.3.3. X-Factor

OPG proposes an X-factor composed of two elements: (i) an industry productivity factor, as calculated by LEI's TFP study of the North American hydroelectric generation industry, and (ii) a stretch factor based on OPG's hydroelectric benchmark performance.

2.3.3.1. Productivity Factor

LEI's TFP study was filed with the OEB as part of the EB-2013-0321 proceeding on December 19, 2014 (the "Initial TFP Study"). LEI updated the Initial TFP Study to include 2013 and 2014 data (the "Updated TFP Study"). Both the Initial TFP Study and the Updated TFP study yielded a productivity factor of -1%. However, for the reasons described below, OPG is proposing a productivity factor of zero in this application.

In late 2013, OPG retained LEI to prepare a hydroelectric generation industry productivity study for OPG's prescribed hydroelectric assets. LEI was responsible for identifying

[9] Since OPG did not apply to adjust payment amounts for 2016, customers have received a benefit associated with the 2015 nuclear tax losses for an additional year

appropriate methodologies of data compilation and peer selection, as well analyzing the data. This subsection briefly reviews LEI's methodology, the peer group selected, and the study's conclusions. The Updated TFP study, which is filed as Attachment 1 to this schedule, sets out each stage of LEI's work in greater detail.

LEI used an index methodology to calculate the industry TFP, like the approach used in the RRFE.[10] An index-based TFP approach measures the ratio of all outputs to all inputs, where input and output indices are constructed using both quantities and prices of outputs and inputs. LEI selected an indexed approach for a number of reasons: it is relatively simple, easy to communicate and ultimately a robust technique that requires significantly fewer observations than other measuring techniques.

The selection of inputs and outputs is an important aspect of designing a TFP study. The inputs and outputs used should be those that accurately reflect actual productivity in the industry, and for which data is readily available and quantifiable. For their study, LEI used two inputs: physical capital (measured in MW), and total O&M (measured in dollars). LEI used a single output: generation (measured in MWh). As a measure, generation also benefits from ubiquity; as it is common to every hydroelectric generator, generation data is readily available and data is generally measured consistently across power plants and companies. LEI also found that generation is the most common measure of output in academic and regulatory studies.

LEI established an appropriate industry peer group based on a "multi-dimensional" set of criteria. Their goal was to identify comparable utilities, while accounting for data-availability issues. They selected firms that have a medium (500-1000 MW) or large (>1000 MW) total hydroelectric capacity. To qualify, peers also needed to have more than one plant, and ideally

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[10] *Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, issued November 21, 2013 and corrected on December 4, 2013 (EB-2010-0379).

the average age of a peer's hydroelectric fleet would be comparable to OPG's prescribed hydroelectric assets. Peers also needed to have specific hydroelectric operations data available for the period from 2002 to 2012. LEI considered a total of 28 North American peers, ultimately including 17 firms in the Initial TFP Study in the industry group, including OPG. In the Updated TFP Study one firm (Alcoa) was removed as it sold hydroelectric assets in 2012 and the remaining hydroelectric capacity was substantially less than the 500 MW capacity criteria used for peer selection. No other changes were made to the peer group.

LEI considered five Canadian peers for inclusion in the industry group, but ultimately was unable to obtain sufficient data related to the hydroelectric-specific O&M expenses. LEI tried to obtain the necessary data in several forums, including StatsCan and NERC databases, annual reports, regulatory filings and other publicly available information. LEI made repeated information requests to all five utilities, but were unable to obtain the information. Consequently, no other Canadian utilities were included in the industry group.

LEI calculated TFP results using two methods: average index growth, and a trend regression approach. The results of the Initial TFP Study and the Updated TFP Study are summarized in Chart 5.

Chart 5 – Summary of Hydroelectric TFP Results

Approach	2002-2012 Information	2013-2014 Update
Average Index	(1.02)	(1.01)
Trend Regression Index	(1.00)	(1.19)

LEI commented on the results, stating that negative TFP results can be expected for a TFP study on a mature hydroelectric industry.[11] During the stakeholder consultation in late 2014 and early 2015, LEI explained that a negative productivity factor for the hydroelectric generation industry is expected, given it is an industry with substantially fixed productive capability, fixed capital stock, and increasing operating and maintenance costs that would naturally lead to negative productivity growth.[12]

The results of the TFP studies notwithstanding, OPG has elected to increase the productivity factor to from negative 1% to zero. OPG believes this approach is consistent with OEB policy. In the electricity distribution context, the OEB has elected not to set rates based on negative productivity growth in the electricity distribution context. In its report on the distribution productivity factor under the RRFE, the OEB stated that it “does not believe it appropriate for a rate setting regime to project and entrench declining productivity expectations into the future.”[13] The OEB determined that the productivity factor value would be zero, despite the negative result of the industry TFP study.

While OPG believes that the -1% TFP factor resulting from both the Initial TFP Study and the Updated TFP Study is accurate, it understands the OEB’s policy position and proposes a zero productivity factor in this application.

In effect, increasing the productivity factor to zero creates an additional 1% stretch factor on OPG’s hydroelectric business during the term of this application. OPG’s performance must exceed the TFP trend identified by LEI in order to meet the reduced rates that result from the hydroelectric price cap index adjustment.

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[11] Updated TFP Study, p. 48
[12] Ex. A1-7-1, Attachment 3, Session notes, p. 4.
[13] EB-2010-0379, *Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario’s Electricity Distributors*, p. 17.

2.3.3.2. Stretch Factor

OPG proposes to use a 0.3% stretch factor based on OPG's performance on independent hydroelectric benchmarking. As described in this section, OPG arrived at this proposal by adopting the range of stretch factors used in the OEB's 4GIRM methodology (i.e., 0%, 0.15%, 0.3%, 0.45% and 0.6%), and identifying a stretch factor that corresponds with the company's hydroelectric benchmark performance.

As required by the OEB's decision in EB-2013-0321, OPG retained Navigant to conduct an independent total-cost benchmarking study of its hydroelectric business.[14] A copy of the hydroelectric benchmarking report is field as Attachment 2 to this schedule.

Navigant benchmarked approximately 92% of OPG's 2013 costs attributable to its regulated hydroelectric operations against a peer group comprised predominantly of U.S. and Canadian generators that represent approximately 100,000 MW of installed capacity. Facilities comprising the peer group are diverse in size, type and age, and include hydroelectric generation stations with reservoirs, run-of-river generating facilities, and pumped storage stations. Chart 6 summarizes the peer group composition and compares it to OPG's regulated hydroelectric facilities:

Chart 6 – Composition of Peer Group and Comparison to OPG Regulated Hydro

	Peer Group	OPG
No. of Station Groups	222	54
Median Station Age (years)	45	84.5
Median Station Group Size (MW)	152	10
Median Unit Size (MW)	37	5

[14] EB-2013-0321, Decision with Reasons (November 20, 2014), pages 17-18.

Navigant excluded costs that were unique to OPG's regulated hydroelectric operations. Costs not benchmarked include adjustments to centrally held pension and OPEB costs, IESO non-energy charges, costs attributable to electricity sales and trading, and corporate business development costs. Navigant separately benchmarked OPG's regulated hydro investment costs (i.e., regulatory and sustaining project OM&A and capital investment) and reliability performance (i.e., availability and EFOR).

OPG's regulated hydroelectric operating costs benchmark in the second quartile relative to the study's peer group based on Partial Function Cost. Navigant identified Partial Function Cost as the key cost metric for benchmarking purposes to assess OPG's relative performance to its peers. (The Total Function Cost metric includes Gross Revenue Charges – a regulatory water and property tax not within OPG's control and which does not apply to others in the peer group). With respect to investment, the regulated hydro facilities benchmark in the second quartile, with marginally lower investment than the median compared to the peer group. The results of the benchmarking are summarized in Chart 7.

Chart 7 – Hydroelectric Benchmarking Results

	Partial Function Cost[15] ($M)* ***Key Measure**	**Total Function Cost[16] ($M)**	**Investment[17] ($M)**	**Availability (%)**	**Forced Outage (%)**
OPG Regulated Hydro	201	527	140	92.8	1.3
1st Quartile	114	142	64	95.7	0.3

[15] Partial Function Cost includes costs incurred for hydroelectric station operations, maintenance, waterways and dams, buildings and ground, and HTO & Corporate support costs. Navigant identified Partial Function Cost as the key performance indicator of OPG's regulated hydroelectric facilities.

[16] Total Function Cost includes Partial Function Cost, as well as costs incurred for Public Affairs and Regulatory which, in the case of OPG, is mostly Gross Revenue Charge payable on hydroelectric production.

[17] "Investment" includes both Capital and Project OM&A expenditures.

Median	203	318	146	90.7	1.3
3rd Quartile	408	625	444	81.5	4.1

OPG has set the proposed hydroelectric stretch factor based on the company's performance on Partial Function Cost. Navigant found that OPG's regulated hydroelectric facilities are effectively at the median for the hydroelectric generation industry on this measure. Using the range of stretch factors applied in the 4GIRM method, OPG's performance should result in a 0.3% stretch factor.

2.4. Incremental and Advance Capital Module Eligibility

As in 4GIRM, OPG would be eligible to request an Incremental Capital Module ("ICM") funding for qualifying hydroelectric capital projects. Any such request would be prepared pursuant to OEB policy.[18] Although OPG has not included an Advance Capital Module ("ACM") in this application, the company's proposed regulatory framework would permit the use of an ACM or ICM in subsequent applications.

2.5. Unforeseen Events (Z-Factor)

OPG proposes that the OEB's policy on unforeseen events would apply during the term of this application, as set out in OEB policy.[19] OPG proposes that the company's regulatory materiality threshold of $10 million apply.

2.6. Deferral and Variance Accounts

[18] EB-2014-0219, *Report of the Board: New Policy Options for the Funding of Capital Investments* (Sept. 18, 2014).
[19] *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, July 14, 2008.

OPG proposes to continue all existing deferral and variance accounts approved by the OEB as discussed in Ex. H1-1-1. As OPG is not rebasing hydroelectric payment amounts, the impact of any change to the company's common equity ratio approved by the OEB pursuant to OPG's request in Ex. C1-1-1 would be applied through the proposed Hydroelectric Capital Structure Variance Account described in Ex. H1-1-1.

OPG will continue to report the balances in its deferral and variance accounts as directed by the OEB in EB-2010-0008. OPG intends to monitor these balances and may make an application to dispose of these account balances during the 2017-2021 period.

2.7. Off-Ramp

By June 30 of each year, OPG is required to file an analysis of the actual annual regulatory return, after tax on rate base, both dollars and percentages, for the regulated business (i.e. both hydroelectric and nuclear combined).[20] This analysis includes a comparison of the regulated business' achieved ROE against the approved ROE included in the payment amounts. OPG proposes that this reporting requirement will be the basis for determining if its actual ROE is outside the +/-300 basis point trigger established by the RRFE for determining whether a regulatory review may be initiated.[21]

3. NUCLEAR FACILITIES RATE-SETTING PROPOSAL

3.1. Summary of Nuclear Rate-setting Proposal

OPG has endeavoured to develop a form of Custom IR that is both consistent with the OEB's letter of February 17, 2015, and compatible with the state of the company's nuclear business during the 2017-2021 IR period. As described in this schedule and elsewhere in this

[20] EB-2010-0008 Decision With Reasons, p. 151..
[21] RRFE Report, October 18, 2012, p.10 and the references cited therein.

application,[22] both of OPG's nuclear facilities are entering into a period of significant change. During the IR period, OPG will begin refurbishing the Darlington Nuclear Generating Station. At the same time, the company will carry out the works necessary to extend operations at the Pickering Nuclear Generating Station. Throughout this period, OPG must be able to meet customers' expectations that the company operate safely and reliably, and to continue generating clean, low-cost electricity.

As there is no prescribed IR regime for OPG's nuclear facilities, OPG has developed a Custom IR framework that is based on the principles set out in the RRFE, the OEB's prior guidance on incentive ratemaking, and on stakeholder feedback. The nuclear Custom IR framework is tied to OPG's performance on the total generating cost benchmarking that underlies the company's gap-based business planning process. The proposed Custom IR framework applies elements of 4GIRM – in particular, a benchmark-based stretch factor – in a manner that is compatible with OPG's regulatory and business context.

OPG's proposed nuclear Custom IR framework has been informed by various sources, including:

(i) The OEB's 2012/2013 consultation on incentive rate-making at OPG (the "OEB Consultation")[23];

(ii) The OEB's Filing Guidelines for OPG (the "Filing Guidelines")[24];

(iii) The principles reflected in the RRFE;

(iv) application stakeholder consultations[25]; and

(v) Other factors including prior OEB decisions, the Government of Ontario's Long-Term Energy Plan, O. Reg. 53/05, and OPG's business planning process.

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[22] See in particular Ex. A1-3-1, Ex. A1-3-2, and Exhibits D and F.
[23] EB-2012-0340, *Report of the Board: Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets*.
[24] *Filing Guidelines for Ontario Power Generation Inc.*, revised November 11, 2011 (EB-2011-0286).
[25] Ex. A1-7-1.

The major elements of the proposed nuclear Custom IR framework are set out in Chart 8, along with corresponding policy objectives from the RRFE and other sources:

Chart 8 – Summary of Nuclear Custom IR Framework

Policy Objective(s)	Source	Corresponding aspect(s) of Nuclear Rate-making Framework
Adopt a longer-term approach to payment amount-setting based on the parameters for a multi-year Cost of Service application and a Custom IR framework	OEB Consultation Report, p. 9 OEB Letter of February 17, 2015 O. Reg. 53/05[26]	Nuclear Ratemaking proposal includes five future test years with individual forecast revenue requirements. (As noted below, the application layers elements of IR onto this foundation.) Elements of the Custom IR framework are detailed below.
Include meaningful efficiency incentives derived from external benchmarking	RRFE, p. 17	Providing up-front benefit to customers through stretch factor reduction of revenue requirement. Stretch factor applied to revenue requirement arising OM&A costs that are independent of the major projects during the IR period. These stretch reductions are incremental to performance improvements resulting from OPG Nuclear's gap-based business planning process, discussed in Ex. F2-1-1. Stretch factor was determined by adopting the range of stretch factor values from 4GIRM[27] and applying the range to OEB-approved nuclear total generating cost benchmarking.

[26] O. Reg. 53/05, section 6(2)12
[27] 0% to 0.6%

Policy Objective(s)	Source	Corresponding aspect(s) of Nuclear Rate-making Framework
Provide tangible benefits and consequences for operating performance Encourage sustainable, year-over-year efficiency gains	OEB Consultation Report, p. 9 RRFE, p. 59	Stretch reductions persist year-over-year, incenting OPG to find further savings in each year of the application term, as would occur under 4GIRM. The 100% variable rate design of OPG's payments means that failure to achieve production forecast has direct financial consequences for the company, creating a meaningful incentive to continuously improve productivity.
Be aligned with performance outcomes Performance measures should be directly linked to desired performance outcomes	RRFE, pp. 3, 59	OPG is proposing annual reporting on the company's performance to provide meaningful measures of the company's nuclear performance. The proposed measures reflect identified RRFE performance outcomes. Annual reporting will include all of the measures used in OPG's nuclear benchmarking. Application includes robust evidence of the company's nuclear operations and project forecasts. The application of off-ramps applies to the achieved return on equity for OPG's combined regulated operations as discussed in Section 2.7, above.

Policy Objective(s)	Source	Corresponding aspect(s) of Nuclear Rate-making Framework
It would not be appropriate for OPG's nuclear assets to move to a pure IR regime based on TFP, input cost indices, Z-factors, and off-ramps before Darlington refurbishment and Pickering closure are complete.	OEB Consultation Report, p. 8	While OPG agrees that it is not appropriate to transition the company's nuclear assets to a "pure IR" framework at this time, the 100% variable rate design, the proposed stretch factor and performance reporting requirements are meaningful IR elements consistent with the RRFE.

In 2012 and 2013, the OEB held a consultation to consider how to include elements of incentive regulation within OPG's rate-making regime. Parties were divided on the appropriate pacing and form of IR for OPG's nuclear facilities. During the consultation, some stakeholders expressed the view that IR may never become appropriate for nuclear facilities.[28] Others accepted that nuclear IR may be more appropriate after the DRP is complete and the Pickering facility has been shut down.

On March 28, 2013, the OEB issued a report on the outcome of the consultation (the "2013 Report"). In the 2013 Report, the OEB stated that:

> "the large capital expenditures and reduced production associated with the DRP and the Pickering closure <u>do not favour the implementation of a 'pure IR regime' (i.e., one based on TFP with input cost indices, Z-factors, and off-ramps) in the immediate future</u>."[29]

The OEB stated that OPG could move toward "a methodology that achieves some of the same objectives as IR" before Darlington Refurbishment and Pickering closure are

[28] OEB Consultation Report, p. 5.
[29] OEB Consultation Report, p. 8 [emphasis added].

complete.[30] The proposed nuclear Custom IR framework attempts to strike such a balance, reflecting the fact that OPG's capital and operating costs will vary significantly with the refurbishment of the Darlington facility and the extension of operations at Pickering, but also implementing benchmark-driven stretch reductions in aspects of the company's nuclear operations where it is reasonable to do so.

The proposed nuclear Custom IR framework reflects the OEB's conclusions. It is based on five individual nuclear revenue requirements, but includes incremental stretch reductions that are sustained, year-over-year, creating a meaningful incentive to continuously improve performance and cost efficiency during the IR period.

3.2. Stretch Factor Proposal

As described above, any form of incentive regulation proposed for OPG's nuclear assets must be appropriate in the context of the significant programs planned for the company's nuclear facilities during the IR period. OPG proposes a benchmark-based stretch factor that will provide a meaningful performance incentive during the term of this application.

OPG recognizes the OEB's expectation that an IR mechanism should incent performance improvements, and should be based on measures that are external to the company's forecasts. To achieve this, OPG proposes to apply a benchmark-based stretch factor to revenue requirement attributable to the company's nuclear Base OM&A and allocated corporate support services OM&A.[31] This reduction is in addition to the performance improvement initiatives reflected in the company's gap-based nuclear business planning process. The proposed stretch reduction has the effect of reducing revenue requirement for these two significant categories of expenditures below forecast.

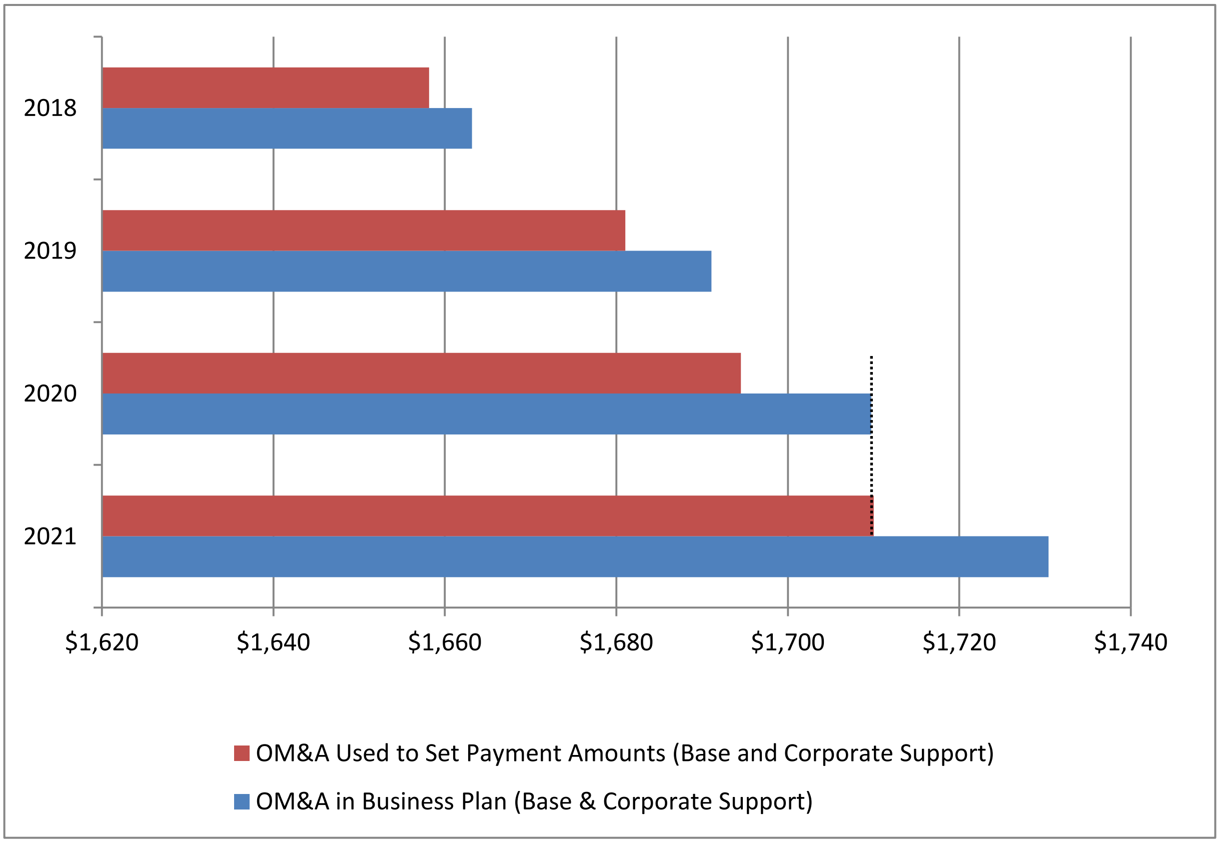
[30] OEB Consultation Report, p. 9.
[31] Descriptions of nuclear Base OM&A and corporate support services are available at Ex. F2-2-1 and Ex. F3-1-1, respectively.

The proposed stretch reduction targets elements of the company's nuclear costs that constitute a significant amount of OPG's nuclear revenue requirement during this application. The stretch factor applies to an average of $1.7 billion[32] or approximately 75% of OPG's total nuclear OM&A in each year of the application.

As discussed in section 3.2.1 below, OPG is proposing a 0.3% stretch factor. The stretch reduction is cumulative, resulting in a greater reduction to applicable revenue requirement each year of the IR period. As illustrated in Figure 1, the stretch factor grows over the term of the application, resulting in a $20.4M stretch reduction in 2021, effectively reducing the revenue requirement for Base and Corporate Support OM&A to the level forecast for the prior year.

[32] See Chart 10 for annual stretch eligible OM&A costs

Figure 1 – Nuclear Stretch Factor Reductions



OPG views Base OM&A and Corporate Support OM&A as proxies for the overall level of the company's nuclear operating expenditures where it is reasonable to drive efficiencies. OPG does not expect that all elements of these costs can be reduced. For example, many functions within nuclear Base OM&A are related to safety and legislative requirements. Base OM&A includes several critical, regulated functions including safety, emergency preparedness, inspections, operations and maintenance.[33] While these functions are within Base OM&A (and therefore subject to the stretch reduction), OPG will not compromise functions that are

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[33] Many of these functions are required for OPG to comply with the *Nuclear Safety and Control Act* (Canada) and are mandated by the CNSC. Nuclear Base OM&A also includes work dealing with environmental issues.

mandated by the CNSC or that could otherwise increase safety or environmental risks or the risk of non-compliance with legislated requirements.

The proposed stretch reductions are in addition to efficiencies and performance improvements within the company's business planning processes. OPG continually strives to improve the company's performance and operational efficiency where it can do so safely within operational requirements (e.g., CNSC requirements) and without affecting reliability. Through the gap-based nuclear business planning process described in Ex. F2-1-1, OPG develops initiatives to meet these goals. The performance initiatives incorporated in the business planning process and the corresponding performance and operational efficiency improvements are reflected in the forecast expenditures in this application.

As noted above, the stretch factor applies to approximately 75% of OPG's nuclear OM&A. While OPG does not expect to find material efficiencies in the remaining 25% during the term of this application, it will seek to improve performance and reduce costs where it can responsibly do so.

3.2.1. Derivation of Proposed Stretch Factor

OPG proposes a stretch factor of 0.3%, which is based on the methodology used by the OEB to set electricity distribution rates. Under the RRFE, distributors may be subject to a range of stretch factors from 0% to 0.6%,[34] based on their benchmark performance. OPG has adopted the OEB's range in its proposed ratemaking frameworks for both hydroelectric and nuclear generating facilities.

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[34] Under the RRFE, electricity distributors are assigned to one of five performance cohorts based on their forecast costs relative to econometrically predicted benchmark costs. Based on their determined performance cohort, distributors are assigned a stretch factor of 0%, 0.15%, 0.3%, 0.45% or 0.6%..

As set out in the 2015 Nuclear Benchmarking Report, Darlington's Total Generating Cost per MWh performs in the top quartile, and the Pickering facility is in the fourth quartile.[35] OPG used a production-weighted average to determine a combined stretch factor value of just below 0.3%. Chart 9 illustrates the derivation of OPG's proposed stretch factor, based on the most recent OEB-approved nuclear production forecast.

Chart 9 – Derivation of Nuclear Stretch Factor

Input	Value
OEB-approved 2015 Darlington production (TWh)	25.0
OEB-approved 2015 Pickering production (TWh)	21.6
Darlington stretch factor (based on benchmark performance)	0.0%
Pickering stretch factor (based on benchmark performance)	0.6%
Production-weighted average stretch factor	0.3%

OPG has reduced the requested payment amounts by 0.3 per cent of the company's nuclear Base OM&A and allocated corporate support OM&A beginning in 2018. The amounts shown in Ex. F2-2-1 reflect the full forecast revenue requirement. The stretch reduction is applied when determining the company's payment amounts in Ex. I1-3-1.

In order to emulate the effect of the stretch-factor in the OEB's 4GIRM price-cap framework, OPG has calculated annual stretch reductions such that prior years' reductions are maintained (i.e., reductions to revenue requirement made in 2018 are carried forward to subsequent

[35] OPG has used its OEB-approved total generation cost benchmarking performance to determine where the company's nuclear division should fall on the OEB's range of stretch factors. OPG's 2015 Nuclear Benchmarking Report is filed at Ex. F2-1-1, Attachment 1. The Total Generating Cost benchmarking results are on p. 65.

years, on the presumption that the company should be incented to find additional savings each year). Reductions are proposed beginning in 2018, with additional reductions in 2019, 2020, and 2021. This mirrors the operation of the stretch factor under 4GIRM.

Chart 10 shows the product of applying the 0.3% stretch factor to Base OM&A and allocated corporate support OM&A.

Chart 10 – Stretch Reduction Amounts

($M)	**2018**	**2019**	**2020**	**2021**
Base & Corporate Support OM&A	1,663.2	1,691.1	1,709.7	1,730.4
Stretch Factor	0.3%	0.3%	0.3%	0.3%
Annual Stretch Reduction to Nuclear Revenue Requirement	**5.0**	**10.1**	**15.2**	**20.4**
Base & Corporate Support OM&A Used to Determine Payment Amounts	**1,658.2**	**1,681.0**	**1,694.5**	**1,710.0**

The total reduction over the term of the application is $50.6M. Although the 0.3% stretch reduction is constant, the “snow plow” effect of maintaining prior years’ reductions means that the $20.4M reduction in 2021 is a 1.2% reduction to that year’s stretch-eligible OM&A, or a 0.9% reduction to total nuclear OM&A.

This stretch reduction is incremental to the performance improvements required to achieve OPG’s business plan. Customers will benefit from these “up-front” budget reductions, and OPG will bear the risk of any shortfall.

3.2.2. Productivity Factor is Not Applicable

OPG is not proposing a nuclear industry productivity adjustment as part of the proposed X-factor. The nature and scale of capital work planned for the IR period mean that past productivity trends would not be a reasonable indicator of predicted productivity for OPG during the IR period.

3.3. Annual Adoption of OEB Prescribed ROE

OPG proposes that the company's annual nuclear Return on Equity ("ROE") be the OEB's prescribed ROE as determined by the OEB each year pursuant to the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009.

The five nuclear revenue requirements filed in this application are based on the OEB's prescribed ROE of 9.19 per cent for 2016, which was the most current available at the time of filing.

As discussed in Ex. C1-1-1, OPG proposes to use the following methodology to establish the ROE for the nuclear business for the 2017 to 2021 period:

- For the first year of the test period (2017), the ROE will be set using the prevailing ROE specified by the OEB in accordance with the OEB's Cost of Capital Report as of the effective date of the Payments Amount Order;
- The 2017 ROE will be used to determine the revenue requirement approved by the OEB from 2018 to 2021;
- For the second through fifth year of the test period (2018 to 2021), the ROE will be set annually using the prevailing ROE specified by the OEB in accordance with the OEB's Cost of Capital Report;
- The revenue requirement impact of the variance 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 will be recorded in the proposed Nuclear ROE Variance Account, as described at Ex. H1-1-1 Section 6.3.

3.4. Operational Effectiveness

"Operational effectiveness" is one of the four outcomes the OEB seeks to promote in the RRFE. The RRFE defines the operational effectiveness outcome as "continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives."[36]

Achieving operational effectiveness involves balancing two sets of outcomes: continuously improving processes and practices to provide customers with better value for money, while simultaneously delivering the performance outcomes that customers expect.

OPG's nuclear business balances these outcomes in four ways:

1. A performance-based business planning process that drives the company to achieve safety, reliability, value-for-money, and human performance targets;
2. Annual benchmarking using an OEB-approved methodology to assess the company's performance;
3. Staffing and compensation strategies designed to ensure key resource are available when needed, to minimize risks, and to ensure safe and efficient operations;
4. Extensive planning to help ensure the Darlington Refurbishment Program ("DRP") and extended operation of the Pickering Nuclear Generating Station are completed on time and on budget.

3.4.1. Performance-based Business Planning and Benchmarking

Through benchmark-driven performance improvement and value-for-money initiatives, OPG's nuclear business planning process pushes the company to create budgets that reflect continuous improvement in performance and cost efficiency.

As described in Ex. F2-1-1, benchmark performance is central to OPG's nuclear business planning process. The company uses annual benchmarking to assess OPG's performance relative to the industry on a set of key performance indicators, which are divided among the

[36] RRFE, page 2.

four cornerstones of OPG's nuclear business: safety, reliability, value for money, and human performance. OPG determines annual performance targets based on the company's performance on the benchmarked key performance indicators.

The annual nuclear business planning process starts with internal reviews of the current planning framework, the confirmation and updating of business objectives and priorities, requirements set out in the corporate-wide business planning instructions, a review of the status of operational and performance plans and related capital and OM&A expenditures, and the identification of emerging issues. Out of this process, strategic and performance objectives for OPG nuclear are determined and prioritized.[37]

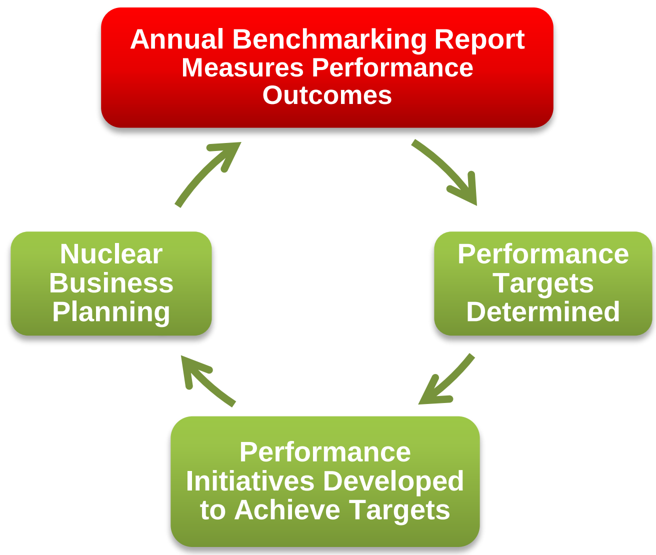
Once it has set performance objectives, OPG employs performance improvement initiatives to achieve the desired outcomes. OPG's nuclear business plan currently includes initiatives intended to improve reliability, human performance, and value-for money.[38] The Nuclear Business Planning and Benchmarking evidence in Ex. F2-1-1 includes three "case studies" of past nuclear performance initiatives that have helped OPG improve its performance in recent years. These are provided at Ex. F2-1-1, section 3.5.

Ultimately, the company measures and assesses its results through the subsequent round of benchmarking. Based on the benchmark outcomes, OPG may set new performance targets and revise its initiatives accordingly. This performance-based planning process allows OPG to track the company's results against targets, and to set appropriate targets for each successive year, creating a cycle of continuous performance and cost efficiency improvement.

Figure 2 illustrates OPG's performance-based nuclear business planning process, at a high level.

[37] More information on OPG's business planning processes is provided in Ex. A2-2-1 and F2-1-1.
[38] Some initiatives are intended to address multiple outcomes. For further detail, please see Ex. F2-1-1.

Figure 2: Nuclear Business Planning Process



3.4.2. Major Nuclear Performance Initiatives

OPG's business plan includes four major nuclear performance initiatives that OPG plans to implement during the IR period:

i. Human Performance,
ii. Outage Performance,
iii. Equipment Reliability, and
iv. Parts Improvement.

Details of these initiatives are included in the Nuclear Business Planning and Benchmarking evidence at Ex. F2-1-1.

OPG's business plan is based on the successful execution of these initiatives. To the extent that OPG does not achieve the targeted benefits from these initiatives, the company's costs and nuclear generation forecast are at risk. OPG may also develop other initiatives during the course of the IR period, depending on the outcomes reflected in the annual nuclear benchmarking report.

3.4.3. Staffing and Compensation

In the period prior to this application, OPG has made significant progress in reducing the company's staffing levels and controlling compensations costs. As discussed in Ex. F4-3-1, OPG's Business Transformation project involved restructuring the company around a centre-led model, reducing regular headcount by nearly 2,700 positions between 2011 and 2015, while avoiding severance package costs. Although the Business Transformation initiative has concluded, the company still employs a philosophy of continuous improvement in managing its resources and in regular operations.

OPG has also been successful in controlling upward pressure on compensation costs. The company has negotiated agreements with both the Power Workers' Union ("PWU") and the Society of Energy Professionals ("Society") that will keep wage escalation below inflation. These agreements run from April 1, 2015 - March 31, 2017 for the PWU, and from January 1, 2016 – December 31, 2018 for the Society. Prior to these agreements, typical union salary increases have been in the range of 2% to 3% for OPG and for other large companies in Ontario's electricity sector.

OPG has also controlled compensation costs for non-union ("Management") employees in several ways. The company froze base salary for Management employees between 2011 and 2015. In addition, OPG continues to follow legislated requirements restricting compensation increases to senior Management employees (Vice President and above) and limiting the company's performance-based compensation program.

In an independent compensation benchmarking study, Willis Towers Watson has confirmed that OPG's overall Total Direct Compensation is now at the market level.

More information on OPG's compensation, including the Towers Watson benchmarking study, is filed at Ex. F4-3-1.

3.4.4. Detailed Planning for DRP and Pickering Extended Operations

A system of continuous improvement is often based on making incremental refinements to recurring processes, year-over-year. The business planning process described above reflects this form of incremental efficiency improvement. In contrast, the DRP and Pickering extended operations are unique, multi-year projects. Given the size and stand-alone nature of these projects, OPG has taken extensive measures to ensure that the projects deliver the best value for Ontario's electricity customers.

For more information on the efficiencies and cost performance measures incorporated in the DRP, please see Ex. D2-2-1 through Ex. D2-2-10 and Ex. F2-7-1. For Pickering Extended Operations, please see Ex. F2-2-3.

4. PERFORMANCE REPORTING

OPG understands that the OEB expects utilities to provide meaningful insight into their performance during the course of multi-year applications. Consistent with the RRFE, OPG is proposing to report on a suite of measures that reflect performance on key company outcomes during the term of this application. As discussed in section 4.2, OPG proposes to report annually on the company's measures during the term of this application. Specifically, OPG proposes to report the company's performance on each of the measures identified in section 4.1, which are important inputs to OPG's business planning processes. This reporting would be in addition to OPG's current reporting as directed in EB-2010-0008.

As discussed in Ex. F2-1-1, OPG uses annual nuclear benchmarking to assess performance against industry peers in the four cornerstones of safety, reliability, value for money and human performance. Benchmarking results contribute to establishing targets to reduce performance gaps or maintain current performance, as appropriate. OPG believes that the company's annual benchmark results will be helpful performance reporting measures for the OEB and stakeholders.

The proposed benchmark reporting measures are consistent with the RRFE outcome of operational effectiveness (including measures covering system reliability, cost performance and service quality such as safety and environmental performance). These measures reflect outcomes that are both meaningful to customers and important inputs to the company's regular business planning processes. In addition, OPG intends to continue the reporting directed by the OEB in EB-2010-0008 which includes achieved regulatory ROE, the principal financial viability outcome included in the RRFE.

OPG does not have measurable performance objectives that are analogous to a distributor's mandated conservation and demand management targets or renewable generation connections; consequently OPG is not proposing any specific measures of public policy responsiveness. However, OPG understands that the general RRFE definition of this outcome is that "utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board)."[39] In this regard, OPG is the agent of government/public policy in a direct way, as it is mandated by the Province to support the LTEP and other public policy objectives.

The RRFE Customer Focus outcome is a significant factor in OPG's planning and operations. OPG is closely engaged with the communities in which it operates, and continues to enhance the role of customer engagement in its business planning process. OPG's customer engagement activities and plans are discussed separately in section 5, below.

[39] RRFE, p. 2.

4.1. Proposed Performance Measures

OPG proposes to report the company's annual benchmarking performance measures. The hydroelectric performance measures set out in Chart 11 are the same as the key performance areas filed in OPG's prior payment amounts application (EB-2013-0321, Ex. F1-1-1, Appendix B). The nuclear performance measures in Chart 12 are the benchmarks used in the company's annual nuclear benchmarking report.

Chart 11: Annual Hydroelectric Performance Measures

Hydroelectric Performance Measures	
Category	**Measure**
Safety	All Injury Rate (per 200k hours)
	Environmental Performance Index (%)
Reliability	Availability Factor (%)
	Equivalent Forced Outage Rates (%)
Cost Effectiveness	OM&A Unit Energy Cost ($/MWh)

1 **Chart 12: Annual Nuclear Performance Measures**

Nuclear Performance Measures

(Separate measures will be filed for Darlington and Pickering Stations)

Category	Measure
Safety	All Injury Rate (per 200k hours)
	Collective Radiation Exposure (person rem/unit)
	Airborne Tritium Emissions (curies)
	Industrial Safety Accident Rate (#/200k hours)
	Fuel Reliability Index (microcuries /gram)
	2-year Reactor Trip Rate (#/7000 hours)
	3-year Auxiliary Feedwater System Unavailability (#)
	3-year Emergency AC Power Unavailability (#)
	3-year High Pressure Safety Injection Unavailability
Reliability	Forced Loss Rate (%)
	Unit Capability Factor (%)
	Nuclear Performance Index (%)
	On-line Deficient Maintenance Backlog (work orders / unit)
	On-line Corrective Maintenance Backlog (work orders / unit)
	Chemistry Performance Indicator Annual YTD (#)
Cost Effectiveness	Total Generating Cost per Net MWh ($/MWh)
	Non-Fuel Operating Cost per Net MWh ($/MWh)
	Fuel Cost per Net MWh ($/MWh)
	Capital Cost per MW Design Electrical Rating ($k/MW)
Human Resources	18-month Human Performance Error Rate (#/10k ISAR hours)

4.2. Annual Performance Reporting Process

OPG proposes an annual written process for reporting on the prior year's performance and identifying targets for the following year. Beginning in 2017, OPG would 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 new year for each measure.

OPG believes that these measures will give the OEB and interested parties a clear and meaningful view into the company's operation during the 2017-2021 period. As is the case for electricity distributors, OPG proposes that no rewards or penalties be attached to the company's performance. In OPG's view, annual reporting exists to give the OEB and stakeholders a clear view of OPG's performance during the longer term of this application. The OEB will be able to understand whether OPG is meeting operational targets and financial expectations.

5. CUSTOMER ENGAGEMENT

5.1. Overview

This section reviews the various ways in which OPG engages with the individuals, businesses and institutions that consume electricity in Ontario and considers customers when planning work and operating its generating facilities. This schedule also describes OPG's ongoing plans to expand the formal role of customer outreach in the company's business planning process.

The RRFE requires that electricity distributors work to provide services in a manner that responds to identified customer preferences. OPG does not have a direct relationship with electricity consumers, since it sells electricity wholesale into the IESO-controlled market. As a result, OPG does not perform the transactional customer activities that a distributor does. OPG does not manage customer accounts, respond to service calls, or make investment decisions that directly affect the delivery of electricity to individual customers. Nonetheless, the electricity that OPG generates – and how it generates that electricity – affects all Ontarians. In that sense, the ultimate consumers of electricity in the province are all OPG's customers.

OPG considers customers' interests in business planning. As described in this schedule, OPG engages with customers when planning projects, making operational decisions, and participating in communities.

This schedule summarizes the various forms of customer engagement that OPG executes during the course of its normal business operations, divided into three broad categories, each of which is discussed separately in this schedule:

i. Community Partnerships,
ii. Indigenous Community Relations, and
iii. Public Information and Safety Programs.

In addition to these ongoing forms of community and customer engagement, during the IR term OPG intends to expand its work to identify customers' preferences and to consider them in its business planning process. To that end, OPG plans to launch an expanded customer engagement program to help inform the company's business planning. Section 5.6 of this schedule provides more information about the company's customer engagement plans.

5.2. Community Partnerships

OPG is a major presence "on the ground" in many communities across the province. OPG coordinates with and attempts to accommodate the needs and preferences of the communities that may be affected by operational decisions or projects. OPG also works in partnership with many Indigenous communities in which the company's facilities reside.

This section describes how OPG works with communities to help ensure that the company's projects are planned and executed in a manner that reflects the preferences of local communities, and that its operations minimally affect local communities.

5.2.1. Operational Coordination

OPG considers and accommodates community feedback in various aspects of its regular operations, including the company's ongoing Nuclear Community Advisory Councils, Community Leader , and Waterway Coordination programs.

5.2.1.1. Nuclear Community Advisory Councils

OPG's Nuclear Generating Stations have a significant role to play in the Clarington and Pickering communities. OPG strives to understand host communities' concerns and to be transparent in providing residents with information about the company's nuclear facilities. To that end, OPG has established Community Advisory Councils ("CAC") for both the Darlington and Pickering generating stations.

The Nuclear CACs were established in the 1990s, and are comprised of members from a large number of sectors from across the community. CAC membership includes community associations, municipal government, health, environment, education, youth, business and members at large. CAC members live or work in the vicinity of the plants, and serve on a voluntary basis.

The CACs meet between six and eight times per year. During those meetings, the members receive briefings from OPG staff and other experts. Although meetings focus on environment, public health, safety and economic issues, the topics vary depending on the issues of interest to the community. CAC members have opportunities to question OPG and to discuss what they have heard.

The CACs are an important bridge between OPG and the communities where the company's Nuclear Generating Stations are located. It allows OPG's senior management to hear directly from members of the community, giving the community a direct connection to the company and allowing the company to better understand and respond to community questions, concerns and preferences.

5.2.1.2. Community Leader Engagement

In addition to the community engagement processes described above, OPG engages with local leaders in communities where the company's larger generating facilities are located. Engaging with community leaders helps OPG ensure that it has a clear, unbiased perspective on the issues that matter to major segments of the local community.

OPG identifies local leaders in government, business, academic, media and other sectors that reflect a spectrum of views on OPG's role in the community. Discussions may cover a number of topics, ranging from safety and environmental issues to upcoming company projects at local facilities. In order to encourage interviewees to speak frankly and comprehensively, OPG commits that any discussions will be kept confidential.

Being qualitative in nature, engagement with community leaders provides directional indication of community views from informed individuals from a spectrum of sectors and interests. OPG's senior management is able to draw upon these views when making business decisions.

5.2.1.3. Waterway Coordination

OPG's hydroelectric generating stations rely on the same waterways that many Ontarians live near, and rely on for their water supply, work and leisure. OPG operates its hydroelectric generating facilities in coordination with communities and governmental agencies to support public safety during flood events, emergencies and in the course of normal operations. For many rivers, Water Management Plans have been established to account for the needs of the various groups that use and rely on the river. OPG also modifies some of its operations at hydroelectric generating stations to accommodate other users of Ontario's waterways both on an on-going basis and for special events.

OPG coordinates its use of Ontario waterways with organizations including the Ontario Ministry of Natural Resources and Forestry, local conservation authorities, local municipalities, Indigenous communities, the Federal Department of Fisheries and Oceans, and Parks Canada. In times of extreme watershed conditions, OPG may be able to play a moderating role. In flood-prone conditions, OPG helps to manage the release of water to mitigate risks to local communities (both up-stream and down-stream from the company's generating facility, depending on the location of the flood risk). Similarly, OPG may be called upon during periods of drought to support conservation efforts and aquatic habitat.

OPG also maintains an extensive Waterway Public Safety Program to mitigate public safety risks associated with the company's facilities. Details of this program and OPG's other public safety measures are described in section 5.5 of this schedule.

OPG receives requests from users of the waterways regarding special events, such as the Royal Canadian Henley Regatta. Now in its 134th year, the regatta is one of the largest amateur rowing tournaments in North America, and it is held on Martindale Pond in St. Catherine's. In order to support the community and allow the regatta to proceed, OPG reduces flows from its DeCew Falls Generating Station for several hours per day throughout the regatta. Ramping production down and back up is not a trivial endeavour. This process requires multiple safety inspections and coordination with the community. However, OPG shares provincial waterways with customers and local communities. As such, the company takes reasonable steps to support the needs of the customers and communities with which it shares Ontario's waterways.

5.2.2. Project Planning and Execution

OPG's regulated capital projects are often significant endeavours that have the potential to affect local communities in a number of ways.

OPG's projects have a socioeconomic dimension. Just as the company's large projects can materially add to Ontario's economic growth, its projects can also have a positive effect on the local community's economy.

In addition, OPG's projects require significant logistical coordination in host communities, such as altering traffic flows or requiring safety-related restrictions on access to areas of land and waterways. Projects often require an influx of personnel, either on a temporary or permanent basis. OPG also takes measures to mitigate risk to a community's environment, archeological record or heritage sites.

In order to address these various potential effects on host communities, OPG consults with host communities throughout the planning and execution of capital projects. The elements and scale of a project-specific consultation depend on the nature of the project and its potential to affect the local community.

For example, when OPG plans to carry out sustaining capital work at a generating station, the company assesses the potential for the project to affect the local community and identifies what forms of consultation and information sharing may be required. Each project is different, so OPG makes these assessments on a case-by-case basis.

For larger projects, OPG's community outreach can be quite broad, including town hall meetings to discuss potential impacts and solicit customer input. The specific forms of outreach vary with the nature of the project, its location, and other factors. Where possible, community feedback will be taken into account and reflected in the project plan. OPG also makes use of dedicated websites for major projects, providing information and soliciting input from the widest possible audience.

The appropriate form and the extent of community engagement activities will depend on the circumstances of a given project. Not all projects require dedicated consultations; it would not be efficient or cost effective for OPG to hold town hall meetings for smaller projects that occur exclusively within OPG's facilities and have no material impact on the community. When OPG identifies a potential community impact in connection with a smaller project, such as road closures, it takes appropriate measures to inform local residents and businesses. As part of this process, OPG provides contact information for customers who may have questions or concerns.

5.3. Academic Collaboration

OPG also works with academic and other industry partners to research and promote public safety in connection with electricity generation. By collaborating and sharing existing information with academic researchers, OPG is able to promote public benefits, like flood prevention. By sharing information, OPG can promote innovation and reduce costs for researchers.

As an example, OPG collaborates with Natural Sciences and Engineering Research Council of Canada ("NSERC") Canada FloodNet, a multi-disciplinary research network that is partly funded by NSERC. FloodNet allows efficient coordination between stakeholders, connecting researchers from across Canada and pooling data from OPG and other industry and government partners. FloodNet is then able to develop enhanced flood forecast tools and flood management capacity, which ultimately reduce the damage, socio-economic impacts and human distress caused by flooding, and help protect community water systems and the environment.

5.4. Indigenous Community Relations

OPG is committed to building and growing mutually beneficial working relationships with Indigenous communities near its current and future operations. These relationships are built on a foundation of respect for the culture and customs of Indigenous peoples, and established and maintained through ongoing dialogue aimed at preserving openness, transparency and trust.

Where appropriate, OPG pursues prospective generation-related developments with Indigenous communities that can provide the basis for long-term, mutually beneficial, commercial arrangements.

OPG's practice of consultation with Indigenous communities pre-dates the statutory duty to consult. OPG's commitment to consultation has been beneficial to both the company and to Indigenous communities. By working to resolve grievances and to build relationships, OPG believes that future projects and continued operation will be able to proceed more efficiently and deliver the best outcomes for Indigenous communities, customers, and the company.

A copy of OPG's First Nations and Métis Relations Policy is included as Attachment 4.

5.5. Emergency Management and Public Safety Programs

Public safety is a critical concern for OPG. In addition to the community engagement processes described above, OPG keeps the general public informed about and prepared for emergencies and other safety-related issues through several programs.

- Public safety around OPG's dams and hydroelectric generating facilities is critical to OPG. In addition to physical safety measures (e.g., signage, fences, booms and buoys), OPG maintains a proactive dam safety communications program. The company's "Stay Clear, Stay Safe" campaign runs year-round on various media, featuring safety messages tailored to the varying risks between seasons. Designed in coordination with the Centre for Addiction and Mental Health, the campaign targets groups and activities at risk. OPG continues to work closely with the Ontario Provincial Police its public safety campaign.

A copy of OPG's recent "Stay Clear. Stay Safe." print brochure is included as Attachment 5. The campaign's television ads can be viewed online at https://www.youtube.com/user/opgvideos.

STAY
CLEAR.
STAY
SAFE.

Figure 3: The logo of OPG's waterway public safety campaign

- Each of OPG's regions has an Emergency Response Plan that is developed and continually maintained in coordination with community leaders (e.g., mayors' offices, Indigenous Communities, MPPs, fire services and other first responders). OPG meets regularly with these community leaders to review the emergency plans and to help the company's community partners conduct their own Hazard Identification and Risk Assessment processes.

- OPG also conducts annual dam safety exercises. These exercises are more than planning meetings – they involve simulated emergencies that unfold over a number of hours or even multiple days, requiring responses from OPG and other groups. For example, a simulated dam leak could require the OPP to set up barricades and road blocks while OPG's teams draw down the dam sluice gates or otherwise respond to the simulated emergency. In order to make the simulation effective, OPG may arrange to have individuals attempt to bypass barricades or otherwise complicate the emergency.

- OPG regionalizes its safety signage to help effectively communicate safety hazards to local communities. The signage in Figure 4 is an Ojibway warning used in northern communities, reading "Danger – Dam Ahead – Keep Out".

Figure 4: Ojibway Safety Signage used in Northern Communities

5.6. Customer Engagement and Business Planning

As Ontario's largest electricity generator, OPG plays an important role in the economic life of the province and in the daily lives of Ontario families, businesses and institutions, and considers customers' interests when making business decisions. Although OPG has no formal customer engagement obligations, it continues to believe that the company can best maintain the trust of its customers and host communities through business plans that reflect customers' preferences.

As discussed in Ex. A2-2-1, OPG's business planning process is currently informed by several customer-related factors, including the economic climate, trends in electricity costs and consumers' ability to pay. However, to date, the company has not conducted structured customer outreach expressly intended to inform business planning. OPG believes that a more formal customer engagement process may provide valuable insight into customers' preferences with respect to the company's priorities and plans. OPG intends to develop such a process during the IR period. OPG hopes to build on customer engagement work that other OEB-regulated companies are conducting and, where possible, may look for opportunities to collaborate with other regulated entities to engage with customers more effectively.

ATTACHMENTS

Attachment 1:	Updated Hydroelectric Total Factor Productivity Study
Attachment 2:	Hydroelectric Benchmarking Study
Attachment 3:	London Economics International, Inflation Factor Analysis for OPG's Regulated Hydroelectric IRM, December 17, 2014 and January 27, 2015 stakeholder presentations
Attachment 4:	OPG First Nations and Métis Relations Policy
Attachment 5:	"Stay Clear. Stay Safe." Brochure
Attachment 6:	London Economics International, memo responding to Pacific Economic Group's "IRM Design for Ontario Power Generation", December 22, 2016

NUCLEAR RATE SMOOTHING AND MID-TERM PRODUCTION REVIEW

1.0 PURPOSE

This evidence sets out OPG's proposals for smoothing nuclear payment amounts during the 2017 to 2021 test period, and for a mid-term review of the nuclear production forecast for the second half of the test period.

2.0 NUCLEAR RATE SMOOTHING

2.1 Overview

OPG proposes that annual nuclear base payment amounts reflect a constant 11 per cent per year rate increase during the 2017 to 2021 test period (the "smoothed rate"). OPG further proposes that a deferral account be established to record the difference between the total annual nuclear revenue requirement approved by the OEB starting in 2017 and the portion of that revenue requirement each year that produces the proposed annual 11 per cent payment amount increase when combined with the OEB approved nuclear production forecast for the corresponding year.

OPG's proposal is intended to mitigate rate impact and volatility beginning January 1, 2017 and ending when the Darlington Refurbishment Program ends (the "deferral period" as defined in O. Reg. 53/05, s. 0.1 (1)). The rate impact and volatility in the test period are driven by reduced production as Darlington units are taken out of service to be refurbished, partially offset by production at the Pickering generating station in 2021 due to the plan to extend operations, and costs associated with the Darlington Refurbishment Program ("DRP"). OPG's proposal is consistent with the amendments to O. Reg. 53/05 (the "regulation"), which came into force as of January 1, 2016 and are filed as Ex. A1-6-1, Attachment 1.

OPG proposes an 11 per cent annual smoothed rate increase for the 2017 to 2021 period, which would result in a cumulative deferred revenue requirement of approximately $1.6B[1] based on OPG's proposed revenue requirement, including reductions from the nuclear stretch factor adjustment.[2] This proposed rate increase would result in stable payment amount increases during the first five years of the deferral period, while supporting adequate levels for OPG's credit metrics.

The average residential customer bill impact of OPG's rate proposals is slightly less than 0.7 per cent annually or approximately $1.05 on a typical monthly residential customer bill each year. If OPG were to propose a constant nuclear base rate increase that recovered the entire proposed nuclear revenue requirement for the 2017 to 2021 period, that rate increase would be approximately 15 per cent per year, and the customer bill impact would be over 1.2 per cent annually or approximately $1.85 on a typical monthly residential customer bill each year.

2.2 Requirements of O. Reg. 53/05

Ontario Regulation 53/05 sets out certain processes and parameters that OPG and the OEB must follow regarding the smoothing of OPG's nuclear payment amounts during the deferral period.[3]

The regulation requires that, for each year of the deferral period, the OEB must approve a nuclear revenue requirement and must also determine a portion of that approved revenue requirement to defer.[4] The OEB is required to make this decision with the aim of stabilizing year-over-year changes in payment amounts.[5] Ontario Regulation 53/05 confirms that rate smoothing applies when determining the amount of revenue requirement to defer and that the OEB's approval of OPG's nuclear revenue requirement is not restricted by rate smoothing.[6]

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[1] Annual deferred amounts provided in Chart 4. The deferred amount excludes interest of approximately $0.28B based on OPG's annual long-term debt rates discussed in Ex. C1-1-2.
[2] Ex. N1-1-1 Table 1, line 27.
[3] O. Reg. 53/05 defines the deferral period which commences January 1, 2017 and ends when the Darlington Refurbishment Project ends.
[4] O. Reg. 53/05, s. 5.5 (1).
[5] O. Reg. 53/05, s. 6 (2), sub-para. 12 (i).
[6] O. Reg. 53/05, s. 6 (2), sub-para. 12 (iii).

Pursuant to the regulation, OPG is required to establish a rate smoothing deferral account ("RSDA") to record the difference between:

A. the total OEB-approved revenue requirement for the nuclear facilities for each year in the deferral period, and
B. the portion of the revenue requirement in (A) that is used in connection with setting payment amounts for that year.[7]

Ontario Regulation 53/05 also requires OPG to record interest on the balance of the RSDA at the OEB approved long-term-debt rate for OPG, compounded annually.[8]

Ontario Regulation 53/05 also states that the OEB must approve both the annual nuclear revenue requirements and the amount of the approved revenue requirement to be deferred on a five year basis for the first ten years of the deferral period, and then periodically as determined by the OEB.[9] The OEB must also ensure that OPG recovers the balance recorded in the deferral account on a straight line basis over a period not to exceed ten years, beginning at the end of the deferral period (the "recovery period").[10]

2.3 Rate Smoothing Considerations

While O. Reg. 53/05 establishes certain processes and parameters governing the establishment of smoothed nuclear payment amounts, the OEB is required to apply its judgement in order to set a smoothed rate that is just and reasonable. In developing its rate smoothing proposal, OPG considered the objectives of the OEB and the Renewed Regulatory Framework for Electricity Distributors ("RRFE") performance outcomes.[11] With these factors in mind, OPG developed a set of considerations that informed its rate smoothing proposal.

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[7] O. Reg. 53/05, s. 5.5 (1).
[8] O. Reg. 53/05, s. 5.5 (2).
[9] O. Reg. 53/05, s. 6 (2), para. 12 (ii).
[10] O. Reg. 53/05, s. 6 (2), para. 12 (iv)
[11] *Ontario Energy Board Act, 1998*, section 1(1), in particular, "to protect the interests of consumers with respect to prices" and "to facilitate the maintenance of a financially viable electricity industry." OPG considered the RRFE objectives of Customer Focus and Financial Performance relevant to the setting of smoothed rates.

FINANCIAL PERFORMANCE

1) Financial Viability (Leverage and Cash Flow Impacts): This criterion focuses on maintaining levels for the company's credit metrics that are adequate to support an investment grade credit rating, and ensuring sufficient cash flow to support the company's debt and interest obligations. As discussed in Ex. C1-1-2, OPG forecasts issuing $4B in long-term debt over the 2017 to 2021 period. An investment grade credit rating is critical to OPG's ability to obtain cost effective financing.

OPG used two financial metrics to gauge the potential impact of rate smoothing alternatives on the above objectives: Debt-to-Earnings Before Interest Taxes Depreciation and Amortization ("EBITDA") ratio and the Funds from Operations ("FFO") Adjusted Interest Coverage ratio. The Debt-to EBITDA ratio is used by Standard and Poor's as a measure of financial risk. A forecast Debt-to-EBITDA ratio of greater than 5.5 indicates a high level of financial risk, which could lead to a credit rating downgrade. The FFO Adjusted Interest Coverage ratio is reported in OPG's external financial filings (i.e., Management Discussion and Analysis) as an indicator of OPG's ability to support the level of debt by meeting interest obligations from operating cash flows. OPG's target threshold for this ratio is a minimum of three times. OPG's rate smoothing proposal reflects the company's best attempt to stay within the above thresholds while taking into account the other considerations

CUSTOMER FOCUS

2) Rate Stability: Ontario Regulation 53/05 provides that the OEB's rate-smoothing decisions should be made "with a view to making more stable the year-over-year changes in the payment amount."[12] In an environment of escalating revenue requirements and decreasing production, stability implies a constant rate change each year of the deferral period. Stability during the RSDA recovery period[13] would be similarly achieved using the same rate change each year. For customers, stability would allow them to better predict the impact of OPG generation on their electricity

[12] O. Reg. 53/05 Section 12(i)
[13] O. Reg. 53/05 requires recovery over a period not to exceed ten years, beginning at the end of the deferral period. OPG assumes a 10 year period given the magnitude of the peak account balance

bills. For OPG, stable rate changes would improve the predictability of cash flows at a time when the DRP and the end of commercial operations at the Pickering station are expected to reduce production while drawing on OPG's financial resources. OPG's proposal reflects a constant rate change during the first five years of the deferral period and was developed by considering rate impacts over the full deferral and recovery periods, as discussed below.

3) Long-term Perspective: As a substantial portion of the revenue requirement will be deferred for future collection, the rates set in one period will necessarily affect rates to be established in the future. These future rate effects should be considered when setting rates for the test period, in order to avoid creating abrupt rate swings in the future. Rates should be reasonable considering the entire cost deferral and recovery cycle. For example, a smoothed rate that is too low during the deferral period will result in large rate increases during the recovery period. The opposite it also true.

4) Post-Recovery Transition: A rate smoothing proposal should attempt to minimize rate transition issues on completion of RSDA recovery. OPG's costs and production are expected to be in a steady state on completion of the smoothing account recovery period (i.e., the "new normal"). The average forecast unsmoothed rate (i.e., the rate excluding any rate smoothing recoveries) from 2032 to 2036 is approximately \$120/MWh (discussed in section 2.4). Ideally, the smoothed rate at the end of the recovery period should not differ substantially from the steady state rate. This would avoid abrupt rate changes following the end of the recovery period.

5) Intergenerational Equity: The fundamental concept of smoothing is that costs incurred in one period are deferred for recovery in a future period. Ontario Regulation 53/05 supports this treatment, and provides that costs deferred for recovery will earn OPG's long-term debt interest rate compounded annually as determined by the OEB. The smoothed rate should balance the customer bill impacts of deferred recovery with the carrying costs that will ultimately be borne by customers in subsequent periods as a result of that deferral.

6) Customer Bill Impact: The four Customer Focus considerations discussed above all affect the short-term and long-term impact on customer bills. The magnitude of the customer bill impact over the full deferral and recovery period should be reasonable in the circumstances.

2.4 Rate Smoothing Alternatives

Ontario Regulation 53/05 requires the OEB to set smoothed annual payment amounts by deferring specific amounts of approved nuclear revenue requirement. In this application the OEB is setting a smoothing rate for the 2017 to 2021 period, and revenue requirement and production information for this period is required to do so. The amount of revenue requirement to be deferred each year is the net amount resulting from OEB decisions on the annual nuclear production forecasts, annual nuclear revenue requirements, and the rate of annual increase in nuclear base payment amounts. The revenue requirement and production forecasts[14] proposed in this application are summarized in Chart 1. Rate smoothing alternatives are provided at the end of this section.

Chart 1
Nuclear Revenue Requirement and Production

	2017	2018	2019	2020	2021
Proposed Revenue Requirement ($M)	$ 3,202	$ 3,223	$ 3,310	$ 3,824	$ 3,438
Forecast Production (TWh)	38.10	38.47	39.03	37.36	35.38

Ontario Regulation 53/05 requires the OEB to authorize recovery of the balance in the RSDA over a period not to exceed ten years.[15] As the magnitude of the costs being deferred is in the billions of dollars, OPG's smoothing proposal assumes RSDA recovery over the maximum ten year period.

Since rates set for the 2017 to 2021 period will necessarily have implications for the rates set later in the deferral and recovery periods, an understanding of forecast nuclear costs and

[14] Production forecast details for Darlington and Pickering are provided in Ex E2-1-1 Table 1. Revenue Requirement values are net of stretch factor reductions, as presented in Ex. I1-3-1 Table 1.
[15] O. Reg. 53/05 section 6 (2), subparagraph 12 (iii).

production for the entire deferral and recovery period is necessary context for the rate smoothing proposal. While it is not possible to forecast revenue requirement and production out 20 years with a high degree of accuracy, below OPG provides its current view of the approximate longer-term revenue requirement and production forecasts, along with indicative average rates that would result for the 2021-2036 period absent rate smoothing.

Chart 2

Five-Year Revenue Requirement, Production and Average Rate

(Absent Rate Smoothing)

	2017-2021	2022-2026	2027-2031	2032-2036
Anticipated Revenue Requirement ($BN)	$ 17.0	$ 18.1	$ 18.2	$ 17.1
Anticipated Production (TWh)	188	130	136	141
Average Rate ($/MWh)	$ 90	$ 139	$ 135	$ 121

The average rate (absent rate smoothing) for the 2032 to 2036 period reflects both the planned completion of the DRP and assumed completion of activities and costs associated with the planned end of commercial operations at Pickering. OPG believes that the average forecast 2032 to 2036 rate is a reasonable proxy for the rate that will prevail after the cost deferral and recovery cycle (i.e., the “new normal”). To minimize the impact of transitioning to non-smoothed rates after the RSDA is recovered over the assumed ten year period, the final rate in the recovery period should be similar to the post-transition rate (i.e., approximately $120/MWh forecast above).

The following chart provides a summary of the outcomes from a range of rate smoothing alternatives. The alternatives reflect a constant annual rate increase for the ten year deferral period during which the DRP is forecast to be completed, and the resulting constant annual rate change required to recover amounts deferred and carrying costs over the following ten year recovery period. For each alternative, OPG has provided the approximate peak RSDA account balance, an estimate of the total interest accumulated in the RSDA to the end of the recovery period, projected credit metrics during the deferral period, the rate change both in $/MWh and percentage terms on transition to the steady state rate following the recovery period (i.e., approximately $120/MWh), and an estimated average monthly customer bill impact over the full deferral and recovery periods.

Chart 3
Smoothing Alternatives – Outcomes

2017 - 2021 Rate Increase	12.0%	11.0%	10.0%	9.0%	8.0%
2022- 2026 Rate Increase	12.0%	11.0%	10.0%	9.0%	8.0%
2027 - 2035 Rate Increase	(6.4)%	(3.4)%	(0.3)%	2.6%	5.4%
Peak Account Balance ($B)	$2.4	$3.5	$5.0	$6.9	$9.5
2017 - 2036 Total Interest ($B)	$0.7	$1.6	$3.0	$4.5	$5.9
Interest Cost / Deferred Revenues Ratio	0.2	0.5	0.8	0.9	0.9
FFO Interest Coverage > = 3* (2017-2021) / (2022-2026)	3.7 / 6.3	3.6 / 5.3	3.5 / 4.5	3.5 / 3.9	3.4 / 3.3
DEBT to EBITDA < = 5.5* (2017-2021) / (2022-2026)	6.1 / 5.1	6.2 / 5.3	6.3 / 5.5	6.3 / 5.7	6.4 / 6.0
Transition Impact: 2037 Rate Change ($/MWh / %)	$26/MWh / 27%	$2/MWh / 2%	$(28)/MWh / (19%)	$(60)/MWh / (33%)	$(95)/MWh / (44%)
Average Bill Impact: 2017-2036 (%)	0.2%	0.3%	0.4%	0.6%	0.8%
Average Bill Impact: 2017-2036 ($ / month)	$0.24	$0.42	$0.65	$0.90	$1.16

*Weakest Ratio

2.5 Application of the Criteria and OPG's Proposal

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

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

i. 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 applied “financial viability” as a threshold criterion to identify the range of potentially acceptable rate smoothing alternatives shown in Chart 3. OPG 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).

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

iii. Post-Recovery Transition: The assessment was based on the size of the change in rates at the end of the recovery period (smaller is better) to the forecast steady state rate of approximately $120/MWh.

iv. Intergenerational Equity: The assessment was based on the ratio of total interest costs to total amounts deferred (total interest / total amounts deferred). The lower the ratio, the lower the cost of deferring revenue under that alternative. 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).

v. Customer Bill Impact: The assessment was based on average customer monthly bill impacts for the entire deferral and recovery period. Consistent with the Rate Stability criterion, the impact was determined using a constant rate increase during the deferral period (i.e., both 2017 to 2021 and 2022 to 2026) and a constant rate change during the recovery period (2027 to 2036) as identified in Chart 3. Lower customer bill impacts are better.

In OPG’s assessment, the 11 per cent smoothing is the best alternative as it was either the best or second best on four of the five considerations above, and no worse than third best on the remaining consideration. The proposed nuclear payment amounts proposed in Ex. I1-3-1 have been determined based on this level of deferred recovery. OPG therefore proposes to defer the collection of approximately $1.6B in nuclear revenue requirements for 2017 through

2021, which is the sum of the deferred revenue requirement amounts for those years shown in Chart 4.

Chart 4

OPG Proposed Deferred Nuclear Revenue Requirement[17]

	2017	2018	2019	2020	2021
Proposed Revenue Requirement ($M)	$ 3,202	$ 3,223	$ 3,310	$ 3,824	$ 3,438
Forecast Production (TWh)	38.10	38.47	39.03	37.36	35.38
Smoothed Rate ($/MWh)	$ 65.81	$ 73.05	$ 81.09	$ 90.01	$ 99.91
Smoothed Revenue ($M)	$ 2,507	$ 2,810	$ 3,165	$ 3,362	$ 3,535
Deferred Revenue Requirement ($M)	$ 694	$ 412	$ 145	$ 462	$ (97)

3.0 MID-TERM PRODUCTION REVIEW

OPG seeks approval of a mid-term production review in the first half of 2019 (i.e., prior to July 1, 2019) for:

1) an update of 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 application period (July 1, 2019 to December 31, 2021); and
2) disposal of applicable audited deferral and variance account balances (most accounts would 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 period extending beyond December 31, 2018.

3.1 Rationale for Mid-Term Review

In this application, OPG has provided a nuclear production forecast that covers the full five-year period from January 1, 2017 to December 31, 2021. The company's nuclear production forecast and forecasting process are described in detail in Ex. E2-1-1. The production forecast is based on a set of current assumptions that are challenging to meet, with the risk of

[17] Proposed Revenue Requirement per Ex I-1-1 Table 2
Forecast Production per Ex E-2-1 Table 1
Smoothed Rate determined by escalating the existing $59.29 approved nuclear payment amount from EB-2013-0321 by 11% each year
Smoothed Revenue determined by applying the Smoothed Rate to the Forecast Production
Deferred Revenue calculated as the difference between the Proposed Revenue Requirement and the Smoothed Revenue

deviations from forecast increasing into the second half of the application. OPG's mid-term review application will include the revised production forecast underpinning its latest approved business plan for the period July 1, 2019 to December 31, 2021 (the "mid-term production forecast"). The mechanics of the mid-term review proposal are discussed in section 3.2.

Substantial uncertainty exists relating to events that could result in substantial impacts on OPG's production in the latter half of OPG's five-year application. Circumstances could result in substantially higher or lower production than currently forecast. If production is higher than forecast, customer bills would be unnecessarily inflated (i.e., the higher production would result in a credit balance in the proposed Mid-term Nuclear Production Variance Account, to be refunded to customers in the next payment amount application). If production is lower than forecast, OPG may not recover its revenue requirement. Mitigating this risk benefits both customers and the company.

OPG expects that the nuclear production forecast that will be included in its future approved business plans will reflect an increased level of certainty related to events that may affect production during the second half of the test period, providing a sufficiently robust basis for setting reasonable production performance targets for the second half of the test period that would be fair to both customers and OPG.

As discussed during consultation with stakeholders, several factors make it extremely difficult to accurately forecast OPG's annual nuclear production over the five-year period covered by this application:

i. Public Policy Changes: Changes to public policy, especially the Government of Ontario's Long Term Energy Plan ("LTEP") could impact OPG's nuclear production. In particular, a change to the refurbishment schedule for future units at the Darlington generating station could materially alter OPG's production schedule within the period of this Application.
ii. Pickering Extended Operations: Canadian Nuclear Safety Commission ("CNSC") approval is still required and, as discussed in Ex. F2-2-3, OPG has not yet completed

work necessary to confirm that the Pickering units would be fit to operate beyond 2020.

iii. Execution of Darlington Refurbishment Program: If refurbishment of the first unit at Darlington is completed earlier or later than scheduled, production may vary. In addition, there is a risk that the post-refurbishment forced loss rate at Darlington may vary from OPG's current forecast. These factors have the potential to materially decrease or increase production, depending on the circumstances.

iv. Regulatory Requirements and Approvals: OPG's nuclear facilities are subject to significant regulatory oversight. Changing requirements and work required to comply with existing requirements have the potential to affect OPG's nuclear production forecast.

v. Aging Facilities: The risk of unplanned outages increases as units begin to approach their end of life, in particular for Pickering given on-going work on asset condition assessment and fuel channel work and pending CNSC licence renewals.

OPG expects that it will be better able to assess these and other risks, and their potential effect on production, at the time of the proposed mid-term review.

The mid-term review of nuclear production is also consistent with the rate-smoothing requirements in O. Reg. 53/05 and would protect both customers and OPG. The regulation requires the OEB to determine revenue requirements for the nuclear facilities for each year on a five-year basis, and to determine the portion of the approved revenue requirement to be recorded in the RSDA.[18] Subject to the OEB concluding that rates are no longer just and reasonable pursuant to Section 78.1 of the Act, the regulation does not entitle the OEB to revisit those approved revenue requirement amounts during the five years. However, while the revenue requirement must be determined on a five-year basis, no such limitation exists for the determination of production.

The production forecast is a critical element of OPG's rate-setting framework given OPG's rate structure. As noted in Ex. E2-1-1, there are a number of factors that could materially

[18] O. Reg. 53/05, sub-paragraphs 6(2)12 (i) and (ii).

impact OPG's production which are too uncertain to predict with reasonable precision. Given the relatively long term of this application and the uncertainty of nuclear production during that period, a mid-term review of nuclear production and related fuel costs for the second half of the application term (i.e., July 1, 2019 to December 31, 2021) would help address the forecast uncertainty inherent in OPG's production forecast as it looks further into the future and provides a basis to set reasonable production performance targets for the second half of the application term.

In general, it is more difficult to forecast events further in the future. This difficulty increases further when the subject matter of the forecast is inherently uncertain. Since the inception of regulation by the OEB, there have been a number of variances between OEB approved and actual production. It has proven difficult to forecast nuclear production in the past where OPG's Pickering and Darlington facilities were operating in a comparatively steady state compared to the operating circumstances that will be facing these facilities during the application period. Even with a mid-term review, the proposed ratemaking methodology will result in a significant increase in production forecast risk compared to previous applications.[19]

As discussed in Ex. A1-3-2, a completely variable rate provides a strong financial incentive to OPG to achieve or surpass the OEB approved production forecast, thereby increasing the quality of service (e.g., increased availability, reduced EFOR) provided to customers. The approved production forecast is effectively a performance target with financial rewards and penalties.

3.2 Mechanics of Mid-Term Production Review

OPG proposes to file an application to review the company's updated nuclear production forecast and associated fuel costs in the first quarter of 2019. The scope of this application would be limited to a review of OPG's nuclear production forecast for the period from July 1, 2019 to December 31, 2021, any consequential revisions to forecast fuel costs, and the disposition of audited December 31, 2018 balances in deferral and variance accounts

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[19] In previous applications, OPG's payment amounts have been based on forecast production of two years or less.

including any remaining unamortized portions of previously approved amounts with recovery periods extending beyond December 31, 2018. OPG does not propose to re-open any other elements of this Application in the mid-term review.

The application will present the impact of the production variance from July 1, 2019 to December 2021. The production variance will be the difference between: (i) the nuclear production forecast approved in this Application and, (ii) the nuclear production forecast proposed by OPG in the mid-term review application. The annual production variance will be multiplied by the net of the approved smoothed nuclear payment amount and the average fuel cost in the approved revenue requirement for the applicable year. The amounts determined above will be recorded in the proposed Mid-Term Nuclear Production Variance Account described in Ex H1-1-1.

DRIVERS OF DEFICIENCY

1.0 PURPOSE

This evidence presents the major drivers of revenue deficiency for the nuclear facilities over the 2017-2021 period as determined in Ex. I1-1-1 Table 3 and updated in Ex. N1-1-1 Attachment 2.

2.0 OVERVIEW

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

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

3.0 DRIVERS OF DEFICIENCY FOR THE NUCLEAR FACILITIES

3.1 Lower Production (51 per cent of revenue deficiency)

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

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

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

3.2 Darlington Refurbishment (20 per cent of revenue deficiency)

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

3.3 Pickering Extended Operations Enabling Costs (5 per cent of revenue deficiency)

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

3.4 Impact of Changes in Nuclear Station End-of-Life Dates on Nuclear Liabilities (6 per cent of revenue deficiency)

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

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

the Bruce B nuclear units to recognize the Province's December 2015 announcement of an updated refurbishment agreement between the IESO and Bruce Power L.P. The net increase in the revenue requirement consists of an increase related to the Bruce facilities (through a reduction in Bruce Lease net revenues) and a decrease related to the prescribed nuclear facilities.

3.5 Impact of Changes in Nuclear Liabilities Reflecting 2017 ONFA Reference Plan (-5 per cent of revenue deficiency)

On December 20, 2016, OPG filed Ex. N1-1-1 Impact Statement updating its pre-filed evidence. This update included changes to forecast costs associated with OPG's nuclear liabilities since the pre-filed evidence, reflecting the projected accounting impact of the 2017-2021 ONFA Reference Plan approved by the Province in December 2016 with an effective date of January 1, 2017. The projected accounting impact is a year-end 2016 decrease in the nuclear ARO of approximately $1.5B and a corresponding decrease in nuclear ARC. The resulting revenue requirement decrease is mainly driven by the decrease in the nuclear liabilities costs for the Bruce facilities, primarily due to the impact of the lower Used Fuel Disposal program cost estimates. The updated nuclear liabilities costs are discussed in Ex. N1-1-1 and detailed in Ex. N1-1-1 Table 6.

3.6 Remaining Depreciation and Amortization Expense (6 per cent of revenue deficiency)

Remaining nuclear depreciation and amortization expense is the change in depreciation and amortization expense excluding that related to DRP and nuclear liability costs, which are discussed above. Remaining nuclear depreciation and amortization expense for prescribed facilities (including the associated tax gross-up) is forecast to be higher over the 2017-2020 period, reflecting nuclear operations capital in-service additions to rate base. Depreciation and amortization expense declines significantly in 2021, as Pickering reaches the facility's assumed end of life date of December 31, 2020. Depreciation and amortization expense is presented in Ex. F4-1-1.

3.7 Outage OM&A Expenses (3 per cent of revenue deficiency)

Forecast nuclear outage OM&A expenses[6] are higher in the test period, primarily due to a number of planned outages in accordance with OPG's aging and life cycle management programs, in addition to and separate from the refurbishment of the Darlington units. The outage work in 2017-2019 effectively replaces two scheduled planned outages for Unit 2 in 2016 and 2019 which would otherwise have been undertaken absent Unit 2 refurbishment. In addition, Pickering's outage OM&A forecast in 2021 includes expenditures associated with a six-unit Vacuum Building Outage (planned every 12 years). Additional detail on outage activities and costs is provided in Ex. F2-4-1 and Ex. F2-4-2.

3.8 Remaining/Other OM&A Expenses (12 per cent of revenue deficiency)

Remaining/Other OM&A expenses changes in OM&A expenses that do not include DRP-related increases in OM&A, Pickering Extended Operations enabling costs or nuclear outage costs. Drivers of the increase in remaining/other OM&A include an increase in nuclear base OM&A costs due to labour costs, including escalation reflecting collective agreement provisions, as well as purchased services and new CNSC requirements. Purchased services increase to fund work programs to maintain asset reliability, address equipment aging issues and for fire hazard assessment and emergency management. New CNSC requirements related to Fitness for Duty are discussed in Ex. N1-1-1, pp. 20-21. Nuclear base OM&A costs are presented in Ex. F2-2-1 and Ex. F2-2-2. Compensation and benefits are discussed in Ex. F4-3-1.

3.9 Fuel Costs (-4 per cent of revenue deficiency)

Fuel costs discussed here exclude those related to the nuclear liabilities adjustment discussed above. The forecast decrease in fuel costs for the prescribed nuclear facilities over the 2017-2021 period reflects lower generation, as discussed above, and lower fuel bundle costs. The lower forecast fuel bundle costs are primarily due to lower cost of uranium concentrate partially offset by higher prices for conversion services and fuel bundle manufacturing. Nuclear fuel costs are discussed in Ex. F2-5-1 and Ex. F2-5-2.

[6] Other than enabling costs for Pickering Extended Operations discussed in section 3.6 above.

3.10 Other (4 per cent of revenue deficiency)

The “Other” revenue requirement driver category includes a number of factors. The two main causes of the increase in this cost driver are a decline in non-energy revenue and lower Bruce Lease net revenues (other than the impact of the 2015 nuclear liabilities adjustment and station end-of-life changes discussed in section 3.4 and the impact of the 2016 nuclear liabilities adjustment discussed in section 3.5). The decline in non-energy revenue is primarily the result of lower heavy water sales due to the depletion of inventory. Lower Bruce Lease net revenues are due to a combination of factors including lower forecast lease revenues and higher used fuel expenses. Non-energy revenue is discussed in Ex. G2-1-1 and Ex. G2-1-2. Bruce Lease net revenues are discussed in Ex. G2-2-1, as updated in Ex. N1-1-1.

The remaining costs in this category consist of a residual decrease in the cost of capital and associated tax gross-up, lower property taxes, and a residual decrease in income taxes not included in the drivers discussed above. The residual decrease in the cost of capital is mainly due to a lower allowable return on equity value published by OEB in October 2016 compared to that reflected in the EB-2013-0321 payment amounts as discussed in Ex. N1-1-1. The residual decrease in income taxes primarily reflects the impact of higher forecast cash expenditures on nuclear waste management and decommissioning, net of forecast disbursements from the nuclear segregated funds, for the prescribed nuclear facilities. Taxes are discussed in Ex. F4-2-1, as updated in Ex. N1-1-1. The cost of capital is discussed in Ex. C1-1-1, as updated in Ex. N1-1-1, as well as Ex. C1-1-2 and Ex. C1-1-3.

Chart 1: Nuclear Deficiency for 2017 - 2021 Period

Line No		($M) 2017	($M) 2018	($M) 2019	($M) 2020	($M) 2021	Reference
1	**EB-2013-0321 Average Approved 2014 & 2015 Revenue Requirement**	**2,834.0**	**2,834.0**	**2,834.0**	**2,834.0**	**2,834.0**	Note 1a
2	Revenue at EB-2013-0321 Payment Amount ($59.29/MWh)	**2,258.9**	**2,280.9**	**2,313.9**	**2,214.8**	**2,097.9**	Note 2a
3	Lower Production (line 1 - line 2)	**575.2**	**553.1**	**520.2**	**619.2**	**736.1**	
	Changes in Revenue Requirement:						
4	Darlington Refurbishment	75.7	26.9	(9.1)	528.8	559.4	Note 3a
5	Pickering Extended Operations Enabling Costs	25.6	55.3	107.1	104.3	0.0	Ex. F2-2-3 Chart 2
6	Impact of Changes in Nuclear Station End-of-Life Dates on Nuclear Liabilities	31.8	36.2	42.2	129.7	132.2	Ex. C2-1-1 Table 5, line 18
7	Impact of Changes in Nuclear Liabilities Reflecting 2017 ONFA Reference Plan	(22.9)	(32.8)	(3.7)	(84.8)	(127.0)	Ex. N1-1-1 Chart 3.2.1 line 8
8	Remaining Depreciation and Amortization Expense *(other than lines 4, 6 & 7)*	99.9	136.9	143.7	132.4	(141.7)	Note 4a
9	Outage OM&A Expenses *(other than line 5)*	75.8	59.8	29.9	12.2	11.8	Note 5a
10	Remaining/Other OM&A Expenses *(other than lines 4, 5, 6, & 7)*	81.8	103.5	164.4	182.2	194.6	Note 6a
11	Fuel Costs *(other than lines 6 & 7)*	(49.8)	(47.8)	(37.5)	(41.4)	(56.7)	Note 7a
12	Other	50.1	55.5	48.7	42.3	51.8	Note 8a
13	**Total Change in Revenue Requirement** (lines 4 through 12)	**367.8**	**393.5**	**485.8**	**1,005.8**	**624.4**	
14	**Total Revenue Deficiency** (line 3 + line 13)	**943.0**	**946.6**	**1,005.9**	**1,625.0**	**1,360.6**	

Notes

1a Ex. I1-1-1 Table 2, Line 11

OEB APPROVED 2014	OEB APPROVED 2015	AVERAGE
2,790.4	2,877.6	2,834.0

2a

REDUCED PRODUCTION	2017	2018	2019	2020	2021
Test Period Production (Ex. E2-1-1 Table 1, line 3, cols. (e) to (i)) **(TWh)**	38.1	38.5	39.0	37.4	35.4
Nuclear Base Payment Amount (EB-2013-0321 Payment Amount Order, App D, line 3) **($/MWh)**	$59.29	$59.29	$59.29	$59.29	$59.29
Forecast Revenue ($M)	2,258.9	2,280.9	2,313.9	2,214.8	2,097.9

Note	Driver of Revenue Requirement Change	EB-2016-0152 *(references shown are to EB-2016-0152 exhibits)*		EB-2013-0321 *(references shown are to EB-2016-0152 exhibits unless otherwise noted)*	
3a	**Impact of Darlington Refurbishment Program (DRP)**	**DRP revenue requirement impact comprises:**		**DRP revenue requirement impact comprises:**	
		OM&A Expenses	Ex. F2-1-1 Table 1, line 5, cols. (e) to (i)	OM&A Expenses	Ex. H1-1-1 Table 11a, Table to Note 1, col. (a), line 4a
		Cost of Capital	(Ex. B3-1-1 Table 1, line 9, cols. (f) and (i) and line 16 (cols. (c),(f) and (i)) x Ex. C1-1-1 Tables 1-5 col. (c), line 6) + ((Ex. B3-1-1 Table 1, line 9, cols. (f) and (i) and line 16 (cols. (c),(f) and (i)) x Ex. C1-1-1 Tables 1-5 col. (b), line 5) x (Ex. N1-1-1 Chart 3.4, line 6 - Ex. C1-1-1 Tables 1-5 col. (c), line 5)	Cost of Capital	Ex. H1-1-1 Table 11a, Table to Note 6, col. (c), line 3b
		Depreciation	Ex. F4-1-1 Table 2, line 2, cols. (e) to (i)	Depreciation	Ex. H1-1-1 Table 11a, Table to Note 6, col. (c), line 5b
		Income Tax	[(Ex. B3-1-1 Table 1, line 9, cols. (f) and (i) and line 16, cols. (c), (f) and(i) x Ex. C1-1-1 Tables 1-5, col. (b), line 5 x Ex. C1-1-1 Tables 1-5, col. (c), line 5) + Ex. F4-1-1 Table 2, line 2, cols. (e) to (i), less Ex. F4-2-1 Table 3b, Note 3 + ((Ex. B3-1-1 Table 1, line 9, cols. (f) and (i) and line 16 (cols. (c),(f) and (i)) x Ex. C1-1-1 Tables 1-5 col. (b), line 5) x (Ex. N1-1-1 Chart 3.4, line 6 - Ex. C1-1-1 Tables 1-5 col. (c), line 5)] x 25% / (1-25%)	Income Tax	(Ex. H1-1-1 Table 11a, Table to Note 6, col. (c), lines 4b+5b-6b) x 25% / (1-25%)
4a	**Impact of Other Depreciation and Amortization Expense**	**Impact of Other Depreciation and Amortization Expense is calculated as:**		**Impact of Other Depreciation and Amortization Expense is calculated as:**	
		Total Depreciation and Amort.	Ex. N1-1-1 Table 1, line 17, cols (a) to (e)	Total Depreciation and Amort.	Ex. I1-1-1 Table 2, line 4, (cols. (a)+(b))/2
		Less: Darlington Refurbishment Depreciation	Ex. F4-1-1 Table 2, line 2, cols. (e) to (i)	Less: Darlington Refurbishment Depreciation	Ex. H1-1-1 Table 11a, Table to Note 6, col. (c), line 5b
		Less: Nuclear Liabilities Impact Reflecting 2017 ONFA Reference Plan	Ex. N1-1-1 Table 6, line 1, cols. (a) to (e) less cols. (f) to (j)		
		Less: Nuclear Liabilities Impact of 2015 Station Life Changes	Ex. C2-1-1 Table 5, line 1, cols. (a) to (e) less cols. (f) to (j)		
5a	**Increase in Outage OM&A Expenses**	**Outage OM&A expenses are calculated as:**		**Outage OM&A expenses are calculated as:**	
		Total Outage OM&A	Ex. F2-4-1 Table 1, line 7, cols. (e) to (i)	Total Outage OM&A	EB-2013-0321: Ex. F2-4-1 Table 1, line 6 (cols. (e)+(f))/2
		Less: Pickering Extended Operations Enabling Costs (Outage OM&A)	Ex. F2-2-3 Chart 2, line 5		
6a	**Other OM&A Expenses**	**Other OM&A Expenses are calculated as:**		**Other OM&A Expenses are calculated as:**	
		Total OM&A Expenses	Ex. N1-1-1 Table 1, line 15, cols. (a) to (e)	Total OM&A Expenses	Ex. I1-1-1 Table 2, line 2 (cols. (a)+(b))/2
		Less: Outage OM&A Expenses	As calculated in Note 5a	Less: Outage OM&A Expenses	EB-2013-0321: Ex. F2-4-1 Table 1, line 6 (cols. (e)+(f))/2
		Less: Pickering Extended Operations Enabling Costs	Line 5		
		Less: Nuclear Liabilities Impact Reflecting 2017 ONFA Reference Plan	Ex. N1-1-1 Table 6, line 3, cols. (a) to (e) less cols. (f) to (j)		
		Less: Darlington Refurbishment OM&A Expenses	Ex. F2-1-1 Table 1, line 5, cols. (e) to (i)	OM&A Expenses	Ex. H1-1-1 Table 11a, Table to Note 1, col. (a), line 4a
		Less: Nuclear Liabilities Impact of 2015 Station Life Changes	Ex. C2-1-1 Table 5, line 3, cols. (a) to (e) less cols. (f) to (j)		
7a	**Decrease in Fuel Costs**	**Fuel Costs are calculated as:**		**Fuel Costs are calculated as:**	
		Total Fuel Expense	Ex. N1-1-1 Table 1, line 16, cols. (a) to (e)	Total Fuel Expense	Ex. I1-1-1 Table 2, line 3 (cols. (a)+(b))/2
		Less: Nuclear Liabilities Impact of 2015 Station Life Changes	Ex. C2-1-1 Table 5, line 2, cols. (a) to (e) less cols. (f) to (j)		
		Less: Nuclear Liabilities Impact Reflecting 2017 ONFA Reference Plan	Ex. N1-1-1 Table 6, line 2, cols. (a) to (e) less cols. (f) to (j)		
8a	**Other**	**Impact of Other is calculated as:**		**Impact of Other is calculated as:**	
		Total Revenue Requirement	Ex. N1-1-1 Table 1, line 24, cols. (a) to (e)	Total Revenue Requirement	Ex. I1-1-1 Table 2, line 11 (cols. (a)+(b))/2
		Less: Revenue requirement change factors identified	Notes 3a to 7a + Line 5 + Line 6 + Line 7	Less: Revenue requirement change factors identified	Notes 3a to 7a

TESTIMONY OF DR. PATRICIA D. GALLOWAY PRESIDENT AND CHIEF EXECUTIVE OFFICER, PEGASUS GLOBAL HOLDINGS, INC. ON BEHALF OF ONTARIO POWER GENERATION INC. RE: EB-2016-0152 – 2017-2021 PAYMENT AMOUNTS APPLICATION BEFORE THE <u>ONTARIO ENERGY BOARD</u>

JULY 2016

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List of Acronyms & Abbreviations

AACE International	AACE
Actual Cost	AC
Board of Directors	Board
Budget Variance	BV
Change Control Board	CCB
Coordination & Control Schedule Level 2	CCL2
Cost Breakdown Structure	CBS
Cost Performance Index	CPI
Cost Variance	CV
Critical Path Method	CPM
Curriculum Vita	C.V.
Darlington Refurbishment Program	DRP, or “Program”
Earned Value	EV
Earned Value Management	EVM
Engineering, Procurement, and Construction	EPC
Facilities and Infrastructure Projects	F&IP
First in a While	FIAW
First of a Kind	FOAK
Integrated Reporting Plan	IRP
National Association of Corporate Directors	NACD
Ontario Power Generation Inc.	OPG
Operating Experience	OPEX
Project Planning and Controls	PP&C
Pegasus Global Holdings, Inc.	Pegasus-Global
Planned Value	PV

Program Change Control Board...PCCB

Program Evaluation and Review Technique... PERT

Program Integrated Master Schedule..PIMS

Program Management Office.. PMO

Project Management Institute .... PMI

Project Management Professional.. PMP

Readiness to Execute ....RTE

Release Quality Estimate .... RQE

Resource Breakdown Structure...RBS

Retube and Feeder Replacement...RFR

Risk Management and Oversight...RMO

Royal Institute of Chartered Surveyors... RICS

Safety Improvement Opportunities..SIO

Schedule Performance Index .... SPI

Schedule Variance ....SV

U.S. Government Accountability Office... GAO

Work Breakdown Structure .... WBS

EXECUTIVE SUMMARY

Sections I-III of my testimony begins with an introduction of my background, qualifications and experience relevant to the engagement, followed by the purpose and summary of my testimony that identifies the scope of the assessment and overall conclusions, and lastly provides educational information on megaprojects and megaprograms, including organization of such projects, the policies and procedures commonly used, project controls, pre-execution planning, and cost treatment of megaprograms in a regulatory environment.

Section IV provides the detailed findings and conclusions of my assessment of the Darlington Refurbishment Program (DRP or Program). These findings and conclusions are specifically identified by the following corresponding subsections as they appear in my testimony:

A. DESCRIPTION OF THE DARLINGTON REFURBISHMENT PROGRAM

- The DRP is considered a megaprogram by every measure generally used within the industry.
- OPG is treating the DRP as a First-of-a-Kind (FOAK) program, which is appropriate in my opinion.
- Specific FOAK and First-in-a-While (FIAW) work has been elevated as a key risk and factored into the probabilistic modeling for the $12.8B estimate.[1]
- OPG is utilizing a multi-prime contractor model, with OPG serving as the integrator between the prime contractors and having responsibility for the entire Program.
- OPG anticipates each unit outage to have a duration of 37 to 40 months, with an overall duration of 112 months for the complete refurbishment of all four reactors.

B. ORGANIZATION AND PEOPLE

[1] The $12.8B estimate includes $2.4B in interest and escalation.

- OPG is using a strong matrix organization comprised of full-time project managers with considerable authority and full-time functional support staff, which I consider appropriate.
- The content and scope of OPG's program and project management plans is consistent with industry best practices and other megaprojects and megaprograms I have reviewed.
- OPG sought to find the most qualified individuals in the industry to manage the Program and I found that the individuals assigned to the Program are qualified and competent.
- 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.
- The Program Management Organization and Staff decisions were reasonable and in accordance with good utility practice.

C. POLICIES AND PROCEDURES

- OPG's policies and procedures are exemplary in their thoroughness and alignment with other individual policies and procedures and industry best practices.

D. PROJECT CONTROLS

- Project controls are managed from both a program and project-level, with appropriate project controls systems in place.

1. ESTIMATING AND COST MANAGEMENT

  - OPG's estimating process and basis of estimate align with industry best practices, with appropriate adaptations to account for the uniqueness of the Program.

- Due to the FOAK nature of the DRP, benchmarking was largely tied to OPG's operating experience and subject matter expertise, but also included available cost data from other refurbishment projects.
- The $1.7B of contingency included in the estimate is reasonable, and based on a thorough risk assessment and Monte Carlo analysis, utilizing a P90 confidence level.
- There is no specific confidence level considered as a best practice, but using a P90 confidence level provides OPG with a high probability of completing the Program within the $12.8B estimate.
- OPG's cost management procedures align with industry standards for program financial monitoring and control.
- OPG established appropriate processes and oversight for the management of contingency.
- OPG has procedures and processes in place to effectively monitor and capture actual costs and evaluate performance against the physical work completed, similar to or beyond what I have observed on other megaprograms.

2. SCHEDULE MANAGEMENT

- OPG ensures that contractors prepare schedules in accordance with OPG's policies, which are reviewed and aligned to the Program Integrated Master Schedule (PIMS).
- Schedule development activities and the level of detail developed at this time is consistent with what I have observed on other megaprograms.
- OPG's selection of a P90 confidence level for the Unit 2 schedule is reasonable and in accordance with the robust risk analyses that were performed.

- It is typical for megaprograms, such as the DRP, to be managed on a planned duration that is less time than reflected in the high-confidence schedule.
- 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.

3. RISK MANAGEMENT

- OPG undertook a number of activities in its identification of key risks to the Program and development of processes in order to manage those key risk factors.
- OPG's risk management processes is typical of what I would expect to find in a megaprogram such as the DRP and utilizes the fundamental steps of: planning; identification; assessment; treatment; and, monitoring and control.
- OPG identified key risk areas from major themes of risk and incorporated these into the risk registers, with risk mitigation plans developed for the identified risks.
- OPG appropriately took into account lessons learned from other refurbishment projects, other nuclear projects, and other megaprojects and megaprograms.
- OPG's cost and schedule contingency development aligns with industry standards through identifying risks, estimating the probability of occurrence and impact, considering risk responses, addressing cost and schedule dependency, assessing overall outcomes through Monte Carlo simulations, and estimating and evaluating contingency.
- OPG has identified those risks that could potentially impact the Program and instituted practices in accordance with industry standards that allow OPG early identification of emerging risks to quickly implement mitigation plans.

4. REPORTING MANAGEMENT

- OPG has established a repository for metrics and reporting data, including a comprehensive and tiered metrics infrastructure.
- OPG has developed an Integrated Reporting Plan (IRP) to communicate how information and data is distributed on the Program.
- Performance and progress will be measured through Earned Value Management (EVM) techniques, which is typical within the construction industry.
- The types of reports that OPG is and will be using are what I would expect to see on a megaprogram such as the DRP.

E. PROGRAM EXECUTION

- The Facilities and Infrastructure Projects (F&IP) and Safety Improvement Opportunities (SIO) were not necessarily completed per the initial planned schedule and estimate, however, I did not find any fundamental issues that would impact the Program execution and there is no impact to the Breaker Opening milestone.
- Many of the F&IP and SIO were executed under the pre-existing Projects and Modifications organization before the DRP organization was in place and did not use the “gated process” that will be used for the DRP execution.
- OPG’s decision to substantially complete Unit 2 before starting Unit 3 will allow for effective implementation of lessons learned from Unit 2.
- The DRP development is at a point in its execution where I would expect an owner to be in a megaprogram at this stage of execution.

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Dr. Patricia D. Galloway. My business address is 1750 Emerick Road, Cle Elum, Washington 98922.

Q. What is your occupation?

A. I am the President and Chief Executive Officer of Pegasus Global Holdings, Inc. (Pegasus-Global), a management consulting firm that provides services to the energy and infrastructure industries globally, specifically focusing on megaprojects and megaprograms. I am the Director of this engagement for Pegasus-Global.

Q. Please summarize your educational background and professional experience.

A. My qualifications and experience are contained in my curriculum vita (C.V.) attached as **Exhibit No. PG-1**. In summary, I received a doctorate in Infrastructure Systems (Civil) Engineering from Kochi University of Technology in Kochi, Japan in 2005, a Master's in Business Administration from the New York Institute of Technology in 1984, and a Bachelor's of Civil Engineering from Purdue University in 1978. I have over 38 years of experience in the construction and utility industries. I have performed extensive work on behalf of both public and private sector clients, on a wide-range of complex, global engagements involving the construction, engineering, and procurement of megaprojects and megaprograms. I have an extensive background in engineering, construction, and project management, including project controls and scheduling. I have been involved with pre-design, engineering, procurement, construction, and commissioning work for large complex projects like the Darlington Refurbishment Program (DRP, or Program). This work includes significant experience in management decision making, governance evaluations, estimate review and evaluation, contract risk reviews, contract strategy, bidding and bid solicitation for such projects, procurement, design change review, constructability reviews, project controls, schedule resource loading and activity evaluation, cost control, progress reporting, quality assurance and control, startup and operations, commissioning, testing and maintenance. I have worked on engineering and construction projects in over 60 countries. I am a licensed Professional Engineer currently in 15 U.S. States, Manitoba, Canada, and Australia. I am a certified Project Management Professional (PMP) by the Project Management Institute (PMI) and a Certified Quantity Surveyor in the fields of Project Management and Risk Management by the Royal Institute of Chartered Surveyors (RICS). I hold a Certificate in Dispute Resolution from Pepperdine Law School (Straus Institute), a Diploma in International Arbitration from Oxford (CIARb), and a Certificate in Director Education from the National Association of Corporate Directors (NACD) and have also served on several corporate boards for both for-profit corporations and non-profit corporations. I also served on the National Science Board, appointed by President Bush and Senate confirmed, from 2006-2012, having served as its Vice Chair from 2008-2010.

Q. What types of power plants have you worked on over your career?

A. My power plant experience includes work on over sixty power plants, the majority being nuclear units, also including coal, natural gas, IGCC, hydro, waste-to-energy, geothermal, solar, and wind power. My full work experience is described in my C.V., which I have attached as **Exhibit No. PG-1** to my testimony.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. Pegasus-Global was engaged by Torys LLP to provide an independent and objective assessment of the degree to which Ontario Power Generation Inc.'s (OPG) plan and approach to the execution of the DRP, including the processes in place for management of costs and schedule, program controls and its application of any contingency, are consistent with the way other megaprojects and megaprograms of similar magnitude, scale, and complexity have been carried out.

Q. Can you summarize how you conducted your review?

A. Yes. Pegasus-Global began its evaluation with a review of the organization established to manage and oversee the design and construction of the Program. We then reviewed the policies, procedures, and other relevant documents used in the planning and execution of the Program. In general, this included evaluating the governance, organizational structure, project controls, estimate, contingency, and schedule, and pre-execution planning of the Program. Once familiar with the processes, policies, and procedures in place and the current status of the Program, I led our team through interviews with key personnel at OPG who have responsibility for the execution and oversight of the Program to gain additional understanding of how key personnel plan to implement the processes, policies, and procedures in place to execute the Program.

Q. Can you summarize the findings of your assessment?

A. Yes. Based on the review of OPG's governance, policies and procedures, and project controls developed and in use for the Program, and interviews conducted with OPG personnel, I found that OPG has reasonably and prudently prepared for its execution of the DRP. My summary findings include:

- OPG's approach for executing the Program is consistent with the approach typically used on other megaprograms and in several areas exceed what I have seen on other megaprograms of similar magnitude, scale, and complexity.
- It is my opinion that the extensive pre-execution planning that was undertaken places OPG in a favorable position to have successful execution of the Program. This pre-execution planning includes: the incorporation of lessons learned from Darlington and other nuclear projects including Point Lepreau Nuclear Generating Station, Bruce Nuclear Generating Station, Pickering Nuclear Generating Station, Vogtle Electric Generating Plant, Watts Bar Nuclear Generating Station, as well as non-nuclear megaprojects such as the London Olympics and Heathrow International Airport; the use of industry best practices for development of the Release Quality Estimate (RQE); and, the policies, procedures, and project control tools that were developed and in use for Program execution.
- 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.

III. BACKGROUND INFORMATION

A. MEGAPROJECTS AND MEGAPROGRAMS

Q. Can you define what is meant by a construction megaproject?

A. Yes. Megaprojects are generally defined within the industry as very large-capital investment projects (costing more than $1B USD) that attract a high level of public attention or political interest because of substantial direct and indirect impacts on the community, environment, and companies that undertake such projects.[1] Other attributes of a megaproject include:

- execution of an engineered facility or structure which is complex or unusual;
- an extended execution schedule (greater than four years measured from initial concept development to final completion);
- multiple equipment and material suppliers;
- multiple specialty trade contractors;
- multiple project stakeholders/investors; and,
- multi-national party stakeholder involvement.

Q. Why is the distinction between a construction megaproject and a typical construction project important when assessing the management organization and tools to manage the megaproject?

A. Challenges that one faces on a typical construction project are orders of magnitude less challenging than one faces on a megaproject. Lack of a sound contextual basis against which to examine and judge the decisions made and actions taken by management during the execution of a construction project can lead to findings, conclusions and opinions which are inaccurate measures of the reasonableness or prudence of those management decisions and actions. Thus, one needs to understand the context of executing a megaproject when evaluating decisions and actions.

Q. Are all megaprojects the same?

A. No. The technological complexities of megaprojects, in and of themselves, mean that each megaproject presents unique challenges, any of which may have a direct bearing on the context within which the management of a project should be examined and judged. Because of the size, duration, and complexity of any megaproject, establishing the context within which the management and execution of that project should be examined for reasonableness or prudency must be individually set to reflect the unique factors which existed during the execution of that project. This often includes a lack of suitable projects from which to benchmark against, as each megaproject features its own complexities and environment in which it is executed.

Q. Are megaprojects more "complex" than a typical construction project?

A. Yes. Actual management of a megaproject is in itself more complex than the management of a typical construction project. For example, in a megaproject there is simply not a "one-size-fits-all" or "best" methodology for allocating or contracting for the numerous different sub-scopes of work required in a megaproject. The sheer size and complexity of most megaprojects generally results in an execution methodology that involves multiple delivery methodologies and contracting approaches. For example, the specialty trade elements of a process or power generation megaproject may in themselves cost more and take longer than the average construction project, requiring the use of multiple specialty trade contractors, each working on an element of the whole and each under a different tailored contractual agreement. A typical construction project may hire one specialty trade contractor to execute the entire scope of that specialty work; on a megaproject, management will have to work with multiple contractors in order to gain sufficient resources to execute that trade specialty scope of work.

Q. What is the difference between a megaproject and a megaprogram?

A. A megaproject is one large and complex project with all the attributes I have previously discussed. A megaprogram still possesses all the same attributes as a megaproject, but is comprised of multiple individual projects, many of which may constitute a megaproject on its own.

Q. Given the unique circumstances of a megaprogram and recognizing the stresses that accompany those circumstances, how does the management of a megaprogram differ from that of typical construction projects?

A. The greatest difference in managing a megaprogram from a typical construction project lies in management's willingness to understand and accept that conditions will change. On megaprojects, and particularly megaprograms, it is important for the owner to acknowledge that even with the best forecast in place, it is still a forecast, and over the extended duration of execution, factors can and will change that may challenge the original forecast. Management and control approaches, processes, procedures and systems must be flexible and adaptable to these changing conditions. Ultimately, megaprogram management relies on the ability to adjust repeatedly to a myriad of competing forces to maintain the greatest possible control over the project environment as it evolves.

B. ORGANIZATION OF MEGAPROGRAMS

Q. What type of organizational or management structures do megaprograms utilize?

A. Typically, megaprograms utilize a matrix type of organization, which provides “checks and balances” to ensure adherence to risk, cost, schedule, and quality. When properly implemented, matrix organizations facilitate flexibility and adaptability needed to adapt and respond to changing conditions. A matrix organization can be quite effective in adjusting repeatedly to a myriad of competing forces to maintain the greatest possible control over the program environment as it evolves.

Q. What is a “matrix organization”?

A. Generally, a “matrix organization” is an organizational structure in which project managers share responsibility with functional managers for assigning priorities and directing the work of persons assigned to the program. For example, a project controls lead may be assigned to a project manager for execution of a given project. Under a matrixed arrangement, the project controls lead will bring specific knowledge to perform given tasks on a project under a particular project manager (e.g. cost estimating and forecasting), while still maintaining a reporting relationship with the project controls manager.

C. POLICIES AND PROCEDURES

Q. What is the importance of having a good set of policies and procedures in place before executing a megaprogram?

A. Policies and procedures serve as the foundational documents from which a megaprogram is managed and controlled. They provide guidance for implementing effective project controls, which in turn provide senior management with the information necessary to make informed decisions on the program.

Q. How do the policies and procedures provide guidance for effectively executing a project?

A. It begins with a project charter, which creates a formal record of the existence of the program, defines the overall scope of work, and provides senior management a mechanism to formally accept and commit to the program.[2] From there, program management plans and project management plans support the framework of project controls during execution by describing the functional support to the program (program management plan) and how the specific aspects of a project within the program will be planned, executed, monitored, controlled, and closed (project management plan). Depending on the needs of the program or project, further topic-specific plans may be developed and implemented to provide additional guidance during execution (e.g. schedule management plan, cost management plan, risk management plan, etc.).

Q. How can it be determined if a policy and procedure is adequate?

A. There are a variety of project management and construction industry organizations and government bodies that have written extensively as to recommended practices, suggested guidelines, and other advice as to what constitutes best practices in project and program management. Aspects of these practices and guidelines detail the expected requirements of planning, executing, and controlling a project or program and can be compared to the policies and procedures in place by an organization to determine if the requirements are being addressed.

During execution, senior management, in its oversight role, will have first-hand insight into if the intent of the policies and procedures is being met through the reporting information it regularly receives. In addition, as a regular practice, organizations typically implement audits of specific aspects of a project or program to ensure the requirements are being met. These audits can be conducted by the internal audit group of the organization and/or by a third-party group.

Q. Do policies and procedures evolve during the execution phase?

A. Yes, when there is an identified need to expand, refine, or otherwise revise an aspect of project controls, the related policies and procedures will be updated to reflect these changes. Construction projects, especially megaprojects, are inherently dynamic with a variety of influences both inside and outside the project that may adjust the project controls needs. Progressive elaboration of the policies and procedures allows for a continually improved process to manage and oversee the execution based on the actual conditions of the project or program.

D. PROJECT CONTROLS

Q. What are "project controls"?

A. "Project controls" is a general term of art within the construction industry denoting the systems used by management to enable it to measure progress and performance, assess remaining work, and report the current status of specific aspects of a project, an entire project, or a program of projects. The most common aspects of project controls include: cost management; schedule management; risk management; and, reporting management. These primary project controls are most intertwined with project performance as to the physical execution of the project.

1. ESTIMATING AND COST MANAGEMENT OF MEGAPROJECTS/MEGAPROGRAMS

Q. Why are cost estimates important for the Owner and other stakeholders?

A. Cost estimates allow the owner and other stakeholders to obtain a summation of the individual cost elements of a project or program to estimate the future (or completed) costs, based on the information available at the time of the estimate. During execution, the cost estimate serves as a baseline against which program management can measure performance and identify possible trends that management uses for decision-making relative to program execution.

Q. Would you please explain the applicable industry standards for cost estimating?

A. Many government bodies and project management or construction industry groups have written at great length about how to properly prepare and develop a cost estimate. Common themes reappear across these groups constituting best practices in estimating. For example, the U.S. Government Accountability Office (GAO) has a twelve-step guide to estimating:[3]

1. Define estimate's purpose;
2. Develop estimating plan;
3. Define program characteristics;
4. Determine estimating structure;
5. Identify ground rules and assumptions;
6. Obtain data;
7. Develop point estimate and compare it to an independent cost estimate;
8. Conduct sensitivity analysis;
9. Conduct risk and uncertainty analysis;
10. Document the estimate;
11. Present estimate to management for approval; and,
12. Update the estimate to reflect actual costs and changes.

Similarly, AACE International (AACE, formerly known as the Association for the Advancement of Cost Engineering) summarizes the cost estimating process as including: *"...planning for the estimate, quantifying scope, applying cost to the scope, pricing of the project, reviewing, validating, and documenting the estimate."*[4]

Each aspect of developing an estimate has recommendation and guidelines from the various industry-recognized sources that further provide guidance to proper estimate development.

Q. What is a 'basis of estimate'?

A. Essentially, a basis of estimate documents an understanding of what the estimate means, from its scope, the way it was developed, its assumptions, its expected accuracy and confidence levels, as well as inclusions and exclusions to the estimate.[5]

Q. Are there different levels of cost estimates as defined in the industry which provide for an expected accuracy range?

A. Yes. AACE has defined five classes of estimates based on the various estimate characteristics (maturity level of project definition deliverables, end usage, estimating methodology, expected accuracy range, and effort to prepare estimate). The maturity level of project definition deliverables (e.g. scope definition, plans and schedules, drawings, calculations, etc.) is the primary characteristic in determining the class of estimate, as it relates to the quality and completeness of the information available to the estimators.[6]

Q. Are the AACE estimate classification recommended practices in general use within the power industry?

A. Yes. It would be unusual to find a large, complex power project that did not utilize the AACE estimate classification recommended practices, and other AACE estimating guidelines, during development of the project estimate. AACE supports the usage of its recommended practices within the power industry with its development of industry-specific estimate classification recommended practices, such as for Engineering, Procurement, and Construction (EPC) work in the process industries (Recommended Practice No. 18R-97) and the hydropower industry (Recommended Practice No. 69R-12). However, even with its common usage and acceptance within the power industry, AACE noted, *"It is understood that each enterprise may have its own project and estimating process and terminology, and may classify estimates in particular ways."*

AACE added that its cost estimate classification system, *"provides a generic and generally-acceptable classification system that can be used as a basis to compare against."*[7]

Q. How is estimating a megaprogram different than estimating a typical linear project?

A. With most linear projects, the scope is confined to an individual project, typically the type of project that has been executed in the past by an organization (e.g. new transmission lines, pipelines, etc.) and is generally executed in a "point a" to "point b" trajectory, with little outside influence. On a megaprogram, the estimate is comprised of multiple projects that have varying degrees of interdependency with one another, often involving a multitude of disciplines. As a result, understanding the interfaces between the projects within a megaprogram is paramount to developing a sound estimate.

Q. What is meant by a 'confidence level'?

A. A confidence level reflects the probability that the actual result of an estimate or schedule will be more favorable than the estimated amount or duration. Confidence levels are typically generated through probabilistic risk modeling, often using Monte Carlo analysis and simulations that represent probabilities, not certainty.

Q. What is a Monte Carlo analysis?

A. A Monte Carlo analysis is a risk quantification technique that uses a mathematical simulation to forecast the probability of completing the project on time or within budget. The analysis takes a range estimate for each project task and then generates a random number within that range for each task. The computer software performs this thousands of times during a simulation run. The modeling requires an identification of a probability for each critical item relative to the probability of occurrence and probability of impact if it occurs, along with the monetary and time impact. This modeling results in many iterations being run to generate a cumulative probability distribution curve for a complete estimate. The probability factors that are in the Monte Carlo simulations are commonly 30%, 50%, and 90%, meaning that there is a corresponding likelihood of an underrun on the estimate, and expressed as "P30", "P50", and "P90". For example, with a P50 confidence level, there is an equal chance (50%/50%) of an underrun or overrun. The Monte Carlo analyses take the uncertainty of cost or duration estimates into account. By utilizing a higher confidence number (e.g. P90), the owner and stakeholders reduce a significant amount of risk due to cost overruns. This is accomplished by utilizing a contingency amount that corresponds to the high confidence number selected in order to account for those identified risks, should they emerge.

Q. How do confidence levels differ from a point estimate?

A. A point estimate provides the value most likely to be realized on a project, given the information available at the time it was developed. A confidence level, on the other hand, provides additional information in identifying the underlying uncertainty of the estimate by providing a range of possible costs based on a specified probability level. For example, a project with a point estimate of $100 million could produce a range of $80 million to $120 million at a P90 confidence level.

Q. What are the reasons for selecting a higher or lower confidence level?

A. Selection of a confidence level is primarily reflective of the risk appetite of the owner. If the owner wishes to reduce the risk of overrunning the estimate, using a higher confidence level reduces the likelihood of a budget overrun and provides provisions for risks unknown at the time of the estimate, but likely to appear as the project progresses. On a megaprogram, given the extended duration for execution and increased complexities compared to a typical project, it is common for a high confidence level to be selected as it provides more assurance that the estimate will be adequate for the duration of the program.

Q. What are the general objectives of cost management?

A. In general, cost management involves planning, managing, and controlling costs to help facilitate a project being completed within its approved budget.

Q. Are there industry standards relative to how owners apply cost management on megaprojects and megaprograms?

A. Yes. As PMI notes, cost management begins with development of the policies, procedures, and processes to be used during execution.[8] Cost estimating allows the owner to identify the expected costs of the individual components of the project, based on the information known at the time of the estimate, and facilitates the establishment of a control or baseline budget.[9] During execution, cost management focuses on monitoring the status of the project relative to the budget. This is typically accomplished by comparing actuals to the estimate or plan, evaluating metrics (i.e. earned value), and trending and forecasting to predict future values based on current performance.[10] These tools provide management with necessary information as to the status of the project, allowing management to make informed decisions.

Q. What is the purpose of contingency?

A. Owners establish contingency levels based on an acceptable risk level, degree of uncertainty, and the desired confidence levels for meeting baseline requirements. When used to absorb the impacts of uncertainty, the contingency is a form of risk mitigation.[11] AACE provides that contingency is *"An amount 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."*[12] AACE also identifies that contingency typically covers such uncertain "items, conditions, or events" as: planning and estimating errors and omissions; minor price fluctuations; design developments and changes within the scope; and, variations in market and environmental conditions. In summary, contingency typically falls into one of three categories: 1) cost estimating uncertainty; 2) schedule estimating uncertainty; and/or, 3) discrete risks. Contingency typically excludes: major scope changes; extraordinary events (e.g. major strikes, natural disasters); management reserves; and, escalation or currency effects. Generally, contingency is expected to be expended during the execution of a project or program as the uncertainties manifest.[13]

Q. What is the purpose of management reserves?

A. Unlike contingency, which covers identified, but not yet realized risks, management reserves are intended to address unforeseeable emergencies that cannot be effectively managed using contingency as they are such magnitude and rarity that they go beyond project-specific risks (e.g. terrorist attacks, changes in the political environment that impact the program, etc.). Also, unlike contingency, management reserves are not part of the overall cost baseline from which performance of a project or program is measured.[14] An owner may choose to add a management reserve as a mechanism to have funding available to the project or program in the event of truly unforeseen events, but would not include such reserves in the project or program's cost estimate. Management reserve is thus not included in the budget since it is not expected or intended to be expended.[15]

Q. Are there industry standards that establish what an appropriate amount of contingency is?

A. While there is not a lone standard method in which contingency is calculated, there are general methods that are commonly used within the industry based on the experience and preference of the estimating organization. Such methods include:[16]

- Expert judgement – based on experience and competency in risk management.
- Predetermined guidelines – using standardized percentages for a simple calculation, or more complex scoring mechanisms using elements of parametric modeling.

- Simulation analysis – combining expert judgment with an analytical model in a simulation to provide a probabilistic output.
- Parametric modeling – generally an algorithm based on multi-variable analysis of quantified risk drivers versus cost growth outcomes for historical projects.

Contingency development typically combines more than one of the above methods.[17]

Q. How would contingency typically be developed for a megaprogram?

A. Using the practices discussed in my testimony above, contingency development for a megaprogram would be based on consideration of the work plan and an identification of those risks that could happen and the associated potential cost and schedule impact. These risks are then typically modeled through a probabilistic simulation, which in turn, provides various outcomes for management consideration relative to appropriate amounts of contingency based on those modeled risks and respective impacts.

Q. How is contingency typically identified in the budget estimate?

A. From a budget perspective, contingency is a separate project cost element or line item in the budget estimate. As a discrete line item contingency is subject to the same processes as any other cost element, with one exception; unlike most cost elements, the contingency amount may increase or decrease from month-to-month (as funds are used to address realized risks, or funds are returned to the program contingency when risks expire or projects are completed).

Q. How is contingency typically managed and controlled on a megaprogram?

A. It is common practice for contingency to be both distributed to individual projects within a megaprogram and to an overall program contingency. This is a reflection of acknowledging the identification of both project-specific risks and overall program risks. Use of contingency typically is approved by the project manager, senior management, or possibly the president/board of directors, depending on the amount needed and the thresholds for its use established by the company (e.g. the project manager may have approval to use up to $1 million, cumulatively, in contingency, amounts needed beyond that would need approval from a more senior person or group in the organization).

Q. What happens to unused contingency when a project within the megaprogram is completed?

A. Given the level of risk on a megaprogram, it is expected that unused contingency for an individual project within a program is reallocated to the program, which reflects the nature of managing a program versus an individual project. This is similarly true for multi-unit programs. If one unit is completed under its budget estimate, the unused contingency is allocated back to the overall program, which may be used by any remaining units should their respective budgets be exhausted. The way a program estimate is developed and supported is based on this interconnectivity of the various projects that comprise the program, and not a collection of isolated projects for which there is no interdependence. Thus, remaining contingency will only truly be unused when the overall program reaches its completion.

2. SCHEDULE MANAGEMENT

Q. Are there industry standards for schedule development applicable to megaprograms?

A. Yes. PMI and AACE, along with other entities such as the GAO, have developed best practices for schedule development, similar to what these organizations prescribed for other aspects of project controls. PMI prescribes that key steps of schedule development include: defining milestones; designing the project's activities; sequencing activities; determining resources and durations for each activity; analyzing the schedule output; and, approving the baseline schedule.[18]

Q. What are the general objectives of schedule management?

A. The general objectives of schedule management are to identify what activities are of a critical nature (and the relationship those activities have to one another), how the various vendors' or contractors' activities relate to the critical path, and to provide the means to recognize deviation from the plan and take corrective and preventive actions that minimize risk.[19] Schedule management and control typically involves usage of different "levels" of a common integrated master schedule to address the specific needs of the various audiences.

Q. What is meant by a schedule "level"?

A. Levels of a schedule, from Level 0 to Level 5 typically, are commonly used within the construction industry to designate the level of depth a given schedule depicts, with a higher level of schedule providing an increased level of detail. These different levels of schedule are summarized as follows:[20]

- Level 0: Depicts the total project from start to finish, effectively a single bar demonstrating the project timeline and often includes major milestones.
- Level 1: A high-level schedule showing key milestones and summary activities by major phase, stage, or project being executed to provide information to assist in the decision

making process. A Level 1 schedule may or may not be the summary roll-up of a more detailed critical path schedule.

- Level 2: Generally used to communicate the integration of work throughout the lifecycle of a project, including interfaces between key deliverables and participants (contractors). Level 2 schedules assist in identifying project areas and deliverables that require actions and/or course correction.
- Level 3: Prepared to communicate the execution of the deliverables for each of the contracting parties. Development of a Level 3 schedule is generally the output of a critical path scheduling software (e.g. Primavera P6) and provides enough detail to identify critical activities.
- Level 4: Used to communicate the production of work packages at the deliverable level, providing project managers, superintendents, and general foremen with enough detail to plan and coordinate contractor or multi-discipline/craft activities.
- Level 5: Usually considered to be "working schedule" that reflect highly detailed task requirements for specific activities. This detailed level of schedule is typically used by superintendents and general foremen directing and overseeing actual work in the field.

3. RISK MANAGEMENT

Q. You previously discussed in your testimony that as part of the cost estimating industry standards that it was important to conduct a risk and uncertainty analysis to identify the areas within the estimate with a significant risk or opportunity. What is a risk?

A. Risk is an uncertain event or condition that, should it occur, would affect at least one program or project objective. Risk is unpredictable and involves uncertainty, whether that be in the form of a threat or an opportunity. Risk is always in the future. However, based on experience, those involved in the program execution and the program risk assessment can predict what items or events may happen. Based on an individual's prior experience an expected prediction of risks can be made based on items or events that have happened before, but may not manifest on the particular project being assessed. It is those risks that can be predicted that are commonly called "known unknowns," a term widely used in the industry, including by major U.S. government agencies.[21] The risk portion of risk management consists of addressing each high priority risk and developing a risk response (mitigation plan) or countermeasure (for threats) or an enhancement plan (for opportunities).

Q. What is the difference between "risks" and "issues"?

A. Risks, as I stated, are in the future. An issue, on the other hand, is a problem that occurs in the present that the Program Team has to deal with. Risk management is proactive, whereas issue management is reactive. The purpose of risk management is to be proactive rather than reactive regarding things that might go wrong on the program and, just as important, those things that would enhance program success.

Q. Are there specific steps that typically can be undertaken in applying risk management to a program such as the DRP?

A. Yes. There are typically five steps one would undertake in development of a risk management program: 1) planning how risk will be approached for the program; 2) identifying the risks that would potentially emerge in the program; 3) assessing, quantifying, and prioritizing those risks; 4) developing a response to those risks; and, 5) monitoring and managing risk, both those identified and new emerging risks, during program execution.

Q. What is a risk register?

A. A risk register takes the identified risks and categorizes them into various types or "themes" of risk that are entered into a spreadsheet or risk database, which typically features such information as the risk and its ranking, along with the risk owner, and mitigation actions. The risk register is essentially a tracking system. Similar to other project control tools, it tracks risks throughout the program's execution through regular occurring updates and reviews. The primary purpose of the risk register is to support the owner's management decisions and actions and to avoid and/or minimize cost overruns and delays. The likelihood of occurrence and the nature and magnitude of the risks are used for prioritizing risk mitigation actions. The risk register is a tool for allocating managerial responsibility for specific tasks and for reporting and monitoring the status of the risks. The effective use of this project control tool includes regular and frequent reporting on each risk until the risk or the program passes a point where the risk is no longer an issue and is retired.

4. REPORTING MANAGEMENT

Q. What are the general objectives of progress reporting?

A. The main objective of reporting is to consolidate performance data to provide the necessary information to program management in a reasonable time and in an understandable format that allows program management to make the necessary decisions based on the Program's reported status.[22]

Q. What types of information is typically provided in performance or progress reporting?

A. Performance and progress reporting typically is as elaborate as the project or program being reported. For instance, on a small or routine project, a simple status report will provide information such as overall percent complete and a status dashboard for individual elements (e.g. schedule, cost, risk, etc.). PMI notes that more elaborate reports may include:[23]

- *"Analysis of past performance,*
- *Analysis of project forecasts (including time and cost),*
- *Current status or risks and issues,*
- *Work completed during the period,*
- *Work to be completed in the next period,*
- *Summary of changes approved in the period, and*
- *Other relevant information, which is reviewed and discussed."*

On large and complex projects, such as megaprojects or megaprograms, it is common for there to be multiple types of reports used that each serve a specific intent as far as the information gathered or the intended audience of the report.

G. PRE-EXECUTION PLANNING

Q. Describe the pre-execution planning for megaprograms.

A. Pre-execution planning occurs at different levels. At a strategic level, governance framework, functions and processes must be developed. This process would include, for example:

- Determining governance requirements for the megaprogram and how those functions and processes will be integrated into existing governance frameworks;
- Developing a schedule and roadmap for implementing the governance requirements, including prioritizing those requirements, identifying the resources required, and determining whether it may be possible to leverage existing resources or streamline existing governance frameworks;
- Establishing governance roles, responsibilities and authorities; and,
- Establishing the governance functions and processes, which then also must be tested.

Q. What other pre-execution planning occurs?

A. Although it may be called different names, a Planning Process Group will establish the total scope of the effort, define and refine the objectives, and develop the course of action that will be required to attain those objectives. The output of the Planning Process Group is a program management plan (which again may be called different names) and related program documents, which address all aspects of the scope, time, costs, quality, communications, human resources, risks, procurement, and stakeholder management. This process, of course, requires a significant amount of time and funds relative to the size and complexity of the program or project being planned.

Q. Please provide some more detailed examples of the pre-execution planning that would occur in the development of the program management plan and related program documents.

A. For example, schedule management would include the identification of the planned work scope, activity definition and sequence, activity resource and durations estimates, and the development of a schedule. Under cost management, the scope of planned work would be identified, costs would be estimated, and a budget would be determined. Under risk management, the planned work would be identified, risks would be identified, qualitative and quantitative risk analyses would be performed, and risk mitigation responses would be developed. These program documents, and the activities, costs, resources, durations, etc., contained therein, are all interdependent, and must be aligned so that they are consistent with the scope, and enable the objectives of the program management plan, and at a higher level, the program charter. This alignment can be a complex process that takes a significant effort to achieve.

Q. Is it typical in a megaprogram for the pre-execution phase to include execution of smaller projects in accordance with the proposed procedures and project control tools so that those procedures and project control tools can be tested and lessons learned incorporated?

A. Yes. In a megaprogram, program management will often identify a few projects on which the project control tools can be "tested". This allows for lessons learned to be incorporated into the program management plan as well as then being able to adjust and/or enhance those project control tools in order to avoid and/or minimize any issues during execution of the program that may have been encountered in the pre-execution phase. By undertaking these initial projects prior to the execution phase of the overall program, opportunity exists to anticipate the types of problems that may potentially occur in the future and adjust its planning accordingly to mitigate such risks.

Q. **Is it possible to rigidly follow an execution plan set early in a megaprogram for the megaprogram's entire duration?**

A. Typically, no. Construction projects inherently are executed within a dynamic environment and can be influenced by a myriad of factors, events and issues arising during the execution. Progressive elaboration of the execution plan allows the program management team to continuously improve the process in place as more detailed and specific information is obtained.

H. COST TREATMENT OF MEGAPROGRAMS FOR REGULATORY PURPOSES

Q. Is it typical for a utility to allocate all of its planning costs in a multi-unit megaprogram to the first unit, instead of allocating those costs across all units?

A. Yes. With a multi-unit megaprogram, while there are many common costs that benefit all units, those costs must be expended to allow even the first unit to be operable. For example, a program, or any of its individual projects or units, cannot proceed until all of the policies, procedures, and project control tools and systems are established in addition to the actual development of the schedule, cost estimate, and risk management plan. As another example, common facilities needed for all units often have to be completed prior to execution of the first unit, meaning the costs of such facilities are absorbed upfront, even though the later units will have the benefit of the facilities being in place. Therefore, given the net benefit to the program, it is both appropriate and reasonable to allocate all of the planning costs to the first unit, because that is the most cost-efficient way for the program to proceed.

Q. Is it unusual for a megaprogram, such as the Darlington Refurbishment Program, to have its entire cost estimate approved by the regulatory body prior to the program's execution?

A. No. I am aware of a number of regulated utility projects where the commissions approved the cost estimate before the program was executed. For example, the Georgia Public Utility Commission approved the cost estimate for the construction of the multi-billion dollar Vogtle Nuclear Units 3 and 4, as did both the Mississippi Public Utility Commission regarding the construction of the Kemper IGCC Generating Power Project, and the Indiana Utility Regulatory Commission regarding the Edwardsport IGCC Power Plant. The Georgia PUC found that, *"as a matter of fact that Georgia Power's projection for the total costs* [Georgia Power share $6.4B] *for Vogtle 3 and 4 is reasonable."*[24] The Oregon Public Utility Commission in its Order regarding the $514 million estimate for the Carty combined cycle natural gas fired plant found that the plant's cost estimate was reasonable and prudent.[25] The State Corporation Commission of the

Commonwealth of Virginia approved the cost estimate of the Greensville County Power Station, a 1588 MW natural gas combined cycle plant, noting in its order, *"We find that the estimated cost of the Project-$1.33 Billion (excluding financing costs) –is reasonable. …Dominion has established in this proceeding that the estimated capital costs of the Project, along with the protections negotiated by Contract, are reasonable and prudent."*[26] I also understand that the South Carolina Public Utility Commission also approved the $4.5B 2007 ($6.3B with escalation) cost estimate for the two 1117 MW units SCANA nuclear project prior to its execution.[27]

Q. In the United States, do the regulatory commissions regularly allow costs to go into rate base before a project is completed?

A. Yes. Due to regulatory uncertainty that occurred in the late 1980s and 1990s regarding inclusion of costs into rate base and that decision not being made until the project was completed, in order to provide incentives to utilities to construct new projects, upgrade existing projects and address concerns regarding regulator uncertainty, a number of states passed statutes and implemented accompanying regulation to mitigate risks. Regulations generally include some or all of the following elements: approval to construct the project, approval of the cost estimate, and allowing recovery of pre-construction costs, etc.

IV. PROGRAM-SPECIFIC

A. DESCRIPTION OF THE DARLINGTON REFURBISHMENT PROGRAM

Q. Do you consider the Darlington Refurbishment Program a megaprogram as defined within the industry?

A. Yes. My review of the DRP has identified that it has the following attributes of a megaprogram:

- The refurbishment is complex from both an engineering and construction perspective;
- Total execution duration from the Breaker Opening until its estimated completion is approximately 9 1/2 years;
- Engineering for later units will overlap with construction of the first unit;
- There are multiple specialty equipment and material suppliers;
- There are multiple specialty trade contractors;
- There are multiple project stakeholders at both the ownership and the consumer levels; and,
- There is much public and political interest.

By every measure generally used in the industry, the DRP is classified as a megaprogram.

Q. What is your understanding of the overall purpose and scope of the Darlington Refurbishment Program?

A. I understand the purpose of the Program is to extend the operating life of the Darlington Station by approximately 30 to 35 years. The refurbishment involves an outage for replacement of life-limiting components, as well as an inspection and maintenance or replacement of other components that are most effectively done during the refurbishment outage.

Q. Would you consider this a First-of-a-Kind (FOAK) program?

A. Yes. My understanding of OPG's planning is that OPG is treating this as a FOAK program, and in my opinion, it makes sense to do so. While there are other Canadian nuclear units that have gone through refurbishments, including Point Lepreau Generating Station, Bruce Nuclear Generating Station, and the Pickering Nuclear Generating Station, the difference between those refurbishments and the DRP is the fact that the refurbishment of each DRP unit will be performed while immediate adjacent units remain in operation. In addition, each unit refurbishment will begin from a hot unit versus other refurbishments that involved units that were laid up for an extended period of time prior to the refurbishment. There is simply not a good model for a brownfield nuclear project, other than general megaprogram models, in terms of scope, schedule, and cost. I am not aware of another project in which one nuclear reactor has been shut down and refurbished from a hot state while the other immediate adjacent reactors continue to operate. This further makes it difficult to compare or benchmark this Program with any other. Further, the DRP will involve other FOAK aspects involving design, equipment, and execution methods.

Q. Did you assess OPG's planned execution for dealing with the FOAK aspects of the Program?

A. Yes. From my assessment, I determined that OPG is utilizing its Project Oversight Standard, which provides the oversight principles and requirements to be applied to the DRP and specifies that increased levels of oversight from multiple groups will apply to Program areas that include new processes or technology. For example, the FOAK work goes before the Options Review Board to vet readiness. The Options Review Board is chaired by the Vice President, Refurbishment Execution and consists of senior representatives from Operations and Maintenance, Engineering, Planning and Controls, Execution, Supply Chain, Finance and External Oversight. My assessment further found that the execution of FOAK and First-in-a-While (FIAW) work has been elevated as a key risk and has been factored into the probabilistic modeling for the $12.8B cost estimate for the Program.[2] This will require a cross-cutting comprehensive mitigation strategy.

Q. What is OPG doing to mitigate the FOAK/FIAW risks?

A. In review of DRP documentation and interviews with OPG personnel, I have identified that engineering, project teams, and various execution and functional groups are identifying work that is FOAK or FIAW using a rating tool containing 40-plus prompts and 0-3 scoring in the following six areas:

- New design/innovation/software unique to project;
- New line of equipment, devices, materials;
- New installation method/tools or first time in 5/10/20 years;
- Work that is new to performing group and oversight or both;
- Equipment/assets that have not been maintained/accessed for 5/10/20 years; and,
- Unprecedented scale of activity (>10x, >20x, >50x).

Specific mitigation actions are then defined for FOAK/FIAW risks, and tracking of the mitigation actions is in progress. All of this work is being integrated into the work program at a strategic and tactical level.

Q. Did you determine what contracting strategy OPG is using for the Program?

A. Yes. My assessment found that OPG is approaching the contracting strategy for the Program using a multi-prime contractor model in which there is more than one prime contractor working on the Program. OPG has a separate contract with each prime contractor, and each prime contractor is responsible for the completion of the work under its particular contract, but not for the entire Program. OPG is the integrator between the prime contractors and is responsible for the

[2] The $12.8B estimate includes $2.4B in interest and escalation.

entire Program including deliverables, cost and schedule. This is, in my opinion, important given the scale, technical complexity and integrated nature of the Program. As noted earlier in my testimony, this contracting model is typical of what would be expected on a megaproject or megaprogram.

Q. What is the overall schedule for the Darlington Refurbishment Program?

A. Based on the information I have reviewed, OPG anticipates a high confidence duration for each unit outage of 37 to 40 months. The schedule begins with the Darlington Unit 2 outage in October 2016. It will take up to 112 months (to February 2026) to complete refurbishment of all four reactors.

B. ORGANIZATION AND PEOPLE

Q. Before discussing the capabilities of the OPG Program Management Team, what do you understand to be the division of responsibility on the Program?

A. Based on my review of the Program record and interviews with OPG personnel, I identified that a separate Nuclear Refurbishment Organization has been established within OPG. Its charge, as established by the DRP Charter, is to plan and execute the refurbishment, as well as returning the units to operations and manage the refurbishment closeout.[28] The Nuclear Refurbishment Organization receives support from many functions, both nuclear and non-nuclear, within the Company.[29] I also determined that OPG is using a matrix organizational structure which, as discussed earlier in my testimony, is common in megaprograms. I found that OPG is using a strong matrix organization comprised of full-time project managers with considerable authority and full-time functional support staff,[30] which I consider appropriate for the DRP.

Q. Did OPG develop program and project management plans and are they consistent with industry best practices?

A. Yes. I determined that OPG initially developed a Program Charter that generally defined the scope to be undertaken and from that Charter, developed program and project management plans. I found the content and scope of OPG's program and project management plans consistent with industry best practices and what I have seen in megaprojects and megaprograms at this stage of their life cycle.

Q. Did you assess OPG's oversight of the Program?

A. Yes. I found that oversight of the Program occurs both externally and internally. The Program oversight occurs from the following groups: The Board of Directors (Board); independent experts; the Darlington Refurbishment Committee (a Board subcommittee); Internal OPG Audit; the Nuclear Safety Review Board; the Refurbishment Construction Review Board; the CEO and

Enterprise Leadership Team; Management Systems Oversight (MSO); the Program Assurance Group; and, steering committees for each major vendor. MSO acts as the Program Owner for oversight, which entails monitoring compliance with project and program standards to ensure Program objectives are achieved and facilitating and coordinating internal and external audit and oversight functions.[31]

Q. In your opinion does OPG possess the required experience and expertise to design and construct a megaprogram the size and complexity of the Darlington Refurbishment Program?

A. Yes. I found that OPG has a long history of managing nuclear construction projects and was intimately involved with the engineering and management of those projects. We interviewed 15 individuals involved in the DRP at different levels and functions. The group represented a vast amount and a breadth of nuclear experience. For example, some individuals had actually been involved in the original construction of Darlington. Others had come to the DRP after years of experience in multiple nuclear programs. My conclusion was that OPG sought to find the most qualified individuals in the industry to manage the Program and the individuals that were assigned to manage the Program are qualified and competent.

Q. What were your findings and conclusions pertaining to the OPG oversight of the Darlington Refurbishment Program?

A. I conclude that OPG senior management, executive management, and the Board of Directors: (i) have efficient oversight processes in place; (ii) are focused on important process/progress issues; (iii) are participating fully in strategic decisions; and, (iv) are active in issue resolution and are informed and engaged in the planning and pre-execution phases. I also conclude that OPG's oversight process is thorough, complete and consistent with what I would expect from a reasonable and prudent utility company embarking on this type of megaprogram.

Q. Was OPG's approach to its Program Oversight Organization and Staffing for the Darlington Refurbishment Program reasonable for a megaprogram?

A. Yes. The evolution of the program structure, organization, and staffing that I observed is evidence of management attention and action. I found that the Program Management Organization and Staffing decisions were reasonable and in accordance with good utility practice.

C. POLICIES AND PROCEDURES

Q. Did you conduct an examination of OPG procedures and processes as part of your review?

A. Yes, our assessment included a review of OPG's corporate and program-specific policies and procedures.

Q. Can you provide an overview of the types of policies and procedures OPG has in place to facilitate execution of the Darlington Refurbishment Program?

A. Effectively, I found that OPG has structured its policies and procedures into three tiers of supporting documents. At the highest level, "OPG Governance" provides general oversight to OPG's planning and controls through documents such as OPG's Project Management Standard and Project Oversight Standard. In the next tier, OPG has a set of documents that provide additional detail for its nuclear projects portfolio. These cover planning and controls elements such as the gating process, scoping, estimating, risk management, cost control, and scheduling (among others). These same planning and controls elements are further defined for the specific of the DRP in the program-specific tier of OPG's policies and procedures.

Q. How do the Darlington Refurbishment Program-specific policies and procedures differentiate from the organizational policies and procedures?

A. The DRP Charter explains how the Program's policies and procedures align with the overall requirements and expectations of OPG.[32] This is effectively the difference between the different tiers of policies and procedures. At an organizational and portfolio level, they communicate the general requirements and expectations; whereas at the program level, they expand on those requirements and expectations to define how the work will actually be performed, monitored, and controlled during execution of the Program.

Q. What types of program-specific policies and procedures has OPG implemented?

A. My assessment found that OPG has established and implemented program-specific policies and procedures to support the scoping, estimating, risk management, scheduling, project control, and records and document management processes. In addition, a set of 23 program management plans were implemented to address the function-specific requirements and processes for DRP execution (e.g. planning and controls, environmental, contract management, operations, quality, etc.).

Q. What were your overall findings of your review of OPG's policies and procedures?

A. 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.

D. PROJECT CONTROLS

Q. What did you find relative to how project controls are implemented and managed on the Program?

A. 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.[33] I found that OPG has a dedicated program management plan for its intended use during planning and execution of the Program.[34] 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).

1. ESTIMATING AND COST MANAGEMENT

Q. Did you assess OPG's role in developing the Program Release Quality Estimate?

A. Yes. I found that OPG had two primary functions in the RQE development: 1) provide oversight to and approval of EPC vendor estimates; and, 2) facilitate and perform estimate vetting, reviews, and validations of estimate submissions with confirmation of the recommended class of estimate achieved.[35]

Q. What is the intent of the Release Quality Estimate?

A. It is my understanding that the intent of the RQE is to have a 4-unit cost and schedule estimate for the purposes of obtaining execution phase approval of the DRP. The RQE incorporates: scope; engineering design; contracting strategy; cost estimates; schedule; owner's costs; contingency; and, interest and escalation.[36]

Q. Did the RQE development align with GAO's best practices and twelve step estimating process you mentioned earlier in your testimony?

A. Yes, it did. My assessment of how the OPG estimating process aligned with the twelve-step process developed by the GAO[37] is summarized as follows:

1. <u>Define estimate's purpose</u>. *"The Darlington Refurbishment Project Release Quality Estimate has been developed as a culmination of the Refurbishment Project planning effort to establish a high confidence, four-unit total program life cycle cost estimate."*[38]
2. <u>Develop estimating plan</u>. *"The Nuclear Refurbishment RQE Cost Estimate Plan, NK-38-PLAN-09701-10235, provides the outline of the activities required to generate a total program cost estimate as a progression from the previous program funding approved, Release 4D November 2014. This plan defines the estimating activities executed to developed the total program cost."*[39]

3. Define program characteristics. *"The DRP is a four-unit 30 year life extension project conducted through unit outages and comprised of replacement of life-limiting components, as well as, maintenance or replacement of other components most effectively conducted during a refurbishment outage period. Key scopes of work comprise re-tube & feeder replacement, turbine generator refurbishment & controls modifications, steam generator cleaning & inspections, fuel handling modifications & replacements, and balance of plant modifications & replacements."*[40]
4. Determine estimating structure. *"The DRP scope is organized into groupings of categories and project groups identified as bundles."* The DRP scope was also developed into a work breakdown structure (WBS).[41]
5. Identify ground rules and assumptions. *"Assumptions made within previous estimates have been validated and transformed into plans with the assumptions closed out accordingly…Estimate basis and remaining assumptions recorded within the RMO Assumptions & Basis Log."*[42]
6. Obtain data. *"The development of the RQE comprises bottoms up estimates generated from EPC Vendors for each project bundle, OPG functional and owner costs generated from OPG estimate owners, and the consolidation of all costs (historical, actual and estimate) by the RQE team and coordinated by the RQE Project Manager."*[43]
7. Develop point estimate and compare it to an independent estimate. In addition to the internal review process, areas of RQE underwent independent review and assessment.[44]
8. Conduct sensitivity analysis. 3-point estimates (optimistic, realistic, and pessimistic) were developed, challenged, and reviewed for all possible variables associated with discrete risks and cost and schedule uncertainties.[45]
9. Conduct risk and uncertainty analysis. *"The determination of DRP contingencies has been made through a robust bottoms up risk review and analysis process, building up from vendors, OPG Projects and, finally OPG Program risk and contingency analysis."*[46]

10. Document the estimate. The Basis of Estimate report, as I discuss later in my testimony, provides the overview of the methodology and process used in development of the RQE.[47]
11. Present estimate to management for approval. The RQE was presented to the OPG Board and approved in a November 2015 meeting.[48]
12. Update the estimate to reflect actual costs and changes. The RQE represents a progression from the previous program funding approved.[49]

Q. Did you review the basis of estimate that OPG developed for the RQE?

A. Yes. I found that OPG prepared a comprehensive basis of estimate document that explicitly aligns with the guidelines established by AACE in its Recommended Practice 34R-05, "Basis of Estimate." OPG detailed its adherence to AACE Recommended Practice 34R-05 as an appendix to the basis of estimate, which summarized the topics outlined by AACE Recommended Practice 34R-05 with the RQE package elements to detail the completeness of the basis of estimate.[50]

Q. Did OPG take into consideration the experience of other refurbishment projects in its development of the RQE?

A. Based on my review and the interviews conducted, it is my understanding that OPG benchmarked against the available cost data from other refurbishment projects at Point Lepreau, Pickering, and Bruce Units 1 and 2, incorporating lessons learned from these projects into the DRP estimate. Due to the limited available data as a result of the uniqueness and FOAK nature of the Program, I understand that benchmarking was largely tied to OPG's operating experience and subject matter expertise.

Q. What Class of estimate is the RQE considered?

A. I understand that the RQE was determined by OPG to be a Class 3 estimate, based on 93% of the EPC execution work estimates comprising of detailed cost line items, which were developed from:

- Bottoms up work flow steps and operations;
- Construction work packages and work tasks;
- Assembly level cost line items by trade discipline; and,
- Site and work face conditions.

The remaining 7% of the execution work was estimated at a summary or semi-detailed level.[51] The largest two bundles, from a cost standpoint, are the Retube and Feeder Replacement (RFR) and Turbine Generator scopes, which collectively comprise 41% of the overall RQE. I understand that these two bundles were developed at a Class 2 estimate level, which provides a higher level of detail than a Class 3 estimate.

Q. What is the expected accuracy range of a Class 3 estimate per AACE?

A. Per AACE recommended practice 18R-97,[52] 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. AACE notes that the expected accuracy range provides a general framework for likely outcomes of actual costs, but is affected by the state of technology, availability of applicable reference cost data, and other such risks.

Q. What were your conclusions regarding OPG's estimating process?

A. I found that OPG, in its basis of estimate, noted that AACE's recommended practices 17R-97 and 18R-97 cover "new construction" projects and do not fit a nuclear refurbishment project without adaptations to accomplish the intent of measuring and aligning the maturity of the project definition with the expected cost accuracy of execution to funding, corporate risk governance, and gating process. I further found that OPG appropriately made the necessary adaptations from that note in AACE's recommended practices and with the completion of detailed engineering and work planning on the DRP, provided management with high confidence as to the Program's scope, cost, and schedule estimates.[53] I also understand that OPG determined the RQE to have a -10% to +25% expected accuracy range based on its detailed EPC estimate vetting and review.[54] I find the estimating process OPG used to be reasonable and aligned with industry standards and what I have seen in other megaprograms.

Q. Based on the expected accuracy range, what do you consider to be the appropriate amount of contingency?

A. Ultimately, it is management's decision to determine the appropriate amount of contingency based on the level of confidence it chooses to fund a program. As I discussed earlier in my testimony, there are various accepted practices for determining the amount of contingency on a project or program. Conducting risk analyses provides management with a mechanism for reaching a determination on what is an appropriate contingency amount.

Q. Did you assess whether the amount of contingency included in the RQE by OPG was reasonable given the nature of the DRP?

A. Yes. In review of the DRP documentation and through interviews with OPG personnel, I have determined that OPG's $1.7B of contingency for the DRP is reasonable. I base this finding on my understanding of the robust method in which OPG determined its contingency amount, which included a comprehensive risk assessment, Monte Carlo simulations, vetting by internal and external parties, and the decision to use a P90 confidence level.

Q. Is it appropriate to use the P90 confidence level to determine the amount of contingency?

A. Yes. 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.

Q. Does the estimate account for risks sufficiently?

A. Yes. My assessment found that risks were accounted for as part of the robust contingency development exercises implemented by OPG. Key risks that were considered for contingency on the Program include:[55]

- Schedule extension – contingency is provided to cover the risk of delay up to the high confidence schedule duration, totaling $503 million. This was derived from a detailed analysis of risks and uncertainties associated with critical path activities.
- Estimating uncertainty – because an estimate is truly an 'estimate', contingency is provided to account for the possibility that the actual cost to complete the project may be greater than the estimated cost (exclusive of discrete risk impacts).
- Resource management/bridging between units – contingency is provided to retain critical trades and leadership resources between periods of specific resource demand, totaling $50 million. This is to account for the fact that between periods, such as between completion of Unit 2 and beginning Unit 3, key resources may leave to take on other work. Losing such resources would result in the need to re-train staff and reduce opportunities for gaining efficiencies.

- Vendor performance – contingency is provided to hire replacement contractors, re-train the resources, and self-perform work for short periods, if necessary, in the event that vendor performance becomes irrecoverable.

Q. Did you reach a conclusion as to whether or not OPG met accepted industry standards for estimating on the Program?

A. Yes. I found that OPG's estimating process is well-defined in its policies and procedures and the results of the estimating process are fully explained within the basis of estimate document as well as summarized in material presented to OPG's Board. OPG had a clear intent to ensure its process aligned with industry standards as prescribed by organizations such as AACE, and followed through on that intent by holding itself to the industry standards and documenting its results.

Q. Did you reach any overall opinions concerning the RQE $12.8B estimate for the DRP?

A. Yes. From my review and evaluation of the contemporaneous documentation and the interviews of OPG management, at the time the RQE cost estimate was completed, OPG had ample reason to feel confident in the accuracy of RQE estimate. I found the methodologies employed by OPG to develop the RQE estimate to be *world-class*. A review of all the relevant documentation and interviews with OPG project personnel confirmed the fact that the methodologies employed met all accepted industry standards and guidelines as promulgated by AACE. As I discussed earlier in my testimony, the use of a P90 confidence level, along with the detailed estimate development process, provides OPG with appropriate assurances that the DRP can be completed within the $12.8B estimate.

Q. Does OPG have in place the necessary cost management procedures to monitor expenditures against the RQE?

A. Yes. Through my review of the Program project controls and OPG's management of costs, I identified aspects of OPG's cost controls to include:[56]

- 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*.[57]

Q. How will costs be tracked and forecasted on the Program?

A. My understanding is that OPG has developed a Cost Breakdown Structure (CBS) that mirrors the WBS and also contains cost-only elements such as contingency and interest that are not included in the WBS. The CBS identifies all the Control Accounts used by the Program, each of which contains one or more Work Packages. Budgets for all work are established at the Work Package level, with actual costs being captured at this level to support cost performance monitoring.[58] I also determined that cost forecasting is accomplished by analyzing work performed against the work planned, identifying potential trends, verifying the remaining work, and determining the impact of performance to date on the estimated cost and schedule going forward. The Project Managers are accountable for having the forecast updated, as necessary, to reflect the current status and expected performance of the individual projects.

Q. Does OPG have reasonable processes in place for managing contingency during the execution of the Program?

A. Yes. It is my opinion that OPG has established appropriate processes and controls for management of contingency during the Program's execution. All program or project contingency changes will be documented and reflected in the Program risk register, which I discuss later in my testimony, and reviewed and dispositioned by the Change Control Board (CCB) and the Program Change Control Board (PCCB). OPG's policies dictate that drawdown of contingency will be avoided whenever possible through the effective management and mitigation or risks and trends.[59] When a risk or trend cannot be fully mitigated, a drawdown of contingency will occur.

Q. Are the OPG cost management processes in accordance with industry best practices and typical of what you have found on other power plant megaprograms?

A. Yes. As noted by PMI, *"Much of the effort of cost control involves analyzing the relationship between the consumption of project funds to the physical work being accomplished for such expenditures."*[60] As discussed above, OPG has the procedures and processes in place to effectively monitor and capture the actual costs and evaluate performance against the physical work completed, and in my opinion, in many aspects exceeds what I have found on other megaprograms similar to the size and complexity of the DRP.

2. SCHEDULE MANAGEMENT

Q. Did you assess how the schedule for the Program developed?

A. Yes. Based on my review of the DRP information, and as discussed in interviews with OPG personnel, the schedule development process for the Program involved multiple steps, with each step generating a schedule subcomponent that can stand alone to inform the Project Team of that aspect of the final schedule. From my assessment, I understand the schedule development process to include:[61]

- Creation of a Level 1 schedule (Program Integrated Master Schedule, or "PIMS") based on the outage segments;
- Creation of a WBS and execution structure;
- Creation of a resource breakdown structure;
- Creation of a responsibility assignment matrix;
- Creation of a Level 3 schedule with the ability to roll-up to a Level 2 schedule (Nuclear Program Coordination & Control Schedule, or "CCL2");
- Integration and alignment of the Level 2 schedule with the Level 1 outage schedule;
- Integration of the Level 3 schedules with the interface milestones; and,
- Baselining the integrated schedule.

I found that OPG ensures that contractors prepare schedules in accordance with OPG's "Nuclear Projects Scheduling Requirements from EPC Contractors." The contractors' Level 3 schedules are reviewed and then integrated and aligned to the CCL2 and PIMS, using a common WBS and coding guideline.[62]

Q. How are the interfaces between the various projects and vendors managed in the schedule?

A. I determined that OPG created a separate interface/integration project schedule that provides overall control on all work window interfaces. All vendor and OPG schedules are required to communicate their schedule interdependencies to this project, which allows for communication of vendor schedule progress to other dependent schedules.[63]

Q. How are costs integrated with the schedule?

A. I determined that costs and schedule are integrated at the work package. This allows for monitoring and measuring earned value. As noted in the Planning and Controls Program Management Plan, *"Once the schedule updates are progressed and statused by work package, the physical percent complete, actual start, actual finish, forecast start and forecast finish is prepared and integrated into the cost system used for earned value calculation…"*[64]

Q. Did you determine whether the Program Integrated Master Schedule was fully developed at the time of your testimony?

A. At the time of this testimony, the PIMS is still being vetted and reviewed. A Rev. C version of the schedule is considered by OPG to be approximately 60-70% complete. It is expected that the final PIMS will be fully complete by mid-September 2016, which will then set a control baseline for cost and schedule.

Q. Is this level of schedule development at this time reasonable and what you would expect to see at this stage of the Program?

A. Yes. Breaker Opening is not scheduled to occur until October 2016. The schedule development activities and the level of detail developed at this time is consistent with other megaprograms similar to the size and complexity of the DRP that I have seen at this stage of development.

Q. Has the Unit 2 schedule been fully integrated with the RQE estimate and the Program risk assessment?

A. Essentially yes. There is approximately 4% of the Unit 2 project that has not been fully integrated from a cost, schedule, and risk perspective. This 4% accounts for smaller bundles of scope, typically balance of plant type work, that is non-critical path and will not materially impact the schedule. These remaining bundles currently lack a complete detailed design. Typically, this level of completeness would be expected at this point in the megaprogram. As such, these bundles lack fully refined quantities and, as a result, will carry a higher contingency. As the schedule is vetted and refined through September 2016, OPG's processes will provide for a check to ensure that the baseline schedule and baseline costs are in sync.

Q. Do you believe it is reasonable to use the high-confidence P90 schedule for execution of Unit 2?

A. 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.

Q. How will OPG manage the schedule?

A. Based on my review, it is my understanding that OPG will manage the Program towards a planned outage duration based on the Level 3 schedules provided by each vendor as integrated into the PIMS. The planned outage duration completes the Program in a shorter duration than the high-confidence schedule. In order to maximize success of the Program, planned non-critical path work (e.g. Balance of Plant work) will not exceed 60% of the critical path (i.e. the RFR bundle).

Vendors will maintain and update their schedules with oversight from the OPG master scheduler.[65]

Q. Is it reasonable to manage the Program based on a planned outage duration?

A. Yes. It is typical on megaprojects and megaprograms, such as the DRP, which are planned to be executed over an extended time to manage the execution based on a planned outage duration. This provides additional assurances that the project or program will be completed within the high-confidence schedule.

Q. Does OPG's schedule processes align with industry standards?

A. Yes. GAO provides ten best practices associated with high-quality and reliable schedules.[66] These practices also align with what is prescribed by AACE and PMI. My assessment of how the OPG scheduling process aligned with the ten best practices provided by GAO is summarized as follows:

- <u>Capturing all activities</u>: *"The schedule should reflect all activities as defined in the project's work breakdown structure (WBS)…"*
    - <u>DRP Schedule Management</u>: *"In order to successfully implement the Multi Level Scheduling Model we will utilize the WBS functionality in P6 to allow progress on lower activities to roll up through the WBS to Work Packages and Control Accounts."*[67]
- <u>Sequencing all activities</u>: *"The schedule should be planned so that critical dates can be met. To do this, activities need to be logically sequenced—that is, listed in the order in which they are to be carried out."*
    - <u>DRP Schedule Management</u>: *"Tasks are linked together and sequenced to identify the relationships between deliverables, sub-deliverables, activities, tasks, and subtasks."*[68]

- Assigning resources to all activities: *"The schedule should reflect the resources (labor, materials, overhead) needed to do the work…"*
  - DRP Schedule Management: *"Crew codes will be used to estimate resources and provide resource demand curves. All level 3 activities will be resource loaded. Labour will be identified in hours. Commodities such as Pressure Tubes or Control Valve can also be included in the RBS* [Resource Breakdown Structure]. *Common critical equipment such as the Turbine Hall Crane will also be included in the RBS in order to identify conflicts in requirements."*[69]
- Establishing the duration of all activities: *"The schedule should realistically reflect how long each activity will take."*
  - DRP Schedule Management: *"To identify the time- risk associated with a critical or near critical activity or task, the Darlington Refurbishment and/or contractor staff should apply the Program Evaluation and Review Technique (PERT)."*[70]
- Verifying that the schedule can be traced horizontally and vertically: *"The detailed schedule should be horizontally traceable, meaning that it should link products and outcomes associated with other sequenced activities."*
  - DRP Schedule Management:[71]
    - *"A horizontal schedule review of the sequence of scheduled activities and logic ties is performed to ensure prerequisites or constraints are satisfied…"*
    - *"A vertical slide of activities scheduled to be executed concurrently is reviewed…"*
- Confirming that the critical path is valid: *"The schedule should identify the program critical path—the path of longest duration through the sequence of activities."*
  - DRP Schedule Management:

        - *"The JV developed the Logic Flow Diagrams with OPG operations and project management and represents the combination of JV and OPG activities that make up the overall project critical path. The duration is based on the as performed Tool Performance Guarantee times and was agreed to between OPG and the JV."*[72]
        - *"Input from all project bundles have been incorporated in the critical path and window durations. Each bundle and project was assessed at the level of schedule."*[73]

- Ensuring reasonable total float: *"The schedule should identify reasonable float (or slack)—the amount of time by which a predecessor activity can slip before the delay affects the program's estimated finish date—so that the schedule's flexibility can be determined."*
    - DRP Schedule Management: *"Based on daily status updates in Level 3 schedules, the Master Schedulers will analyze the schedule accuracy, float, extra time and overruns with respect to impact on interfaces across work group or execution windows within segments."*[74]
- Conducting a schedule risk analysis: *"A schedule risk analysis uses a good critical path method (CPM) schedule and data about project schedule risks and opportunities as well as statistical simulation to predict the level of confidence in meeting a program's completion date, determine the time contingency needed for a level of confidence, and identify high-priority risks and opportunities."*
    - DRP Schedule Management: *"P50 and P90 durations have been calculated through detailed schedule risk PERT analysis and adjusted based on management experience."*[75]
- Updating the schedule using actual progress and logic: *"Maintaining the integrity of the schedule logic at regular intervals is necessary to reflect the true status of the program."*

  - DRP Schedule Management: *"Level 3 schedules will be updated daily or weekly during the execution phase based on the Outage Segment requirement…Daily updates will include actualizing activities and entering percent complete."*[76]
- Maintaining a baseline schedule: *"The schedule should be continually monitored so as to reveal when forecasted completion dates differ from planned dates and whether schedule variances will affect downstream work."*
  - DRP Schedule Management: *"The progress data is verified and reviewed by OPG. Once reviewed, a variance analysis is produced to provide reasons for any schedule slippages and to determine necessary corrective action/recovery plans when needed. A critical path analysis is also produced using level 3 schedule details."*[77]

Based on my assessment and as summarized above, I found that 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.

3. RISK MANAGEMENT

Q. Did you assess whether OPG undertook any risk management activities to prepare OPG for execution of the Program?

A. Yes. My assessment found that OPG undertook a number of activities in its identification of key risks to the Program and development of processes in order to manage those key risk factors in addition to others that may emerge throughout the Program execution. I determined that the activities performed by OPG in preparation of the Program included: identification of risk management process;[78] a detailed review of program and project risk and contingencies, development of risk registers based on the detailed review of program and project risks;[79] development of mitigation plans should identified risks emerge;[80] and, development of a Risk Management and Oversight (RMO) Tool that provides project managers with a platform to perform risk management activities for the projects that comprise the Program.[81]

Q. Did you assess whether the risk management process provides OPG with the necessary guidance and direction to ensure risks are closely monitored and managed so as to minimize threats to the $12.8B RQE?

A. Yes. I found that OPG's risk management process provides the authority that ties together all the activities that I described earlier in my testimony – i.e., risk identification, analysis, and mitigation – with a functional complete perspective. The process is an integral part of the overall Program planning that informs all members of the DRP of the risks to the Program, how they will be managed, and who will manage them through the DRP execution. I further found that OPG's risk management process is supported through the incorporation of risk management plans into the individual project management plans. I found that OPG's risk management process is typical of what I would expect to find in a megaprogram such as the DRP, and, like all of the planning documents, the risk management process is a dynamic document that is being used to guide day-to-day decisions by the Program and Project Teams.

Q. How did OPG undertake its identification of risks that may arise on the Program?

A. Through my review of the Program record and my interviews with OPG personnel, I found that risks were identified through a number of sources, including operating experience and external lessons learned, project manager direction, and through the Program Management Office (PMO) risk department proactively seeking input and providing oversight support. Specific activities that facilitated the identification of risks include: facilitated risk workshops; Basis of Estimate and contingency development reviews; and, project schedule reviews.[82] For example, I determined that during the contingency development, the risk register items were input into a RQE template where additional discrete risk and cost uncertainty information, such as three-point estimates, was populated. These RQE templates were subjected to a rigorous screening and challenge process, which included a review panel of subject matter experts.[83]

Q. Did you determine whether OPG developed risk registers?

A. Yes. I found that OPG identified key risk areas from major themes of risk and incorporated these key risks areas into the risk registers. I found that the key risk areas were assigned to executive owners and included a cross-cutting, comprehensive mitigation strategy. Examples of the key risk areas that were identified include: availability/retention of project leadership; availability of skilled craft resources/supervision; and, vendor performance. [84]

Q. Did OPG develop risk mitigation plans for these risks?

A. Yes. As part of my review, I examined a sample of the mitigation plans that were developed for these key risk areas. For example, the mitigation plan for vendor performance included:

> *"A Readiness to Execute oversight plan has been issued. This will support the detailed readiness assessment challenge process leading to the readiness milestone in June 2016. Plans to improve collaborative activities with the vendors for Engineering, Procurement and Construction have been developed. It includes active management and assisting*

vendors in removing barriers to work. A Nuclear Construction Supervisor Academy is operational, and is integral in improving vendor supervisory performance. The integrated field readiness walk downs at T-6 months and T-3 months with refurbishment and vendor teams will also promote better vendor performance overall in the field portion of work."[85]

Q. Did OPG, in its risk planning, take lessons learned from past experience or other nuclear projects into account?

A. Yes. 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. There have also been lessons learned from the Darlington SIO and F&IP, which included the Darlington Energy Complex, Darlington Water and Sewer, Heavy Water Storage and Drum Handling Facility, Darlington Operations Support Building Refurbishment, Refurbishment Project Office, Electrical Power Distribution System, RFR Island Support Annex, Vehicle Screening Facility and the Re-tube Waste Processing Building. 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.[86]

Q. How has risk been integrated with cost and schedule?

A. OPG evaluated risks and uncertainties for each segment of the Program, leading to the development of schedule and estimate contingency and the basis for the high-confidence (P90) schedule and estimate.[87]

Q. Did OPG's cost and schedule risk contingency development align with industry standards?

A. Yes. OPG's cost and schedule contingency development aligns with industry standards, such as those prescribed by AACE. AACE explained that, *"The probability and impact of risks/uncertainties are specified and the risks/uncertainties are linked to the activities and costs that they affect. Using Monte Carlo techniques one can simulate both time and cost, permitting the impacts of schedule risk on cost risk to be calculated."*[88] I found that OPG has completed this effort by identifying risks, estimating the probability of occurrence, estimating the risk impact, considering risk responses, addressing cost and schedule dependency, assessing overall outcomes through Monte Carlo simulations, and estimating and evaluating contingency.

Q. Did you assess whether OPG has risk management processes in place to use during execution?

A. Yes. I understand that risk management on the Program is guided by the "Nuclear Projects Risk Management" manual, which provides direction as to both the day-to-day risk management activities and the risk management preparations for authorization packages presented at funding gates/committees.[89] In addition, as I previously discussed in my testimony, the Program utilizes an RMO tool that provides project managers with a platform to perform risk management activities for the projects. The RMO tool was developed by OPG to consolidate various risk-related logs into one source in order to streamline work flows. It includes issues log, OPEX [Operating Experience], Lessons Learned, Oversight Findings and Plan, and new daily SharePoint logs to establish a comprehensive resource for risk management.[90] The RMO is owned and administered by the PMO, which also provides training, support, and guidance for the use of the RMO tool.[91] As part of the monitoring and reporting of risks, I found that OPG can incorporate known risks into the forecasts through calculating a project's current estimate at completion or estimate to completion. The cost forecast is then justified through a pending contract change or by managing the specific risk through mitigation plans.[92]

Q. How is the risk register maintained during execution?

A. I determined that the risk register is maintained both at the Program-level and at the individual project level. The Program risk register is managed by the risk management group of PP&C and 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 managed by each individual bundle and contains risks that apply to project work within the given bundle (e.g. balance of plant, fuel handling, etc.).[93]

Q. How are risks reported?

A. 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.[94] 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.

Q. Do OPG's risk management processes align with industry standards and are they in accordance with prudent utility practices?

A. Yes. I found that OPG's risk management processes utilize the fundamental steps of: planning; identification; assessment; treatment; and, monitoring and control,[95] which align with industry standard practices such as those prescribed by PMI[96] and AACE.[97]

Q. In your opinion, will OPG's risk management process assist OPG and the DRP stakeholders in maintaining confidence that the Program can be executed within the $12.8B estimate?

A. Yes. 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. Further, I found that OPG developed through its Monte Carlo risk simulation modeling, the necessary risk contingency to address such risks, thereby providing a high confidence that the Program can be executed within the $12.8B RQE.

4. REPORTING MANAGEMENT

Q. Did you determine what types of reports will be generated by OPG during execution of the Program?

A. Yes. I found that OPG has established a repository within the DRP Data Warehouse for metrics and reporting data. A comprehensive, tiered metrics infrastructure has been established and will be maintained at the program, project, and functional levels to measure progress in areas of: environment, health, and safety; scope; schedule; cost; and, quality.[98] In addition, a variety of standard reports will be generated during the Program's execution. I also identified that straw-models for all key reports are being developed to ensure adequate information is available to support decision making and actions. OPG has indicated that all key reports will be in place by the fourth quarter of 2016.[99]

Q. How are decisions communicated across the Program?

A. Through my review of the Program record and interviews with OPG personnel, I found that OPG developed an Integrated Reporting Plan (IRP) to communicate how information and data is grouped, presented, and distributed to accommodate the management of the Program, Bundles, and projects.[100] The IRP identifies all stakeholders, frequency, and elements to be reported on.

Q. How can OPG gain assurance that the information it receives from contractors is accurate and adequate for reporting requirements?

A. During the pre-execution phase, I found that OPG observed that contractors were not adequately reporting low-level events, which made identification and response to adverse trends difficult. To correct this, I found that OPG has embedded staff at the contractors' premises to assist with enhancing low-level reporting and trending capability, which facilitates identifying corrective actions at an early stage.

Q. How will progress be measured and reported during execution?

A. I understand that OPG utilizes Earned Value Management (EVM) as the fundamental mechanism in evaluating the Program's overall cost and schedule status.[101] Elements of EVM include:

- Planned Value (PV) – the current Control Budget assigned to the work;
- Earned Value (EV) – the dollar value of work performed in terms of the approved budget assigned to the work;
- Actual Cost (AC) – the dollar amount of actual cost incurred as recorded in the OPG financial source system;
- Schedule Performance Index (SPI) – ratio of EV to PV;
- Cost Performance Index (CPI) – ratio of EV to AC;
- Cost Variance (CV) – difference between EV and AC;
- Budget Variance (BV) – difference between PV and AC; and,
- Schedule Variance (SV) – difference between EV and PV.

The above EVM elements are facilitated through the PP&C group. Based on my review, it is my opinion that OPG has a thorough system in place to capture, analyze, report, and respond to progress on the Program.

Q. Does the measurement of progress align with industry standards?

A. Yes, earned value is a widely accepted tool for measuring progress on a program or project and should provide for reliable progress reporting and process control.[102]

Q. Will the reports as developed or envisioned provide the necessary information upon which OPG management can make reasoned and informed decisions regarding the execution of the Program?

A. Yes. The types of reports that OPG is and will be using are what I would expect to see on a program the size and complexity of the DRP and should provide the necessary information in a timely manner to management for incorporation into its decision-making process.

E. PROGRAM EXECUTION

Q. In your opinion, does the fact that the Facilities and Infrastructure Projects and Safety Improvement Opportunities were not executed per the cost and schedule plan foreshadow similar issues in the execution of the DRP?

A. No. Many of these projects were executed under the pre-existing Projects and Modifications organization and did not use a “gated process” that will be used for the DRP execution. While the F&IP and SIO were not completed per the initial planned schedule and estimate when the RQE was submitted, I did not find any fundamental issues that would impact the Program execution. Recovery plans were designed and initiated. Further, I did not find that there were any impacts on the Breaker Opening milestone for the Program’s execution. As is typical in any pre-execution period, there are certain projects or activities that must be completed to allow for execution. In addition, as discussed earlier in my testimony, one benefit of having initial projects completed pre-execution is to be able utilize proposed project procedures and project control tools in order to adjust and/or enhance those procedures and project controls to effectively monitor and manage issues as they arise. The lessons learned from these F&IP and SIO occurred in areas such as collaborative planning, scope clarity and control, estimating, scheduling, material tracking, contractor/construction oversight, sub-surface risks, and contract and claims management and have been incorporated into the execution planning for the overall Program. As discussed next in my testimony, OPG has also internalized the process of incorporating lessons learned into its execution planning with its Readiness to Execute (RTE) Plan. Finally, I found that OPG’s decision to substantially complete Unit 2 before starting Unit 3 was made to allow the effective implementation of lessons learned.

Q. What do you understand OPG’s Readiness To Execute (RTE) Plan to entail?

A. I understand that the RTE Plan includes four plan periods:

- In the lead-up period, the test plans for the test period are developed, and table top exercises are defined to test those plans, processes and activities that cannot be directly tested during the implementation of the test modifications.
- In the pre-test period, work programs and proxies for the test period are refined, challenge meetings are conducted, the Execution Team is indoctrinated on the RTE Plan, and preparation for RTE field work occurs.
- In the test period, field work activities and table top exercises are executed, and the basis of information is developed for conducting extensive lessons learned reviews, focused improvements and corrections to training, work processes, team dynamics and worker and team behaviors.
- Finally, in the implementation of lessons learned period, identified changes are made based on vetted results from the test period, and change management is conducted to ensure that all parts of the integrated execution are practicing the changes in their work.

My assessment determined that the first three plan periods have been completed, and as of the date of my testimony, the final plan period is underway.

Q. Is the planned execution status of the DRP at a stage that you would expect to find at this point in time on a megaprogram?

A. Yes. The policies and procedures, project control tools and systems, as well as the risk management processes are comprehensive, thorough and align with industry best practices. As stated in more detail previously in my testimony, the methodologies employed by OPG to develop the RQE are world class, well-defined, and fully explained. Those methodologies certainly meet all accepted industry standards. The development of the PIMS is typical of what I have seen on megaprograms of this size and complexity. In terms of integration with the RQE estimate and the Program's risk assessment, only four percent remains to be detailed and integrated, and that is to be expected at this point in the process. Although the F&IP and SIO have not been completed per the initial planned schedule and estimate, the Breaker Opening milestone date for program execution has not been affected, and lessons learned have been incorporated. The RTE work will continue until Breaker Opening as OPG makes identified changes based on vetted results from the Test Period and conducts change management to ensure that all parts of the integrated execution are practicing the changes in its work. Finally, the PIMS will be finalized and issued and the Unit 2 Execution Estimate will be finalized and approved by the Board. Again, the current stage of the DRP development is where I would expect an owner to be in a megaprogram, such as the DRP, as of the date of this testimony.

1 **ENDNOTES**

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[5] AACE International, Recommended Practice 34R-05, "Basis of Estimate", April 4, 2013
[6] AACE International, Recommended Practice 17R-97, "Cost Estimate Classification System", November 29, 2011
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Exhibit PG-1

DR. PATRICIA D. GALLOWAY

President and Chief Executive Officer

PROFESSIONAL EXPERIENCE

Pegasus Global Holdings, Inc. – 2008-Present

As President and Chief Executive Officer of Pegasus Global Holdings, Inc.® (Pegasus-Global), Dr. Galloway oversees all aspects of the firm's management consulting services. Her experience and expertise centers on megaprojects. She has consulted on matters covering the entire project delivery process in the energy and infrastructure industries, working on behalf of private and public sector clients globally. She is an international arbitrator and mediator and serves on several arbitral institutional panels. Dr. Galloway also served as a member of the U.S. National Science Board, appointed by U.S. President Bush with Senate confirmation in 2006 for a six-year term, serving on its executive committee and as its Vice Chair from 2008 to 2010. She received an honorary Doctor of Science from the South Dakota School of Mines in 2011.

With over 38 years of experience, Dr. Galloway's experience includes: strategic advice to boards and senior management concerning governance, management structures and performance, contracting strategies, contract development and risk reviews, project controls, and contract administration; risk management including evaluating corporate-wide enterprise risk management programs, project risk identification, assessment and analysis, trend evaluations and risk reduction plans; Auditing including performance, prudence, and management audits; Integrity Generally Accepted Processes & Practices (G.A.P.P.) Analysis™ of corporate and project specific policies and procedures and benchmarking; and Alternative Dispute Resolution (ADR) services including claims avoidance, non-testifying expert consulting including Testing Expert Evidence,® litigation strategy, assistance in legal counsel and arbitrator selection, and serving as an arbitrator and mediator.

Dr. Galloway has extensive global experience having worked on some of the world's largest projects including: over 30 nuclear power plant projects; Duke Energy's Coal Ash Basin Closure Program; Kemper County IGCC coal plant; Edwardsport IGCC coal plant; Vogtle Nuclear Units 1,2,3,4; Sakhalin Island, Russia, Oil and Natural Gas Pipeline Project; Cadereyta Refinery Project, Mexico; HBJ Pipeline Project, India; Murrin Murrin nickel-cobalt mine, Western Australia; the Tsing Ma Bridge, Hong Kong; Panama Canal; Seattle Sound Transit Light Rail Program; London's Crossrail Project; Citylink Project, Melbourne, Australia; Venice Lagoon Floodgate Project, Italy; Xiaolangdi Dam, China; and, City of Winnipeg, Canada, Capital Improvement Program.

She serves as an advisor to multiple owner and contractor clients including board audit and compliance committees and has served as a member of various risk management assessment and independent review panels (IRP), including advisor to the New York Thruway Authority for the approximately $4 billion New Tappan Zee Bridge, her appointment by both the Governors of Washington and Oregon to the IRP for the Columbia River Crossing Project, and by the Washington Legislature and Governor as Chair of the Expert Review Panel (ERP) for the $3.5 billion Alaskan Way Viaduct Replacement Program.

Dr. Galloway is often retained as a keynote speaker regarding arbitration, mediation, leadership, women in engineering, and risk management. Dr. Galloway has served as a guest lecturer at multiple universities including: Manhattanville College, the University of Melbourne; UCLA; New York Institute of Technology; Central Washington University; University of Wisconsin; Harbin University of Technology in Harbin, China; the University of Bologna, Italy; the Old Master's Program at Purdue University; University of British Columbia and the West Virginia's University Center for Women's Studies Programs.

The Nielsen-Wurster Group. – 1981-2008

Prior to joining Pegasus-Global, Dr. Galloway was the Chief Executive Officer and Principal of The Nielsen-Wurster Group Inc. (Nielsen-Wurster), an international management consulting firm which specialized in management consulting, risk management and dispute resolution. She served as both a consulting and testifying witness in numerous arbitration forums regarding projects throughout the world: refineries, offshore platforms, oil depots, LNG facilities, petrochemical plants, gas pipelines and compression modules, power plants (wind, nuclear, fossil fuel, gas-fired, combined-cycle, hydroelectric, waste-to-energy, transmission), hotels, casinos, stadiums, commercial offices, hospitals, universities, civic and convention centers, parking garages, process plants, wastewater treatment plants, landfills, airports, highways, bridges, tunnels, mass transit, railroads, port facilities, dams, bulk pharmaceutical plants, manufacturing and other projects.

She was also the Chief Executive of Nielsen-Wurster Asia-Pacific, a Nielsen-Wurster subsidiary corporation, which was located in Melbourne, Australia. In addition, Dr. Galloway served as President of another Nielsen-Wurster subsidiary Nielsen-Wurster ESB, a joint venture with the Electricity Supply Board of Ireland that specialized in power plant maintenance software.

CH2M Hill – 1978-1981

Before joining Nielsen-Wurster, Dr. Galloway was employed by CH2M Hill assigned to the $1.6B Milwaukee Water Pollution Abatement Program (MWPAP). Her responsibilities at CH2M Hill on the MWPAP included preparation of project management training courses, project controls including estimating and critical path scheduling and tunnel inspection, being the first woman tunnel inspector in Wisconsin. In her last role at the MWPAP as the Master Program Scheduler her responsibilities included the preparation and updating of the Program Master Schedule, coordination of all project schedules, involvement with cost engineering functions, preparation of all program / project schedule progress reports for public and client presentations and monitoring compliance with court orders imposed on the Program. Other activities at the MWPAP included authoring a scheduling manual; preparation of bid documents, on-site tunnel inspection, and coordination of a project manager's training series.

Industry Activity – 1978-Present

Dr. Galloway is an internationally recognized leader in the engineering and construction arena. In 2004, she served as the first woman President of the American Society of Civil Engineers (ASCE). Dr. Galloway has been recognized by her peers and is an elected member to the College of Commercial Arbitrators, the National Academy of Construction, the Pan American Academy of Engineering, and the position of Fellow in several professional organizations.

Dr. Galloway is regularly consulted by private and public organizations and government entities on trends in the industry, the media regarding current topics and events, universities seeking input on university curricula, mentor programs, engineering education, research and diversity issues, and professional societies relative to topics of interest to its membership. Her achievements have been highlighted by TED with her TEDx talk on "Are Engineers Human", on Sky News Australia TV, ADR Perspectives, PM Network, *Time* magazine, CNN Lou Dobbs, Discovery Channel, *Engineering News Record*, and Federal Technology Watch. Dr. Galloway was also a blog writer for *Engineering News Record* discussing current trends, challenges, and hot topics in the construction industry.

REGISTRATIONS / CERTIFICATIONS

- Certificate in Dispute Resolution, Pepperdine Law School (Straus Institute)
- Diploma in International Commercial Arbitration, Oxford, Jesus College (CIArb)
- Certificate of Director Education, National Association of Corporate Directors (NACD)
- Professional Engineer in the following U.S. locations:

- Arizona #16978
- Colorado #28566
- Florida #44498
- Georgia #031939
- Kansas #19495
- Kentucky #17690
- Mississippi #25328
- New Hampshire #12184
- Ohio #72520
- New Jersey #GE-29321
- New York #060684-1
- Pennsylvania #PE-046146-R
- Washington #28262
- Wisconsin #21786-006
- Wyoming #PE-4974

- Professional Engineer in the following global locations:
  - Australia, Institution of Engineers Australia, CPEng #1194740
  - Canada, Province of Manitoba #15061
- International Registry of Professional Engineers in the discipline of Civil Engineering, Construction Management by the United States Council for International Engineering Practice (USCIEP) #131
- Certified Examiner, National Council of Examiners for Engineering and Surveying (NCEES) #12046
- Certified Project Management Professional (PMP) #0012-84
- Professional Member of the Royal Institution of Chartered Surveyors, Faculties of Project Management and Risk Management (MRICS)
- Certified Forensic Claims Consultant (CFCC), AACE

ARBITRATION EXPERIENCE

Dr. Galloway is a Fellow of the Charted Institute of Arbitrators (CIArb) and of the College of Commercial Arbitrators (CCA) where she co-chairs its Construction Committee. Dr. Galloway is a member of the American Arbitration Association's (AAA) Board of Directors and its Executive Committee and Past Chair of the AAA's National Construction Dispute Resolution Committee (NCDRC). Her arbitral panel memberships include:

- AAA: Master Mediation, Megaproject, Energy, Commercial, Construction, and, Large Complex Case.
- The International Center for Dispute Resolution (ICDR) Panel, including its International Energy Arbitration List;
- International Center for Conflict Prevention & Resolution (CPR): Energy, Construction, and Cross-Border
- The United States Council for International Business (USCIB) International Chamber of Commerce (ICC) Panel.

She has served as a sole arbitrator, Chair and member of three-member panels arbitrating a large number of disputes involving commercial, construction and energy issues of private and governmental facilities in the energy, process, and building industries. Dr. Galloway has experience with numerous arbitration forums including: ICC, UNCITRAL, Singapore International Arbitration Center (SIAC), and the London Court of International Arbitration (LCIA), with disputes ranging from US$1 million to US$6 billion.

BOARDS AND DIRECTORSHIPS

For-Profit Boards

- Pegasus Global Holdings, Inc., 2000-Present
- Bergmann and Associates, 2012-2016
  - Governance Committee, 2015-2016
  - Future Leader Development Committee, 2013-2016
- Unionville Vineyards (Partner), 1986-2008
- The Nielsen-Wurster Group, Inc., 1984-2008

- Nielsen-Wurster Asia-Pacific Pty. Ltd., 2001-2008
- Unionville Aviation, 1987-2005
- Nielsen-Wurster ESB 1986-1989

Non-Profit Boards

- Central Washington University Foundation Board of Trustees, 2012-Present
  - Treasurer, 2013-2015
- Pacific Science Center, 2012-Present
  - CEO Search Committee, 2014-2015
  - Development Committee, 2013-Present
  - Co-chair of the Festival of Fountains 2014
  - Chair of the Foundations of Science Breakfast 2015
  - Co-chair of the Foundations of Science Breakfast 2014
  - Finance and Audit Committee, 2012
  - Science & Education Advisory Committee, 2012-Present
- Life Support, Board of Trustees (Philanthropic Organization) 2010-Present
- The Patricia Galloway and Kris Nielsen Foundation, 2009-Present
- American Arbitration Association, 2009-Present
  - Executive Committee, 2014-Present
- National Science Board, (Presidential Appointment and Senate Confirmation) 2006-2012
  - Vice Chair, 2008-2010
  - Executive Committee, 2010-2011
  - Chair, 60th Anniversary Committee, 2008-2010
  - Sustainable Energy Task Force Committee, 2007-2009
  - Audit & Oversight Committee, 2006-2012
  - Polar Research Committee, 2006-2012
  - Committee on Strategy & Budget, 2006-2012
  - International Task Force Committee, 2006-2008
- Pan American Academy of Engineering, 2006-2011
- Order of the Engineer, National Board of Governors, 2004-2008
- Project Management Institute, College of Scheduling, 2003-2006
- American Society of Civil Engineers, 1992-1995, 2002-2005
- American Society of Civil Engineers Foundation, 2002-2005
- Construction Institute, 2004-2005
- Civil Engineering Research Foundation (CERF), 2002-2004
- Purdue University Engineering Alumni Board, 1991-2001
- Hoover Medal Award Board, 1996-1999

Advisory Boards / Committees

- Chair, Duke Energy's Coal Ash Basin Closure Program Management Oversight Board, 2015-Present
- University of North Carolina Charlotte (UNCC) National Ash Management Advisory Board, 2015-Present
- Co-Chair, College of Commercial Arbitrators (CCA) Construction Committee, 2015-Present
- Central Washington University President's Advisory Board, 2013-Present
- AAA National Construction Dispute Resolution Committee, Past Chair, Member since 2005
- Seattle Chamber of Commerce Community Development Roundtable, 2013-2014
- Roebling Global Technical School, 2012-2015
- Independent Expert Review Panel for Alaskan Way Viaduct Replacement Project, Chair, 2011-2015

- SR520 Strategic & Technical Advisory Panel (STAT), 2011-2014
- New York Institute of Technology (NYIT) Engineering Dean's Advisory Council, 2011-2016
- Eastern Washington Governor's Business Advisory Council, 2007-2012
- Initiative for Sustainable Infrastructure, 2007-2016
- Major Science Initiatives International Advisory Committee, Canadian Foundation for Innovation, 2011-2012
- Discovery Channel, Science Channel Board of Advisors, 2009-2012
- Independent Review Panel for Columbia River Crossing Bridge Project, 2010
- Construction Industry Institute Advisory Board, 2006-2010, Co-Chair, RT-260, Reimbursable Contracts
- Construction Superconference Advisory Board, 2007-2010
- American Society of Civil Engineers Industry Leadership Council, 2008-2010
- University of Nebraska Charles W. Durham School of Architectural Engineering and Construction Academic Review Team, 2009
- Purdue University Engineering Dean's Advisory Council, 2004-2007
- Engineers for a Sustainable World, Member of Advisory Board, 2003-2007
- National Science Foundation Engineering Directorate Advisory Committee, 2004-2006
- National Science Foundation International Directorate Advisory Committee, 2006
- Civil Engineering Research Foundation (CERF), Member of Corporate Advisory Board, 2001-2005
- Project Management Institute, Publications Advisory Board, 1991-1993
- Extraordinary Women in Engineering Project, 2004-2009

Editorial Boards

- ASCE Journal of Legal Affairs and Dispute Resolution in Engineering and Practice Board, 2009-Present

AWARDS AND HONORS

- Fellow, Chartered Institute of Arbitrators (CiArb), 2015
- Fellow, College of Commercial Arbitrators (CCA), 2014
- Outstanding Director, American Arbitration Association (AAA), May 2014
- The Center for Computer-Assisted Legal Instruction CALI Excellence for the Future Award for Excellence in Arbitration and Advocacy, Pepperdine Law School, March, 2013
- Profiles in Leadership, New York Institute of Technology (NYIT), 2013
- Honorary Doctor of Science, South Dakota School of Mines, December 2011
- Women's Enews.org, 21 Leaders for 21st Century Honoree for, "Architect of Spaces for Women in Engineering and Science," May, 2011
- ASCE 2010 *Journal of Legal Affairs and Dispute Resolution in Engineering and Practice* Best Scholarly, Feature, Case Study Paper Award for "Design Build/EPC Contractor's Heightened Risk – Changes in a Changing World," July, 2010
- National Association of Professional Executive Women (NAPEW) "Woman of the Year" in Prudence Audit Consultation, 2008
- G. Brooks Ernest Award, Cleveland (Ohio) Chapter of ASCE, 2007
- Engineering Excellence and Leadership Award, George Mason University, 2007
- CSI Michelangelo Award Panel of Judges, 2006 - 2007
- Pan American Academy of Engineering, 2006
- Sigma Kappa Colby Award, 2006
- "Who's Who in America," Edition 68, 2005-Present
- Key Women in Energy-Global Awards, Energy Leaders Council, 2005

- National Academy of Construction, 2005
- "Who's Who of American Women," 2004 – Present (listed since 1983)
- "Who's Who in the World," 2004- Present
- "Who's Who in Science and Engineering," 2002-Present (listed since 2002)
- YWCA Tribute to Women Honoree, 2004
- Society of Women Engineers' Upward Mobility Award, 2003
- Kentucky Governor's Award-Kentucky Colonel, 2004
- Lafayette High School Hall of Fame, Inducted 2001
- National Academy of Engineering: Celebration of Women, 2000
- White House Commission: 2000 Design Award, 1999
- Professional Leadership Award, National Professional Women in Construction, 1995
- Purdue University Distinguished Engineering Alumni Award, 1991
- Mercer County Engineer of the Year Award, 1990
- White House Fellowship Regional Finalist, 1990
- Glamour Magazine's Ten Outstanding Young Working Women for 1988
- Somerset County's Outstanding Women in Business and Industry, October 1987
- "Who's Who in America's Emerging Leaders," 1987 - Present
- Engineering News Record, "Top Women in Construction," October 1986
- "Distinguished New Engineer," Society of Women Engineers, 1980

EDUCATION AND COURSES

- Diploma in International Commercial Arbitration, Jesus College, Oxford, Chartered Institute of Arbitrators, 2015
- Certificate in Dispute Resolution, Pepperdine University School of Law, Straus Institute for Dispute Resolution, Malibu, California, 2014
- Ph.D., Infrastructure Systems (Civil) Engineering, Kochi University of Technology, Kochi, Japan, 2005
- M.B.A., New York Institute of Technology, New York, Magna cum Laude, 1984
- B.S., Civil Engineering (double major in Structures and Construction Management), Purdue University, West Lafayette, Indiana, 1978

INDUSTRY/ACADEMIC RESEARCH

- Co-Chair and member of Research Team, *CII Guide to Reimbursable Contracting, Implementation Resource 260-2,* Construction Industry Institute, The University of Texas at Austin, 2011
- Co-Chair and member of Research Team, *CII Construction Industry Institute Reimbursable Contracts, Research Summary 260-1,* Construction Industry Institute, The University of Texas at Austin, 2008-2010
- National Research Council (NRC) Committee for Advancing the Productivity and Competitiveness of the U.S. Construction Industry Workshop, 2008 – 2009
- Kochi University of Technology, Doctoral Dissertation, Engineering Education Reform, 2005

WEBINAR INSTRUCTOR

- American Arbitration Association
- Project Management Institute College of Scheduling
- Engineer Your Life

AUTHORED BOOKS/FORWARDS/CHAPTERS

- *Here Comes the Egg,* Children's book, co-authored with the late Dr. Kris R. Nielsen, Dog-ear Publishing, 2014
- "Dodd-Frank's Impact on the Utility Industry and the "Utility" of the Integrity Index in Assessing Counterparty Risk," co-authored with William Riggins and Lynn Brewer, Chapter, *Business & Corporate Integrity,* ABC-CLIO Publishing, 2014
- Galloway, Patricia D., Nielsen, Kris R., Dignum, Jack L., *Managing Gigaprojects-Advice From Those Who've Been There, Done That,* ASCE Press, Reston, VA American Society of Civil Engineers, 2013
- Galloway, Patricia D., *The 21st Century Engineer: A Proposal for Engineering Education Reform*, ASCE Press, Reston, VA American Society of Civil Engineers, 2007
- "Interview: Patricia Galloway," *Connecting Students to STEM Careers, Social Networking Strategies,* Camille Cole, International Society for Technology in Education, ISBN 978-1-56484-291-6, published 2011
- Foreword to Lunsden, Reese, *The View From Here, Optimize Your Engineering Career From the Start*, Illumina Publishing, 2011
- "Engineering in Government and Public Policy," Section 4.5.3, UNESCO Report, Engineering: Issues, Challenges and Opportunities for Development, United Nations, UNESCO Publishing, 2010 Paris, France
- Galloway's 21st Century Engineer: An Essay Review, , Volume 12 Number 14, October 8, 2009, Robert Calfee, University of California, Riverside, Stanford University, Thomas Stahovich, University of California, Riverside, http://www.edrevv.info/essays/v12n14index.html
- Foreword to Kusayanagi, S.; Niraula, R.; and Hirota, Y., *Principles and Practice of International Construction Project Management*, EIKO-SHA, Tokyo, Japan, 2009
- Foreword to Williams, F. Mary and Emerson Carolyn J. , *Becoming Leaders*, ASCE Press, Reston, VA, American Society of Civil Engineers, 2008
- Foreword to Hatch, Sybil E., *Changing our World: True Stories of Women Engineers*, ASCE Press, Reston, VA, American Society of Civil Engineers, 2006
- "Anticipating Problems: Project Risk Assessment and Project Risk Management," co-authored with K. Nielsen, Chapter 6, *Collaboration Management, New Project and Partnering Techniques*, edited by H. Shaughnessy, John Wiley & Sons 1994

MEMBERSHIPS

- American Bar Association (ABA)
  - Forum Committee on the Construction Industry, 2013-Present
  - Dispute Avoidance & Resolution Committee, 2013-Present
  - International Construction Committee, 2013-Present
  - Section of International Law, 2013-Present
- American Nuclear Society (ANS)
- American Society of Civil Engineers (ASCE) (Fellow)
  - Past President, 2004 - 2005
  - National President, 2003 - 2004
  - National President-Elect, 2002 - 2003
  - International Director of the Board, August 1992 - 1995
- Association for the Advancement of Cost Engineering International (AACEI) (Fellow)
  - Chair, National Committee-Women in Project Controls, 2004 - 2005
  - Member, National Planning and Scheduling Committee, 2003-2011

  - Member, Executive Director Search Committee, 2009-2010
- Association for International Arbitration (AIA)
- Chartered Institute of Arbitrators (CIArb) 2014-Present
- Chi Epsilon (National Civil Engineering Honor Society)
- College of Commercial Arbitrators (CCA)
  - Construction Committee, Co-Chair, 2015-Present
  - International Committee
  - Energy Committee
- Construction Institute (CI)
- Dispute Review Board Foundation (DBRF)
- Institution of Civil Engineers, United Kingdom (ICE) (Fellow)
- Institution of Engineers - Australia (Fellow)
- Inter-Pacific Bar Association (IPBA)
  - Member of Committee "T", Construction, 1999 - Present
- Japan Society of Civil Engineers (JSCE)
- National Academy of Construction (NAC)
- National Association of Corporate Directors (NACD)
- National Council of Examiners for Engineering and Surveying (NCEES)
- Order of the Engineer
- Pan American Academy of Engineers
- Project Management Institute (PMI)
  - Chair, 3rd International College of Scheduling Conference, Orlando, Florida, April 2006
  - Chair, Board of Directors, College of Scheduling, 2003 - 2006
  - Chair, 2nd International College of Scheduling Conference, Scottsdale, Arizona, May 2005
  - Chair, International College of Scheduling Conference, Montreal, Canada, April 2004
  - Member, Publications Advisory Board, 1991 - 1993
- Society for Social Management Systems
  - Honorary Chair, 2011-present
  - Chair, 2006 - 2010
- Tau Beta Pi (Honorary Member)

TECHNICAL PAPERS AND PRESENTATIONS

Dr. Galloway is a prolific writer and world renowned speaker having authored over 120 papers, 30 peer reviewed journal articles and nearly 200 public speaking (including over 45 keynote addresses) engagements regarding leadership, corporate governance, ethics and professionalism, communication, risk management, dispute resolution, contract administration, program and project management, project controls, women in engineering and other topics.

Dr. Galloway has also been featured in many international publications:

- "Why are There Still So Few Women in Construction", Seattle Daily Journal of Commerce, March 3, 2016
- "Former ASCE President Leads Expertise to High-Speed Transportation Project", *Civil Engineering News,* Published by ASCE, December, 2013
- "Petticoats and Slide Rules," *PE, The Magazine for Professional Engineers,* published by NSPE, July, 2014
- "Risk by the Numbers," *PM Network,* Project Management Institute, March 2012, Volume 26 Number 3
- "STEM to the Rescue?" *PE, The Magazine for Professional Engineers,* published by NSPE, March, 2012

- "Patricia Galloway: Changing the Face of Construction and Engineering," *ENR New York, A Supplement to Engineering News-Record,* October 10, 2011
- "Staying Smart: Engineers and Universities Advance Career-Long Learning," *ENR.com,* October 31, 2011
- "Interview with Dr. Patricia Galloway: CEO of Pegasus Global Holdings Inc. and First Woman President of the American Society of Civil Engineering," The Daily Femme, New York., April 25, 2011
- *PM Network Magazine*, Project Management Institute, March 2011 Vol. 25, No. 3 "Too Big to Handle? Megaprojects and meeting the triple constraints"
- *Public Works Magazine,* March 2011, Op-ed article: "Something Fishy with Failures?"
- ASCE Industry Leaders Council, Monthly "Insights – Perspectives from Civil Engineering Industry Leaders," podcast, January 31, 2011
- "2011 – Seven Who Blaze New Pathways," 21 Leaders for the 21st Century, Women's Enews.org, January 4, 2011
- "Engineering Future Success For Students," NYIT Magazine, Winter, 2011
- Curiosity Project, Discovery Channel, Screening in 2011
- *National Society of Professional Engineers*, Member Spotlight, Fall, 2010
- *New York Institute of Technology Magazine*, Summer 2010, Volume 8, Number 3, Cover and Feature Article, "Top of Their Game"
- *Flynn's Harp*, July 21, 2010, Feature Article, "Is Gulf Spill Oil Industry's Three Mile Island?"
- Touch Stone International Learning Management System, Online English Teaching Program, February 2010
- Interview with Patricia D. Galloway, *ADR Perspectives*, February 2010
- *Federal Technology Watch*, "Interview with National Science Board Vice Chair," January 26, 2009
- Profile of Patricia Galloway. Hatch, Sybil, *Changing Our World: True Stories of Women Engineer,* American Society of Civil Engineers, 2006
- "Building a Better Role Model," Continental Airline's *In-Flight* Magazine, November 2005 Issue
- Bad Idea. You'll Flunk Out. *Time* Magazine, Science Section, First Person: Pat Galloway, Authored by Deirdre Van Dyk, March 7, 2005 Issue
- America's Infrastructure, Live Media Radio and Television appearances in over 25 cities across the United States, October 2004
- *Engineering Marvels-Seven Modern Engineering Wonders of the World*, Co-host to ABC / Discovery Channel Television Series, April, 2004
- People "Pat Galloway: Civil Engineer, Company CEO," by Kathleen McGinn, *U.S.1 Newspaper*, New Jersey, February 3, 2003
- "First Woman President Installed to Lead Civil Engineering Society," *EWRI Currents*, Vol. 5, No. 4 Winter 2003/2004
- "Going International: Profit or Peril?", Interview with Patricia D. Galloway, Executive Vice President, The Nielsen Wurster Group, Inc., *Worldwide Projects*, Spring 1993

Arbitration / Mediation / Dispute Resolution

Publications

- "The Art of Allocating Risk in an EPC Contract to Minimize Disputes", International Bar Association Annual Conference, Washington DC, September 14, 2016
- "Streamlining the Arbitration Process Through Innovative Methods of Handling Fact Witnesses", International Bar Association, *Construction Law International*, Vol. II, Issue 2, June 2016
- "Is Construction Arbitration Ready for Online Dispute Resolution?" *International Construction Law Review,* Informa, Volume 30, Part 2, April, 2013
- "Engineering a Successful Negotiation," *Journal of Legal Affairs & Dispute Resolution in Engineering and Construction,* American Society of Civil Engineers, Volume 5, Number 1, February 2013

- "Dispute Resolution Under FIDIC – The Parties' Options," co-authored with L. Martinez and M. Marra, *Transnational Dispute Management (TDM) Journal,* TDM 7 November, 2012, www.transnational-dispute-management.com
- "Using Experts Effectively and Efficiently in Arbitration," *Dispute Resolution Journal,* American Arbitration Association, September/October 2012
- "Mapping Strategies for a Successful Mediation," co-authored with K. Nielsen, *Nepal Council of Arbitration (NEPCA) Half Yearly Bulletin,* Volume 18, February, 2012
- "Mapping Strategies for a Successful Mediation," co-authored with K. Nielsen, *Construction Law International,* International Bar Association, Volume 6, Issue 4, December 2011
- "Saving Time by Using Experts Effectively in Arbitration," Superconference, San Francisco, December 16, 2011
- "The Engineer's "Study Notes" for Understanding the Arbitration Process," *Journal of Legal Affairs and Dispute Resolution,* American Society of Civil Engineers, Volume 3, Number 2, May 2011
- "Arbitration is Voluntary and a Creature of Contract and Party-Appointed Arbitrators," American Bar Association, Mid-Winter Meeting of the Construction Forum Proceeding, New York City, January 20, 2011
- "Is Mediation a Real Option for Resolving Disputes?," Blog, *Engineering News Record*, June, 2009
- "Cumulative Impact, Current Trends in Construction Law," International Project Management and Dispute Resolution: The South Central American Project, International Arbitration Disputes Conference in conjunction with Peckar & Abramson; São Paulo, Brazil, June 5 – 6, 2006
- Delay: Use of CPM Schedules for Concurrency, Allocation, Proof, and Window Analysis, Proceedings, Hurry Up and Slow Down: Dealing with Delays in Construction, American Bar Association Forum on the Construction Industry Conference, New York, New York, January 23, 1997
- "The Contractor's Right to Finish Early," Proceedings, Hurry Up and Slow Down: Dealing with Delays in Construction, American Bar Association Forum on the Construction Industry Conference, New York, New York, January 23, 1997
- "CPM Schedule Delay: Window Analysis, Concurrency, and Proof," co-authored with K. Nielsen and M. Ramey, World Conference on Construction Risk, Paris, France, April 28 - 29, 1994
- "Disruption / Productivity Cost Claim Analyses," co-authored with K. Nielsen, Construction Disputes-Analysis and Management, Winnipeg, Canada, November 1 - 5, 1993
- "CPM Scheduling Delay: Window Analysis, Concurrency and Proof," co-authored with K. Nielsen and M. Ramey, Construction Disputes-Analysis and Management, Winnipeg, Canada, November 1 - 5, 1993
- "Using an Expert Effectively in ADR," Resolving Disputes in International Construction Contracts Through ADR Techniques, AAA & Nielsen-Wurster conference proceedings, Geneva, Switzerland, November 12 – 13, 1992
- "Overcoming Schedule Delay-Analyzing and Resolving this Project Nemesis," co-authored with K. Nielsen, IIR National Construction Conference, Sydney, Australia, August 28 - 29, 1991
- "International Construction Dispute Proofs," co-authored with K. Nielsen, Nordnet '91 Transactions: The Practice and Science of Project Management, Trondheim, Norway, June 3 - 5, 1991
- "Pricing and Proving Contractor Claims for Changes in Scope and Unforeseen Conditions," Proceedings, Construction Litigation Superconference, Andrews Conferences, Inc., April 11 - 12, 1991
- "Computerized Document Control-The Expert Witness's View," co-authored with Pamela Moon, The *International Construction Law Review Journal*, Volume 8, Part 2, April 1991
- "Pricing and Proving Contractor Claims for Changes in Scope and Unforeseen Conditions," Proceedings, Construction Litigation Superconference, Andrews Conferences, Inc., December 6 - 7, 1990
- "Contract Administration," Proceedings, Arbitration and Mediation Construction Claims Seminar, American Arbitration Association, Charleston, West Virginia, November 1, 1990
- "Resolving Claims: Selecting the Right Alternative," AAA 'Resolving Construction Disputes,' Hershey, Pennsylvania, October 5, 1990

- "Evaluating the Contractor's Right to Finish Early," co-authored with K. Nielsen, Project Management Institute Book of Proceedings, Calgary, Alberta, Canada, October 16, 1990
- "Concurrent Schedule Delay in International Contracts," co-authored with K. Nielsen, *The International Construction Law Review*, Volume 7, Part 4, pp. 386 - 401, October 1990
- "Schedule Delay Concurrency Issue Analysis & Proof," co-authored with K. Nielsen, Proceedings, International Cost Congress, Paris, France, April 1990
- "Pricing, Proving and Calculating Construction Claims," Proceedings, Construction Litigation Superconference, Andrews Conferences, Inc., April 6 - 7, 1989
- "Proof Development for Construction Litigation," co-authored with K. Nielsen, *The American Journal for Trial Advocacy*, Volume 7, No. 3, Cumberland School of Law of Samford University, Birmingham, Alabama, Summer 1984; Yearbook of Construction Articles, Volume 4, Federal Publications, 1985
- "Second Guessing the Engineer," co-authored with K. Nielsen, *Civil Engineering*, American Society of Civil Engineers, November 1985
- "Avoiding Lengthy and Costly Litigation by Negotiation Resolution Methods," co-authored with K. Nielsen, Proceedings, American Society of Civil Engineers Spring Convention, Denver, Colorado, April 1985
- "Window Analysis: An Innovative Concept to Schedule Delay Analysis," co-authored with K. Nielsen, Project Management Institute, Philadelphia, Pennsylvania, October 1984
- "Schedule Delay: A Productivity Analysis," co-authored with K. Nielsen, and J. Leverette, Project Management Institute National Convention Proceedings, Houston, Texas, October 1983

Conference Presentations / Teaching / Instruction

- Panelist, "International Construction and Infrastructure Projects; The Latest Conflict-Management Options", Rio de Janeiro, Brazil, November 18, 2015
- Panelist, "Effective Advocacy and Management in Arbitration: The Efficient Hearing," American Arbitration Association (AAA)'s Forum on the Construction Industry, April, 2015
- "Megaproject Arbitration-Why It's Different", American Arbitration Association, Construction Conference, Santa Monica, CA, March 26, 2015, Panel Member
- "Retooling Arbitration for Mega Project Construction Claims," Construction Superconference in Las Vegas, NV, December 2014, Panel Member
- "Managing Megaprojects in the Midst of Adversity," American Society of Civil Engineers (ASCE) Global Engineering Conference in Panama City, Panama, October 2014
- "Construction Mediation and the User Experience; Pathways to Settlement and Satisfaction," Associated General Contractors (AGC), Webinar presented with Harold Coleman, June 2014
- "Recent Construction Case Law Blitz," Construction Superconference in San Francisco, CA, December 2013, Panel Member
- " What Advanced Arbitration Procedures Do In House Counsel Most Favor and What Do Neutrals Say About Them", Construction Superconference, San Francisco, CA, December 2013, Panel Member
- "Contract Risk Reviews-Getting it Right Before Tender", Cutting Edge 2013: Conference on Megaprojects in Seattle, WA, November 2013
- "The Future of Dispute Boards in the Power Industry," Dispute Resolution Board Foundation, Facilitator, September 2013. Miami Beach, FL
- "The Art of Attorney Advocacy in Complex Energy and Commercial Arbitration," Energy Bar Association and International Institute for Conflict Prevention and Resolution, presented with Robert Wax, Steve Shapiro and Duncan MacKay, Washington, D.C., June 7, 2013
- "Using Experts Effectively in Arbitration by Counsel and Neutrals," American Arbitration Association Webinar, presented with Stanley P. Sklar, April 30, 2013
- "Online Dispute Resolution: The Next-Generation Construction ADR Process," North West Dispute Resolution Conference, American Arbitration Association, Seattle, March 29, 2013

- "Contractually Specified Alternative Dispute Resolution," FIDIC Americas Contract Users' Conference, New York City, October, 3, 2012
- "Optimizing Your Client's Construction Arbitration Hearing," co-presented with Mr. Albert Bates, American Arbitration Association Spring Conference, New York City, June 1, 2012
- "Building the Construction Arbitration Process to Optimize its Advantages," American Arbitration Association / International Centre for Dispute Resolution Neutrals Conference, Scottsdale, Arizona, March 9 – 10, 2012
- "Arbitration is Voluntary and a Creature of Contract and Party-Appointed Arbitrators," American Bar Association, Mid-Winter Meeting of the Construction Forum Proceeding, New York City, January 20, 2011
- "Construction Dispute Resolution in the U.S. – International Techniques That Can Be Used Domestically," American Arbitration Association Webinar, presented with Albert Bates, May 10, 2010
- Panel Member, "Controlling the Discovery Monster in Arbitration," NW Dispute Resolution Conference in Seattle, May 1, 2010
- Moderator, The Cultural and Legal Landscape to Consider – Regional Considerations for International Construction Projects, 8th Annual Miami International Arbitration Conference, March 21 - 22, 2010
- "Hot Topics in International Construction Dispute Resolution," American Arbitration Association Webinar, presented with John W. Hinchey, September 10, 2009
- "Construction Delay-How Opposing Experts Can Come to Different Conclusions From the Same Set of Facts: Honest Mistake, System Failure or Deceptive Practice," Construction Claim Advisor - Audio Conference, November 12, 2007
- Panel Member, "Intellectual Honesty in Proving Delay," Project Management Institute College of Scheduling Conference, Vancouver Canada, April 17, 2007
- "Common Disputes on Light Rail Transit Projects and How to Resolve Them," Construction Superconference, San Francisco, California, December 7 - 8, 2006
- "Cumulative Impact, Current Trends In Construction Law," International Project Management and Dispute Resolution: The South Central American Project, São Paulo, Brazil, June 5 - 6, 2006
- Panelist, "Intellectual Honesty in Proving Delay," Federal Board of Contract Appeals, Hilton Alexandria Mark Center, Alexandria, Virginia, April 3, 2001
- "Analyzing Schedule Delay, Minimizing Risks in Construction Projects and Resolving Construction Disputes," Hong Kong, September 28 - 29, 1998
- "Delay: Use of CPM Schedules for Concurrency, Allocation, Proof, and Window Analysis, Hurry Up and Slow Down: Dealing with Delays in Construction," American Bar Association Forum on the Construction Industry Conference, New York, New York, January 23, 1997
- "The Contractor's Right to Finish Early, Hurry Up and Slow Down: Dealing with Delays in Construction," American Bar Association Forum on the Construction Industry Conference, New York, New York, January 23, 1997
- "Delay: Use of CPM Schedules for Concurrency, Allocation, Proof, and Window Analysis," Taisei Corporation P.M. Conference, Tokyo, Japan, October 31, 1996
- "CPM Schedule Delay: Window Analysis, Concurrency, and Proof," World Conference on Construction Risk, Paris, France, April 28 - 29, 1994
- "Disruption / Productivity Cost Claim Analyses," Construction Disputes-Analysis and Management, Winnipeg, Canada, November 1 - 5, 1993
- Co-presenter, "Schedule Delay Analysis & Early Completion," Nielsen-Wurster Seminar on Managing Risk and Minimizing Disputes in Construction Contracts, Hilton Head Island, South Carolina, October 6 - 8, 1993
- "CPM Scheduling Delay: Window Analysis, Concurrency and Proof," Construction Disputes-Analysis and Management, Winnipeg, Canada, November 1 - 5, 1993
- Co-presenter, "Schedule Delay Analysis," WASHTO Annual Conference, Oklahoma City, Oklahoma, June 23 - 24, 1993

- Presenter, "Early Completion Claim Analysis and Expert Delay Analysis," The Nielsen-Wurster Seminar on Construction Issues Facing the Public Transportation Industry, Sacramento, California, April 28 - 30, 1993
- Co-presenter, "Utilizing an Expert Effectively in ADR," Resolving Disputes in International Construction Contracts through ADR, AAA and Nielsen-Wurster conference, Geneva, Switzerland November 12 - 13, 1992
- "International Construction Law – Opportunities and Risks in the '90's", The American Bar Association Forum on the Construction Industry, Stouffer Mayflower Hotel, Washington, D.C., November 5 – 6, 1992
- "Analyzing Scheduling Delays by Use of Window Analysis," The Nielsen Wurster Seminar on Managing and Resolving Construction Disputes, Lake Tahoe, Nevada, March 1992; San Diego, California, April 1992; Key West, Florida, October 1992
- "Overcoming Schedule Delay-Analyzing and Resolving this Project Nemesis," IIR National Construction Conference, Sydney, Australia, August 28 - 29, 1991
- "Pricing and Proving Contractor Claims for Changes in Scope and Unforeseen Conditions," Construction Litigation Superconference, Andrews Conferences, Inc., April 11 - 12, 1991
- "Pricing and Proving Contractor Claims for Changes in Scope and Unforeseen Conditions," Construction Litigation Superconference, Andrews Conferences, Inc., December 6 - 7, 1990
- "Contract Administration," Arbitration and Mediation Construction Claims Seminar, American Arbitration Association, Charleston, West Virginia, November 1, 1990
- "Resolving Claims: Selecting the Right Alternative," American Arbitration Association, Hershey, Pennsylvania, October 5, 1990
- Co-presenter, "Construction Dispute Seminar," Florida Department of Transportation, Tallahassee, Florida, August 1989
- "Pricing, Proving and Calculating Construction Claims," Construction Litigation Superconference, Andrews Conferences, Inc., April 6 - 7, 1989
- "Analyzing Schedule Delays By Use of Window Analyses," The Nielsen Wurster Group Construction Disputes Seminar, San Antonio, Texas, April 1991; New Orleans, Louisiana, April 18 - 20, 1988
- "Construction Delay Analysis," The Nielsen-Wurster Group Construction Disputes Seminar, New Orleans, Louisiana, April 18 - 20, 1988
- "Pricing Contractor's Claims," American Society of Civil Engineers Course, "Construction Claims," Anchorage, Alaska, March 1986; San Francisco, California, May 1987
- "Window Analysis: An Innovative Concept to Schedule Delay Analysis," Project Management Institute, Philadelphia, Pennsylvania, October 1984
- "The Use of Schedules in Claim Preparation," The Nielsen-Wurster Group Construction Dispute Proofs Seminar, Conference, New Orleans, Louisiana, 1988 and 1989; Seattle, Washington, 1987; Lake Buena Vista, Florida, May 18 - 20, 1983; Minneapolis, Minnesota and Denver, Colorado, April 1984; Tampa, Florida and Boston, Massachusetts, May 1984
- "Schedule Delay: A Productivity Analysis," Project Management Institute National Convention, Houston, Texas, October 1983

Management / Prudence / Performance Audits

Publications

- "Cost-Recovery for Pre-Approved Projects," co-authored with David L. Cousineau, *Public Utilities Fortnightly*, June 2013
- "Leadership and Risks during a Global Financial Crisis," co-authored with K. Nielsen and J. Dignum, *The Fifth Civil Engineering Conference in the Asian Region* (CECAR5), Sidney, Australia, August 9-11, 2010
- "New Day for Prudence," co-authored with K. Nielsen and Charles W. Whitney, *Public Utilities Fortnightly,* December 2009

- "Design-Build/EPC Contractor's Heightened Risk-Changes in a Changing World," *Journal of Legal Affairs and Dispute Resolution,* American Society of Civil Engineers, February 2009, Volume 1, Number 1."
- "The Ubiquitous Requirement of Performing to High International Standards," co-authored with K. Nielsen, published Proceedings, The Second Civil Engineering Conference in the Asian Region, Tokyo, Japan, April 16 - 18, 2001
- "Combining PURPA, Prudence and Avoided Cost Rate Design; A New Cost Engineering Environment," co-authored with K. Nielsen, Proceedings, American Association of Cost Engineers 9th Annual Mid-Winter Symposium Transactions, San Francisco, California, February 1987. Reprinted, Cost Engineering, Volume 31, No. 1, page 16, January 1989
- "The 5-Year Living Schedule," co-authored with R. Cochran, American Association of Cost Engineers Annual Convention, Atlanta, Georgia, June 1987
- "Preparing for the Utilities' Future-Managing the Prudence Issues," co-authored with K. Nielsen, *Electric Potential*, Volume 2, No. 4, July - August 1986
- "Utilities Forced Delays-Controllable or Uncontrollable," co-authored with K. Nielsen, Proceedings, American Association of Cost Engineers Annual Convention, Chicago, Illinois, June 1986
- "Preparing for Utilities Future-An 'Attack Plan' for Minimizing Disallowable Costs In Outage and Future Capital Construction," co-authored with K. Nielsen, American Association of Cost Engineers, 8th Annual Mid-Winter Symposium Transactions, New Orleans, Louisiana, February 1986; Project 2, 5th Annual Outage Symposium Proceedings, Cambridge, Massachusetts, May 1986
- "Utility Prudence Time Impact Evaluation," American Association of Cost Engineers Annual Convention Transactions, Denver, Colorado, July 1985
- "The Prudence Management Audit: A New Challenge For the Civil Engineer," co-authored with K. Nielsen, American Society of Civil Engineers Spring Convention, Denver, Colorado, April 1985
- "Performance Audits," co-authored with D. Law, Proceedings, Project Management Institute Symposium, Toronto, Ontario, Canada, October 1982

Conference Presentations / Teaching / Instruction

- "The Nuclear Industry Post-Fukushima," *Platts 8th Annual Nuclear Energy Conference*, Bethesda, Maryland, February 9, 2012
- Deutsche Bank "Road Show," London, U.K., June 8 – 12, 2010
- Deutsche Bank "Road Show," London, U.K., April 20 – 24, 2009
- Utilities Serving Our Needs: US Experience in Serving Its Communities, National Engineering Forum-Energy, Water and Telecommunications, Cooma, NSW, Australia, April 21, 1999
- Panel Moderator, "The Multi-Billion Dollar Issue Facing the Nuclear Power Industry: Decommissioning Versus Life Extension," The Future of the US and International Environmental Industry, Washington, D.C., November 10 - 12, 1997
- Co-presenter, "Electric Utility Capital Project Prudence Issues," National Association of Regulated Utility Commissioners Annual Meeting, Hartford, Connecticut, May 1985
- Co-presenter, "Prudence Concepts," American Association of Cost Engineers, Ramapo Section, April 1985
- "Performance Audits," Project Management Institute Symposium, Toronto, Ontario, Canada, October 1982

Program/Project Management

Publications

- "Engineer's Liability Considerations in Specifying Corrugated High Density Polyethylene (HDPE) Pipe," *Journal of Professional Issues in Engineering Education & Practice* American Society of Civil Engineers, January 2008

- "Managing Risks on Defense Projects Using CPM Scheduling," co-authored with Ed Blow, Scheduling The Next Generation: Third PMI College of Scheduling Conference, Orlando, Florida, April 23 - 26, 2006
- "CPM Scheduling - How Industry Views Its Use, Cost Engineering," *The AACE International Journal of Cost Estimation, Cost / Schedule Control, and Project Management*, January 2006
- "Is Our Perspective Truly Global?", American Society of Civil Engineers, *ASCE News*, April 2004
- "CPM Scheduling-Its Importance in Monitoring and Demonstrating Construction Progress," published proceedings, Japan Society of Civil Engineers, JSCE First International Symposium on Construction and Project Management-Human Resources Development under Globalization, Tokyo, Japan, October 16 - 17, 2003
- "Privatization and the Use of IVHS in the 1990s," Proceedings, ASCE Transportation Conference on IVHS, co-authored with K. Nielsen and M. Ramey, San Diego, California, October 1995
- "The Utilization of Computer Technology in the Presence of Evidence," co-authored with Pamela Moon, La Gestion de los Asuntos Mercantiles en los Juzgados de Primera Instancia, Madrid, Spain, October 26, 1994
- "CPM Schedule Delay: Window Analysis, Concurrency, and Proof," co-authored with K. Nielsen and M. Ramey, Nielsen-Wurster Seminar on Emerging Risks in Construction: How to Minimize, Manage and Avoid Disputes, New Orleans, Louisiana, May 10 - 12, 1995; Indian Wells, California, October 19 - 21, 1994
- "International Contract Administration Issues: Project Documentation, Dispute Proofs, Programmes, Productivity," co-authored with K. Nielsen, IDLI Conference, Rome, Italy, December 12, 1991
- "Delivering a Successful Project, Proceedings, Civil Engineering International Conference on Asian Infrastructure," Sustainable Development and Project Management, Manila, Philippines, February 19 - 20, 1998
- "Defining Scheduling," The Nielsen-Wurster Group Construction Dispute Proofs Seminar Handbook, Conference, New Orleans, Louisiana, 1988 and 1989; Seattle, Washington, 1987; Lake Buena Vista, Florida, May 18 - 20, 1983; Minneapolis, Minnesota and Denver, Colorado, April 1984; Tampa, Florida and Boston, Massachusetts, May 1984
- "Preparing a Project Control Specification," co-authored with K. Nielsen, Proceedings of Eleventh Annual PROJECT / 2 Utility Users Group Conference, Birmingham, Alabama, November 17 - 19, 1986
- "Failure Proof Your Projects," co-authored with K. Nielsen, *Consulting Engineer*, June 1985
- "Scheduling the Super Projects, preprint, Engineering and Construction Projects, The Emerging Management Roles," ASCE Specialty Conference, New Orleans, Louisiana, March 17 - 19, 1982
- "Schedule Control for CPM Projects," co-authored with K. Nielsen, *Journal of the Construction Division*, Proceedings of the Society of Civil Engineers, Volume 107, No. CO2, June 1981

Conference Presentations / Teaching / Instruction

- "The Unique Aspects of Managing Megaprojects in Asia", Keynote, University Lecture Series given at University of Melbourne, March, 2014
- "Hyperloop: Transforming Transportation," UCLA Ideas Lecture Series, co-presented with Marco Villa, January, 2014
- "Managing GigaProjects," Lecture, Construction Management School, Central Washington University, November, 2013
- "The Outlook for Construction in the Power Industry over the Next Decade," panelist, The Construction Superconference, San Francisco, California, December 13, 2012
- "Starting and Growing a Global Business--from Cle Elum, WA," Keynote with Dr. Kris Nielsen, Central Washington University, College of Business Innovation and Entrepreneurship Speaker Series, February, 2012

- "Managing Complex Projects: Best Practices Here & Abroad," panelist, McGraw Hill's Ground Breaking Women in Construction annual conference, The McGraw Hill Companies, New York, New York, May 9, 2011
- "Managing Your Projects to Minimize Disputes," Lecture, Construction Management School, Central Washington University, November 9, 2009
- "Trends in the Construction Industry," U.S. Law Firm Group Construction Committee, Buffalo, NY, October 23, 2009
- "Design-Build Contracting in a Changing World," CH2M Hill in-house design-build conference, Denver, CO, October 10, 2008
- "Reading Between the Pipes," IKO Concrete Pipe Association, Kentucky, June 27, 2008
- "Mega Projects - A Primer for Finance (or How Can Finance Help Improve Results)," Nexen Finance Forum Scottsdale, AZ - Co-presentation with Jack Dignum February 19, 2008
- "Managing Risks on Defense Projects Using CPM Scheduling," Scheduling The Next Generation: Third PMI College of Scheduling Conference, Orlando, Florida, April 23 - 26, 2006
- "CPM Scheduling and How the Industry Views Its Use," Association for the Advancement of Cost Engineering International's 49th Annual Meeting, New Orleans, Louisiana, June 26 - 29, 2005
- Speaker, "CPM Scheduling - How Industry Views its Use," Second Annual PMI College of Scheduling Conference, Scottsdale, Arizona, May 22 - 24, 2005
- "CPM - Current Trends in Education: A Comparative Study Between Europe, Asia and North America," On the Road to Better Scheduling-PMICOS Conference, Montreal, Canada, April 25 - 28, 2004
- PMI Scheduling Practice Standard Panel, On the Road to Better Scheduling-PMICOS Conference, Montreal, Canada, April 25 - 28, 2004
- Moderator, "The Impacts to Public Contracting in a Post 9 / 11 Environment," Luncheon Panel, Construction Super Conference, San Francisco, California, December 2003
- "CPM Scheduling," Visiting Professor, Special Lecture Series, Kochi University of Technology, Kochi, Japan, November 22, 2003
- "Mission of the Civil Engineer in the Movement of Globalization," Michigan Tech University, Houghton, Michigan, January 16, 2003
- Moderator, "Conception to Birth of a Project," Infrastructure 2000, San Francisco, California, June 7, 2000
- "Harmonizing Japanese and US Practices for Effective Project Management," Taisei Corporation M.I.T. Conference, Tokyo, Japan, November 1, 1996
- "Employing Effective Project Management to Achieve Project Success," Taisei Corporation P.M. Conference, Tokyo, Japan, October 31, 1996
- "Tricks of the Trade New Uses and Misuses of CPM Scheduling," BCQS Project Managers Chartered Quantity Surveyors, The Nielsen-Wurster Group Construction Management Consultants, Whitman Breed Abbott & Morgan Construction Attorneys' Seminar on Controlling Construction Risk and Conserving Your Cash, Radisson Hotel, Grand Cayman Islands, February 26, 1996
- "Privatization and the Use of IVHS in the 1990s," ASCE Transportation Conference on IVHS, San Diego, California, October 1995
- Co-presenter, "Construction Scheduling: Preparation, Liability, Claims and Damages," Panama Canal Commission, June 12 - 16, 1995
- "The Utilization of Computer Technology in the Presence of Evidence," co-authored with Pamela Moon, La Gestion de los Asuntos Mercantiles en los Juzgados de Primera Instancia, Madrid, Spain, October 26, 1994
- "CPM Schedule Delay: Window Analysis, Concurrency, and Proof," Nielsen-Wurster Seminar on Emerging Risks in Construction: How to Minimize, Manage and Avoid Disputes, New Orleans, Louisiana, May 10 - 12, 1995; Indian Wells, California, October 19 - 21, 1994

- “The Contractor's Right to Finish Early,” Nielsen-Wurster Seminar on Emerging Risks in Construction: How to Minimize, Manage and Avoid Disputes, New Orleans, Louisiana, May 10 - 12, 1995; Indian Wells, California, October 19 - 21, 1994
- Co-presenter, "Project Manager nei settore delle construzioni," Visiting Professor, University of Bologna, SINNEA, Bologna, Italy, May 25 - 27, 1994
- Co-presenter, "Project Management for Design and Construction," Panama Canal Commission, Panama, June 28 - July 2, 1993
- Co-Presenter, "International Contract Administration Issues: Project Documentation, Dispute Proofs, Programmes and Productivity," Training Workshop on International Construction Contracts and Contractor Claims, The International Development Law Institute (IDLI), Rome, Italy for the Finnish International Development Agency (FINNIDA), Helsinki, Finland, October 13 - 16, 1992
- “Contract Administration,” Master’s Degree Course, SINNEA, Instituto Di Studi Per La Cooperazione E La Piccola E Media Impresa, Bologna, Italy, September 25, 1992
- “Effective Construction Contract Administration,” University of Wisconsin-Madison, College of Engineering, Madison, Wisconsin, April 7 - 10, 1992
- “International Contract Administration Issues: Project Documentation, Dispute Proofs, Programmes, Productivity,” IDLI Conference, Rome, Italy, December 12, 1991
- Co-presenter, "Inefficiency Seminar," Florida Department of Transportation, Deland, Florida, August 1991
- Co-presenter, "Advanced CPM Scheduling," Pennsylvania Department of Transportation, West Palm Beach, Florida, May 1991
- Co-presenter, "Contract Administration," West Virginia Division of Energy, Charleston, West Virginia, March 1991
- Co-presenter, "CPM Scheduling," Kentucky Department of Transportation, Lexington, Kentucky, December 1989
- CPM Scheduling Seminar, Reale, Fosse & Perry, P.C., Pittsburgh, Pennsylvania, November 1989
- Claims Avoidance Seminar, Loney Construction Co., Inc., Keene, New Hampshire, January 1989
- Minimization of Claims Seminar, Weyerhaeuser Paper Company, Jackson, Mississippi; Birmingham, Alabama, November 1988
- “Defining Scheduling,” The Nielsen-Wurster Group Construction Disputes Seminar, New Orleans, Louisiana, April 18 - 20, 1988
- “Scheduling Super Projects,” Visiting Professor, University of Wisconsin, Madison, Wisconsin, January 1987
- “Preparing a Project Control Specification,” Eleventh Annual PROJECT / 2 Utility Users Group Conference, Birmingham, Alabama, November 17 - 19, 1986
- “Construction Claims Prevention and Analysis,” Visiting Professor, University of Wisconsin, Madison, Wisconsin, May 1985, June 1986 and May 1987
- “Defining Scheduling,” The Nielsen Wurster Group Construction Dispute Proofs Seminar, Conference, New Orleans, Louisiana, 1988 and 1989; Seattle, Washington, 1987; Lake Buena Vista, Florida, May 18 - 20, 1983; Minneapolis, Minnesota and Denver, Colorado, April 1984; Tampa, Florida and Boston, Massachusetts, May 1984
- “The Schedule, Its Use and Development,” The Nielsen-Wurster Group Scheduling Seminar, Conference, Atlanta, Georgia, October 1983
- Session Moderator, "Super Projects, Case Studies," ASCE Spring Convention, Philadelphia, Pennsylvania, May 1983
- Session Moderator, "Project Management Control," ASCE Spring Convention, New York, New York, May 1981

Risk Management

Invited and Keynote Presentations

- "Assessing and Remediating Systemic Counterparty Risks," Electric Utility Consultants, Inc. (EUCI), Conference, Baltimore, Maryland, November 8, 2012
- Keynote Address "Role, Responsibility and Risk Considerations of the Engineer Regarding Sustainability," Florida Engineering Society Annual Meeting, Naples, Florida, August 8, 2008
- Keynote Speaker, "Engineer, Contractor and Owner Risk in Constructed Projects," Wisconsin Transportation Builders Association WISDOT Contractor Engineer Conference, Madison, Wisconsin, January 31, 2008
- Keynote Address, "How Leaders Should be Viewing Risk Today," CII Annual Conference, Orlando, Florida, August 1, 2007
- Keynote Address, "Risks and Liabilities in Specifying HDPE Pipe," Mountain States Concrete Pipe Association 5th Annual Concrete Pipe Seminar, Illinois, February 28, 2007
- Keynote Address, "Engineer, Contractor and Owner Risk in Constructed Projects," Wisconsin Transportation Builders Association WISDOT Contractor Engineer Conference, Madison, Wisconsin, January 31, 2007
- Keynote Address, "Risks and Liabilities in Specifying HDPE Pipe," Mountain States Concrete Pipe Association 5th Annual Concrete Pipe Seminar, Salt Lake City, Utah, October 26, 2006
- Keynote Address, "Risks and Liabilities in Specifying HDPE Pipe," American Concrete Pipe Association Fall Short Course, Charlotte North Carolina, October 16, 2006

Publications

- "Risk by the Numbers," co-contributed with Jack Dignum, *PM Network,* Project Management Institute, March 2012, Volume 26 Number 3
- "Design-Build/EPC Contractor's Heightened Risk – Changes in a Changing World," *Journal of Legal Affairs and Dispute Resolution,* American Society of Civil Engineers, February 2009, Volume 1, Number 1."
- "Risk Based Processes that Assure Anti-Corruption Processes and Promote Transparency and Governance in Resource Extraction Industries," co-authored with Kris Nielsen, International Conference on Infrastructure Development and the Environment, Abuja, Nigeria, September 10 - 15, 2006
- "Risk Management-Now More Than Ever," Published Proceeding, World Engineers' Congress, Session C2. Sustainable Development of Mega-cities on Model of Transportation Structure, Model of Public Transportation First and so on, Shanghai, China, November 2 - 5, 2004
- "Basic Project Execution Risk Management," co-authored with J. Dignum, Proceedings, North American Tunneling 2002 Conference, Seattle, Washington, May 18 - 22, 2002
- "Risk Management Analysis Techniques for Projects With Significant Environmental Issues," co-authored with K. Nielsen, Proceedings, ASCE-SAS Second Regional Conference and Exhibition, Beirut, November 16 - 18, 1995
- "Project Risk Management-A Necessity for Today's Engineered Projects," Proceedings of the American Society of Civil Engineers Saudi Arabia Section First Regional Conference and Exhibition on Advanced Technology in Civil Engineering, Manama, Bahrain, September 18 - 20, 1994
- "Anticipating Problems: Project Risk Assessment and Project Risk Management," co-authored with Kris Nielsen, Chapter 6, "*Collaboration Management, New Project and Partnering Techniques*," edited by H. Shaughnessy, John Wiley and Sons 1994
- "Project Risk Management – Achieving Goals," co-authored with K. Nielsen, Proceedings, 11th INTERNET World Congress on Project Management, Florence, Italy, June 16 – 19, 1992

Conference Presentations / Teaching / Instruction

- “Design-Build/EPC Contractor's Heightened Risk - Changes in a Changing World,” Canadian Society of Civil Engineering Conference, May 30, 2009
- “Role, Responsibility and Risk Considerations Of the Engineer Regarding Sustainability,” Florida Association of County Engineers and Road Superintendents, Doral, Florida June 26, 2008
- “The 21st Century Engineer,” Seminar to the Civil Department, Civil Department Advisory Committee and to the Engineering Department, University of British Columbia (UBC) Vancouver, British Columbia, Canada, May 1, 2008
- “Viewing Risks and Liability in Light of Sustainability,” The Environment and Critical Infrastructure, IBTTA Facilities Management Conference, Orlando, Florida, April 29, 2008
- “Role Responsibility and Risk Considerations for the Engineer Regarding Sustainability,” Kentucky American Concrete Pipe Association Conference, Louisville, Kentucky, October 5, 2007
- “How Leaders Should be Viewing Risk Today,” AES Global Engineering & Construction Conference, San Francisco, California, September 18, 2007
- “Risks and Liabilities in Specifying HDPE Pipe,” American Concrete Pipe Association Fall Short Course, San Antonio, Texas, October 13, 2006
- “Risk-Based Processes that Assure Anti-Corruption Processes and Promote Transparency and Governance in Resource Extraction Industries,” International Conference on Infrastructure Development and the Environment, Abuja, Nigeria, September 10 - 15, 2006
- “Basic Project Execution Risk Management,” North American Tunneling 2002 Conference, Seattle, Washington, May 18 - 22, 2002
- Panelist, "Using Risk Management Techniques to Improve the Return on Investment," The Global Construction Superconference, London, United Kingdom, November 5 - 6, 2001
- Presenter, "Risk Assessment & Management," Foster Wheeler Law Department Conference, Warren, New Jersey, October 23 - 24, 2001
- The Industry Forum for Contractors, Owners and Their Attorneys, "The Nielsen-Wurster Group Examines the Risks That Must be Recognized and Managed by Owners and Contractors in a Lump Sum, EPC Project," prepared by William K. Kerivan, presented by Patricia D. Galloway and Marianne C. Ramey, The 14th Annual Construction Industry Networking Nirvana, The Millennium Construction Superconference, The Fairmont Hotel, San Francisco, California, December 9 - 10, 1999
- “Managing the Unknowns in Restarting Projects,” Inter-Pacific Bar Association Ninth Annual Meeting and Conference, Shangri-La Hotel, Bangkok, Thailand, April 30 - May 4, 1999
- Panel Moderator, "Dealing with Risks on Nuclear Waste Sites," The Environmental Superconference, Washington, D.C., April 28 -29, 1999
- Panel Moderator, "Minimizing Risk in Design / Build Projects," Construction Superconference, San Francisco, California, December 10 - 11, 1998
- In-House Training Seminar, "Project Risk Management," Panama Canal Commission, Panama, March 9 - 12, 1998
- Co-presenter, "Panel of Experts-Specific Risks to Consider," World Conference on Construction Risk III, Paris, France, April 25 - 26, 1996
- “Risk Management Analysis Techniques for Projects With Significant Environmental Issues,” ASCE-SAS Second Regional Conference and Exhibition, Beirut, November 16 - 18, 1995
- Co-presenter, "Panel of Experts-Specific Risks to Consider," World Conference on Construction Risk II, Singapore, October 5 - 6, 1995
- “Project Risk Management-A Necessity for Today's Engineered Projects,” ASCE-India Section, Calcutta, India, January 30, 1995
- Co-presenter, "Construction Management and Administration, Construction Claims and Project Risk Management," In-House Training Seminar, Pt. Wijaya Karya, Jakarta, Indonesia, January 23 - 27, 1995

- "New Risks with CPM Scheduling-Tricks of the Trade," Nielsen-Wurster Seminar on Emerging Risks in Construction: How to Minimize, Manage and Avoid Disputes, New Orleans, Louisiana, May 10 - 12, 1995; Indian Wells, California, October 19 - 21, 1994
- "A New Game Plan for Intelligent Risk Identification / Allocation, Charting the Course to the Year 2000-Together!," DART, Hyatt-Lexington, Lexington, Kentucky, October 16 - 19, 1994
- "Project Risk Management-A Necessity for Today's Engineered Projects", Tarumanagara University, Jakarta, Indonesia, May 2, 1994
- Co-presenter, "Project Risk Management," Panama Canal Commission, Panama, April 20 - 22, 1994
- "Project Risk Management-Achieving Goals," 11th INTERNET World Congress on Project Management, Florence, Italy, June 16 - 19, 1992
- Co-chairman, Moderator, "Reducing Risks and Liability through Better Specifications and Inspection," ASCE Specialty Conference, San Diego, California, Spring 1981

Leadership / Ethics / Professionalism

Invited and Keynote Presentations

- Keynote Address, "Unlocking Your Leadership Potential: 4C's to Success", Manhattanville College, Purchase, NY, Women's Institute Inaugural Women's Leadership Symposium, June 3, 2015
- Keynote Address, "Enhancing Your Leadership Skills", American Dental Academy Annual Conference, Tucson, AZ, March 5, 2015
- Keynote Address, "The 21st Century Leader: The Path to Success in a Global Economy," 21st Century Leaders Speaker Series, New York Institute of Technology, New York City, November 3, 2010
- Keynote Address, "Using Organizations to Advance Tomorrow's Leaders," Keynote Luncheon Speaker, Annual Conference, Association for Women in Science Advance Workshop, Washington, D.C., October 29, 2009
- Keynote Address, "Leadership-How Professional Organizations Can Assist," NSF Advance Workshop, Washington, DC., October 29, 2009
- Keynote Luncheon Address, "Ethics and Professionalism-their Importance to Engineers in the 21st Century," Kentucky Society of Professional Engineers, 2008 Annual Convention, Louisville, Kentucky, April 24, 2008
- Keynote Address, "Engineer's Role in Public Policy," International Symposium on Social Management Systems, Three Gorges Dam, China, March 11, 2007
- Keynote Address, "Engineering Leadership in the 21st Century," Second Annual Luncheon at George Mason University, Fairfax, Virginia, January 30, 2007
- Keynote Address, "The Engineer's Role and Responsibility in Specifying HDPE Pipe," American Concrete Pipe Association Short Course, Nashville, Tennessee, May 5, 2006
- Keynote Address, "Leadership, Stewardship and Control," 9th Australian International Performance Management Symposium, Canberra, Australia, March 1, 2006
- Keynote Address, "What it Takes to be a Leader," Evening with Industry; California Polytechnic State University, San Luis Obispo, California, January 27, 2006
- Keynote Address, "The Engineer's Role and Responsibility in Specifying HDPE Pipe," American Concrete Pipe Association Short Course, Las Vegas, Nevada, November 9, 2005
- Keynote Address, "Leadership," *Visiting Professor, Special Lecture Series, Kochi University of Technology*, Kochi Japan, November 22, 2004
- Opening Keynote Speaker, "Leadership and Professionalism," Rebuilding Together Annual Convention, Seattle, Washington, October 2004
- Keynote Speaker, "The Engineers Role in Public Policy, Globalization and Ethics and Professionalism," ASCE Annual Leadership Conference, New Orleans, Louisiana; New York, New York; Portland, Oregon; Chicago, Illinois, January - March 2004

- Keynote Speaker, "Ethics and Professionalism," *Tau Beta Pi Annual Awards and Induction Dinner at eh University of Florida*, December 2003
- Keynote Speaker, "Ethics and Professionalism," Society of American Military Engineers Annual Conference, Seattle, Washington, May 2003
- Keynote Dinner Address, "Motivating the Engineer," Project Management Institute, Delaware Chapter Meeting, Wilmington, Delaware, October 1989

Publications

- "Educating the Master Builder of the 21st Century Strategically," *Leadership and Management in Engineering,* American Society of Civil Engineers, Volume 11, Number 2, April 2011
- "Using Professional Organizations To Advance Tomorrow's Leaders," *Leadership and Management in Engineering,* American Society of Civil Engineers, October 2010, Volume 10, Number 4, pp 141 – 143
- "Ethics, Standards of Care and Your Engineering Profession," *Kentucky Engineer*, Official Publication of the Kentucky Society of Professional Engineers, Volume 44, Fall 2007 Panel Member, "Key to Company Success in Today's Global Market," Shaping the Future: Global Talent Leadership in Engineering, Princeton, New Jersey, November 2, 2006
- "The Urgent Need for Leadership in Project Controls Management Ethic," Proceeding, 9th Australian International Performance Management Symposium, Canberra, Australia, February 2, 2006
- "Innovation-Engineering a Better Engineer for Today's Work Force," *Journal of Leadership and Management in Engineering*, American Society of Civil Engineers, Volume 4, Issue 4, pp. 127 - 132, October 2004
- "Lest We Forget-The Engineering Heroes," American Society of Civil Engineers, *ASCE News*, September 2004
- "What Do Dmitrov, Russia, and a Civil Engineer's Dream Have in Common?", American Society of Civil Engineers, *ASCE News*, August 2004
- "Engineers Laugh at Lawyers and Legal Issues, but Should They?", American Society of Civil Engineers, *ASCE News*, July 2004
- "Governance Restructuring: Leading ASCE into the Future," American Society of Civil Engineers, *ASCE News*, June 2004
- "ASCE's Institutes: Inclusive or Divisive," American Society of Civil Engineers, *ASCE News*, March 2004
- "Professionalism-Have We Forgotten?", American Society of Civil Engineers, *ASCE News*, February 2004
- "Public Policy: Friend or Foe in Advancing the Civil Engineering Profession," American Society of Civil Engineers, *ASCE News*, January 2004
- "Our Enthusiasm Can Be Persuasive," American Society of Civil Engineers, *ASCE News*, December 2003
- "Faculty Licensure-Will it Better the Profession?", American Society of Civil Engineers, *ASCE News*, November 2003
- "Innovative Benefits In a Small Consulting Firm," ASCE *Journal of Leadership and Management in Engineering, Winter* 2001, Volume 1, Number 1, pp. 45 - 47
- "Adjust Work Arrangements to Entice, Retain Professionals," *Engineering News Record*, Viewpoint Column, January 3 - 10, 2000

Conference Presentations / Teaching / Instruction

- "Ethics and Professionalism-Their Importance in the Oil and Gas Industry," Offshore Technology Conference, Houston, Texas, May 1, 2006
- "Professionalism," Visiting Professor, Harbin University of Technology, Harbin, China, November 1, 2004
- "Leadership and Professionalism," Boeing Corporation, Seattle, Washington, July 2004

- "Leaders and Leadership," Visiting Professor, Special Lecture Series, Kochi University of Technology, Kochi, Japan, November 20, 2003
- "Roles and Responsibilities of a Board Director," ASCE Board Orientation, Nashville, Tennessee, November 2003
- "Innovative Benefits in a Small Consulting Firm," 1999 ASCE Civil Engineering Conference and Exposition, Charlotte Convention Center, Charlotte, North Carolina, October 17 - 20, 1999
- Panel Moderator, "Management of Construction Risk on Infrastructure Projects in Latin America," The Latin American Market, The Fourth Annual Conference, Turnberry Isle Resort & Club, Aventura, Florida, November 17 - 19, 1998
- "Project Controls and Their Significance on International Projects," AusAID, Canberra, Australia, August 21, 1998
- "Delivering a Successful Project, Worldwide Infrastructure Partnerships," New York, New York, June 24, 1998
- "Civil Engineering with Stars and Stripes," presented at a joint ASCE / ICE Meeting, Epsom, United Kingdom, July 5, 1994

Engineering/STEM Education

Invited and Keynote Presentations

- "Are Engineers Human," TEDx Manhattan Beach, Manhattan Beach, CA, November 2014
- "Expanding Your Horizon," STEM Workshop, Central Washington University, Ellensburg, WA, March 2014
- "Successful K-12 STEM Education," Project Lead The Way, Pacific Science Center, Seattle, Washington, February 28, 2012
- Commencement Speaker, December 2011 graduating class, South Dakota School of Mines, Rapid City, South Dakota, December 17, 2011
- Keynote Address, "Why it's Cool to be an Engineer," Morgan Middle School, Annual Career day, Ellensburg, WA, February 18, 2011
- Keynote Address: "My Personal STEM Story," Open Forum to Engineering School, North Dakota State University, January 31, 2011
- Keynote Address, "Teachers – The Key to Empowering our Nation's Engineering Resources," Project Lead The Way (PLTW), Counselor Conference, Seattle University, Seattle, WA, December 13, 2010
- Keynote Address, "The Critical Need to Change the Face of Science and Engineering," Discovery Channel STEM Discovery Conference, Silver Springs, MD, August 5, 2010
- Keynote Address, "The 21st Century Engineer," The University of Texas at Arlington, Arlington, Texas, April 14, 2010
- Keynote Opening Address, Society of Social Management Systems 2010 Annual Symposium, Kochi University, Kochi, Japan, February 4, 2010
- Keynote Address, "Challenges Facing the Civil Engineer of the 21st Century," Canadian Society of Civil Engineering Conference, New Foundland, May 28, 2009
- Keynote Luncheon Address, "The 21st Century Engineer," Engineer's Week, University of Kentucky, Lexington, KY, February 20, 2009
- Keynote Dinner Speaker, "The Critical Need to Change the Face of Science and Engineering," NSF Advance Conference, Charleston, West Virginia, October 21, 2008
- Keynote address, "Mentoring for the 21st Century," annual Hoover Lecturer, Iowa State University, Ames, Iowa, October 1, 2008
- Keynote Dinner Speaker, "The 21st- Century Engineer: A Proposal for Engineering Education Reform," Cal Poly Pomona College of Engineering, Pomona CA, May 30, 2008
- Keynote Dinner Speaker, "Being A Leader In The 21st Century," ASCE Younger Member Evening Lecture, San Diego CA, May, 27, 2008

- Keynote Dinner Speaker, "The 21st Engineer," ASCE, The G. Brooks Earnest Awards Dinner, Cleveland, Ohio, October 9, 2007
- Keynote Address, "Engineering Education Reform," International Symposium on Social Management Systems, Three Gorges Dam, China, March 9, 2007
- Keynote Address, 2007 Western Regional Younger Member Council Banquet and Awards Ceremony, The Seattle ASCE Younger Member Forum, Seattle, Washington, February 24, 2007
- Keynote Address, "Innovation-Engineering A Better Engineer for Today's Workforce," Construction Innovation Forum, NOVA Awards Dinner, Dearborn, Michigan, April 2004

Publications

- "STEM to the Rescue?" *PE, The Magazine for Professional Engineers,* published by NSPE, March, 2012, includes contributions from Patricia D. Galloway
- "*Connecting Students to STEM: Social Networking Strategies*," International Society for Technology in Education (ISTE), 2011, Authored by Camille Cole, includes excerpts from Patricia D. Galloway
- Forward to "*The View From Here: Optimizing Your Engineering Career From the Start*," Reece Lumsden, Illumina Publishing, 2011
- "New Trends in Engineering Management Education," ASEE Conference, Pittsburgh PA, June 23, 2008
- Galloway, Patricia D., "*The 21st Century Engineer: A Proposal for Engineering Education Reform*", Reston: American Society of Civil Engineers, 2007
- "Bachelor's Plus, The Rationale for 'Raising the Bar' in Engineering Education," *Licensure Exchange*, Publication of National Council of Examiners for Engineering and Surveying, Clemson, South Carolina, March 2004

Conference Presentations / Teaching / Instruction

- Panel Member, *"Making the Case for STEM Education, Part III: A Perspective from Outside the K-12 Educational System,"* Washington State LASER's STEM Education Leadership Institute, Seattle, Washington, June 26, 2012
- Panel Moderator, "*The Future of Science and Engineering Research and Education as the National Science Foundation Celebrates Its 60 th Anniversary*," Advancing Science Serving Society (AAAS)Annual Conference "Bridging Science and Society, " San Diego, California, February 20, 2010
- Panel Moderator "*The Creative Science Studio (CS squared,"* Advancing Science Serving Society (AAAS)Annual Conference "Bridging Science and Society, "San Diego, Ca, February 19, 2010
- "New Trends in Engineering Management Education," ASEE Conference, Pittsburgh PA, June 23, 2008
- Panel Member, "Engineering Education Reform-Solutions for Professional Survival," Workplace Dynamic Panel, September 28, 2006
- Panel Member, "Engineering Education Reform-Solutions for Professional Survival," American Association of Engineering Societies, Chicago, Illinois, June 19 - 20, 2006
- Engineering Educational Reform, Panelist, Curriculum Reform Leader's Conference, Purdue University, West Lafayette, Indiana, August 30, 2005

Women in Engineering / Diversity Issues

Invited and Keynote Presentations

- "Are Engineers Human," TEDx Manhattan Beach, Manhattan Beach, CA, November 2014
- "The Construction Industry: From an Industry to a Profession," ENR Groundbreaking Women in Construction Conference, New York City, May 9, 2012
- Keynote Address, "The Four C's of Success," Expanding Your Horizons, Washington State University – Tri-Cities Campus, March 24, 2012
- Keynote Address, "The Four C's of Success," Kiewit 4th Annual Women in Construction Leadership Conference, Omaha, Nebraska, December 11, 2011

- Keynote Address, "Using Organizations to Advance Tomorrow's Leaders," Keynote Luncheon Speaker, Annual Conference, NSF ADVANCE, Increasing the Participation and Advancement of Women in Academic Science and Engineering Careers, Program Meeting on "Broadening Participation", NSF/Association for Women in Science Advance Workshop, Washington, D.C., October 29, 2009
- Keynote Luncheon Speaker, "What it Takes to Be a Leader," National Women in Construction Leadership Forum, San Francisco, California, September 2004
- Keynote Address, "The Love for Amelia Earhart and the Undying Quest for her Discovery," Zonta Awards Luncheon, Albany, New York, May 2004
- Keynote Address, "What it takes To Be A Leader," Women in Engineering Leadership Institute (WELI) Leadership Summit, University of Connecticut, Windsor, Connecticut, May 2004
- Keynote Speaker, "Breaking Through the Glass Ceiling," HDR Women's Forum 2000, Embassy Suites, Kansas City, Missouri, March 31, 2000

Publications

- "Using Professional Organizations to Advance Tomorrow's Leaders," Forum, Leadership and Management in Engineering Journal, American Society of Civil Engineers, October, 2010
- Engineering Education "Today in History" Blog: First Female Engineer in ASCE, Engineering Pathway, March 14, 2009
- "What Girls Want From Their Profession," *Geo-Strata*, Volume 6, Issues 1 pp.19-21, January / February 2006
- "Extraordinary Stories of Women in Engineering," National Academy of Engineering, May 3, 2004
- "Emily, Amelia, *et. al*,: Who Are These Women And Why Should We Care?", American Society of Civil Engineers, *ASCE News*, May 2004
- "Leadership: Women's Role in Engineering," A Civil Engineered World, a publication of ASCE's International Affairs Department, Volume 13, Issue 1, March 2000
- "The 2-Engineer Family," Proceedings, Society of Women Engineers, National Convention, Detroit, Michigan, June 1982

Conference Presentations / Teaching / Instruction

- "Advocacy and Outreach, Best Practices," Panel, Powering the Network, U.S. Women in Nuclear Conference, Seattle, WA, July 19, 2010
- "How to Increase the Number of Women in Engineering," ADVANCE luncheon, University of Washington, Seattle, WA, October 23, 2008.
- "The Critical Need to Change the Face Of Science and Engineering," NSF sponsored workshop- Building Diversity in Higher Education: Strategies for Broadening Participation in the Sciences and Engineering, Charleston, WVA, October 21, 2008
- "Becoming a Leader in the 21st Century," West Virginia University Center for Women's Studies Residency Program, March 31-April 4, 2008
- "Footprints for Success: Being a Female Leader in Engineering," National Symposium for the Advancement of Women in Science (NSAWS), Harvard University, April 13, 2007
- "Creating an Effective Media / Public Affairs Campaign," First National Summit on the Advancement of Girls in Math and Science, Washington, D.C., May 15, 2006
- Panelist, "Ground Breaking Women in Construction," Los Angeles, California, September 21, 2005
- Panelist, "Rising to Lead," Women's Leaders Tour, Advancement of Technology for Women (ATW), Albany, New York, Austin, Texas; San Jose, California, April - May 2004
- Panelist, "How to Become a Leader," Women in Engineering Leadership Institute (WELI) Leadership Summit, University of Connecticut, Windsor, Connecticut, May 2004
- Moderator, "High Heels are Replacing Hard Hats in the Boardroom," Construction Superconference, The Fairmont Hotel, San Francisco, California, December 8, 2000

- "So Mrs. Roebling-What's Your Side of the Story?", a one-woman play, written by P. Galloway, 1995 ASCE Annual Convention, San Diego, California, October 1995 (over 50 play performances, multiple venues, 1995-1998)
- "The 2-Engineer Family," Society of Women Engineers, National Convention, Detroit, Michigan, June 1982

Climate Change / Sustainability

Invited and Keynote Presentations

- Keynote Address, "The Role of the 21st Century Engineer in the Midst of Global Engineering Crisis," International Symposium on Futures in Civil & Construction Engineering Institution, Seoul Korea, June 17, 2008
- Keynote Address, "The Framework of Sustainability for Engineering Design Considerations," Society for Social Management Systems 2008 Kochi, Japan. March 6, 2008
- Keynote Address, "Role, Responsibility and Risk Considerations of the Engineer Regarding Sustainability," 10th Annual INFTRA-ARHCA-CEA 2007 Transportation Conference, Alberta, Canada, March 19 - 20, 2007
- Keynote Address, "The Mission of the Civil Engineer in the Movement of Globalization," Vechellio Special Lecture Series, Virginia Tech, Blacksburg, Virginia, October 2004
- Annual Convention Keynote Speaker, "Engineer for a Sustainable World," Stanford University, California, September 2004
- Keynote Speaker, "Does Scheduling Make Any Sense in Today's World?", On the Road to Better Scheduling-PMICOS Conference, Montreal, Canada, April 25 - 28, 2004

Publications

- "Problems in Underground Construction: Lessons Learned from Failures and Methods Developed for Success," co-authored with M. Petrov, Proceedings, Underground Space for Sustainable Urban Development, ITA-AITES 2004 World Tunnel Congress, Singapore, May 2004
- "Mission of the Civil Engineer in the Movement of Globalization," published proceedings, Japan Society of Civil Engineers, JSCE First International Symposium on Construction and Project Management-Human Resources Development under Globalization, Tokyo, Japan, October 16 - 17, 2003
- "Mission of the Civil Engineer in the Movement of Globalization," ASCE *Journal of Leadership and Management in Engineering*, Journal Issue 3, Volume 3, pp. 122 - 127, July 2003

Conference Presentations / Teaching / Instruction

- "Responding to Climate Change: The Role of the Engineer," ASCE International Program, American Society of Civil Engineers, International Program, November 6, 2008
- "The Engineer's Role in Public Policy," Institution of Civil Engineers Sustainable Development Forum, New York, New York, September 9, 2005
- "Problems in Underground Construction: Lessons Learned from Failures and Methods Developed for Success," Underground Space for Sustainable Urban Development, ITA-AITES 2004 World Tunnel Congress, Singapore, May 2004

PATRICIA D. GALLOWAY *Representative Engagement Experience [Does not include engagements where served as arbitrator]*		
Industry	**Type**	**Project Name**
Power	**Nuclear**	Darlington Nuclear Generating Station, Darlington Refurbishment Project, Canada
Power	**Nuclear**	Bellefonte Nuclear Power Plant, Unit 1 Completion, United States (Alabama)
Power	**Nuclear**	Levy 1 & 2 Nuclear Power Plant, United States (Florida)
Power	**Nuclear**	Vogtle 3 & 4 Nuclear Generating Station, United States (Georgia)
Power	**Nuclear**	Seabrook Unit 2 Nuclear Generating Station, United States (New Hampshire)
Power	**Nuclear**	Millstone Nuclear Generating Station Unit 3, United States (Connecticut)
Power	**Nuclear**	Cooper Nuclear Station, United States (Nebraska)
Power	**Nuclear**	Connecticut Yankee Nuclear Plant, United States (Connecticut)
Power	**Nuclear**	Millstone Point Nuclear Generating Station, Units 1, 2 and 3, United States (Connecticut)
Power	**Nuclear**	Indian Point Nuclear Power Plant Unit 3, United States (New York)
Power	**Nuclear**	Salem and Hope Creek Nuclear Power Plants, United States (New Jersey)
Power	**Nuclear**	South Texas Nuclear Plant, United States (Texas)
Power	**Nuclear**	Trojan Nuclear Power Plant, United States (Oregon)
Power	**Nuclear**	Shoreham Nuclear Plant, United States (New York)
Power	**Nuclear**	Nine Mile Power Plant, United States (New York)
Power	**Nuclear**	Bellefonte Nuclear Power Plant, United States (Alabama)
Power	**Nuclear**	Millstone 2 Nuclear Power Plant, Waterford, United States (Connecticut)
Power	**Nuclear**	Washington Public Power Supply Nuclear Plants, United States (Washington)

PATRICIA D. GALLOWAY Representative Engagement Experience [Does not include engagements where served as arbitrator]		
Industry	**Type**	**Project Name**
Power	**Nuclear**	Diablo Canyon Nuclear Power Plant, United States (California)
Power	**Nuclear**	Comanche Peak Steam Nuclear Electric Station, Units 1 & 2, United States (Texas)
Power	**Nuclear**	Clinton Nuclear Generating Station, Decatur, United States (Illinois)
Power	**Nuclear**	Pilgrim I Nuclear Power Plant, United States (Massachusetts)
Power	**Nuclear**	Vogtle 1 & 2, Nuclear Generating Station, United States (Georgia)
Power	**Nuclear**	Palo Verde Nuclear Generating Station, United States (Arizona)
Power	**Nuclear**	Perry Nuclear Generating Station, United States (Ohio)
Power	**Nuclear**	Seabrook Nuclear Generating Station Unit 1 and Unit 2, United States (New Hampshire)
Power	**Nuclear**	Waterford Nuclear Power Plant Unit 3, United States (Louisiana)
Power	**Nuclear**	Shoreham Nuclear Power Plant, United States (New York)
Power	**Nuclear**	Hanford, United States (Washington)
Power	**Nuclear**	Wolf Creek, United States (Kansas)
Power	**Nuclear**	Maine Yankee Nuclear Power Plant, United States (Maine)
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Western U.S. Combined Cycle Plant, United States
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Salem Harbor Combined Cycle Plant, United States (Massachusetts)
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Duke Energy Coal Ash Basin Closure Program, United States

PATRICIA D. GALLOWAY *Representative Engagement Experience [Does not include engagements where served as arbitrator]*		
Industry	**Type**	**Project Name**
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Kemper County IGCC Power Plant, United States (Mississippi)
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Edwardsport IGCC Power Plant, United States (Indiana)
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Iatan Unit 1 & 2 Super-critical pulverized coal plant, United States (Kansas, Missouri)
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Scherer Fossil Power Plant (4 Units), United States (Georgia)
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	La Paloma Combined Cycle Power Plant, United States (California)
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Sacramento Municipal Utility District (SMUD) Cosumnes Combined Cycle Plant, United States (California)
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Marshall Islands Power Plant Demolition, United States Territory (Marshall Islands)
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Paiton Units 1 & 2, Indonesia
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Paiton Units 7 & 8, Indonesia
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	JEA Northside, United States (Florida)
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Osbourne, Australia
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Jiu Jiang Power Plant, China
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Cleveland Electric Illuminating Company, Fossil Power Plants, United States (Ohio)

PATRICIA D. GALLOWAY *Representative Engagement Experience [Does not include engagements where served as arbitrator]*		
Industry	**Type**	**Project Name**
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Jeffrey Energy Center, United States (Kansas)
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Wolf Hollow Plant, United States (Texas)
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Covert Plant, United States (Michigan)
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Dearborn Industrial Generation Project, United States (Michigan)
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Illinois Power Company, United States (Illinois)
Power	**Cogeneration/ Combined Cycle/Fossil Fuel**	Fossil Power Plant, Bulgaria
Power	**Geothermal**	Wayang Windu Geothermal Power Project, Indonesia
Power	**Hydro**	Alto Maipo Project, Chile
Power	**Hydro**	Xiaolangdi Dam, China
Power	**Hydro**	Casecnan Multi-Purpose Project, Philippines
Power	**Hydro**	Cirata II, Indonesia
Power	**Hydro**	Sulpher Creek Hydro Power Plant, United States (California)
Power	**Hydro**	Mill to Bull Creek Tunnel, United States (California)
Power	**Waste to Energy**	Valorsul Waste-To-Energy Plant, Portugal
Power	**Solar**	Eastern U.S. Solar Program, United States
Power	**Wind Power**	Brazos Wind Farm, United States (Texas)

PATRICIA D. GALLOWAY *Representative Engagement Experience [Does not include engagements where served as arbitrator]*		
Industry	**Type**	**Project Name**
Power	**Wind Power**	Caprock Wind Farm, United States (New Mexico)
Power	**Transmission**	Rockdale-West Middleton Project, United States (Wisconsin)
Power	**Transmission**	Interstate Transmission Line Project, (Western Region) United States
Power	**Storm Hardening**	PSE&G, United States (New Jersey)
Infrastructure / Transportation	**Roadways**	SR-99 Alaskan Way Viaduct Replacement Project, United States (Washington)
Infrastructure / Transportation	**Roadways**	SR-520, United States (Washington)
Infrastructure / Transportation	**Roadways**	Shawnee Mission Parkway, United States (Kansas)
Infrastructure / Transportation	**Roadways**	KDOT Project, United States (Kansas)
Infrastructure / Transportation	**Roadways**	New Jersey Turnpike, Section 5B-3, United States (New Jersey)
Infrastructure / Transportation	**Roadways**	Melbourne City Link, Australia
Infrastructure / Transportation	**Roadways**	Turnpike Operations Management System, United States (Florida)
Infrastructure / Transportation	**Roadways**	State Highway US 290 Travis County, United States (Texas)
Infrastructure / Transportation	**Roadways**	State Highway SR-21, United States (Florida)
Infrastructure / Transportation	**Roadways**	Asphalt Resurfacing Project, Highway 9, United States (Nebraska)
Infrastructure / Transportation	**Roadways**	Electronic Toll Collection System, United States (Florida)
Infrastructure / Transportation	**Roadways**	Blue Route Section 200, United States (Pennsylvania)
Infrastructure / Transportation	**Roadways**	Lief Erikson Tunnel, United States (Minnesota)
Infrastructure / Transportation	**Roadways**	Veteran's Expressway, Tampa, United States (Florida)

PATRICIA D. GALLOWAY *Representative Engagement Experience [Does not include engagements where served as arbitrator]*		
Industry	**Type**	**Project Name**
Infrastructure / Transportation	**Roadways**	Interstate 75, Kentucky (Lexington and Covington Road) United States (Kentucky)
Infrastructure/ Transportation	**Bridges**	Tappan Zee Bridge, United States (New York)
Infrastructure / Transportation	**Bridges**	Columbia River Crossing, Independent Review Panel, United States (Oregon, Washington)
Infrastructure / Transportation	**Bridges**	Houston Ship Channel (Baytown) Cable-Stayed Bridge, United States (Texas)
Infrastructure / Transportation	**Bridges**	Hillsborough Avenue Bridge, United States (Tampa, Florida)
Infrastructure / Transportation	**Bridges**	151st Street Bridge Project, United States (Kansas)
Infrastructure / Transportation	**Bridges**	Hong Kong Tsing Ma Bridge, China
Infrastructure / Transportation	**Bridges**	Nairn Avenue Overpass Project, Canada
Infrastructure / Transportation	**Bridges**	New Smyrna Beach Bridge, United States (Florida)
Infrastructure / Transportation	**Bridges**	Hastings Bridge, Hastings, United States (Minnesota)
Infrastructure / Transportation	**Bridges**	Post Tensioned Segmental Bridge, Bexar County, United States (Texas)
Infrastructure / Transportation	**Bridges**	Interstate Highway Bridges, United States (Indiana)
Infrastructure / Transportation	**Bridges**	Gloucester Inlet Bridge, United States (Massachusetts)
Infrastructure / Transportation	**Airports**	Yosemite International Airport, United States (California)
Infrastructure / Transportation	**Airports**	Port of Seattle, United States (Washington)
Infrastructure / Transportation	**Airports**	Kuala Lumpur International Airport, Malaysia
Infrastructure / Transportation	**Airports**	Indianapolis International Airport, United Airlines Maintenance Operation Center, United States (Indiana)

PATRICIA D. GALLOWAY *Representative Engagement Experience [Does not include engagements where served as arbitrator]*		
Industry	**Type**	**Project Name**
Infrastructure / Transportation	**Telecommunication**	AT&T Broadband, United States (Illinois, Missouri, Michigan)
Infrastructure / Transportation	**Defense**	TADRS (Tactical Air Defense Radar System), Australia
Infrastructure / Transportation	**Rail**	Sound Transit Light Rail, United States (Washington)
Infrastructure / Transportation	**Rail**	Phoenix Light Rail Transit, United States (Arizona)
Infrastructure / Transportation	**Rail**	Vancouver Millennium Sky Train Project, Canada
Infrastructure / Transportation	**Rail**	Pentagon City Subway Station, United States (Virginia)
Infrastructure / Transportation	**Rail**	Rohr Transit Cars, United States (Washington, D.C)
Infrastructure / Transportation	**Rail**	North Harlem To Brewster (Hudson Harlem Lines) Electrification Program, United States (New York)
Infrastructure / Transportation	**Rail**	London Crossrail Project, United Kingdom
Infrastructure / Transportation	**Rail**	Taisei-Metro Extension Project, Bulgaria
Infrastructure / Transportation	**Rail**	Regional Fast Rail Project (RFRP), Australia
Infrastructure / Transportation	**Rail**	Southern New Jersey Light Rail Transit System, United States (New Jersey)
Infrastructure / Transportation	**Rail**	Singapore Mass Rail Transit, Singapore
Infrastructure / Transportation	**Rail**	Toronto Transit Commission Subway Line Expansion, Canada
Infrastructure / Transportation	**Rail**	Shaw Subway Station, United States (Washington, D.C.)
Infrastructure / Transportation	**Rail**	Stamford Railroad Station Stamford, United States (Connecticut)
Infrastructure / Transportation	**Ship / Seaport**	Central Terminal Expansion Claim Review, United States (Washington)

PATRICIA D. GALLOWAY *Representative Engagement Experience [Does not include engagements where served as arbitrator]*		
Industry	**Type**	**Project Name**
Infrastructure / Transportation	**Ship / Seaport**	Port of Seattle, United States (Washington)
Infrastructure / Transportation	**Ship / Seaport**	Lahad Datu Port Expansion, Malaysia
Infrastructure / Transportation	**Ship / Seaport**	Panamá Canal Transfer Station, Panamá
Infrastructure / Transportation	**Ship / Seaport**	Riofil / Manila South Harbor Pier 5 Extension, Philippines
Infrastructure / Transportation	**Ship / Seaport**	City of Venice Floodgate, Italy
Infrastructure / Transportation	**Ship / Seaport**	F/V Arctic Storm Ship Conversion, United States (Washington)
Infrastructure / Transportation	**Ship / Seaport**	Deep Sea Drilling Ship, United States (Texas)
Infrastructure / Transportation	**Other**	American Concrete Pipe Association (ACPA) Independent Research, United States (Tennessee)
Infrastructure / Transportation	**Other**	Japan Ministry of Land, Infrastructure and Transport, Analysis of US Public Construction Contracting Practice, Japan
Infrastructure / Transportation	**Other**	Fish Barrier Project (FBP) United States (Washington)
Infrastructure / Transportation	**Other**	Seattle Public Utilities (SPU) and SeaTran, United States (Washington)
Industrial / Process	**Chemical / Petrochemical**	Palmetto Lime Facility, United States (South Carolina)
Industrial / Process	**Chemical / Petrochemical**	PET Production Plants, Argentina, Holland, Spain
Industrial / Process	**Chemical / Petrochemical**	Zinc Recovery Plant, United States (California)
Industrial / Process	**Chemical / Petrochemical**	FMC Baltimore Sulfentrazone Plant, United States (Maryland)
Industrial / Process	**Chemical / Petrochemical**	Seraya Island Petrochemical Project, Singapore
Industrial / Process	**Oil / Gas**	Nations Petroleum Steam – Flood Project, United States (California)

PATRICIA D. GALLOWAY Representative Engagement Experience [Does not include engagements where served as arbitrator]		
Industry	**Type**	**Project Name**
Industrial / Process	**Oil / Gas**	PML Project, Singapore
Industrial / Process	**Oil / Gas**	Minerva Project, Australia
Industrial / Process	**Oil / Gas**	PEMEX Combisa EPC 22, Mexico
Industrial / Process	**Oil / Gas**	GASYRG Pipeline, Bolivia
Industrial / Process	**Oil / Gas**	PEMEX, Cantarell Project, Mexico
Industrial / Process	**Oil / Gas**	Foster Wheeler SINCOR Coker Project, Venezuela
Industrial / Process	**Oil / Gas**	Luberef Refinery Project, Saudi Arabia
Industrial / Process	**Oil / Gas**	PEMEX Demineralization Plant, Mexico
Industrial / Process	**Oil / Gas**	Perez Companc-Norcen-Corod Oritupano-Leona Oil Fields, Eastern Venezuela
Industrial / Process	**Oil / Gas**	Altona Refinery Expansion, Australia
Industrial / Process	**Oil / Gas**	INCO 92 Project, Gas Recompression Plants, Venezuela
Industrial / Process	**Oil / Gas**	Ahmadi Oil Distribution Facility, Kuwait
Industrial / Process	**Oil / Gas**	Nippon Steel On-Site Auditing / Risk Management
Industrial / Process	**Pulp & Paper Mill**	Chemical Recovery System at Pulp & Paper Mill, United States (Mississippi)
Industrial / Process	**Pulp & Paper Mill**	Weyerhaeuser Pulp and Paper Mill, Training, Contract and Administration
Industrial / Process	**Microchip**	Sperry Micro-Chip Manufacturing & Research Facility, United States (Minnesota)
Industrial / Process	**Pipelines**	Sakhalin Pipeline Project, Russia
Industrial / Process	**Pipelines**	Bolivia Pipeline, Bolivia
Industrial / Process	**Pipelines**	Bombax Pipeline Project, Trinidad, Tobago
Industrial / Process	**Pipelines**	HBJ Gas Pipeline, India
Industrial / Process	**Pipelines**	Santa Ana Watershed Project Pipeline, United States (California)
Industrial / Process	**Water Plant**	Central Brown County, United States (Wisconsin)
Industrial / Process	**Water Plant**	Pinellas County Water System Pipeline, United States (Florida)
Industrial / Process	**Water Plant**	Mount Hope Water Main Project, Panama

PATRICIA D. GALLOWAY *Representative Engagement Experience [Does not include engagements where served as arbitrator]*		
Industry	**Type**	**Project Name**
Industrial / Process	**Water Plant**	Water Treatment Plant, United States (Georgia)
Industrial / Process	**Wastewater / Environmental**	Upper Rouge Tunnel, United States (Michigan)
Industrial / Process	**Wastewater/ Environmental**	Passaic Valley Sewerage Commissioners Thickening Centrifuge Facility, United States (New Jersey)
Industrial / Process	**Wastewater / Environmental**	Milwaukee Water Pollution Abatement Program, United States (Wisconsin)
Industrial / Process	**Wastewater / Environmental**	South Bay Wastewater Treatment Plant, California, United States (California)
Industrial / Process	**Wastewater / Environmental**	Babylon Solid Waste Recovery Plant, United States (New York)
Industrial / Process	**Wastewater / Environmental**	Hamilton Wastewater Treatment Plant, United States (New York)
Industrial / Process	**Wastewater / Environmental**	Rockland County Sewer District Treatment Plant, United States (New York)
Industrial / Process	**Wastewater / Environmental**	Secondary Facilities At Newark Bay Pumping Station, United States (New Jersey)
Industrial / Process	**Wastewater / Environmental**	Bowery Bay Wastewater Treatment Plant, United States (New York)
Industrial / Process	**Wastewater / Environmental**	St. Joseph Wastewater Treatment Plant, United States (Missouri)
Industrial / Process	**Wastewater / Environmental**	Bergen Point Wastewater Treatment Plant, United States (New York)
Industrial / Process	**Wastewater / Environmental**	Coney Island Water Pollution Control Project, United States (New York)
Industrial / Process	**Environmental**	New Jersey Sludge Drying / Fertilizer Facility, United States (New Jersey)
Industrial / Process	**Environmental**	Blydenburgh Landfill, United States (New York)
Industrial / Process	**Environmental**	Transuranic Storage Area Retrieval Enclosure, United States (Idaho)
Industrial / Process	**Environmental**	Warren County Landfill, United States (New Jersey)
Industrial / Process	**Environmental**	Weyerhaeuser Fish Hatchery, United States (Oregon)
Industrial / Process	**Environmental**	Asbestos White Paper Development-Evert & Weathesby

PATRICIA D. GALLOWAY Representative Engagement Experience [Does not include engagements where served as arbitrator]		
Industry	**Type**	**Project Name**
Industrial / Process	**Environmental**	Foster Wheeler Asbestos Litigation, United States (New Jersey)
Industrial / Process	**Wastewater / Environmental**	Wastewater Treatment Plant, Canada
Industrial / Process	**Iron / Steel Manufacturing**	POSVEN Hot Briquette Iron Plant, Venezuela
Industrial / Process	**Iron / Steel Manufacturing**	Delta Brands Subcontract PPPL and ARP Expediting Services
Industrial / Process	**Iron / Steel Manufacturing**	IPSCO Mini-Mill, United States (Iowa)
Industrial / Process	**Iron / Steel Manufacturing**	NKK Steel Continuous Galvanizing Project, United States (Michigan)
Industrial / Process	**Iron / Steel Manufacturing**	Republic Steel Mill Project, United States (Ohio)
Industrial / Process	**Iron / Steel Manufacturing**	Union Park CSO Pump Station and Detention Facility, United States (Massachusetts)
Industrial / Process	**Pharmaceutical**	Bulk Pharmaceutical Production Plant, Singapore
Industrial / Process	**Pharmaceutical**	Squibb Animal Test Facility, United States (New Jersey)
Industrial/Process	**Mining**	Iron Mining Expansion Project, Quebec, Canada
Industrial / Process	**Mining**	Nickel-Cobalt Refinery, Western Australia
Industrial / Process	**Fertilizer Plant**	Petro Vietnam Fertilizer Plant, Phu My Province, Vietnam
Buildings	**Educational Facilities**	Princeton University, United States (New Jersey)
Buildings	**Educational Facilities**	DeKalb County School District, United States (Georgia)
Buildings	**Educational Facilities**	Delgado Community College, United States (New Orleans)
Buildings	**Educational Facilities**	Rutgers University Records Center, United States (New Jersey)
Buildings	**Educational Facilities**	Washoe County School District, United States (Nevada)
Buildings	**Educational Facilities**	Plainsboro Middle School, United States (New Jersey)
Buildings	**Educational Facilities**	Hunter College, United States (New York)
Buildings	**Educational Facilities**	York College, United States (New York)
Buildings	**Educational Facilities**	School Project, United States (Indiana)

PATRICIA D. GALLOWAY *Representative Engagement Experience [Does not include engagements where served as arbitrator]*		
Industry	**Type**	**Project Name**
Buildings	**Resorts / Casinos / Hotels**	Regent Las Vegas Resort, United States (Nevada)
Buildings	**Resorts / Casinos / Hotels**	Hotel / Condominium Complex, Indonesia
Buildings	**Resorts / Casinos / Hotels**	Phoenician Hotel and Resort, (Arizona)
Buildings	**Resorts / Casinos / Hotels**	Westin Hotel, United States (Texas)
Buildings	**Resorts / Casinos / Hotels**	Safety Harbor Spa, United States (Florida)
Buildings	**Resorts / Casinos / Hotels**	Intercontinental Hotel, United States (Texas)
Buildings	**Resorts / Casinos / Hotels**	Hyatt Regency Hotel, United States (Missouri)
Buildings	**Apartments / Condominiums / Housing**	99100 Park Towers at Hughes Center, United States (Nevada)
Buildings	**Apartments / Condominiums / Housing**	Ortley Beach Commons, United States (New Jersey)
Buildings	**Apartments / Condominiums / Housing**	Louisville Housing Authority Project, United States (Kentucky)
Buildings	**Centers / Arenas**	University of Washington Basketball Arena, United States (Washington)
Buildings	**Centers / Arenas**	Jacksonville Pre-Trial Detention Center, United States (Florida)
Buildings	**Centers / Arenas**	San Diego Convention Center, United States (San Diego, California)
Buildings	**Centers / Arenas**	Washington State Convention Center, United States (Washington)
Buildings	**Centers / Arenas**	Worcester Civic Center (Centrum), United States (Massachusetts)
Buildings	**Centers / Arenas**	Riverside Civic Center, United States (New York)
Buildings	**Stadiums**	Fresno Multipurpose Stadium, (Grizzlies Stadium) United States (California)

PATRICIA D. GALLOWAY Representative Engagement Experience [Does not include engagements where served as arbitrator]		
Industry	**Type**	**Project Name**
Buildings	**Stadiums**	Arizona State University, Sun Devil Stadium Expansion, United States (Arizona)
Buildings	**Medical / Hospitals**	Alameda County Medical Center / Highland General Hospital, United States (California)
Buildings	**Medical / Hospitals**	Colombo General Hospital, Sri Lanka (Colombo)
Buildings	**Medical / Hospitals**	Stoney Brook Hospital, United States (New York)
Buildings	**Medical / Hospitals**	Madigan VA Hospital, United States (Washington)
Buildings	**Medical / Hospitals**	Kodiak Health Care Facility, United States (Alaska)
Buildings	**Medical / Hospitals**	University Medical Center, United States (Louisiana)
Buildings	**Research Laboratory**	TA-35 Los Alamos National Laboratory, United States (New Mexico)
Buildings	**Offices**	Unit Atrium One Building, United States (Ohio)
Buildings	**Offices**	One Summit Square Office Building, United States (Indiana)
Buildings	**Offices**	Equitable Tower Office Building, United States (New York)
Buildings	**Offices**	Loney Construction Brattleboro Projects, United States (Vermont)
Buildings	**Offices**	IBM Office Complex, United States (New York)
Buildings	**Offices**	Gold Building Parking Garage, United States (Connecticut)
Buildings	**Offices**	American Standard Office Building, United States (Oklahoma)
Buildings	**Distribution / Storage / Warehouse**	Olefins Terminal Storage Complex
Buildings	**Distribution / Storage / Warehouse**	TRW Record Storage Complex, United States (New Jersey)
Buildings	**Distribution / Storage / Warehouse**	New Jersey State Food Distribution Center, United States (New Jersey)
Buildings	**Distribution / Storage / Warehouse**	Trenton Record Storage Center, United States (New Jersey)
Buildings	**Other**	Courthouse Construction Program Oversight, United States (California)
Buildings	**Other**	Parking Garage, United States (Ohio)
Other	**Seminar/Training**	Addressing Delay and Disruption Seminar, Panama Canal Authority, Panama

PATRICIA D. GALLOWAY *Representative Engagement Experience [Does not include engagements where served as arbitrator]*		
Industry	**Type**	**Project Name**
Other	**Seminar / Training**	Nexen Corporate Management, Risk Management / Program /Project Management Training, United States.
Other	**Seminar / Training**	AES: Corporate / Project Management, Risk Management Training, United States & Canada
Other	**Seminar / Training**	Japan Bank for International Cooperation, Japan
Other	**Seminar / Training**	West Virginia DOT Training Seminar, United States (West Virginia)
Other	**Seminar / Training**	Claims Seminar, Texas Department of Transportation, United States (Texas)
Other	**Seminar / Training**	Project Risk Management Seminar, Contract Administration Seminar, Panama Canal Commission, Panama
Other	**Seminar / Training**	Partnering Seminar, Kentucky Transportation Cabinet, United States (Kentucky)
Other	**Seminar / Training**	Florida Department of Transportation, United States (Florida)
Other	**Seminar / Training**	Seminar: Department of Energy, United States (West Virginia)
Other	**Seminar / Training**	University of Wisconsin-Madison Seminar, United States (Wisconsin)
Other	**Seminar / Training**	Fluor Corporate Risk / Claims Management, United States (California)
Other	**Seminar / Training**	Claims Avoidance & Management Training, United States (Arizona)
Other	**Seminar / Training**	Identifying, Minimizing & Quantifying Risk, England
Other	**Seminar / Training**	Claims Seminar On Construction Issues, Canada
Other	**Seminar / Training**	CPM Scheduling Course, United States (Pennsylvania)
Other	**Seminar / Training**	Claims Minimization Seminar, United States (New Hampshire)
Other	**Other**	Nunez Employment Discrimination Suit, United States (Texas)
Other	**Other**	Foster Wheeler Risk Management Corporate Advisor
Other	**Other**	Royal Grading Golf Course and Country Club

PENSION AND OTHER POST EMPLOYMENT BENEFIT COSTS

1.0 PURPOSE

The purpose of this exhibit is to:

- Describe OPG's proposal to maintain the same treatment for pension and other post-employment benefit ("OPEB") costs as that resulting from the OEB's EB-2013-0321 Decision With Reasons ("EB-2013-0321 Decision"), pending the outcome of the OEB's generic consultation on pension and OPEB costs (EB-2015-0040);
- Detail the forecast test period pension contributions and OPEB benefit payments ("cash amounts") included in the proposed nuclear revenue requirements; and
- Present the pension and OPEB amounts for the nuclear facilities determined in accordance with US GAAP ("accrual costs") as well as the differential between pension and OPEB accrual costs and cash amounts.

2.0 OVERVIEW

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 ("LTD") benefits for current employees.[1]

OPG proposes to maintain the same treatment for recovering pension and OPEB costs during the test period as that resulting from the EB-2013-0321 Decision (pp. 87-89), pending the outcome of the OEB's EB-2015-0040 consultation on pension and OPEB costs. In particular, OPG proposes to include pension and OPEB cash amounts in the test period nuclear revenue requirements, and, for both regulated hydroelectric and nuclear facilities, to record differences between actual and forecast cash amounts in the Pension & OPEB Cash Payment Variance Account, and the difference between actual accrual costs and actual cash amounts in the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

[1] The term "other post-retirement benefits" is used to refer to post employment benefit plans other than the RPP and LTD benefits. Unless otherwise noted, OPEB is used to refer to all post-employment benefits other than the RPP benefits.

Consistent with the OEB's findings in EB-2013-0321, OPG is proposing that the future consideration of recovery of the difference between accrual costs and cash amounts for the test period be limited to the outcome of the generic consultation and not be subject to a future prudence review beyond the proceeding for this Application. OPG is providing evidence in this exhibit, Ex. F4-3-1 and elsewhere in the Application to support a review of the forecast accrual costs.

Forecast pension and OPEB cash amounts attributed to the nuclear facilities for the test period are $272.0M in 2017, $280.4M in 2018, $289.5M in 2019, $271.3M in 2020 and $279.9M in 2021. The total difference between pension and OPEB accrual costs and cash amounts is forecast to decease significantly over the period, from an average of $230.8M in 2014-2015 to $49.8M by 2021. Pension cash amounts are forecast to exceed accrual costs starting in 2018. Total forecast pension cash amounts for the nuclear facilities are higher than accrual amounts by $31.5M over the test period, while total forecast OPEB cash amounts are $434.0M lower than the accrual costs over the test period. On an annual basis, test period pension and OPEB accrual costs and cash amounts are significantly lower than in 2014 and 2015.

As discussed in Ex. H1-1-1, given that the EB-2015-0040 generic consultation is ongoing, OPG is not proposing to clear amounts accumulated in the Pension & OPEB Cash Versus Accrual Differential Deferral Account since November 1, 2014. OPG is proposing to clear the December 31, 2015 balance in the Pension & OPEB Cash Payment Variance Account.

Although OPG has aligned its test period proposal for pension and OPEB costs with the OEB's EB-2013-0321 Decision, OPG continues to be of the view that it would be appropriate for OPG to recover its accrual pension and OPEB costs for the following reasons, as set out in detail in OPG's July 31, 2015 submission in the EB-2015-0040 consultation:

- Using accrual accounting for rate setting ensures that rates reflect the true cost of providing the service during the periods to which the rates relate, which minimizes intergenerational inequity and supports efficient consumption through appropriate price signals;

- The use of accrual pension and OPEB costs for rate recovery purposes is consistent with financial accounting requirements, which are developed through a transparent and rigorous process with an objective of appropriately attributing costs across periods. The use of financial reporting requirements provides a reliable and verifiable basis to set just and reasonable rates, and minimizes the financial burden of keeping two sets of records;
- The accrual basis of recovery would provide OPG with revenues on the same basis and in a similar timeframe as the accounting requirement to recognize post-retirement obligations on the company's balance sheet. As such, using the accrual accounting basis for rate-setting would avoid significant adverse financial consequences to OPG (including reductions in net income, write-offs of regulatory asset balances and erosion of shareholder's equity) and corresponding increases in the risks to the shareholder, which are likely to arise if a different basis of recovery is adopted; and
- Maintaining the recovery of costs on an accrual basis promotes consistency and simplicity and supports period-over-period comparability of results, particularly when that basis was previously applied to set the utility's rates, as is the case for OPG.

As OPG is proposing that the EB-2013-0321 regulated hydroelectric payment amounts form the starting point for determining the regulated hydroelectric payment amounts for 2017 to 2021, pension and OPEB cash amounts and accrual costs for the regulated hydroelectric business are not presented in this exhibit.

Section 3 presents the cash amounts, accrual costs and the difference between the two for the nuclear facilities for the historical, bridge and test periods. It also further details OPG's proposed treatment of pension and OPEB costs in this Application. Sections 4 and 5, respectively, set out how the cash amounts and accrual costs presented in section 3 were developed and discuss related trends and variances.

Cash and accrual amounts presented in this Application reflect changes to RPP provisions from the 2015 round of collective bargaining with the Power Workers' Union ("PWU") and

The Society of Energy Professionals ("The Society") and from changes applicable to Management employees (i.e., pension reform), all of which are discussed in Ex. F4-3-1.

The nature of accrual costs and cash amounts presented in this exhibit and the methodologies used to derive them are unchanged from those reflected in EB-2012-0002, EB-2013-0321 and EB-2014-0370.

3.0 PROPOSED TEST PERIOD TREATMENT OF PENSION AND OPEB COSTS

In the EB-2013-0321 Decision, the OEB required OPG to recover cash amounts for pension and OPEB for 2014 and 2015 and established the Pension & OPEB Cash Versus Accrual Differential Deferral Account to record the differential between actual accrual costs and actual cash amounts. The OEB also indicated that it was "not necessarily moving from an accrual to a cash basis for setting OPG's payment amounts" and that "transition to a different accounting treatment of pensions and OPEBs for OPG, if required, would be addressed by the Board in OPG's next cost of service proceeding, having been informed by the outcomes of the generic proceeding" (p. 88). The EB-2013-0321 Decision also clarified that "the Board is not setting aside the difference between the cash and accrual amounts .... for purposes of another future prudence review of these costs", noting that "any future treatment regarding the deferral account would be limited to the outcomes of the generic proceeding" and that "[b]ased on the policy outcome of the generic proceeding, a future panel will decide on the appropriate disposition (if any) of the deferral account balance." (pp. 88-89)

As the EB-2015-0040 generic consultation has not concluded at the time of this Application, consistent with the OEB's EB-2013-0321 Decision, OPG is seeking to include forecast pension and OPEB cash amounts in the nuclear revenue requirements for the test period. With respect to the regulated hydroelectric facilities, the 2017-2021 hydroelectric payment amounts proposed under a price cap incentive regulation approach would continue to reflect the EB-2013-0321 approved forecast cash amounts.

Chart 1 below sets out pension and OPEB cash amounts attributed to the nuclear facilities in the historical, bridge and test years. The cash amounts consist of contributions to the RPP and benefit payments to retirees and dependants under the OPEB plans. OPG's total projected cash amounts for pension and OPEB for 2016-2021 were calculated by an independent actuary, Aon Hewitt, as shown in Attachment 1. Pension contributions, which are typically set by triennial actuarial valuations, are projected to decrease after each such assumed valuation during the test period, effective January 1, 2017 and January 1, 2020, as discussed in section 4.2. Forecast amounts for pension contributions represent estimated minimum required company contributions for current service cost and going concern special payments.[2] Increasing OPEB benefit payments over the period reflect the growing retiree population and expected increases in per capita medical and other costs.

Chart 1

Pension and OPEB Cash Amounts – Nuclear[3] ($M)									
	2013 Actual	**2014 Actual**	**2015 Actual**	**2016 Projection**	**2017 Plan**	**2018 Plan**	**2019 Plan**	**2020 Plan**	**2021 Plan**
Pension	231.6	280.9	284.5	283.3	171.1	175.5	180.3	157.2	162.1
OPEB	78.1	84.5	93.1	96.6	100.9	104.9	109.2	114.1	117.8
Total	**309.7**	**365.4**	**377.6**	**379.9**	**272.0**	**280.4**	**289.5**	**271.3**	**279.9**

Chart 2 sets out pension and OPEB accrual costs attributed to the nuclear facilities in the historical, bridge and test years. OPG's total accrual costs for these periods were determined by Aon Hewitt in accordance with US GAAP, as set out in Attachment 1 for the 2016-2021 projection and Attachment 2 for the 2014-2015 actual amounts.

[2] No solvency special payments are projected for 2016-2021 and none were made in 2013-2015.
[3] Nuclear pension and OPEB amounts presented in this exhibit exclude amounts related to the Nuclear Waste Management Organization ("NWMO"), which is consolidated into OPG's financial statements.

Chart 2

Total Pension and OPEB Accrual Costs – Nuclear[4] ($M)									
	2013 Actual	2014 Actual	2015 Actual	2016 Projection	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Pension	365.4	411.2	414.4	294.6	222.8	167.5	153.0	140.0	131.4
OPEB	223.0	176.1	202.8	192.6	194.6	195.0	196.0	197.0	198.3
Total	**588.4**	**587.3**	**617.2**	**487.2**	**417.4**	**362.5**	**349.0**	**337.0**	**329.7**

As set out in section 2.0 and Ex. H1-1-1, OPG proposes to record the difference between actual accrual costs and actual cash amounts during the test period in the Pension & OPEB Cash Versus Accrual Differential Deferral Account, and the difference between actual and forecast cash amounts in the Pension & OPEB Cash Payment Variance Account. Notwithstanding this proposal in light of the OEB's ongoing generic consultation on pension and OPEB, OPG continues to be of the view that it would be appropriate for it to recover accrual costs for pension and OPEB for the regulated business for reasons summarized in section 2.0.

Chart 3 below sets out the difference between pension and OPEB accrual costs and cash amounts attributed to the nuclear facilities for the historical, bridge and test periods (i.e., the difference between the amounts in Chart 2 and the amounts in Chart 1). The difference is expected to decline significantly by the end of the test period. Cash amounts for pension are expected to exceed accrual costs starting in 2018. This trend reflects lower pension accrual costs discussed in section 5.3. The OPEB cash-to-accrual difference is projected to decline gradually over the test period as cash amounts increase.

[4] Ibid.

Chart 3

Pension and OPEB Accrual-Cash Differential Amounts – Nuclear[5] ($M)									
	2013 Actual	2014 Actual	2015 Actual	2016 Projection	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Pension	133.8	130.3	129.9	11.3	51.7	(8.0)	(27.3)	(17.2)	(30.7)
OPEB	144.9	91.6	109.7	96.0	93.7	90.1	86.8	82.9	80.5
Total	**278.7**	**221.9**	**239.6**	**107.3**	**145.4**	**82.1**	**59.5**	**65.7**	**49.8**

3.1 Presentation of Pension and OPEB Costs in the Application

In costing labour for planning, target setting and financial reporting purposes, OPG includes accrual costs for pension and OPEB in line with US GAAP requirements. Accordingly, OPG's corporate and business unit business plans, which present financial information in accordance with US GAAP, reflect accrual costs for pension and OPEB. This Application is based on OPG's approved 2016-2018 Business Plan and therefore presents business unit and compensation related cost information on the same basis as the business plan.[6] In order to reconcile this presentation with OPG's proposed treatment of pension and OPEB costs in the test period, a negative adjustment in the amount of the forecast differential between pension and OPEB accrual costs and cash amounts (shown in Chart 3) is included as a separate entry in centrally-held costs for the nuclear facilities in each of the test years (Ex. F4-4-1 Table 3, line 2).

4.0 CASH AMOUNTS FOR PENSION AND OPEB

OPG's pension plans are defined benefit pension plans that provide members with a pension amount based on years of service and salary at retirement. The RPP is funded by member (i.e., employee) and OPG (i.e., employer) contributions.[7] The *Pension Benefits Act* (Ontario) ("PBA") sets the minimum funding requirements for registered pension plans to ensure that

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[5] Although the accrual-to-cash differential is presented starting in 2013 for illustrative purposes, 2014 is the first year for which the OEB set payment amounts on the basis of cash amounts for pension and OPEB. Positive amounts represent excess of accrual costs over cash amounts.

[6] As in previous proceedings and as discussed in section 5.2, the current service component of accrual costs is largely reflected in costs charged to the business units, while the other components of accrual costs are held centrally and are assigned and allocated to the business units.

[7] The supplementary pension plan is not funded but is secured by letters of credit.

plans have sufficient assets in place to meet existing and future obligations. Contributions must be made to fund the plan's current service cost (also known as normal cost), as well as deficiencies (i.e., deficits), if any, through defined special payments over a period of time.

The PBA requires actuarial valuations on both going concern and solvency bases to be performed at least once every three years to determine the funded status of a registered pension plan (i.e., the difference between the value of pension fund assets and the actuarial present value of the accrued liability[8] as of the valuation date) and required future contributions. The going concern valuation measures the financial position of the pension plan assuming that the plan continues indefinitely into the future. The solvency valuation measures the financial position of the pension plan, as defined pursuant to the PBA, assuming that the plan is wound-up on the valuation date and all benefits are settled by either lump sum payments or annuity purchases. To the extent that going concern special payments will not eliminate the solvency deficit over a 5-year period, additional payments towards the solvency deficit (i.e., solvency special payments) are required over the 5-year period. Going concern special payments are made over a 15-year period. Valuations are prepared and certified by an independent actuary and must be filed with the Financial Services Commission of Ontario ("FSCO") and the Canada Revenue Agency ("CRA").

In determining the going concern accrued liability and current service cost, an actuary attributes the present value of future expected benefits over each plan member's projected service. The obligation at a particular date is the actuarial present value of the benefits attributed to each member's service rendered up to that date. Employer's current service cost represents the actuarial present value of benefits earned in respect of each additional year of employee service, less any required employee contributions to the pension plan.

In order to establish funding requirements, economic and demographic assumptions are required to determine the plan's accrued liability as of the valuation date and to project current service cost for future years. Examples of economic assumptions include discount rates, inflation rate, and salary escalation rate. Examples of demographic assumptions

[8] The term "accrued liability" and "benefit obligation" may be used interchangeably in this exhibit.

include mortality rates and improvement scale, termination rates, and retirement rates. As discussed below, certain assumptions differ between going concern valuations and solvency valuations. Many of the assumptions used in the going concern funding valuations are also applied in accounting valuations for determining the pension obligation and accrual costs.

Going concern valuation assumptions and methods are determined by the actuary preparing the valuation, in accordance with accepted actuarial practice and taking into account regulatory and legislative constraints and guidance issued by the Canadian Institute of Actuaries ("CIA"), with input from plan sponsors. As prescribed by the PBA, key assumptions used in the solvency valuation are required to be set in accordance with specific CIA standards of practice.

The going concern benefit obligation and funding requirements are determined using a discount rate based on the expected long-term rate of return on pension plan assets, taking into account a margin for adverse deviation for some potential barriers to achieving this return. This long-term rate of return is based on the pension fund asset mix and capital market expectations of future risk and return for each asset class within the fund portfolio, net of passive investment management fees.[9] For the solvency valuation, the discount rates used to determine the benefit obligation are required to be determined in accordance with specific standards of practice issued by the CIA and with reference to government of Canada bonds.[10]

The most recently filed actuarial valuation of OPG's RPP is as at January 1, 2014. That valuation showed that the pension fund was in a deficit position. Specifically, the RPP was 90.5 per cent funded on a going concern basis and 99 per cent funded on a solvency basis. Funding requirements pursuant to the valuation included going concern special payments

[9] The long-term expected rate of return used for US GAAP accrual accounting purposes is determined in a similar way to the going concern discount rate, with the main differences being that the accounting rate does not take into account either a margin for adverse deviation or an allowance for passive investment management fees.
[10] The solvency discount rates are typically lower than the going concern discount rates, as the solvency rates reflect current government bond yields and annuity purchase rates determined using information provided by insurance companies rather than the rate of return expected to be earned on pension fund assets.

(over 15 years), but no solvency special payments.[11] In 2014 and 2015, OPG made approximately the minimum required contributions pursuant to the January 1, 2014 valuation and, subject to employee contribution increases discussed in Ex. F4-3-1, is forecasting contributions on the same basis for 2016. The January 1, 2014 valuation was previously filed with the OEB in EB-2013-0321.[12]

The next actuarial valuation of the OPG RPP is expected to be completed in 2017 using data and assumptions as of January 1, 2017, and must be filed with FSCO and CRA by September 30, 2017. A subsequent valuation would need to be completed as of January 1, 2020 at the latest. The test period nuclear revenue requirements reflect projected RPP contributions for the 2017-2021 period as determined by Aon Hewitt. As discussed further in section 4.1, Aon Hewitt prepared this projection based on information available as of December 31, 2015, extrapolating to the assumed January 1, 2017 and January 1, 2020 future valuation dates.

Cash amounts for OPEB reflect OPG's benefit payments to retirees and dependants in accordance with the provisions of the plans. Forecast OPEB payments for the 2016-2021 period represent the nuclear portion of total estimated future cash flows used by Aon Hewitt to project OPEB benefit obligations over this period.

4.1 Forecasting Pension and OPEB Cash Amounts

Forecasting RPP contributions requires estimating the funded status of the plan as of the date of each assumed future funding valuation. Developing these estimates requires expectations of assumptions that will be used to determine the accrued liability as of these dates, and projections of the actual pension fund performance to those dates. OPG's total projected required RPP contributions for 2017-2021 were calculated by Aon Hewitt, as set out in Attachment 1, by projecting the going concern and solvency funded status of the plan

[11] Although the pension plan was less than 100 per cent funded on a solvency basis, there was no requirement for additional solvency funding since the going concern special payments were determined by the valuation to be sufficient to fund the solvency deficit within 5 years.
[12] EB-2013-0321 Ex. J9.6, Attachment 1.

as at January 1, 2017 and January 1, 2020 based on year-end 2015 information. These projections are reflected in OPG's approved 2016-2018 Business Plan.

In order to project the January 1, 2017 and January 1, 2020 benefit obligations, Aon Hewitt applied the January 1, 2014 funding valuation assumptions, subject to certain updates as at year-end 2015.[13] For the going concern valuation, the main update was a decrease in the discount rate from 5.60 per cent per annum to 5.50 per cent per annum to reflect lower expected long-term returns from pension fund assets based on the pension fund asset allocation and capital market return expectations. For the solvency valuation, the changes were to update the prescribed assumptions, including discount rates as at December 31, 2015 and the mortality assumption, which the CIA has now aligned with the recommendations in their February 2014 CIA Final Report: Canadian Pensioners' Mortality. The January 1, 2017 and January 1, 2020 pension asset values were projected by Aon Hewitt based on the actual December 31, 2015 value, at the expected long-term rate of return of 6.0 per cent per annum discussed in section 5.1.[14]

Aon Hewitt's projections of the funded status of the RPP based on year-end 2015 information indicate that the plan will have a minimal going concern deficit as at January 1, 2017, and will be fully funded on both going concern and solvency bases as at January 1, 2020. As such, the projected minimum required pension plan contributions for 2017 to 2019 based on the projected January 1, 2017 valuation comprise employer current service costs and small going concern special payments. The total minimum required contributions for 2020 and 2021 based on the projected January 1, 2020 valuation represent the employer's current service cost only. For all years of the projection, the employer's current service cost has been reduced to reflect increases in employee contribution levels discussed in Ex. F4-3-1.

Projected benefit payments for OPEB plans reflect the cash flows of the underlying accounting benefit obligations discussed in section 5.0.

[13] Attachment 1, pp. 7-8.
[14] This is the same assumption that was used to project accrual pension costs discussed in section 5.0. The difference between the going concern discount rate of 5.5 per cent and the expected long-term rate of return of 6.0 per cent relates to the factors described in footnote 9.

As in previous proceedings, total OPG projected RPP contributions and OPEB payments for 2016-2021 were attributed to the nuclear facilities in proportion to the respective benefit costs, which are allocated using the methodology discussed in section 5.2. The resulting cash amounts for the nuclear facilities are presented in Chart 1 above.

4.2 Comparison of Pension and OPEB Cash Amounts

Pension contributions for the nuclear facilities were lower in 2013 relative to the 2014-2016 period primarily due to the higher going concern special payments required pursuant to the January 1, 2014 valuation. Pension contributions are forecasted to decrease in 2017 relative to the 2014-2016 period as the projected January 1, 2017 funding valuation indicates a lower going concern deficit and therefore lower going concern special payments for the 2017-2019 period. As noted above, the going concern special payments are forecasted to be eliminated in the January 1, 2020 valuation. There are no actual or projected solvency special payments during the 2013-2021 period.

OPEB benefit payments increased gradually during the historical period and are expected to continue to increase during the bridge and test periods. This trend reflects a growing retiree population and expected increases in per capita medical and other costs.

Charts 4 below presents the EB-2013-0321 projected (2013) and OEB-approved (2014 and 2015) pension and OPEB cash amounts for the nuclear facilities.

Chart 4

EB-2013-0321 Projected Pension and OPEB Cash Amounts – Nuclear ($M)			
	2013	**2014**[15]	**2015**[16]
Pension	290.0	277.9	283.4
OPEB	80.9	77.3	82.4
Total	**370.9**	**355.2**	**365.8**

Actual pension contributions for 2013 were lower than projected primarily because OPG did not make an additional, voluntary contribution to the pension plan assumed in the budget. The actual pension contributions for 2014 and 2015 were largely in line with the OEB-approved forecast amounts. Actual OPEB payments for 2013 were close to projected amounts, while the 2014 and 2015 amounts were higher than the OEB-approved forecast, mainly as a result of retirements.

5.0 ACCRUAL COSTS FOR PENSION AND OPEB

As in EB-2013-0321, OPG's accrual costs for pension and OPEB continue to be determined in accordance with US GAAP and comprise several components. These components are: current service cost (net of required employee contributions for funded plans), interest cost on the benefit obligations at the appropriate discount rate, the expected return on RPP fund assets using an assumed long-term rate of return, amounts for past service costs arising from plan amendments, and amounts for actuarial gains or losses. Actuarial gains and losses consist of experience gains and losses, which arise because actual experience differs from that assumed (e.g., investment experience different than expected or higher or lower inflation

[15] The total of EB-2013-0321 OEB-approved pension and OPEB cash amounts for the nuclear facilities for each of 2014 and 2015 can be re-calculated as follows (subject to rounding): EB-2013-0321 Ex. N2-1-1, Chart 1, "December 31, 2013 Update" lines for Nuclear for each of 2014 and 2015 less EB-2013-0321 Payment Amounts Order, App. A, Table 3a, Note 4, line 1a, col. (a) for 2014 and col. (b) for 2015. The total of 2014 and 2015 OEB-approved nuclear cash amounts for each of pension and OPEB can be re-calculated as follows (subject to rounding): EB-2013-0321 Payment Amounts Order, App G., p. 15, $23.38M x 24 mos. for pension and $6.66M x 24 mos. for OPEB.

than assumed), and adjustments for changes in assumptions (e.g., discount rates or mortality assumptions[16]).

In accordance with US GAAP, OPG's pension and other post-retirement benefit accrual costs for a given year are based on the measurement of benefit obligations and RPP fund assets at the end of the previous year. As discussed below, the full impact of certain events arising during a year is not charged to pension and OPEB costs for that year; rather, certain amounts are accumulated and amortized over future periods. OPG's LTD costs for the current year are based on the measurement of the benefit obligation at the end of both the current and the previous year, in accordance with US GAAP. The full impact of events arising during a year related to LTD benefits is charged to OPEB costs for that year.

Similar to the going concern pension funding benefit obligation, the accounting obligations for pension and other post-retirement benefits continue to be determined using the projected benefit method pro-rated on service. Under this method, an equal portion of the total estimated benefit liability is attributed to each year of service until the date the plan participant would be entitled to the full benefit. The obligation at a particular date is the actuarial present value of the benefits attributed to the service rendered up to that date. The LTD obligation continues to be determined using the projected benefit method on a terminal basis. Under this method, the total estimated future benefit is attributed to the year of service in which a disability occurs.

OPG's pension and OPEB costs and obligations continue to be determined annually by an independent actuary using management's best estimate assumptions, both economic (e.g., inflation, salary escalation and health care cost trends) and demographic (e.g., mortality rates and improvement scale, termination rates and retirement rates).[17] The long-term inflation assumption is based on the most recent long-term outlook view of the consumer price index, informed by economic forecasts and the Bank of Canada's target range of

[16] There have been no changes to mortality assumptions used to develop OPG's US GAAP based pension and OPEB benefit obligations, from those outlined in EB-2013-0321 Ex. N2-1-1, section 2.2 and EB-2013-0321 Ex. L-6.8-1 Staff-112.
[17] Many of the pension assumptions used for accounting purposes are the same as those used in the actuarial valuations for funding purposes discussed in section 4.0.

inflation. The salary escalation rate builds on the long-term inflation assumption, subject to adjustments in the near term for known short-term salary expectations based on collective agreement provisions and other expectations of salary growth. As in EB-2013-0321, the longer term salary escalation rate continues to be equal to the long-term inflation rate plus 0.5 per cent.

In accordance with US GAAP, the discount rates used in determining benefit obligations and accrual costs for pension and OPEB continue to be based on AA corporate bond yields in Canada for the appropriate duration of the benefit obligation. The discount rates used to establish the accrual costs for the historical, bridge and test years were determined using the same approach as in EB-2013-0321.[18]

For purposes of determining pension costs, RPP fund assets continue to be valued using a market-related value of assets. The market-related value used in determining OPG's pension costs recognizes gains and losses on equity assets relative to a six per cent assumed real return over a five-year period. This contributes to the smoothing of impacts from equity market volatility over time. Gains and losses on other than equity assets continue to be recognized in the market-related value of assets immediately.

The expected long-term rate of return on the RPP fund assets continues to be calculated by Aon Hewitt based on the pension fund asset mix and capital market expectations of future risk and return for each asset class within the fund portfolio.[19]

Actuarial gains and losses for pension and other post-retirement benefits are generally amortized over future periods. In accordance with US GAAP, OPG amortizes the net cumulative unamortized gain or loss for each of these plans in excess of 10 per cent of the greater of the benefit obligation and the market-related value of the plan assets over the expected average remaining service life of the employees (i.e., the "corridor approach.") Past service costs or credits for pension and other post-retirement benefits continue to be

[18] EB-2013-0321 Ex. F4-3-1, section 6.3.3.
[19] See footnote 9.

amortized over the expected average remaining service period to full eligibility of the affected employee groups. All actuarial gains and losses and past service costs related to LTD benefits continue to be recognized in the year they arise, in accordance with US GAAP.

5.1 Forecasting Pension and OPEB Accrual Costs

Forecasting pension and OPEB accrual costs requires estimating the values of the benefit obligations and pension fund asset value at the end of the year preceding the forecast year. Developing these estimates requires making projections of the actual pension fund performance as well as projections of assumptions that will be used to determine the actual obligations. Forecasting LTD costs also requires estimating the value of the benefit obligation at the end of the last year in the forecast period.

OPG's total projected pension and OPEB accrual costs for 2016-2021 underpinning this Application were determined by Aon Hewitt using the actual December 31, 2015 values of the benefit obligations and pension fund assets, and the final assumptions as at December 31, 2015. The forecast 2017-2021 costs reflect projections of benefit obligations and pension fund assets at the end of each year in the 2016-2020 period using the December 31, 2015 final assumptions.[20]

Chart 5 below presents the assumptions used to determine OPG's 2013-2015 actual and 2016-2021 projected pension and OPEB accrual costs in accordance with US GAAP.[21]

[20] As the final December 31, 2015 assumptions were used in the projection, the 2016 pension and OPEB costs are expected to be close to the actual costs for the year with the exception of LTD costs, absent any significant unexpected changes in legislation or OPG's operations. The 2016 LTD cost projections are less definitive because the actual costs will be calculated using information as of year-end 2016.

[21] Assumptions for 2013 and 2014 were previously presented in EB-2014-0370 Ex. H1-1-1, Chart 1, in accordance with Canadian GAAP. The only assumption difference between US GAAP and Canadian GAAP applicable to OPG's pension and OPEB costs in those years is the use of the year-end discount rate to determine LTD costs under US GAAP rather than the beginning of year discount rate under Canadian GAAP. As such, the LTD discount rate assumptions shown in Chart 5 for 2013 and 2014 differ from those presented in EB-2014-0370.

Chart 5

Pension and OPEB Accrual Cost Assumptions (rate per annum)					
	2013 Actual[22]	2014 Actual[22]	2015 Actual	2016 Projection[23]	2017-2021 Plan[23]
Discount rate for pension	4.30%	4.90%	4.00%	4.10%	4.10%
Discount rate for other post-retirement benefits	4.40%	5.00%	4.10%	4.20%	4.20%
Discount rate for long-term disability	4.10%	3.30%	3.40%	3.40%	3.40%
Expected long-term rate of return on pension fund assets	6.25%	6.25%	6.25%	6.0%	6.0%
Inflation rate	2.0%	2.0%	2.0%	2.0%	2.0%
Weighted average salary schedule escalation rate[24]	2.5%	2.5%	2.0% from Jan 1, 2015 to Dec 31, 2020 and 2.5% thereafter	1.6% from Jan 1, 2016 to Dec 31, 2021 and 2.5% thereafter	1.6% from Jan1, 2016 to Dec 31, 2021 and 2.5% thereafter
Rate of return used to project year-end pension fund asset values[25]	N/A	N/A	N/A	N/A	6.0% in 2016 to 2020

The actual returns on pension fund assets were 9.2 per cent in 2013, 16.2 per cent in 2014, and 9.7 per cent in 2015.

[22] Except for the LTD discount rate determined at year end, these are the same assumptions used to develop the 2013 and the final 2014 pension and OPEB cost projections presented in EB-2013-0321 (see EB-2013-0321: Ex. F4-3-1, Chart 1 for 2013 and OPG's Argument-in-Chief, p. 97 for 2014).
[23] The assumptions for 2016-2021 can also be found at pp. 6-7 of Aon Hewitt's report in Attachment 1.
[24] The weighted average salary schedule escalation rate of 1.6 per cent per year to the end of 2021 reflects assumptions (1.0 per cent per year to the end of 2017 for PWU-represented employees and 1.0 per cent to the end of 2018 for employees represented by The Society) based on current collective agreement provisions discussed in Ex. F4-3-1, and 2.0 per cent per year (i.e., inflation rate) thereafter. The longer term salary schedule escalation (after 2021) is set at the assumed inflation rate plus 0.5 per cent, as in EB-2013-0321.
[25] Projections of rates of return to determine year-end pension fund asset values are not required for the calculation of the 2013-2016 costs because the actual prior year-end asset values are known.

5.2 Pension and OPEB Accrual Cost Distribution

A portion of OPG's total pension and OPEB accrual costs continues to be charged to the business units as part of standard labour rates and other direct charges. The portion of the costs that is charged to the business units[26] is based on an estimate of the accrual current service cost for pension and OPEB. The remainder of pension and OPEB accrual costs, which includes interest costs on the obligations, the expected return on pension plan assets, amounts for past service costs and actuarial gains and losses, and any current service cost variance from the estimate reflected in standard labour rates and related direct charges to the business units,[26] continues to be recorded as a centrally-held cost (line 1 of Ex. F4-4-1 Table 1 and Table 3).

The centrally-held portion of pension and OPEB costs continues to be directly assigned and allocated to the nuclear business unit, in proportion to amounts of pension and OPEB costs charged to the business unit (including amounts assigned and allocated as part of corporate Support Services costs). This methodology was used in EB-2010-0008, EB-2012-0002, EB-2013-0321 and EB-2014-0370. It was reviewed by HSG Group, Inc. in the cost allocation study filed in EB-2013-0321, as well as by Black & Veatch Corporation Inc. in the cost allocation study filed in EB-2010-0008.

5.3 Comparison of Pension and OPEB Accrual Costs

Chart 6 below provides a breakdown of the 2013-2021 pension and OPEB costs shown in Chart 2 for the nuclear facilities between amounts charged to the business units and those recorded in centrally held costs. As noted above, OPG is providing in Attachments 1 and 2 independent actuarial reports in support of the total OPG forecast 2016-2021 costs and the actual 2014 an 2015 costs, respectively. An actuarial report in support of 2013 actual costs was filed in EB-2014-0370.[27]

[26] Includes pension and OPEB costs assigned and allocated as part of corporate Support Services costs.
[27] Refer to EB-2014-0370 Ex. H1-1-2, Attachment 2. Although that report was prepared on a Canadian GAAP basis, the differences from US GAAP accrual costs are limited to LTD costs. These differences were described in EB-2013-0321 Ex. A2-1-1 and EB-2012-0002 Ex. A3-1-2.

Chart 6[28]

Total Pension and OPEB Accrual Costs – Nuclear[29] ($M)									
	2013 Actual	**2014 Actual**	**2015 Actual**	**2016 Projection**	**2017 Plan**	**2018 Plan**	**2019 Plan**	**2020 Plan**	**2021 Plan**
Pension – Business Unit Charge	222.2	214.6	218.6	228.6	243.0	230.4	239.0	242.4	244.3
Pension – Centrally Held	143.2	196.6	195.8	66.0	(20.2)	(62.9)	(86.0)	(102.4)	(112.9)
Total Pension Cost	**365.4**	**411.2**	**414.4**	**294.6**	**222.8**	**167.5**	**153.0**	**140.0**	**131.4**
OPEB – Business Unit Charge	77.2	74.2	55.6	58.5	67.8	66.2	67.1	68.1	68.6
OPEB – Centrally Held	145.8	101.9	147.2	134.1	126.8	128.8	128.9	128.9	129.7
Total OPEB Cost	**223.0**	**176.1**	**202.8**	**192.6**	**194.6**	**195.0**	**196.0**	**197.0**	**198.3**
Total Pension and OPEB Costs	**588.4**	**587.3**	**617.2**	**487.2**	**417.4**	**362.5**	**349.0**	**337.0**	**329.7**

Total pension accrual costs for the nuclear facilities increased from 2013 to 2014 primarily due to the updated mortality assumptions arising from a comprehensive accounting valuation of pension plan obligations as at December 31, 2013, as discussed in EB-2013-0321[30], and the impact of a lower than expected year-end 2013 pension fund asset value for fixed income investments. The increase was partially offset by the impact of the higher discount rate as at December 31, 2013. The pension accrual costs were largely stable in 2015 compared to 2014, primarily as the impact of the lower discount rate as at December 31, 2014 was largely offset by the impact of a higher than expected year-end 2014 pension fund asset value and negative expected net growth in cost components during 2015.[31] Pension costs for the

[28] "Business Unit Charge" amounts presented in Chart 6 and Chart 7 are equivalent to amounts labelled "Standard Labour Rate Component" in EB-2013-0321 evidence.
[29] See footnote 3.
[30] EB-2013-0321: Ex. N-1-1, Ex. N2-1-1 and Ex. L-6.8-1 Staff-112.
[31] As in previous proceedings, expected net growth (i.e. change) in cost components refers to the impact of changes in current service costs in the normal course, higher interest costs on a higher benefit obligation due to the passage of time, expected changes in the pension asset value, and related changes in amortization of historical actuarial gains or losses.

nuclear facilities are projected to decrease significantly over the 2016-2021 period reflecting negative expected net growth in cost components, primarily due to projected increases in the pension asset value and lower amortization of historical net actuarial losses under the corridor approach. The year-over-year decreases in forecast pension costs in 2016 and 2017 also reflect increases in employee contributions discussed in Ex. F4-3-1. Additionally, the impact of the slightly higher discount rate at December 31, 2015 and the impact of lower staffing levels contribute to the decrease in the costs in 2016 compared to 2015.

Total OPEB accrual costs for the nuclear facilities decreased from 2013 to 2014, mainly due to the lower expected per capita health care benefit costs reflected as part of the comprehensive accounting valuation as at December 31, 2013 and the impact of the higher discount rate as at December 31, 2013. The increase in OPEB costs from 2014 to 2015 was primarily due to the decrease in discount rates at December 31, 2014. OPEB costs are forecast to decrease from 2015 to 2016, mainly as a result of the slightly higher discount rate as at December 31, 2015 and lower staffing levels. In the projection for 2017 to 2021, OPEB costs for the nuclear facilities are expected to remain largely stable.

Chart 7 presents the current service cost component of the total pension and OPEB accrual costs shown in Chart 6. As discussed in section 5.2, total current service cost is comprised of estimated amounts charged to the business units through standard labour rates and other direct charges as well as variances from these estimated amounts, which are included in centrally-held costs. The sum of pension and OPEB current service cost shown in Chart 7 is presented as part of total compensation details at Ex. F4-3-1, Attachment 1, line 45.

Chart 7[32]

Pension and OPEB Accrual Current Service Cost – Nuclear[33] ($M)									
	2013 Actual	**2014 Actual**	**2015 Actual**	**2016 Projection**	**2017 Plan**	**2018 Plan**	**2019 Plan**	**2020 Plan**	**2021 Plan**
Pension – Business Unit Charge[34]	222.2	214.6	218.6	228.6	243.0	230.4	239.0	242.4	244.3
Pension – Centrally Held	(0.2)	(30.9)	32.0	(9.4)	(18.6)	(9.2)	(12.2)	(15.8)	(18.3)
Total Pension Current Service Cost	**222.0**	**183.7**	**250.6**	**219.2**	**224.4**	**221.2**	**226.8**	**226.6**	**226.0**
OPEB – Business Unit Charge[34]	77.2	74.2	55.6	58.5	67.8	66.2	67.1	68.1	68.6
OPEB – Centrally Held	(4.5)	(19.1)	5.1	(0.5)	(9.0)	(8.7)	(10.3)	(11.7)	(12.5)
Total OPEB Current Service Cost	**72.7**	**55.1**	**60.7**	**58.0**	**58.8**	**57.5**	**56.8**	**56.4**	**56.1**
Total Pension and OPEB Current Service Cost	**294.7**	**238.8**	**311.3**	**277.2**	**283.2**	**278.7**	**283.6**	**283.0**	**282.1**

Pension accrual current service cost for the nuclear facilities was lower in 2014 than in 2013 mainly on account of the higher discount rate as at December 31, 2013, partly offset by the impact of updated mortality assumptions from the comprehensive accounting valuation of plan obligations as at December 31, 2013. OPEB accrual current service cost was also lower in 2014 than in 2013, primarily as a result of the higher discount rate as at December 31, 2013 and lower expected per capita health care benefit costs reflected as part of the comprehensive accounting valuation. The higher pension and OPEB current service cost in 2015, compared to 2014, reflected a lower discount rate as at December 31, 2014. The lower pension and OPEB current service cost in 2016 compared to 2015 is mainly due to lower staffing levels and slightly higher discount rates, and, for pension, increased employee

32 See footnote 28.
33 See footnote 3.
34 As shown in Chart 6.

pension plan contributions. The current service cost for both pension and OPEB is largely stable over the test period.

The split of each year's accrual current service cost between business unit charges[35] and centrally-held costs primarily varies with differences between actual and budgeted current service cost amounts, and differences between total estimated payroll for regular employees used to develop standard labour rates and the company's actual payroll.

6.0 CONCLUSION

Although OPG continues to be of the view that it is appropriate for it to recover its pension and OPEB costs on an accrual basis, OPG proposes to continue the treatment for pension and OPEB costs adopted by the OEB in the EB-2013-0321 Decision pending the outcome of the OEB's generic consultation on pension and OPEB.

Both accrual costs and cash amounts for OPG's pension and OPEB plans are projected to decline during the test period. As accrual costs are decreasing at a faster pace, the annual difference between accrual costs and cash amounts is expected to narrow significantly from an average of about $230M per year in 2014-2015 to just under $50M by 2021 (for the nuclear facilities). These decreases reflect, among other factors, pension reforms for represented employees achieved through the 2015 round of collective bargaining with direct involvement and support of the Government of Ontario, as well as similar reforms introduced for the Management group. Cash amounts for pension are expected to exceed accrual costs starting in 2018.

[35] Includes pension and OPEB costs assigned and allocated as part of corporate support services costs.

ATTACHMENTS

Attachment 1: Aon Hewitt Report on OPG's Estimated Pension and OPEB Costs for 2016-2021

Attachment 2: Aon Hewitt Report on OPG's Pension and OPEB Costs for 2014 and 2015

BRUCE GENERATING STATIONS – REVENUES AND COSTS

1.0 PURPOSE

This evidence presents the revenues earned by OPG under the Bruce lease agreement and associated agreements (collectively "Bruce Lease") and the related costs incurred by OPG with respect to the Bruce Nuclear Generating Stations.

2.0 OVERVIEW

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.

For the test period, the net amounts of Bruce Lease revenues and costs are forecast to be ($66.1)M for 2017, ($74.3)M for 2018, ($85.9)M for 2019, ($82.1)M for 2020 and ($93.1)M for 2021 as shown in Ex. G2-2-1 Table 1. In accordance with O. Reg. 53/05 and the OEB's previous findings, these net amounts are applied towards 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. These revenues and costs are subject to the Bruce Lease Net Revenues Variance Account.

On December 3, 2015, the Province announced that an updated contract had been executed between the Independent Electricity System Operator ("IESO") and Bruce Power to enable the refurbishment of Bruce Units 3-8 (the Amended and Restated Bruce Power Refurbishment Implementation Agreement or "ARBPRIA").[1] 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 end-of-life ("EOL") dates of the Bruce units. The negotiated amendments to the Bruce Lease cover several 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.

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 Power's proposed refurbishment of the Bruce units, which provided an opportunity for certain aspects of the lease arrangements between OPG and Bruce Power to be reassessed.

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

- Extension of the lease renewal term by approximately 20 years;
- Elimination of the derivative liability embedded in the lease agreement;
- 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 Ontario Nuclear Funds Agreement ("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.

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

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 are based on the OEB's decision in EB-2007-0905. The methodology for assigning and allocating revenues and costs to the Bruce facilities and under the Bruce Lease 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. As discussed in EB-2010-0008, this methodology was previously independently reviewed and found to be appropriate by Black & Veatch Corporation Inc.[2]

Historically, Bruce Lease net revenues have typically been positive and have reduced the nuclear revenue requirement. While Bruce Lease net revenues are largely stable over 2016-2021, beginning in 2016 the net revenues are currently projected to be negative (i.e., net costs) and therefore increase the nuclear revenue requirement. The forecast decrease in net revenues in 2016-2021 relative to 2015, excluding the impact of the derivative embedded in the Bruce lease agreement, is primarily due to the impact on OPG's nuclear asset retirement obligation ("ARO") and related asset retirement costs ("ARC") of extending the EOL dates of the Bruce units in line with the ARBPRIA, effective December 31, 2015. As discussed in Ex. C2-1-1 and detailed in Ex. C2-1-1 Tables 5 and 6, the estimated impact of these changes is a decrease to the forecast Bruce Lease net revenues of approximately $69.9M in 2016, $72.0M in 2017, $73.5M in 2018, $75.5M in 2019, $120.7M in 2020 and $121.7M in 2021.[3]

Section 3 discusses the key changes to the agreements between OPG and Bruce Power. Section 4 considers the resulting revenue implications and trends. Section 5 considers OPG's costs associated with the Bruce facilities. A year-by-year presentation of Bruce Lease revenues and costs for 2013 to 2021 is provided in sections 4.5 and 5.10, respectively.

[2] EB-2010-0008 Ex .G2-2-1, section 3.0

[3] With respect to the total nuclear revenue requirement, the impact of the December 31, 2015 changes in nuclear station EOL dates and ARO related to the Bruce facilities is partly offset by reductions in the nuclear liability costs for the prescribed nuclear facilities resulting from these changes, as detailed in Ex. C2-1-1

3.0 CHANGES TO BRUCE LEASE AGREEMENT AND ASSOCIATED AGREEMENTS

The following summarizes the key aspects of the 2015 Amendment that affect OPG's revenues and/or serve to limit OPG's financial risk exposure:

1. Lease Term: The maximum term of the lease has been extended by 21 years from December 31, 2043 to December 31, 2064, such that Bruce Power now has options to renew the lease for additional consecutive renewal periods for up to 46 years after the expiry of the initial lease term on December 31, 2018. OPG's test period forecasts assume that Bruce Power will exercise its options to renew the lease.

2. Base Rent: The 2015 Amendment increased base rent payments payable by Bruce Power for the renewal terms commencing in 2019 from effectively \$16M per year[4] to \$16M per year plus annual escalation by the Consumer Price Index (Ontario) ("CPI").[5] As part of the amendment process, the parties acknowledged that the renewal term payments are generally intended to cover the executory costs being incurred by OPG in connection with the lease, such as property taxes for the Bruce site (discussed in section 5.2) and Bruce Lease contract management oversight and administration costs (discussed in section 5.0). The provision for CPI escalation increases the economic value of future base rent payments over the life of the lease. The accounting implications of these changes are discussed in section 4.1.1. The amendment did not affect the existing annual base rent amounts prescribed in the lease agreement for the initial lease term to December 31, 2018.

3. Supplemental Rent: The 2015 Amendment aligned the supplemental rent with the prevailing ONFA-based estimate of OPG's lifecycle costs to manage Bruce Power's used fuel generated after 2015 for which OPG is responsible under the Used Fuel Agreement. Effective January 1, 2016, stipulated dollar amounts of supplemental rent previously payable by Bruce Power for each Bruce unit are replaced with a single average per fuel

[4] As shown in EB-2013-0321 Ex. L-1.3-17 SEC-019, Attachment 2.
[5] The 2015 Amendment also aligned the base rent payment for the first renewal term, for one year in 2019, with the effective annual amounts for subsequent renewal terms, by reducing it from \$32M to \$16M.

bundle cost rate (for all Bruce units), based on ONFA estimates and subject to annual CPI escalation. Accordingly, supplemental rent will now vary each period with the number of fuel bundles discharged by Bruce Power into the irradiated fuel bays.

While the above change has the effect of reducing supplemental rent revenue in the shorter term starting in 2016, it allows the supplemental rent to be aligned, for the remainder of the extended lease term, with prevailing estimates of OPG's lifecycle costs of managing Bruce Power's used fuel waste generated after 2015 as determined through future ONFA reference plan update processes. Any resulting future adjustments to the ONFA-based estimated costs per bundle for used fuel generated after 2015 will now trigger a cumulative true-up of supplemental rent calculated retroactively to January 1, 2016.[6] The true-up amount will be payable (or refundable) over the remaining expected life of the longest running Bruce unit, less five years. This mechanism provides certain protection against potential cost changes arising from future ONFA reference plan updates during the extended term of the lease and replaces the previous terms of the agreement that provided OPG with a single opportunity to adjust, through negotiations, Bruce Power's used fuel fees for the full renewal period of the lease.

The 2015 Amendment also eliminated the requirement for OPG to provide Bruce Power with a partial supplemental rent rebate going forward. Prior to the amendment, supplemental rent was dependent on the Hourly Ontario Energy Price ("HOEP"). As discussed in EB-2013-0321, EB-2012-0002 and EB-2010-0008, a provision in the lease agreement required OPG to provide Bruce Power with a partial rebate of the supplemental rent payments for the Bruce units not subject to the original Bruce Power Refurbishment Implementation Agreement (i.e. Bruce B units) in a calendar year where the annual arithmetic average of the HOEP ("Average HOEP") fell below $30/MWh.

[6] The cost rate in effect in 2016 was derived from the approved 2012 ONFA Reference Plan and will be subject to a future true up adjustment based on cost estimates from the 2017 ONFA Reference Plan update process, which is in progress as of the date of this Application.

The 2015 Amendment eliminated the rebate provision effective December 4, 2015. As a result, the fair value of the derivative liability established in accordance with GAAP to account for the conditional reduction to supplemental rent payments in the future ("Bruce Derivative") was fully reversed by the end of 2015. The liability had a fair value of approximately $299M prior to reversal (approximately $224M after tax).[7] As discussed in section 4.1.2, the reversal of the Bruce Derivative triggered a corresponding reduction in the amount recorded as recoverable from ratepayers in the Derivative Sub-Account of the Bruce Lease Net Revenues Variance Account ("Derivative Sub-Account"). In accordance with the approved methodology for recovering the balance of the Derivative Sub-Account, OPG expects this amount would have otherwise been payable by ratepayers over 2016 to 2019 as the annual rent rebate became payable by OPG.

4. Low & Intermediate Level Waste Management Revenues: Effective January 1, 2016, the volumetric fees payable by Bruce Power for OPG's L&ILW storage and disposal services have been aligned with the prevailing estimate of OPG's lifecycle costs associated with managing Bruce Power's L&ILW (excluding non-routine refurbishment waste) generated after 2015. Similar to used fuel fees (i.e. supplemental rent), the costs are determined through the ONFA reference plan update process and are subject to annual CPI escalation. Any resulting future adjustments to the ONFA-based L&ILW management costs during the lease term for waste generated after 2015 will now trigger a cumulative true-up of the fees calculated retroactively to January 1, 2016.[8] The true-up amount is payable (or refundable) over the expected remaining life of the longest running Bruce unit, less five years. Similar to used fuel fees, this mechanism provides certain protection against potential cost changes arising from future ONFA reference plan updates over the extended term of the lease and replace the previous terms of the agreement that provided OPG with a single opportunity to adjust, through negotiations, Bruce Power's L&ILW fees for the full lease renewal period. The above changes increase OPG's revenues from providing L&ILW management services to Bruce Power starting in 2016.

[7] The value of the Bruce Derivative reversed in December 2015 can be found in OPG's 2015 audited consolidated financial statements at Ex. A2-1-1, Att. 3, pp. 158-159
[8] See footnote 6

4.0 BRUCE LEASE REVENUES

The forecast test period Bruce Lease revenues are $251.1M for 2017, $246.5M for 2018, $245.0M for 2019, $257.4M for 2020 and $223.6M for 2021. Actual Bruce Lease revenues earned by OPG during the 2013-2015 period and forecast to be earned during the 2016-2021 period are summarized in Ex. G2-2-1 Table 2. As in EB-2013-0321, EB-2012-0002 and EB-2010-0008, OPG derives revenues from the Bruce lease agreement and associated agreements, which are described in Sections 4.1 to 4.4 below.

4.1 Bruce Lease Agreement Revenues

As in EB-2013-0321 and EB-2010-0008, revenues from the Bruce lease agreement consist of amortization of a fixed amount of initial deferred rent ($12.1M per year) to the end of 2018, base rent and supplemental rent. Base rent is discussed in Section 4.1.1 and supplemental rent is discussed in Section 4.1.2.

4.1.1 Base Rent Revenue

The Bruce lease contains base rent payments that are preset for each year of the initial lease term up to the end of 2018. These are $88M for 2016, $90M for 2017 and $92M for 2018.[9] As discussed in section 3.0, pursuant to the 2015 Amendment, the renewal term payments starting in 2019 are effectively $16M per year, subject to CPI escalation, and are generally intended to cover the executory costs being incurred by OPG in connection with the lease.[10] As these ongoing costs are also being incurred by OPG currently (i.e. not only during the renewal term), a portion of the annual base rent payments in the 2016-2018 period is also attributed to executory costs, by de-escalating the renewal term amount.

As per the OEB's direction in EB-2007-0905, OPG continues to determine lease revenue in accordance with GAAP for non-regulated businesses. This requires the application of a straight-line basis to determine lease revenue by dividing the total expected base rent

[9] As shown in EB-2013-0321 Ex. L-1.3-17 SEC-019, Att. 2, first column.
[10] Prior to the 2015 Amendment, there was insufficient evidence to characterize, for accounting purposes, a portion of base rent payments as being intended as reimbursement of executory costs.

revenues, excluding any payments intended to cover the lessor's executory costs, by the number of years in the expected lease term determined for accounting purposes. As the full amount of base rent starting in 2019 is now considered to be on account of executory costs, only the base rent payment to the end of 2018 (excluding the portion attributable to executory costs) are subject to the straight line calculation. The portion of the lease payments for executory costs is generally recognized as revenue on the same basis as the costs.

As a result of the significant change in the lease from the 2015 Amendment, US GAAP required the expected lease term to be reassessed for accounting purposes. In line with the ARBPRIA and the 2015 Amendment, the expected lease term for accounting purposes has been extended from December 2036[11] to December 2064, effective January 1, 2016.

Based on the above, starting in 2016, annual base rent revenue consists of a fixed straight-line revenue amount and the portion of the base rent payments attributed to executory costs. The resulting forecast base rent revenue in accordance with US GAAP ranges from $24.2M in 2016 to $25.7M in 2021, compared to the straight line revenue of $38.7M in 2015. This reduction is a timing difference that reflects the longer lease term used to determine the amount of straight-line base rent revenue. As noted in Section 3.0, the 2015 Amendment did not result in changes to the existing base rent amounts payable over the remainder of the initial lease term to the end of 2018 (and increased the economic value of future base rent payments through incorporation of CPI-based adjustments during the renewal term).

Base rent revenue amounts and their calculations are set out in Ex. G2-2-1 Table 2.

4.1.2 Supplemental Rent Revenue, Including Bruce Derivative

As discussed in Section 3.0, effective January 1, 2016, the monthly supplemental rent payable to OPG in addition to base rent represents the volume-based fee for managing Bruce Power's used fuel. Supplemental rent revenue (excluding the impact of the Bruce Derivative) is generally recognized on a cash basis for financial accounting purposes because it is not a fixed amount. Prior to 2016, the supplemental rent was contingent on the

[11] As discussed at EB-2010-0008 Ex. G2-2-1, p. 3.

number and operational state of the Bruce units. Starting in 2016, it is contingent on the number of fuel bundles discharged by Bruce Power into the irradiated fuel bays.

As discussed in section 3.0, the 2015 Amendment removed the HOEP-triggered provision for a conditional partial supplemental rent rebate by OPG to Bruce Power, as of December 4, 2015. As a result, the Bruce Derivative for periods after December 3, 2015 was reversed from OPG's 2015 financial statements in accordance with GAAP. The resulting increase in 2015 Bruce Lease revenues triggered a credit entry of approximately $299M (approximately $224M after tax) in the Derivative Sub-Account. This credit entry reversed amounts previously recorded in the account as recoverable from ratepayers in the future (i.e. over the 2016-2019 period as the rent rebate became payable by OPG).[12] There will be no further impacts on Bruce Lease net revenues from the Bruce Derivative starting in 2016, which eliminates OPG's and ratepayers' future exposure to this obligation.

By the end of 2016, OPG expects the Derivative Sub-Account to have a credit balance of $68.6M, as shown in Ex. H1-2-1, Table 2, line 6, col. (c). The credit largely represents the amount that the OEB authorized to be collected for the Bruce Derivative for the post-December 3, 2015 period through the EB-2014-0370 rate riders.[13] OPG proposes to return this amount to ratepayers over the 2017-2018 period as part of its deferral and variance account clearance proposal set out in Ex. H1-2-1.

The impacts of the Bruce Derivative (including its reversal) on Bruce Lease net revenues for the 2013-2015 period are presented separately in Ex. G2-2-1 Tables 1-3 and Tables 5-6.

[12] Ex. H1-1-1 Table 12, line 10 shows a credit entry of $168.7M for the Bruce Derivative in 2015. This entry is the net amount of the following: a credit entry (after tax) of $224.0M for the Bruce Derivative reversal in December 2015, and debit entries from earlier in the year of approximately $55.4M (after tax) representing increases in the fair value of the Bruce Derivative due to increases in probability-weighted expectations of Average HOEP falling below $30/MWh.

[13] For the period from January 1, 2015 to December 3, 2015, the supplemental rent rebate was triggered and subsequently paid by OPG, on a pro-rated basis, in accordance with the terms of the lease agreement in effect prior to the 2015 Amendment.

4.2 Used Fuel Waste and Cobalt-60 Agreement Revenues

Under the Used Fuel Agreement, OPG remains responsible for managing Bruce Power's used nuclear fuel waste by providing interim storage and long-term disposal services for the used fuel generated at the Bruce stations. OPG also accepts the liability for the interim storage and future disposal of Bruce Power's spent cobalt-60 and, in return, receives payments from Bruce Power. As set out in Ex. G2-2-1 Table 2, these revenues are about $0.5M per year during the test period. Revenues for cobalt-60 storage and disposal services are recorded as the services are provided.

4.3 Low and Intermediate Level Waste Agreement Revenues

Under the L&ILW Agreement, OPG continues to manage the low and intermediate level radioactive waste received from Bruce Power.[14] In return for these services, Bruce Power pays OPG a volumetric, cost-based fee as discussed in section 3.0. OPG is required to maintain the capacity to accept all of the L&ILW received from Bruce Power.[15] Revenues under this agreement continue to be recorded as the services are provided. As set out in Ex. G2-2-1 Table 2 and discussed in section 4.5, L&ILW services revenues increase from $4.0M in 2015 to an average of $31.6M per year during the test period.

4.4 Bruce Site Services Agreement Revenues

This agreement, as amended, provides for various support and maintenance services that are provided by OPG to Bruce Power, and by Bruce Power to OPG, on a cost recovery basis. The services contemplated by this agreement are necessary to accommodate the joint occupancy and use of the Bruce site by OPG and Bruce Power. OPG's site services revenues are set out in Ex. G2-2-1 Table 2 and are approximately $0.7M per year during the test period. The related costs are discussed in Section 5.0 below.

4.5 Comparison of Revenues

A comparison of revenues from the Bruce Lease for the 2013 to 2021 period is provided in Ex. G2-2-1 Table 3. Overall, total non-derivative revenue declines from an average of

[14] Excluding non-routine refurbishment waste
[15] Ibid

approximately $263M per year in the 2013-2015 historical period to an average of approximately $245M per year in the test period. This chiefly reflects a decrease in the base rent revenue recognized for accounting purposes in accordance with US GAAP, and the full amortization of the initial deferred rent at $12.1M per year by the end of 2018,[16] as originally scheduled.[17] Relative to the 2013-2015 period, the higher L&ILW management services revenues and the lower supplemental rent revenues over the test period, both reflecting the 2015 Amendment, are largely offsetting.

The fluctuations in services revenue over 2013-2021 reflect an increase in L&ILW management services revenues as a result of modifications to the L&ILW Agreement fee structure effective January 1, 2016 as described in section 3.0, as well as differences in volumes of L&ILW received or forecast to be received from Bruce Power. Reflecting this, L&ILW management services revenues increase from $4.0M in 2015 to $32.3M in 2016 and average approximately $31.6M over the test period. Differences in waste volumes were the main reason for actual services revenue being below budget in 2013 and below the OEB-approved amounts in 2014 and 2015. As noted in previous proceedings, OPG projects revenues under the L&ILW Agreement based on information received from Bruce Power regarding forecasted L&ILW volumes. Actual waste volumes received are affected by the operations of the Bruce units, including the impact of any waste volume reduction initiatives implemented by Bruce Power, and are not under OPG's control. Lower site services revenue in 2015 compared to other years and the OEB-approved amount include a timing difference related to billings that is expected to be caught up in 2016.

As discussed in Section 4.1.1, base rent revenue is expected to decrease from $38.7M per year over the 2013-2015 period to $24.2M in 2016, due to timing differences arising from the longer expected lease term applied starting in 2016 to recognize revenue on a straight line basis. Base rent revenue increases modestly starting in 2017 as forecast executory costs escalate at an assumed CPI rate of 2% per year.

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[16] As shown in EB-2013-0321 Ex. L-1.3-17 SEC-019, Attachment 2.
[17] The amount and timing of initial deferred rent amortization were not affected by the 2015 Amendment

Supplemental rent revenue is largely stable over the 2013-2015 period.[18] It then decreases from $210.5M in 2015 to $167.6M in 2016, chiefly reflecting the restructuring of supplemental rent payments to align with ONFA-based lifecycle used fuel management cost estimates as discussed in section 3.0. Supplemental rent revenue averages approximately $182M over the test period, with year-over-year fluctuations largely reflecting information received from Bruce Power regarding the forecasted number of used fuel bundles. The relatively higher projected supplemental rent revenue of $200.7M in 2020 reflects an estimate of the fuel bundles assumed to be discharged during the defueling of the first reactor scheduled to undergo refurbishment under the ARBPRIA. The supplemental rent revenue over the test period reflects CPI-based increases per the terms of the 2015 Amendment.

The 2013 budget and the 2014 and 2015 OEB-approved amounts did not include a forecast financial impact associated with the Bruce Derivative. Excluding the Bruce Derivative, the actual supplemental rent revenue in the historical period was generally consistent with the budget (2013) and OEB-approved amounts (2014 and 2015). The impact on actual Bruce Lease revenue of changes in the fair value of the Bruce Derivative in 2013 and 2014 primarily reflected net changes in the probability-weighted expectations of future Average HOEP falling below $30/MWh and was recorded in the Derivative Sub-Account. In 2015, the impact of the Bruce Derivative was a net increase in revenue of $224.9M, of which $298.7M represented the reversal of the embedded derivative liability in December 2015 following the 2015 Amendment as discussed in section 4.1.2, and the remainder was due to increases in the probability-weighted expectations of future Average HOEP falling below $30/MWh recognized in 2015 prior to the reversal of the liability.

5.0 BRUCE LEASE COSTS

The Bruce Lease costs forecast to be incurred by OPG for the test period are $317.3M for 2017, $320.9M for 2018, $330.8M for 2019, $339.5M for 2020 and $316.8M for 2021. Actual Bruce Lease costs incurred by OPG for the 2013 to 2015 period and forecast to be incurred for the 2016 to 2021 period are summarized in Ex. G2-2-1 Table 1 and are further detailed in

[18] Excluding the impact of changes in the value of the Bruce Derivative

Ex. G2-2-1 Table 5. The costs incurred by OPG with respect to the Bruce Nuclear Generating Stations presented in this Application are consistent with those presented in EB-2014-0370, EB-2013-0321, EB-2012-0002 and EB-2010-0008. Certain relatively minor costs incurred by OPG with respect to the Bruce stations, including for services provided under the Amended and Restated Bruce Site Services Agreement and for contract management oversight and administration, continue to be reflected in other aspects of the nuclear revenue requirement and do not form part of the Bruce Lease net revenues.

5.1 Depreciation

Depreciation is calculated on the fixed assets owned by OPG at the Bruce site and leased to Bruce Power. These fixed assets include the associated ARC discussed in Ex. C2-1-1 and shown in Ex. C2-1-1 Table 3. OPG applied the same methodology and depreciation policy as in previous proceedings, also summarized in Ex. F4-1-1, to derive the depreciation expense for 2013 to 2021. The average depreciation forecast for the 2016 to 2021 period is $100.7M per year, based on the closing 2015 Bruce fixed asset balances. The continuity of Bruce fixed asset balances for 2013 to 2021 is presented in Ex. G2-2-1 Table 4.[19]

5.2 Property Tax

Pursuant to the provisions of the Bruce lease agreement, OPG continues to pay the property taxes for the Bruce site as a whole. OPG manages the annual tax assessment process and payments of municipal property taxes to the Municipality of Kincardine and payments-in-lieu of property tax to the Ontario Electricity Financial Corporation, as described in Ex. F4-2-1, Section 6.0. The average forecast property tax cost is $13.8M per year during the test period.

5.3 Accretion

Accretion expense represents the growth in the present value based ARO due to the passage of time. The forecast accretion expense for 2016 to 2021 is derived by reference to the December 31, 2015 ARO balance attributed to the Bruce stations as reflected in OPG's

[19] There are no additions to the Bruce fixed assets as any such additions, except for accounting changes to ARC, are not recorded in OPG's accounting records and are the property of Bruce Power.

2015 audited consolidated financial statements, using the same methodology as in previous proceedings. The recovery methodology for OPG's nuclear liability costs, including accretion expense, is discussed in further detail in Ex. C2-1-1. The continuity schedule for the Bruce ARO is presented in Ex. C2-1-1 Table 3. The average accretion expense is forecast at $574.2M per year during the test period.

5.4 Earnings on Nuclear Segregated Funds

OPG includes the portion of earnings from investments in the nuclear segregated funds attributed to the Bruce stations as a negative cost associated with these stations. These funds are maintained by OPG in accordance with the ONFA to provide funding for the long-term programs of the nuclear liabilities. Discussed further in Ex. C2-1-1, the segregated fund earnings form part of the OEB-approved methodology for recovery of costs associated with OPG's nuclear liabilities for the Bruce assets. The forecast fund earnings for the 2016 to 2021 period are determined using the same methodology as in previous proceedings, by reference to the actual closing balance of the funds attributable to the Bruce stations as reflected in OPG's 2015 audited consolidated financial statements. The continuity schedule for the Bruce portion of the segregated funds is presented in Ex. C2-1-1 Table 3. The average forecast earnings on the segregated funds are $435.4M per year during the test period.

5.5 Used Fuel Storage and Disposal Expenses

As discussed in Ex. C2-1-1, OPG incurs variable costs associated with the storage and disposal of incremental used nuclear fuel produced at the OPG-owned nuclear stations, including the stations on lease to Bruce Power. These costs are included as expenses related to the applicable nuclear assets in the period incurred and are presented as part of the nuclear fuel expense in OPG's consolidated financial statements.[20] The average used fuel storage and disposal expense is forecast at $72.6M per year during the test period.

[20] OPG's costs associated with the cobalt-60 services provided to Bruce Power are presented as part of the costs associated with the nuclear non-energy businesses in Ex. G2-1-1.

5.6 Waste Management Variable Expenses and Facilities Removal Costs

As discussed in Ex. C2-1-1, OPG incurs variable costs associated with managing the low level and intermediate level radioactive nuclear waste produced at the OPG-owned nuclear facilities, including the stations on lease to Bruce Power. Facilities removal costs incurred by OPG to meet its obligations under the Bruce Lease are also included in this category of expenses. The average waste management variable expense and facilities removal costs are forecast at $2.8M per year during the test period.

5.7 Interest

Interest related to the Bruce assets represents an allocation of OPG’s actual/forecast corporate-wide accounting interest expense after attributing project-specific interest to appropriate business units. As in previous proceedings, the allocation is based on a historical proportion of the average net book value of the fixed assets leased to Bruce Power relative to the total average net book value of OPG’s in-service fixed assets (including intangible assets and excluding in-service assets financed by project-specific debt). The average forecast interest expense is $24.9M per year during the test period.

5.8 Current Income Taxes

In calculating current income taxes for the Bruce assets for the historical, bridge and test periods, OPG is following the methodology approved by the OEB in EB-2010-0008 and applied in EB-2013-0321. In particular, current income taxes for the Bruce assets continue to be calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. The amount of taxes is determined by applying the enacted statutory tax rates to taxable income. Taxable income is computed by making adjustments, in accordance with applicable legislation, to the Bruce stand-alone accounting earnings before tax (i.e. the difference between Bruce Lease revenues and Bruce Lease costs) determined in accordance with GAAP, for items with different accounting and tax treatment. The adjustments in 2013 to 2021 are consistent with those presented in EB-2014-0370, EB-2013-0321, EB-2012-0002 and EB-2010-0008. The derivation of actual (2013-2015) and forecast (2016-2021) taxable income and current tax expense is shown in Ex. G2-2-1 Tables 7 and 8.

Tax losses associated with the Bruce assets on a stand-alone basis that arose in prior periods, on or after April 1, 2008, were carried forward, as in EB-2013-0321 and EB-2010-0008, and fully utilized by the end of 2014. The benefit of tax losses forecast to arise in the 2017-2021 test period is realized by carrying them back to reduce taxable income of preceding test period years. The resulting reduction in current income tax expense is reflected in the year in which the loss arises, in accordance with GAAP for non-regulated businesses. The average current income tax expense is forecast at $6.9M per year during the test period.

5.9 Deferred Income Taxes

As previously outlined in EB-2013-0321 and EB-2010-0008, deferred income taxes generally represent the amount of tax that will be payable/recoverable in the future upon reversal of temporary differences between the tax basis and the accounting carrying value of items recorded in the current year, including tax losses.[21] In calculating deferred income taxes for the Bruce assets, OPG continues to follow the methodology approved by the OEB in EB-2010-0008 and applied in EB-2013-0321. Specifically, the deferred income tax expense is determined in accordance with financial accounting requirements for unregulated entities. The actual (2013-2015) and forecast (2016-2021) deferred income taxes are calculated on a stand-alone basis using the actual/forecast Bruce Lease revenues and Bruce Lease costs, as shown in Ex. G2-2-1 Tables 7 and 8. This Table 7 separately shows the derivation of income tax impacts associated with the Bruce Derivative. The average forecast deferred income tax expense is ($35.6)M per year during the test period.

5.10 Comparison of Bruce Costs

A comparison of Bruce Lease costs for 2013 to 2021 is set out in Ex. G2-2-1 Table 6.

5.10.1 <u>Depreciation</u>

[21] EB-2013-0321 Ex. G2-2-1, Section 5.9

Depreciation expense was generally stable over the 2013-2015 period. The expense is forecast to decrease slightly in 2016, compared to 2015, and to remain stable thereafter to 2021 as shown in Ex. G2-2-1 Table 4. The relatively small decrease in 2016 reflects the impact of the extension of the estimated average service lives of the Bruce stations, for accounting purposes, effective December 31, 2015, which is largely offset by the impact of the associated increase of $2,747.5M in the Bruce ARC and ARO recorded at the end of 2015 as shown in Ex. G2-2-1 Table 4 and Ex. C2-1-1 Table 3. As discussed in Ex. F4-1-1, the extensions of the Bruce A and Bruce B station service lives aligned OPG's accounting assumptions with estimated post-refurbishment EOL dates for the Bruce units as set out in the ARBPRIA. In particular, the accounting service life of the Bruce B station was extended from the end of 2019 to 2061. The increase in the Bruce ARC and the underlying increase in the Bruce ARO are discussed in Ex. C2-1-1.

Actual depreciation expense for the historical period was generally consistent with the budget for 2013 and OEB-approved amounts for 2014 and 2015.

5.10.2 Property Tax

The property tax expense fluctuates over the 2013-2021 period, ranging from $11.6M in 2013 and 2014 to a forecast of $15.1M in 2021, primarily as a result of differences in municipal property tax rates and changes in property assessment values. Differences in municipal property tax rates also largely account for the variances between actual and budgeted (2013) and OEB-approved amounts (2014 and 2015) in the historical period.

5.10.3 Accretion

Accretion expense of $404.7M in 2015 was $18.0M higher than in 2014 which, in turn, was $17.7M higher than the 2013 accretion expense. These variances were mainly due to the normal growth in the ARO as a result of the passage of time. The actual expense was largely on budget in 2013 and slightly higher than the OEB-approved amounts in 2014 and 2015, including the effect of lower-than-forecast cash expenditures charged against the ARO.

The increase of $2,747.5M in the Bruce ARO at December 31, 2015 is the main driver for the $106.3M forecast increase in the accretion expense to $511.0M in 2016. In 2017 through 2021, the accretion expense is forecast to increase by an average of approximately $17.3M per year, from $531.4M in 2017 to $617.8M in 2021. This is primarily a result of the normal growth in the liability due to the passage of time.

5.10.4 Earnings on Nuclear Segregated Funds

The fluctuations in the Bruce portion of the nuclear segregated fund earnings over the 2013 to 2015 period were largely a function of changes in CPI, which impact the provincially guaranteed rate of return applicable to the majority of the Used Fuel Fund value. As discussed in Ex. C2-1-1, the Province guarantees a return of 3.25% plus the change in the CPI for the portion of the Used Fuel Fund attributed to the first 2.23 million used fuel bundles.

The Bruce portion of segregated fund earnings was largely on budget in 2013, exceeded the OEB-approved amount in 2014, and was below the OEB-approved amount in 2015. The variances in 2014 and 2015 were, in large part, due to fluctuations in the CPI-adjusted rate of return for the guaranteed portion of the Used Fuel Fund.

During 2016 to 2021, both funds are forecast to grow at a rate of 5.15% per annum consistent with the growth rate per the approved 2012 ONFA Reference Plan, with the net effect of the higher fund asset base, contributions pursuant to the current approved contribution schedule and forecast disbursements giving rise to year-over-year increases in fund earnings of approximately $20M. By 2021, fund earnings are forecast to reach $479.8M.

5.10.5 Used Fuel Storage and Disposal Expenses

Actual used fuel storage and disposal variable expenses increased modestly year over year during the historical period and were higher than the budgeted (2013) and OEB-approved amounts (2014 and 2015). The year-over-year increases reflected normal course increases in the per bundle variable cost rates, expressed in present value terms, due to the passage of time, and fluctuations in the number of fuel bundles used by Bruce Power. The variances from the budgeted and OEB-approved amounts were mainly due to differences from the forecasted number of fuel bundles.

Used fuel storage and disposal variable expenses are projected to increase in 2016 over 2015, primarily due to higher variable cost rates reflecting the impact of the year-end 2015 adjustment to the nuclear liabilities, as discussed in Ex. C2-1-1. Over the 2016 to 2021 period, the expenses range from a low of $64.2M in 2021 to a high of $81.7M in 2020, with year-over-year variances primarily driven by changes in the expected volume of fuel bundles based on information provided by Bruce Power.

5.10.6 Waste Management Variable Expenses and Facilities Removal Costs

Actual expenses in this category are higher in 2014 and 2015, compared to the 2013 actual and the 2016 forecast amounts, mainly due to facilities removal costs incurred in 2014 in connection with OPG's contractual obligation under the Bruce Lease to demolish and remove certain buildings and facilities that reside on land leased to Bruce Power, and changes in 2015 to the 2012 cost estimates related to the implementation of new CNSC requirements for certain facilities (Ex. C2-1-1 Table 3, Note 4). The actual expenses were consistent with the budgeted amount in 2013 and the OEB-approved amount in 2015, and were higher than the OEB-approved amount in 2014 on account of the above noted facilities removal costs. The variability in forecast expenses over the test period reflects fluctuations in waste volumes based on information provided by Bruce Power.

5.10.7 Interest

The interest expense associated with the Bruce assets declined over the historical period from $20.2M in 2013 to $15.0M in 2015, reflecting a lower allocation factor and, in 2015, a decline in OPG's non-project specific corporate debt levels. The expense is projected to increase in 2016 and over the test period, mainly due to forecast increases in OPG's non-project specific corporate debt levels over the period.

The actual interest expense attributed to the Bruce assets was higher than budgeted in 2013 and higher than OEB-approved amounts in 2014 and 2015. This was primarily due to a higher allocation factor from the increase in the net book value of the Bruce fixed assets relative to OPG's total fixed assets following the adjustments to ARC at the end of 2012.[22]

5.10.8 Current Income Taxes

The non-derivative portion of current income tax expense was higher in 2014 over 2013, primarily due to lower nuclear segregated fund contributions in 2014 per the currently approved segregated fund contribution schedule, and slightly higher in 2015 over 2014, mainly due to lower nuclear liability cash expenditures in 2015. The historical period expense was largely consistent with budgeted (2013) and OEB-approved (2014 and 2015) amounts.

Forecast current income taxes are an expense of $43.8M in 2016, $38.2M in 2017, $26.3M in 2018 and $9.1M in 2019 and a recovery of $17.7M in 2020 and $21.4M in 2021. Excluding the impact of the Bruce Derivative, this represents a decline in the expense over the test period compared to 2015. This is mainly due to increasing contributions to the nuclear segregated funds per the currently approved contribution schedule, forecast increases in nuclear liability cash expenditures, and lower base rent payments starting in 2019.

The derivative portion of current income taxes for 2013 to 2015 reflects the incidence of the supplemental rent rebate being payable to Bruce Power in a given year.

5.10.9 Deferred Income Taxes

The historical period year-over-year and actual-to-budget or actual-to-OEB-approved amount variability for the non-derivative portion of deferred income taxes reflects variances in nuclear segregated fund earnings and contributions, and nuclear liability cash expenditures. Excluding the impact of the Bruce Derivative in 2015, the deferred income tax credit of $70.5M in 2016 is forecast to be higher than the credit of $63.4M in 2015, primarily due to the projected increase in accretion expense in 2016. The deferred income tax credits are generally projected to decrease over the test period, from a high of $65.0M in 2017 to a low of $9.6M in 2021, reflecting increases in nuclear segregated fund contributions and nuclear liability cash expenditures, and lower base rent payments starting in 2019.

[22] EB-2013-0321 Ex. C2-1-1

The derivative portion of deferred income taxes fluctuated over the 2013-2015 period as a result of changes in the fair value of the Bruce Derivative, the incidence of the rebate being payable to Bruce Power and, in 2015, the reversal of the derivative liability following the 2015 Amendment.

UNDERTAKING JT1.13

Undertaking

TO PROVIDE COPIES OF THE CONTRACT AMENDMENTS REFERRED TO IN AMPCO-55.

Response

The contract amendments referred to in Ex. L-4.3-2 AMPCO-055 part (b) are attached to this response as follows:

- Attachment 1: Amendment 6 for the Retube and Feeder Replacement Engineering, Procurement and Construction (EPC) Contract with the SNC/AECON Joint Venture.
- Attachment 2: Amendment 2 for the Turbine Generators Engineering Services and Equipment Supply Contract with Alstom.
- Attachment 4: Amendment 2 for the Turbine Generators EPC Contract with the SNC/AECON Joint Venture.
- Attachment 5: Amendment 2 for the Extended Services Master Services Agreement with the SNC/AECON Joint Venture.

In addition to the above, Amendment 1 for the Turbine Generators EPC Contract with the SNC/AECON Joint Venture is attached as Attachment 3 to this response.

Attachments 2-5 are marked “confidential.” However, OPG has determined that these attachments are non-confidential, except where specifically identified. OPG is filing Attachments 2-5 in accordance with the Ontario Energy Board’s Practice Direction on Confidential Filings. Furthermore, OPG notes that consistent with its pre-filed evidence, Attachments 1 - 4 to this undertaking may not include detailed technical information, including information which may constitute nuclear prescribed or security protected information (for example, detailed scopes of work, reactor laser scans, and OPG reference information or information on which the contractor may rely). OPG does not believe this information is necessary for a complete understanding of the contracts relative to OPG’s Application.

As indicated in Ex. D2-2-3, p. 22, the Extended Services Master Services Agreement (ESMSA) with the SNC/AECON Joint Venture is substantially similar to the two other ESMSAs that are in place with each of ES Fox and Black & McDonald. OPG filed a copy of the most recently executed ESMSA with the SNC/AECON Joint Venture at Ex. D2-2-3, Attachment 10. Since the ESMSAs with ES Fox and Black & McDonald were not filed, OPG has not filed Amendment 3 to the ES Fox and Black & McDonald ESMSAs in response to this undertaking. However, Amendment 2 for the SNC/AECON Joint Venture’s ESMSA, which is substantially similar to Amendment 3 for each of the ES Fox and Black & McDonald ESMSAs, is attached as Attachment 5 to this response.

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EXECUTION VERSION

Amendment Agreement Number 2

THIS AGREEMENT is made as of January 1, 2017.

BETWEEN:

ONTARIO POWER GENERATION INC., a corporation existing under the laws of Ontario (**"OPG"**)

and

AECON CONSTRUCTION GROUP INC., a corporation existing under the laws of Canada, and **SNC-LAVALIN NUCLEAR INC.**, a corporation existing under the laws of Canada, acting jointly and severally (collectively, the "**Contractor**") doing business as a contractual joint venture known as the "SLN-AECON, a Joint Venture".

RECITALS

A. OPG and the Contractor entered into an extended services master services agreement dated as of December 19, 2014, as amended by Amendment Agreement Number 1 dated as of July 7, 2015 (collectively, the "**Original Agreement**").

B. OPG and the Contractor have agreed to further amend the Original Agreement as set forth herein.

For value received, the Parties agree as follows:

1. Interpretation

Any defined term used in this Agreement that is not defined in this Agreement has the meaning given to that term in the Original Agreement.

2. Change to Section 1.1 (Definitions)

Section 1.1 of the Original Agreement is hereby amended by:

(a) deleting Section 1.1(jjj) (Performance Fee Pool) in its entirety and replacing it with the following:

> "**(jjj)** **Performance Fee Pool** means, at any point in time, the amount representing [redacted] of the total amount of each Application for Payment accepted by OPG under this Agreement (except any Application for Payment in respect of Fixed Price Work, payment of the Performance Fee or the Core Team Services Fee or any amounts in respect of EPSCA travel and subsistence and training) during the relevant calendar year.";

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(b) deleting Section 1.1(dddd) (Reimbursable Labour Costs) in its entirety and replacing it with the following:

"(dddd) **Reimbursable Labour Costs** means, in respect of each applicable Purchase Order, all labour costs for hourly and salaried personnel which are incurred by the Contractor in good faith for direct labour employed or contracted by the Contractor in the performance of the Work, calculated in accordance with the Reimbursable Labour Costs Table.";

(c) deleting Section 1.1(nnnn) (Statutory Burdens) in its entirety and replacing it with the following:

"(nnnn) **Statutory Burdens** means any statutory assessments incurred by the Contractor in good faith for direct labour employed or contracted by the Contractor in the performance of any Work, such as CPP, EI, WSIB and employee health tax. For greater certainty, the applicable Statutory Burdens are included in the Reimbursable Labour Costs for non-trades personnel and in the Statutory Burdens Multiplier for the Reimbursable Labour Costs for trades personnel."; and

(d) adding Section 1.1(nnnn.1) (Statutory Burdens Multiplier) which will read as follows:

"(nnnn.1) **Statutory Burdens Multiplier** means, in respect of Reimbursable Labour Costs for trades, a fixed percentage calculated in accordance with Part 2 of Schedule 4 which is used to calculate the total Reimbursable Labour Costs for trades personnel.".

3. Change to Section 5.2 (Performance Fee)

Section 5.2 of the Original Agreement is hereby amended by deleting Section 5.2(a) (Addition to Performance Fee Pool) in its entirety and replacing it with the following:

"(a) **Addition to Performance Fee Pool.** In respect of each Application for Payment accepted by OPG under this Agreement (except any Application for Payment in respect of Fixed Price Work, payment of the Performance Fee or the Core Team Services Fee or any amounts in respect of EPSCA travel and subsistence and training), [redacted] of the total amount of the Application for Payment shall be withheld and added to the Performance Fee Pool.".

4. Change to Section 8.1 (Pricing)

Section 8.1 of the Original Agreement is hereby amended by:

(a) Deleting Section 8.1(k) (Rate Escalation for Trades) in its entirety and replacing it with the following:

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"(k) **Rate Escalation for Trades.** The Total Base Wage Packages (which, for greater certainty, exclude the applicable Statutory Burdens included in the Statutory Burdens Multiplier) for trades personnel determined under the applicable collective agreements will be escalated in accordance with such collective agreements. For purposes of this Section 8.1(k), "Total Base Wage Packages" mean the sum of amounts of wages, vacation pay, holiday pay, benefits, pension and other similar compensation items required to be paid by employers under the applicable collective agreements.";

(b) deleting Section 8.1(l) (Rate Escalation for Non-Trades) in its entirety and replacing it with the following:

"(l) **Rate Escalation for Non-Trades.** Subject to Section 8.1(m):

(i) the base salaries of the non-trades personnel who are Core Team members and whose positions are specified in Schedule 2, which base salaries are set out in rate sheets attached to the Purchase Order for the Core Team (as such base salaries may be updated from time to time with the prior written approval of OPG's MSA Representative and the concurrence by the Steering Committee, as evidenced by a Notice to the Contractor signed by OPG's MSA Representative); and

(ii) the rates (which, for greater certainty, include Statutory Burdens) set out in the Reimbursable Labour Costs Table that relate to non-trades personnel,

will be escalated, beginning on April 1, 2016, at the rate per annum approved by the Steering Committee based on the average change in the following indices over the relevant period:

(1) Consumer Price Index published by Statistics Canada;

(2) Consumer Price Index for Ontario published by Statistics Canada;

(3) CPI-XFET (CPI excluding food, energy and the effect of changes in indirect taxes) published by The Bank of Canada;

(4) Ontario Ministry of Labour - Collective Bargaining Highlights - Average Annual Wage Increase for Construction;

(5) EPSCA - Collective Agreements - Average Annual Wage Increase;

(6) PWU - Collective Agreements - Average Annual Wage Increase; and

(7) OPG Society Collective Agreement - Annual Wage Increase,

or such other indices as the Steering Committee may recommend.";

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(c) deleting Section 8.1(m) (Rate Escalation for Certain Non-Trades Personnel) in its entirety and replacing it with the following:

"(m) **Rate Escalation for Certain Non-Trades Personnel.** The rates (which, for greater certainty, include Statutory Burdens) set out in the Reimbursable Labour Costs Table that relate to non-trades personnel holding the position of general foreman will be escalated at the rate applicable to the trade supervised by such general foreman, as determined in accordance with the collective agreement applicable to the trade supervised by such general foreman.";

(d) deleting Section 8.1(q) (Adjustments to Reimbursable Labour Costs Table for Non-Trades Personnel) in its entirety and replacing it with the following:

"(q) **Adjustments to Reimbursable Labour Costs Table for Non-Trades Personnel.** Except for rate escalation set out in Sections 8.1(l) and 8.1(m), the Reimbursable Labour Costs for non-trades personnel (which, for greater certainty, include Statutory Burdens) set out in the Reimbursable Labour Costs Table relating to non-trades personnel will not be subject to any adjustments, unless such adjustments are: (i) required in exceptional circumstances; (ii) approved by OPG in writing prior to their use; and (iii) evidenced in an applicable Worksheet."; and

(e) adding Section 8.1(r) (Adjustments to Statutory Burdens Multiplier) which will read as follows:

"(r) **Adjustments to Statutory Burdens Multiplier.** The Statutory Burdens Multiplier will not be subject to any adjustments, unless such adjustments are: (i) required to place the Contractor in no better and no worse a position following a net increase or net decrease in costs due to changes to Statutory Burdens imposed by the applicable Governmental Authorities; (ii) approved by OPG in writing prior to its use; (iii) calculated in accordance with Part 2 of Schedule 4; and (iv) evidenced in a Notice to the Contractor signed by OPG's MSA Representative. For greater certainty, the Statutory Burdens Multiplier will not be subject to any escalation.".

5. Change to Section 8.3 (Applications for Payment)

Section 8.3 of the Original Agreement is hereby amended by deleting the first two sentences in Section 8.3(a) (Application for Payment) in their entirety and replacing with the following:

"In connection with each Purchase Order, the Contractor will submit to OPG on a timely basis, and in any event by the end of each month or as otherwise specified in the Purchase Order, an Application for Payment which includes an accurate summary of all of its costs for the Work incurred pursuant to that Purchase Order in the previous month or other period, as applicable. OPG will promptly review (and, at its option, audit) each Application for Payment, including, without limitation, the submitted costs against the

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Reimbursable Labour Costs Table and the Reimbursable Non-Labour Costs Table, as applicable, to ensure that such Application for Payment complies with the requirements of this Agreement."

6. Change to Section 8.4 (Payment Terms)

Section 8.4 of the Original Agreement is hereby amended by deleting the last three sentences in Section 8.4(a) (Payment Terms) in their entirety and replacing with the following:

"If OPG considers that any of the submitted costs are not Reimbursable Costs, OPG and the Contractor will work cooperatively to resolve the issue. If OPG and the Contractor cannot reach agreement with regard to any submitted cost, such dispute will be resolved in accordance with Section 11. If OPG and the Contractor agree that a submitted cost is a Reimbursable Cost, or if such submitted cost is determined to be a Reimbursable Cost pursuant to the dispute resolution mechanisms set out in Section 11, such submitted cost will be deemed to be a Reimbursable Cost and may be included in the next Application for Payment submitted to OPG."

7. Change to Section 8.13 (Records and Audits)

Section 8.13 of the Original Agreement is hereby amended by:

(a) deleting Section 8.13(b)(1) in its entirety and replacing it with the following:

"(1) The Contractor will ensure that, for all Work performed under this Agreement, the Contractor, the Subcontractors and Augmented Staff retain all such records and documents as may be requested by OPG on an ongoing basis, which will include, without limitation, proper timesheets, equipment-related records, accounts, invoices and bank records which are necessary for OPG to verify the nature and quality of any such Work and the accuracy of invoices for submitted costs incurred by the Contractor hereunder for any such Work (whether by the Contractor's Personnel or Augmented Staff). Timesheets will identify the provider of the Work, the Work performed, the location of the Work, the relevant period of time during which the Work was performed and the hours incurred."

(b) deleting Section 8.13(b)(2) in its entirety and replacing it with the following;

"(2) The Contractor's costs will be subject to audit by OPG on an ongoing basis during the term of this Agreement. The Contractor's costs will only be reimbursed if they are capable of being fully audited from source documents, as applicable, and if OPG is satisfied, on the basis of documentation provided to OPG by the Contractor, that such costs are Reimbursable Costs or, in respect of Goods, are the Contractor's actual cost (excluding any Canadian goods and services tax/harmonized sales tax levied under the *Excise Tax Act* (Canada)). For greater certainty, the Contractor's labour costs will only be

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reimbursed if they were calculated in accordance with the Reimbursable Labour Costs Tables."

8. Change to Schedule 4 (Reimbursable Labour Costs Tables)

Schedule 4 of the Original Agreement is hereby deleted in its entirety and replaced with the revised document entitled "Schedule 4 – Reimbursable Labour Costs Tables" attached to this Agreement as Attachment A.

9. Original Agreement Remains in Full Force

Except for changes to the Original Agreement set out in this Agreement and any previous Amendments, the Original Agreement remains in full force, unamended.

The Parties have duly executed this Agreement as of the date first above written.

ONTARIO POWER GENERATION INC.

By:

Name: Chief Supply Officer

Title: Stephen E. Oliver

AECON CONSTRUCTION GROUP INC.

By:

Name: Ian Turnbull

Title: Sr. V.P., Energy East

SNC-LAVALIN NUCLEAR INC.

By:

Name: Robert Stewart

Title: Sr. V.P., Operations

SNC-LAVALIN
Approved by SNC-Lavalin Legal Department

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ATTACHMENT A

SCHEDULE 4

REIMBURSABLE LABOUR COSTS TABLES

[See attached]

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SCHEDULE 4

REIMBURSABLE LABOUR COSTS TABLES

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Board Staff Interrogatory #24

Issue Number: 4.1
Issue: 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?

Interrogatory

Reference:
Ref: Exh A1-6-1 Attachment 1

O. Reg. 53/05 requires that the OEB ensure that OPG recovers costs to increase the output of, refurbish or add operating capacity to a generation facility if the costs were prudently incurred. In EB-2007-0905, OPG Payment Amounts April 1, 2008 to December 31, 2009, the OEB established the Capacity Refurbishment Variance Account (CRVA) to be used for this purpose.

Please identify which projects under OPG's Nuclear Operations capital forecast for 2016 to 2021 qualify for treatment under O. Reg. 53/05 and therefore for which the CRVA would be used.

Response

The Darlington Spacer Retrieval Tooling Project's capital (Ex. D2-1-3 Table 2e, line 66) and non-capital (Ex. F2-3-3 Table 2b, line 28) costs qualify for Capacity Refurbishment Variance Account (CRVA) treatment under O. Reg. 53/05.

In addition, Pickering Extended Operations' enabling **non-capital** costs, including the Fuel Channel Life Assurance (FCLA) Project, qualify for CRVA treatment. Pickering Extended Operations are discussed in Ex. F2-2-3 and the FCLA business case is summarized at Ex. F2-3-3 Table 2b, line 34. OPG also believes that the non-capital Fuel Channel Life Extension (FCLE) Project, including ongoing costs (see Full Release BCS attached to Ex. L-6.1-1 Staff-93), as well as the Fuel Channel Life Management (FCLM) Project continue to qualify for CRVA treatment.

The following table sets out the 2016-2021 forecasts for the above non-capital and capital costs reflected in the evidence as well as the actual amounts of these costs for 2015:

Costs Subject to CRVA Treatment

in millions	2015	2016	2017	2018	2019	2020	2021	Total
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

AMPCO Interrogatory #114

Issue Number: 6.1
Issue: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities (excluding that for the Darlington Refurbishment Program) appropriate?

Interrogatory

Reference:
Ref: F2-6-1

a) Please provide the forecast and actual purchases by vendor for the years 2013 to 2015.

b) Please provide the OM&A Purchased Services Nuclear Operations forecast for 2016 to 2021.

Response

a) OPG did not forecast purchases of OM&A services for nuclear operations by vendor for the period 2013-2015. Four vendors were identified in Chart 1 in Ex. F2-6-1, pp. 2-3 as having provided services in excess of a $17M threshold over the period 2013-2015. These vendors are AMEC-NSS, Black & McDonald Ltd., ES Fox Ltd. and Candu Owners Group. Aggregated amounts were provided in Ex. F2-6-1. Chart 1 below sets out the actual purchases over the period 2013-2015 by vendor. For confidentiality reasons, the vendors have been identified as A, B, C and D. Please note that the correct 2014 total amount is $129.4M as shown in Chart 1 below; the total amount for 2014 shown in Ex. F2-6-1, page 1, line 24 is incorrect.

Chart 1 ($M)

Line No.	Vendor	2013	2014	2015
	(a)	(b)	(c)	(d)
1	A	45.0	46.2	65.2
2	B	44.4	42.8	75.7
3	C	23.4	23.5	25.9
4	D	23.4	16.8	n/a
5	**Total**	**136.2**	**129.4**	**166.7**

b) Chart 2 below shows the Nuclear Operations OM&A Purchased Services forecast for each year from 2016-2021.

Chart 2 ($M)

Line No.		2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Total OM&A Purchased Service**	365.3	446.8	466.0	486.8	515.6	498.0

Board Staff Interrogatory #101

Issue Number: 6.2
Issue: Is the nuclear benchmarking methodology reasonable? Are the benchmarking results and targets flowing from OPG's nuclear benchmarking reasonable?

Interrogatory

Reference:
Ref: Exh F2-1-1 page 3 and 16

At page 16 of the reference, it states:

> The TGC/MWh for Darlington has been calculated on a normalized and non-normalized basis for 2017 and 2018 to account for the impact of reduced unit output during Darlington Refurbishment. 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 corporate allocated costs and station costs are largely fixed. 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 continue to compare Darlington's performance using a normalized TGC metric.

a) Please provide the Nuclear Operations internal performance targets for TGC/MWh, on a non-normalized basis or note whether the internal targets are provided in the nuclear business plan filed in response to a previous interrogatory.

b) Please provide the details of the normalized TGC calculation.

c) Is normalizing TGC standard practice for utilities during major nuclear refurbishments?

d) In 2015, ScottMadden validated the ongoing appropriateness of OPG's application of the benchmarking methodology. Was ScottMadden consulted about normalizing TGC during the DRP, and if yes, what was their feedback?

Response

a) The non-normalized TGC/MWh is included in Ex. F2-1-1 Chart 4 (p. 15) and Chart 5 (p. 17).

b) The denominator in TGC/MWh declines as noted in the evidence reference as the planned Darlington units are being refurbished. TGC/MWh is normalized by adding back to the denominator the deemed generation had refurbishment not taken place:

1. Added back generation based on duration of refurbishment (e.g., 365 days X 878 MW X 24 hours).
2. Adjusted for regular scheduled outage (i.e., Unit 2 would have a regularly scheduled outage in 2019 if it were not being refurbished)
3. Adjusted for forced losses based on Darlington's expected forced loss rate (FLR) of 1% instead of the post refurbishment targeted FLRs.

The numerator has been adjusted for higher fuel costs as a result of normalizing the generation. Fuel costs are adjusted based on Total Fuel Bundle Cost and Used Fuel Storage & Disposal costs per Ex. F2-5-1 Table 1.

c) & d) ScottMadden's evaluation of OPG's approach to normalizing TGC/MWh during DRP is attached as Attachment 1. ScottMadden found OPG's normalization approach to be unique but logical, reasonable, and easy to understand.

ScottMadden Evaluation of OPG Proposed Approach to Normalize Cost Metrics During Darlington Refurbishment

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Table of Contents

1. Background

Darlington Nuclear Generating Station (DNGS) is one of two nuclear stations operated by Ontario Power Generation (OPG). DNGS is a four-unit station with a net output of 3,512 megawatts (MW), and it has been producing almost 20 percent of Ontario's electricity needs since the early 1990s. OPG is performing a major mid-life refurbishment of the four nuclear reactors at DNGS (Refurb), which involves the replacement of certain life-limiting components. The execution of the Refurb "mega-project" started in October 2016 with breaker-open on Unit 2. This evolution will take 40 months, and OPG will conduct a six-month "burn-in" period after breaker-close. Other units will follow Unit 2 with scheduled completion of Refurb in 2026.

OPG tracks and benchmarks the performance of DNGS against industry peers under its nuclear cornerstone of value for money using a suite of four cost metrics. OPG believes that two of these cost metrics, Total Generating Cost per MWh (TGC per MWh) and Non-Fuel Operating Cost per MWh (NFOC per MWh), will not be comparable to prior site performance or industry peers during Refurb as a result of significantly reduced MWhs of generation with no corresponding decline in costs, which are largely fixed. In order to ensure that DNGS performance can be tracked and benchmarked during Refurb, OPG intends to "normalize," or adjust to facilitate comparison of these two cost metrics.

2. Executive Summary

OPG asked ScottMadden to provide a written evaluation of its proposed methodology for normalizing Total Generating Cost per MWh (TGC per MWh) and Non-Fuel Operating Cost per MWh (NFOC per MWh), both of which are used to track performance at DNGS. The goal of this normalization is to facilitate easier comparison to industry peers and pre-Refurb performance at DNGS. ScottMadden performed the evaluation according to the approach described in this document and subject to the listed assumptions and qualifications. One noteworthy qualification is that Refurb is a unique "mega-project," and the experience and perspective of other industry professionals, while useful to consider, cannot provide established practice for normalizing cost metrics during this unique project.

ScottMadden concurs with OPG that Refurb will significantly impact station performance indicators for these two cost metrics and that normalization will be necessary to facilitate useful comparisons to past performance and industry peers. ScottMadden also supports OPG's decision to continue to report an unadjusted (i.e., not normalized) version of these cost metrics in conjunction with any normalized version. Further, ScottMadden observed that OPG evaluated a robust list of the options available in selecting its normalization approach and assessed these options against an appropriate set of criteria for selecting a normalization approach that facilitates useful comparisons to past performance and industry peers.

ScottMadden views OPG's current normalization approach for these metrics, as detailed in the Appendix, as unique but logical, reasonable, and easy to understand. These normalized measures can facilitate useful comparisons to past performance and industry peers. And, if the normalized measures are accepted by management and external stakeholders, they can be used to drive performance monitoring and improvement. ScottMadden's evaluation found that, while Refurb is a unique mega-project, a more strongly supported and conventional approach to normalization of cost metrics under comparable scenarios was to adjust the distribution of actual costs to reflect performance of the operating units while using actual MWhs generated in the denominator.

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3. Objectives, Scope and Approach

Objectives and Scope

OPG asked ScottMadden to provide a written evaluation of its proposed methodology for normalizing two cost metrics that are used to track performance at DNGS. The goal of this normalization is to facilitate easier comparison to industry peers and pre-Refurb performance at DNGS for:

1) Total Generating Cost per MWh (TGC per MWh)
    - Numerator is Non-Fuel Operating Cost + Fuel Cost + Capital Cost
    - Denominator is the electrical energy generated and delivered to the grid, metered at DNGS
    - Metric represents total costs incurred per unit of net electrical production in the same period
2) Non-Fuel Operating Cost per MWh (NFOC per MWh)
    - Numerator is Non-Fuel Operating Cost. Denominator is the electrical energy generated and delivered to the grid, metered at DNGS
    - Metric represent Non-Fuel Operating Cost incurred per unit of net electrical production in the same period

ScottMadden's Approach

ScottMadden's approach to completing this evaluation can be broken down into six steps:

1) Understand and document exactly how OPG proposes to normalize these two cost metrics
2) Conduct research on comparable utility capital projects and related utility finance approaches to measure cost performance
3) Compare research findings to OPG approach
4) Develop and document ScottMadden evaluation of OPG approach
5) Send draft of evaluation to OPG for review
6) Finalize report

ScottMadden did not participate in the development of the proposed methodology but, to ensure completion of Step 1, did speak with internal OPG personnel and reviewed various internal OPG documents.

To complete Step 2, ScottMadden spoke with its internal nuclear experts and conducted research to identify other nuclear operators who could provide valuable operational experience (OpEx) for this evaluation. ScottMadden then conducted phone interviews with the following companies:

- NB Power
- Bruce Power
- Duke Energy

ScottMadden and these companies agreed to acknowledge and keep confidential any specific company information provided by OPG. OPG agreed to make every commercially reasonable effort to protect the confidentiality of any specific company information provided in response to the interviews.

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4. Assumptions and Qualifications

Assumptions

In preparing this evaluation, ScottMadden made the following assumptions:

- OPG will continue to report an unadjusted (i.e., not normalized) version of these cost metrics in conjunction with any normalized version
- Documents OPG has shared with ScottMadden reflect current plans for normalization of the cost metrics to be evaluated (TGC/MWh and NFOC/MWh) as of the date of this report
- Information provided by personnel from other companies accurately reflects what was (or would be) their approach to normalizing cost metrics in a comparable situation

Qualifications

ScottMadden's evaluation is subject to the following qualifications:

- Refurb is a unique "mega-project," and the experience and perspective of other industry professionals, while useful to consider, cannot provide established practice for normalizing cost metrics during this unique project
- This evaluation is based solely on the approach described in this document, and ScottMadden does not imply the performance of any additional, specific research
- The ScottMadden evaluation of the OPG approach to normalizing these cost metrics was prepared for the benefit of OPG and is limited to the subject matter expressly stated in this document; no additional ScottMadden opinion is implied or may be inferred
- ScottMadden does not express an opinion in this document on the:
  - Effectiveness of cost management practices at OPG
  - Appropriateness of any costs incurred by OPG

5. Evaluation and Summary

Evaluation

ScottMadden concurs with OPG that Refurb will significantly impact station performance indicators for these two cost metrics and that normalization will be necessary to facilitate useful comparisons to past performance and industry peers.

ScottMadden supports OPG's decision to continue to report an unadjusted (i.e., not normalized) version of these cost metrics in conjunction with any normalized version.

ScottMadden observed that OPG evaluated a robust list of the options available in selecting its normalization approach to these cost metrics, including:

- Adjust numerator (cost)
  - Adjust up – Increase fuel cost using historical cost data on the assumption that no units are offline during refurbishment
  - Adjust down – Reduce fixed costs using allocation factors on the assumption that actual costs do not scale up or down with generation
  - Do not adjust – Make no adjustment to cost

- Adjust denominator (MWhs generated)
  - Adjust up – Increase MWhs using historical data and forced-loss rate (FLR) projections, on the assumption that no units are offline for Refurb
  - Adjust down – Not considered
  - Do not adjust – Make no adjustment to MWhs generated

OPG selected its preferred normalization approach by measuring each option against six criteria:

- Understandability – how easy is it to describe how the metric was normalized?
- Ease of calculation – how easy would it be to perform the normalization and calculate this metric as Refurb continues?
- Protection from understatement – is there sufficient protection from making performance look better than it is through changes to the numerator or denominator?
- Acceptance by station management – would station management believe the metric is reflective of true performance and use it to pursue improvement?
- Acceptance by executive oversight – would OPG management believe the metric is reflective of true performance and use it to pursue improvement?
- Acceptance by external stakeholders – would external stakeholders believe the metric is reflective of true performance and use it to pursue improvement?

ScottMadden believes this is an appropriate set of criteria for selecting a normalization approach that facilitates useful comparisons to past performance and industry peers. Ultimately, the normalized metrics must support effective ongoing performance monitoring and improvement, and, as such, ease of calculation is the least important criterion of the group.

ScottMadden views OPG's current normalization approach for these metrics, as detailed in the Appendix, as unique but logical, reasonable, and easy to understand.

The ScottMadden observations that OPG should consider as supportive of its current normalization approach include:

- Significant historical data on fuel cost is available for use in "normalizing up" the numerator
- Significant historical data on MWhs of generation is available for use in "normalizing up" the denominator
- The current normalization approach is relatively easy to understand and calculate
- The top industry cost organization (the Electric Utility Cost Group or EUCG) allows nuclear operators who were available to generate MWhs but did not do so at the request of the market operator to submit those MWhs as if they generated the MWhs

The ScottMadden observations that OPG should consider as not supportive of its current normalization approach include:

- Allocation of corporate and nuclear support costs to DNGS still inflate the numerator
- OpEx from other companies did not support "normalizing up" costs in the numerator and was focused instead on adjusting the distribution of actual costs to reflect performance

- OpEx from other companies did not support "normalizing up" MWhs in the denominator
  - Other companies used actual MWhs generated (or available to generate) in every case
  - In the noted case where MWhs available to generate were included (see supportive observations above), the unit was operational and the period was hours or days rather than months or years, which is the case with Refurb
  - Other companies did not include potential MWhs in the calculation when a unit was offline due to a capital project

Summary

OPG asked ScottMadden to provide a written evaluation of its proposed methodology for normalizing Total Generating Cost per MWh (TGC per MWh) and Non-Fuel Operating Cost per MWh (NFOC per MWh), both of which are used to track performance at DNGS. The goal of this normalization is to facilitate easier comparison to industry peers and pre-Refurb performance at DNGS. ScottMadden performed the evaluation according to the approach described in this document and subject to the listed assumptions and qualifications. One noteworthy qualification is that Refurb is a unique "mega-project," and the experience and perspective of other industry professionals, while useful to consider, cannot provide established practice for normalizing cost metrics during this unique project.

ScottMadden concurs with OPG that Refurb will significantly impact station performance indicators for these two cost metrics and that normalization will be necessary to facilitate useful comparisons to past performance and industry peers. ScottMadden also supports OPG's decision to continue to report an unadjusted (i.e., not normalized) version of these cost metrics in conjunction with any normalized version. Further, ScottMadden observed that OPG evaluated a robust list of the options available in selecting its normalization approach and assessed these options against an appropriate set of criteria for selecting a normalization approach that facilitates useful comparisons to past performance and industry peers.

ScottMadden views OPG's current normalization approach for these metrics, as detailed in the Appendix, as unique but logical, reasonable, and easy to understand. These normalized measures can facilitate useful comparisons to past performance and industry peers. And, if the normalized measures are accepted by management and external stakeholders, they can be used to drive performance monitoring and improvement. ScottMadden's evaluation found that, while Refurb is a unique mega-project, a more strongly supported and conventional approach to normalization of cost metrics under comparable scenarios was to adjust the distribution of actual costs to reflect performance of the operating units while using actual MWhs generated in the denominator.

APPENDIX A: OPG PROPOSED NORMALIZATION METHODOLOGY FOR COST METRICS

OPG Proposed Normalization Methodology for Cost Metrics

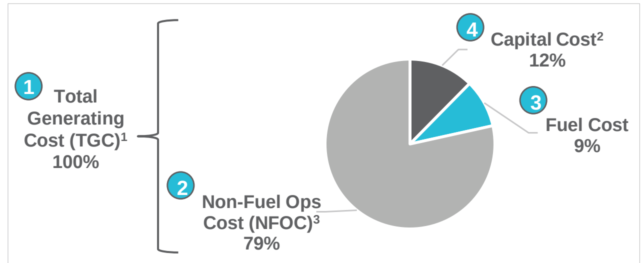
ONTARIO POWER GENERATION

Issue: Comparability of Cost Metrics During Refurbishment

Four different Value for Money (VFM) Metrics, hereafter referred to as Cost Metrics, are used by OPG to measure its Nuclear Stations' performance and to benchmark against industry standards. These metrics include, as outlined in the graphic below:

1. Total Generating Cost (TGC) per MWh
2. Non-Fuel Operating Cost (NFOC) per MWh
3. Fuel Cost per MWh
4. Capital Cost per MW Design Electrical Rating[2]

Illustrative TGC Cost Components (Pickering + Darlington Combined, 2016)



For benchmarking purposes, Cost Metrics do not include:

- Darlington Refurbishment
- P2/P3 Safe Storage Project
- New Nuclear
- NWMO oversight costs

The following costs are fully allocated to operating stations:

- Corporate Operating, Maintenance and Administrative (OM&A)
- Nuclear support cost
- Nuclear capital projects (excluding refurbishment capital costs)
- Minor fixed assets

Issue Summary: For benchmarking purposes, the first two Cost Metrics, TGC per MWh and NFOC per MWh will not be comparable to peers (or steady state operations) during the Darlington refurbishment for two key reasons:

1. **Lower generation (MWhs in the denominator) while the Darlington units are offline and not generating electricity**
2. **Fixed costs which do not scale up or down proportionally with how much electricity the Darlington units generate**

Note: Fuel Cost per MWh and Capital Cost will continue to be comparable because fuel cost varies proportionately with generation and Capital Cost per MW DER will not be impacted by lower generation during refurbishment

Notes: [1] All metrics, with the exception of "capital cost," are denominated by MWhs of generation

[2] "Capital cost," as a standalone metric uses MW Design Electrical Rating (DER) as the denominator, but nominal dollars of capital cost also contribute to the numerator in the "Total Generation Cost (TGC) per MWh" metric

[3] Non-Fuel Operation Cost (NFOC) is "total operating, maintenance & administrative (OM&A) cost" which is comprised of station cost, as well as allocated centralized nuclear support cost and allocated corporate support cost

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OPG Proposed Normalization Methodology for Cost Metrics

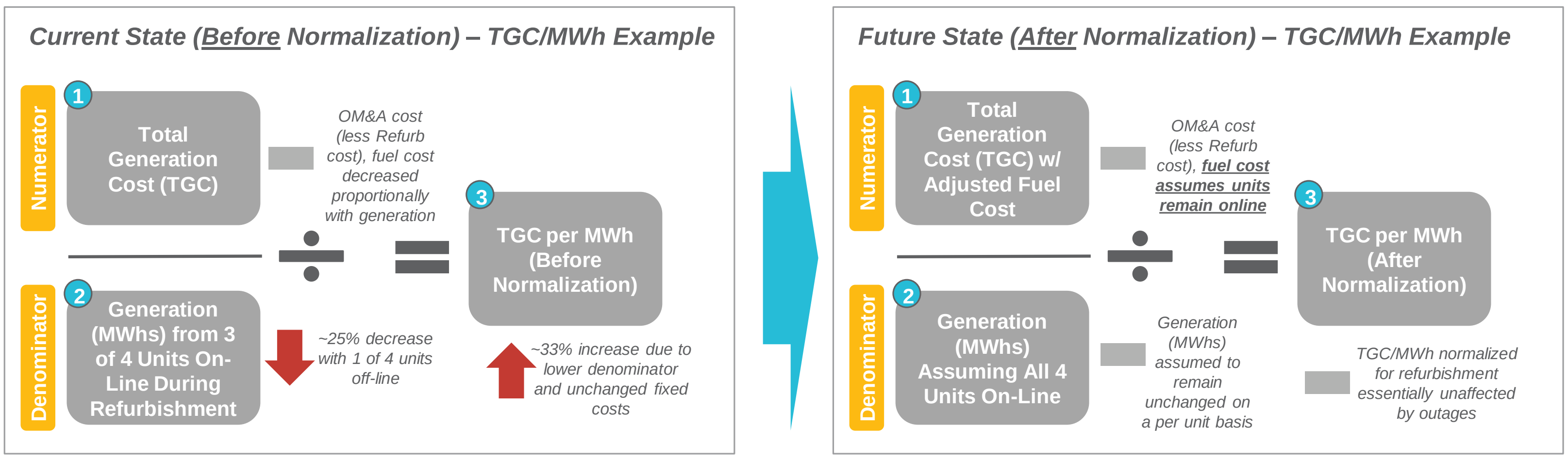
ONTARIO POWER GENERATION

Proposed Solution: Cost Metric Normalization During Refurb

<u>Proposed Solution</u>: In order to compensate for the lost MWhs of net electrical production during refurbishment while the Darlington units are off-line, OPG has proposed reporting Cost Metrics in two ways:

1. **As historically reported, the two Cost Metrics highlighted on the previous slide (TGC and NFOC) would be comparatively higher than would otherwise be the case due to the reduction in generation while the Darlington units are off-line during refurbishment**
2. **"Normalized," assuming that the Darlington units are generating at full capability during the refurbishment, to retain comparability of the two impacted KPIs with peers (and with steady state operations)**

Summary of how the proposed solution would work:



The proposed rationale of this approach is that it provides the OEB with a perspective on the degree and extent to which the two Cost Metrics are impacted by the outages – and how the two Cost Metrics would compare to peers, if not for the outages required to complete the capital projects associated with the refurbishment

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ONTARIO POWER GENERATION

OPG Proposed Normalization Methodology for Cost Metrics

Current vs. Future State: Total Generating Cost per MWh

Total Generating Cost (TGC) per MWh – Current State (Before Normalization)

(**Non-Fuel OM&A Cost[1]** + **Capital Cost[2]** + **Fuel Cost**) = **Total Generation Cost (TGC)**

÷ **Generation (MWhs) from 3 of 4 Units On-Line During Refurbishment** = **TGC per MWh (Before Normalization)**

- Non-Fuel OM&A Cost[1]: *Including station cost and allocated nuclear support and corporate support which are fixed, but excluding Refurb costs*
- Capital Cost[2]: *Only including capital cost associated with ongoing maintenance and investment in operating units (i.e., excluding Refurb capital cost)*
- Fuel Cost: *Declines proportionately with generation during refurbishment outages*

Total Generating Cost (TGC) per MWh – Proposed Future State (After Normalization)

(**Non-Fuel OM&A Cost[1]** + **Capital Cost[2]** + **Adjusted Fuel Cost**) = **Total Generation Cost (TGC)**

÷ (**Generation (MWhs) from 3 of 4 Units On-Line During Refurbishment** + **Assumed Generation (MWhs) from 4th Unit in Refurbishment**) = **TGC per MWh (After Normalization)**

- Non-Fuel OM&A Cost[1]: *Including station cost and allocated nuclear support and corporate support which are fixed, but excluding Refurb costs*
- Capital Cost[2]: *Only including capital cost associated with ongoing maintenance and investment in operating units (i.e., excluding Refurb capital cost)*
- Adjusted Fuel Cost: *Does not decline proportionately with generation during refurbishment outages; assumes units remain online*

Notes: [1] All OM&A costs associated with Refurb are being tracked separately and managed by separate Refurb organization

[2] Capital costs associated with Refurb are excluded and tracked/managed separately in Refurb organization

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OPG Proposed Normalization Methodology for Cost Metrics

ONTARIO POWER GENERATION

Current vs. Future State: Non-Fuel Operating Cost per MWh

Non-Fuel Operating Cost (NFOC) per MWh – Current State (Before Normalization)

Non-Fuel OM&A Cost[1]

Including station cost and allocated nuclear support and corporate support which are fixed, but excluding Refurb costs

=

Non-Fuel Operating Cost (NFOC)

÷

Generation (MWhs) from 3 of 4 Units On-Line During Refurbishment

=

NFOC per MWh (Before Normalization)

Non-Fuel Operating Cost (NFOC) per MWh – Proposed Future State (After Normalization)

Non-Fuel OM&A Cost[1]

Including station cost and allocated nuclear support and corporate support which are fixed, but excluding Refurb costs

=

Non-Fuel Operating Cost (NFOC)

÷

(Generation (MWhs) from 3 of 4 Units On-Line During Refurbishment + Assumed Generation (MWhs) from 4th Unit in Refurbishment)

=

NFOC per MWh (After Normalization)

Notes: [1] All OM&A costs associated with Refurb are being tracked separately and managed by separate Refurb organization

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Board Staff Interrogatory #109

Issue Number: 6.2
Issue: Is the nuclear benchmarking methodology reasonable? Are the benchmarking results and targets flowing from OPG's nuclear benchmarking reasonable?

Interrogatory

Reference:
Ref: Exh F2-1-1 Attachment 2 page 3 and 11 Ref: Exh F4-3-1 Attachment 1

At page 3, it states, "We benchmarked 5,421 OPG Nuclear staff and long-term contractors; 2,036 OPG Nuclear personnel could not be benchmarked."

a) Confirm that these data units are FTE, as used in the balance of the Goodnight report.

b) What is the definition of long-term contractor? What is the equivalent term used by OPG?

c) The total nuclear staff referred to by Goodnight is 7,457 FTE, presumably at March 2014. Attachment 1 to Exh F4-3-1 is a table summarizing FTE for the period 2013 to 2021. The total actual nuclear FTE for 2014 are 8,431.8.
   i. At page 11, Goodnight states that an FTE is 1,890 hours/year (or 36-1/3 hours per week). What factor did OPG use to determine FTE in Attachment 1 to Exh F4-3-1?
   ii. While the FTE data were collected at different times in 2014, please explain the approximately 1,000 FTE difference between the 7,457 FTE referred to in the Goodnight study and the 8,431,8 FTE summarized in Attachment 1 to Exh F4-3-1.
   iii. Using the same categories as lines 3 to 22 Attachment 1 to Exh F4-3-1, please set out the distribution of the 5,421 FTE that were benchmarked by Goodnight.

Response

a) Goodnight data is a combination of regular staff headcount translated into FTEs and long-term contractor FTEs at March 2014.

b) Goodnight Consulting defines a long-term contractor as non-regular staff or purchased services contractors of 6 months or longer duration (Goodnight report at EB-2013-0321 Ex. F5-1-1 Part a, p. 39). OPG does not distinguish between short term and long term contractors in its contractor support services (see definition of non regular labour, augmented staff and other purchase services in Ex. F2-4-1, p. 4).

c) Goodnight refers to 7,457 FTEs, which represent 6,926 regular staff, 195.3 non-regular staff contractor FTEs and 335.7 purchased services contractor FTEs.

i. More specifically, Goodnight is referring to an annual factor of 1,890 hours per year to calculate FTEs for purchased services contractors.

The FTEs in Attachment 1 to Ex. F4-3-1 were determined based on the weekly base hours associated with each position over the course of the year. Different factors were used depending on the base hours of work associated with each regular staff position as follows:

- For an employee whose base hours of work are 35 hours per week, an annual factor of 1,820 hours per year was used

- For an employee whose base hours of work are 37.5 hours per week, an annual factor of 1,950 hours per year was used

- For an employee whose base hours of work are 40 hours per week, an annual factor of 2,040 hours per year was used

ii. The difference of 974.8 FTEs from the 7,457.0 Nuclear FTEs in the Goodnight study to the 8,431.8 actual FTEs for 2014 in Ex. F4-3-1 Attachment 1 is shown in Chart 1 below:

Chart 1

	Total FTEs
Goodnight March 2014 Reported Total	7,457.0
Less: Augmented Staff + Other Purchased Services	(335.7)
Plus:	
Non-Regular Staff Not Benchmarked + Security Protected Staff Excluded + Other (timing differences, etc)[1]	765.0
Indirect Corporate Staff	545.4
Ex. F4-3-1 Attachment 1 2014 Actual	8,431.8

The Goodnight study identified 7,457.0 Nuclear FTEs, consisting of 6,926.0 Regular Staff and 531.0 Contractors. Of the 7,457.0 Nuclear FTEs, Goodnight was able to benchmark 4,890.0 Regular Staff FTEs and the 531.0 Contractor FTEs engaged in baseline steady state operations, for a total of 5,421.0 FTEs. The 531.0 Contractor FTEs in the Goodnight study represent Non–Regular Staff, Augmented Staff and Other Purchase Services. Goodnight was

[1] Provided on an aggregated basis, as OPG is unable to disclose information separately for Security Protected Staff.

unable to benchmark the remaining 2,036.0 Regular Staff FTEs as described at Ex. F2-1-1 Attachment 2, p. 14.

The 8,431.8 FTEs identified in Ex. F4-3-1 Attachment 1 also includes Non-Regular Staff FTEs but excludes 335.7 Augmented Staff and Other Purchase Services FTEs, which have been subtracted in the reconciliation in Chart 1.

The other reconciliation items in Chart 1 include adjustments for:

- 765.0 FTEs for Non-Regular Staff Not Benchmarked, Security Protected Staff Excluded, and Other:
  - Non-regular staff engaged in non-benchmarked activities, primarily outage execution (Ex. F2-2-1 Attachment 2, p. 10). These non-baseline, non-regular staff FTEs were excluded from the 7,457.0 FTES analysed by Goodnight but have been included in the 8,431.8 FTEs.
  - Security Protected Staff. The number of security personnel working at OPG is confidential and therefore OPG did not provide information on Security Protected Staff FTEs to Goodnight. Security Protected Staff are excluded from the 7,457.0 FTEs but have been included in the 8,431.8 FTEs.
  - Other (e.g. timing differences). Goodnight derived FTEs based on March 2014 headcount whereas the 8,431.8 FTEs reflect actual 2014 FTEs.
- 545.4 FTEs for Direct versus Indirect Corporate Staff:
  - Goodnight benchmarked those Corporate Staff directly supporting Nuclear (e.g., Nuclear Finance). Corporate Staff that indirectly support Nuclear (e.g., Treasury) were excluded from Goodnight but have been included within the 8,431.8 FTEs.

iii. Of the 5,421 FTEs benchmarked by Goodnight, these include 335.7 purchased services contractor FTEs, which are not represented in Ex. F4-3-1 Attachment 1. Therefore, 5,085.3 regular and non-regular benchmarked FTEs can be distributed according to the format of Ex. F4-3-1 Attachment 1 lines 3 to 22:

Line No.	**NUCLEAR FACILITIES**	**Goodnight 2014 Study Benchmarked**
1	**Staff** (Regular and Non-Regular)	**FTEs**
2		
3	**Nuclear - Direct**	
4	Management	271.2
5	Society	1,281.3
6	PWU	2,335.7
7	EPSCA	42.5
8	Subtotal	3,930.7
9		
10	**Nuclear - Allocated**	
11	Management	148.0
12	Society	335.7
13	PWU	671.0
14	EPSCA	0.0
15	Subtotal	1,154.6
16		
17	**NUCLEAR FACILITIES**	
18	Management	419.2
19	Society	1,617.0
20	PWU	3,006.6
21	EPSCA	42.5
22	Total	5,085.3
	Contractor FTEs Purchased Services	335.7
	Total	5,421.0

SEC Interrogatory #63

Issue Number: 6.2
Issue: Is the nuclear benchmarking methodology reasonable? Are the benchmarking results and targets flowing from OPG's nuclear benchmarking reasonable?

Interrogatory

Reference:
[F2/1/1, Attach 1] With respect to the 2015 Nuclear Benchmarking Report:

a. Please provide a copy of the 2014 and 2016 versions of the report.

b. Please provide a full breakdown of the calculation of the 3-Year Total Generation Cost per MWh (TGC/MWh) for both Darlington and Pickering. Please explain which of the categories of costs that OPG is seeking to recover in this application are included and which are not included.

c. [p.6] Please provide disaggregated information for Pickering A and Pickering B.

d. [p.6] Please provide the benchmark Results – Plant Level Summary table for each year since 2010.

Response

a. The 2014 Nuclear Benchmarking Report is attached as Attachment 1. The 2016 Nuclear Benchmarking Report is attached as Attachment 3.

b. The breakdown of the calculation of the 3-Year Total Generation Cost per MWh (TGC/MWh) for Darlington and Pickering is provided in Chart 1 below. OPG seeks to recover all categories of costs in this application.

c. Pickering A and B ceased to exist as separate stations when all Pickering units were combined into a single facility in 2011. As such, OPG does not track the requested metrics separately for the former A and B stations. Moreover, since none of the costs that form part of OPG's requested payment amounts are categorized based on the former Pickering A and B stations, OPG fails to see the relevance of the requested breakdown.

d. See Attachment 2.

1 Chart 1 ($M, unless otherwise stated)

2

YEAR 2017	Pickering NGS	Darlington NGS	Total
Stations	615.9	398.8	1,014.8
Nuclear Support	377.8	324.6	702.4
Corporate Support	281.6	218.7	500.3
Total OM&A	**1,275.2**	**942.2**	**2,217.5**
Total Capital	**85.2**	**193.8**	**279.0**
Total Fuel	**114.4**	**105.5**	**219.9**
Total Generation (Twh)	**19.1**	**19.0**	**38.1**
Total $/MWh	**77.36**	**65.23**	**71.30**

YEAR 2018	Pickering NGS	Darlington NGS	Total
Stations	636.0	405.5	1,041.6
Nuclear Support	405.2	280.5	685.6
Corporate Support	289.9	219.8	509.7
Total OM&A	**1,331.1**	**905.8**	**2,236.9**
Total Capital	**29.8**	**228.2**	**258.0**
Total Fuel	**115.5**	**106.5**	**222.0**
Total Generation (Twh)	**19.2**	**19.3**	**38.5**
Total $/MWh	**76.91**	**64.36**	**70.62**

YEAR 2019	Pickering NGS	Darlington NGS	Total
Stations	638.8	391.2	1,030.0
Nuclear Support	441.9	290.2	732.1
Corporate Support	291.5	218.4	509.9
Total OM&A	**1,372.2**	**899.8**	**2,272.0**
Total Capital	**28.0**	**254.4**	**282.4**
Total Fuel	**116.5**	**116.6**	**233.1**
Total Generation (Twh)	**19.4**	**19.7**	**39.0**
Total $/MWh	**78.36**	**64.61**	**71.43**

YEAR 2020	Pickering NGS	Darlington NGS	Total
Stations	619.8	409.2	1,029.0
Nuclear Support	412.4	316.2	728.6
Corporate Support	295.2	219.8	515.1
Total OM&A	**1,327.5**	**945.2**	**2,272.7**
Total Capital	**23.2**	**255.3**	**278.5**
Total Fuel	**120.5**	**107.7**	**228.2**
Total Generation (Twh)	**19.6**	**17.7**	**37.4**
Total $/MWh	**74.93**	**73.82**	**74.40**

YEAR 2021	Pickering NGS	Darlington NGS	Total
Stations	679.2	336.1	1,015.3
Nuclear Support	402.2	252.4	654.6
Corporate Support	304.6	215.9	520.4
Total OM&A	**1,385.9**	**804.4**	**2,190.3**
Total Capital	**23.1**	**176.3**	**199.3**
Total Fuel	**117.9**	**94.8**	**212.7**
Total Generation (Twh)	**18.8**	**16.6**	**35.4**
Total $/MWh	**81.16**	**64.90**	**73.55**

3

ONTARIO POWER GENERATION

ONTARIO POWER GENERATION NUCLEAR

2016 NUCLEAR BENCHMARKING REPORT

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Nuclear Finance – Business Planning and Benchmarking

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1.0 EXECUTIVE SUMMARY

Background

This report presents a comparison of Ontario Power Generation (OPG) Nuclear's performance to that of nuclear industry peer groups both in Canada and worldwide. The report was prepared as part of OPG Nuclear's commitment to "performance informed" business management. The results of this report are used during business planning to drive top-down target setting with business improvement as the objective.

Benchmarking involves three key steps: (a) identifying key performance metrics to be benchmarked, (b) identifying the most appropriate industry peer groups for comparison, and (c) preparing supporting analyses and charts. OPG Nuclear personnel responsible for specific performance metrics assisted in the development of the supporting analyses by providing insight into the factors contributing to current OPG Nuclear performance.

Performance Indicators

Good performance indicators used for benchmarking are defined as metrics with standard definitions, reliable data sources, and utilization across a representative portion of the industry. Good indicators allow for benchmarking to be repeated year after year in order to track performance and improvement. Additionally, when selecting an appropriate and relevant set of metrics, a balanced approach covering all key areas of the business is essential. In accordance with these criteria, 20 key performance indicators have been selected for comparison to provide a balanced view of performance and for which consistent, comparable data is available. These indicators are listed in Table 1 and are divided into four categories aligned with OPG Nuclear's four cornerstones of safety, reliability, value for money, and human performance.

Industry Peer Groups

Peer groups were selected based on performance indicators widely utilized within the nuclear industry with consideration for plant technology to ensure suitable comparisons. Overall, six different peer groups were used as illustrated in Table 1 and panel members are detailed in Tables 7-12 of Section 7.0.

Table 1: Industry Peer Groups

	WANO / COG CANDUs	All North American PWR and PHWRs (WANO)	INPO AP-928 Workgroup	INPO	CEA	EUCG North American Plants (U.S. and Canada)
Safety						
All Injury Rate					X	
Rolling Average Industrial Safety Accident Rate*		X				
Rolling Average Collective Radiation Exposure*	X					
Airborne Tritium Emissions per Unit	X					
Fuel Reliability Index*	X					
2-Year Reactor Trip Rate*	X					
3-Year Auxiliary Feedwater System Unavailability*	X					
3-Year Emergency AC Power Unavailability*	X					
3-Year High Pressure Safety Injection Unavailability*	X					
Reliability						
WANO NPI	X					
Rolling Average Forced Loss Rate*	X					
Rolling Average Unit Capability Factor*	X					
Rolling Average Chemistry Performance Indicator*	X					
1-Year On-line Deficient Maintenance Backlog			X			
1-Year On-line Corrective Maintenance Backlog			X			
Value for Money						
3-Year Total Generating Cost / MWh						X
3-Year Non-Fuel Operating Cost (OM&A) / MWh						X
3-Year Fuel Cost / MWh						X
3-Year Capital Cost / MW DER						X
Human Performance						
Human Performance Error Rate				X		

* Sub-indicator of WANO NPI

Data provided by the World Association of Nuclear Operators (WANO) is the primary source of benchmarking data for operational performance (Safety and Reliability) indicators. Eleven out of the twenty benchmarking metrics have been compared to the WANO/COG CANDU panel. All WANO performance indicators are presented at the unit and plant levels except the Industrial Safety Accident Rate and Emergency AC Power Unavailability which are only measured at the plant level.

Different peer groups were used for a few of the specialized operating metrics which are not tracked through WANO. For maintenance work order backlogs, the peer group consisted of all plants participating in the Institute of Nuclear Power Operations (INPO) AP-928 working group. For human performance comparisons, data was obtained from INPO. For the All Injury Rate metric, the Canadian Electricity Association (CEA) panel was used.

For financial performance comparisons, data compiled by the Electric Utility Cost Group (EUCG) was used. EUCG is a nuclear industry operating group and the recognized source for cost benchmark information. EUCG cost indicators are presented at the plant level and compared on a net megawatt hour generated basis (to be referred to as MWh subsequently) and on a per megawatt (MW) design electrical rating (DER) basis. The only CANDU operators reporting data to EUCG in 2015 were OPG Nuclear and Bruce Power which is not a sufficiently large panel to provide a basis for comparison; hence, the data sets were not limited to a CANDU specific panel. Should more CANDU operators choose to join EUCG in the future, comparisons to a CANDU specific panel will be reconsidered.

All data provided by the peer groups (WANO, INPO, CEA, and EUCG) is confidential. A redacted version of this report, which removes individual plant and unit names, is available from

Nuclear Business Planning and Benchmarking should there be a requirement to publicly release this report.

Of the 20 metrics listed in Table 1, three are used to provide important information regarding major operator performance. These are the WANO Nuclear Performance Index (NPI), Unit Capability Factor (UCF), and Total Generating Cost (TGC) per MWh.

Further information on benchmarking of major operators is provided in Section 6.0 of this report.

Benchmarking Results – Plant Level Summary

Table 2 provides a summary of OPG Nuclear's performance compared to benchmark results.

Table 2: Plant Level Performance Summary

		2015 Actuals			
Metric	**NPI Max**	**Best Quartile**	**Median**	**Pickering**	**Darlington**
Safety					
All Injury Rate (#/200k hours worked)		0.69	N/A[1]	0.44	0.22
Rolling Average[2] Industrial Safety Accident Rate (#/200k hours worked)	0.20	0.00	0.00	0.05	0.08
Rolling Average[2] Collective Radiation Exposure (Person-rem per unit)	80.00	38.17	48.53	97.72	79.55
Airborne Tritium Emissions (Curies) per Unit[3]		1,192	1,784	2,409 ⇩	1,313
Fuel Reliability Index (microcuries per gram)	0.000500	0.000001	0.000001	0.000421 ⇧	0.000122
2-Year Reactor Trip Rate (# per 7,000 hours)	0.50	0.00	0.06	0.17	0.13
3-Year Auxiliary Feedwater System Unavailability (#)	0.0200	0.0000	0.0050	0.0115	0.0000
3-Year Emergency AC Power Unavailability (#)	0.0250	0.0006	0.0041	0.0030	0.0000
3-Year High Pressure Safety Injection Unavailability (#)	0.0200	0.0000	0.0000	0.0000	0.0000
Reliability					
WANO NPI (Index)		93.5	89.4	68.5	83.7 ⇩
Rolling Average[2] Forced Loss Rate (%)	1.00	0.38	1.46	6.85	3.65
Rolling Average[2] Unit Capability Factor (%)	92.00	91.31	88.05	77.32	83.96 ⇩
Rolling Average[2] Chemistry Performance Indicator (Index)	1.01	1.00	1.00	1.06 ⇩	1.00
1-Year On-line Deficient Maintenance Backlog (work orders per unit)		116	160	251 ⇩	174 ⇩
1-Year On-line Corrective Maintenance Backlog (work orders per unit)		7	15	125	24 ⇩
Value for Money					
3-Year Total Generating Cost per MWh ($ per Net MWh)		38.93	44.38	67.36	44.38 ⇩
3-Year Non-Fuel Operating Cost per MWh ($ per Net MWh)		22.60	25.89	56.49	33.19 ⇩
3-Year Fuel Cost per MWh ($ per Net MWh)		7.97	8.73	5.71	5.18
3-Year Capital Cost per MW DER (k$ per MW)		47.33	63.63	33.86	43.52
Human Performance					
18-Month Human Performance Error Rate (# per 10k ISAR and contractor hours)		0.0010	0.0030	0.0055 ⇧	0.0031

Notes
1. No median benchmark available.
2. Indicates a 2-Year Rolling Average for Pickering and a 3-Year Rolling Average for Darlington.
3. 2014 Industry data is used because 2015 results were unavailable at the time of benchmarking.

Green = maximum NPI results achieved or best quartile performance

White = 2nd quartile performance

Yellow = 3rd quartile performance

Red = 4th quartile performance

⇩ Declining Benchmark Quartile Performance vs. 2014

⇧ Improving Benchmark Quartile Performance vs. 2014

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Since achievement of maximum WANO Nuclear Performance Index (NPI) results is recognized within the industry as a measure of desirable performance, performance gaps are assessed against the full WANO NPI result thresholds in addition to median and best quartile performance. Green shaded boxes indicate that maximum WANO NPI performance results were achieved or that performance is first quartile (also referred to in this report as "best" or "top" quartile), which is at or better than the best quartile threshold value. White shaded boxes indicate that performance is second quartile (also referred in this report as "median"), which is at or better than the median threshold value but below best quartile. Yellow shaded boxes indicate that performance is at third quartile, which is at or better than the last quartile threshold value but below the median value. Red shaded boxes indicate that performance is at fourth quartile (also referred in this report as "last"), which is below the third quartile threshold value. Table 2 also identifies, by Nuclear cornerstone, where there has been either improving or declining benchmarking quartile performance relative to 2014 benchmarking results.

For Safety, overall, OPG's nuclear generating stations continue to demonstrate strong performance. OPG Nuclear continues to demonstrate strong performance for the All Injury Rate and the Industrial Safety Accident Rate. Pickering improved in several Safety cornerstone metrics such as the Fuel Reliability Index to top quartile and 2-Year Reactor Trip Rate from 0.36 to 0.17. The Pickering station remained in the last quartile for Collective Radiation Exposure. The Airborne Tritium Emissions indicator saw a decline in industry benchmark ranking at Pickering due to an increase in heavy water leaks, poor vapour recovery dryer performance and the unavailability of the Tritium Removal Facility. Darlington achieved maximum NPI results or best quartile performance for all NPI sub-metrics under the Safety cornerstone.

For Reliability, Pickering remained in the fourth quartile in 2015 when compared to other CANDU plants for the WANO Nuclear Performance Index, Forced Loss Rate (FLR), Unit Capability Factor (UCF) and Chemistry Performance Indicator. Darlington NPI performance fell from the second quartile in 2014 to the third quartile in 2015 as a result of higher FLR and the four unit Vacuum Building Outage resulting in lower unit capability factor. Darlington FLR performance remained in the third quartile when compared to 2014. The Darlington Chemistry Performance Indicator once again remained in best quartile and achieved maximum NPI points. As for the On-line Deficient Maintenance Backlogs, improvement in industry quartiles resulted in lower quartile rankings at both Pickering and Darlington. Darlington fell to the third quartile ranking for the On-line Corrective Maintenance backlogs in 2015 due to an increase in work orders per unit and improvement in industry median quartiles.

Under the Value for Money cornerstone, Pickering remained in the worst quartile for performance in Total Generating Cost (TGC) per MWh and Non-Fuel Operating Cost (NFOC) per MWh. Pickering maintained best quartile performance in Fuel Cost per MWh and Capital Cost per MW DER. Darlington's TGC per MWh fell from the best quartile performance in 2014 to median quartile in 2015. The drop to the last quartile performance in NFOC per MWh was contrasted by sustained top quartile performance in Fuel Cost per MWh and Capital Cost per MW DER at Darlington in 2015. Darlington had the second lowest Fuel Cost per MWh in its industry peer group, while Pickering had the fourth lowest.

In the area of Human Performance, Pickering and Darlington improved their human performance error rate and Pickering improved to the third quartile in 2015, due to an increased focus on initiatives to drive performance.

Report Structure

Sections 2.0 to 5.0 of the report focus on the four OPG Nuclear cornerstone areas, with detailed comparisons at the plant, and where applicable, unit level. Each indicator is displayed graphically from best to worst plants/units (in bar chart format) for the most recent year in which data is available. Zero values are excluded from all calculations except where zero is a valid result.

Next, the historical trend is graphed (in line chart format) using data for the last few years (depending upon availability and metric). Each graph also includes median and best quartile threshold values, and for some WANO operating metrics, the values required to achieve full WANO NPI results.

Following the graphical representation, performance observations are documented as well as insights into the key factors driving performance at OPG's nuclear generating stations.

Section 6.0 of the report provides an operator level summary across a few key metrics. The operator level analysis looks at fleet operators, primarily across North America, utilizing a simple average of the results (mean) from each of their units/plants. Operations related (WANO NPI and UCF) results were averaged at the unit level and cost related (TGC per MWh) results were averaged at the plant level. The list and ranking of operators, for the Nuclear Performance Index and Unit Capability Factor, have been updated to reflect industry developments.

Section 7.0 provides an appendix of supporting information, including common acronyms, definitions, panel composition details and a WANO NPI plant level performance summary of OPG nuclear stations against the North American panel.

2.0 SAFETY

Methodology and Sources of Data

The majority of safety metrics were calculated using data from WANO. Data labelled as invalid by WANO was excluded from all calculations. Indicator values of zero are not plotted or included in calculations except in cases where zero is a valid result. Current data is obtained and consolidated with previous benchmarking data.

The All Injury Rate was calculated using data from the Canadian Electricity Association (CEA). Median information and individual company information was not available for this metric; therefore, only trend and best quartile information is presented. The peer group for this metric is limited to Group I members of CEA for 2011-2015 and Group I and II members for the 2010 period (Section 7.0, Table 10).

Airborne Tritium Emissions per unit data was collected from the CANDU Owners Group (COG) for 2010 to 2014 as displayed in the historical trend line chart. Industry data for 2015 was unavailable at the time of benchmarking. The peer group for this metric is all CANDUs who are members of COG. The bar chart associated with this metric displays graphically the plant performance from best to worst results using 2015 data for OPG stations and 2014 data for all other benchmarked stations that were in service over that period of time. 2014 is the most recent benchmark data with the exception of the one plant, which 2012 is the most recent data. As such, the plant has been excluded from the Airborne Tritium Emissions benchmarking.

Discussion

Nine metrics are included in this benchmarking report to reflect safety performance, including seven of the ten metrics which comprise the WANO Nuclear Performance Index: Industrial Safety Accident Rate, Collective Radiation Exposure, Fuel Reliability Index, Automatic Reactor Trips, Auxiliary Feedwater Safety System Unavailability, Emergency AC Power Safety System Unavailability, and High Pressure Safety Injection Unavailability. The remaining WANO NPI metrics are included in Section 3.0 under the Reliability cornerstone. In addition to the WANO sub-indicators listed above, the CEA All Injury Rate and the COG Airborne Tritium Emissions per unit are included in this section of the report.

Although Pickering's AIR performance declined in 2015, overall OPG's performance was excellent achieving top quartile ranking. Pickering continued to show maximum WANO NPI results or top quartile performance for six other metrics under the Safety cornerstone, third quartile performance for Airborne Tritium Emissions, and worst quartile performance for the Collective Radiation Exposure. Darlington showed very strong performance, achieving maximum NPI results (and/or best quartile ranking for 2015) for all NPI safety metrics. Darlington Airborne Tritium Emissions remained in the second quartile in 2015.

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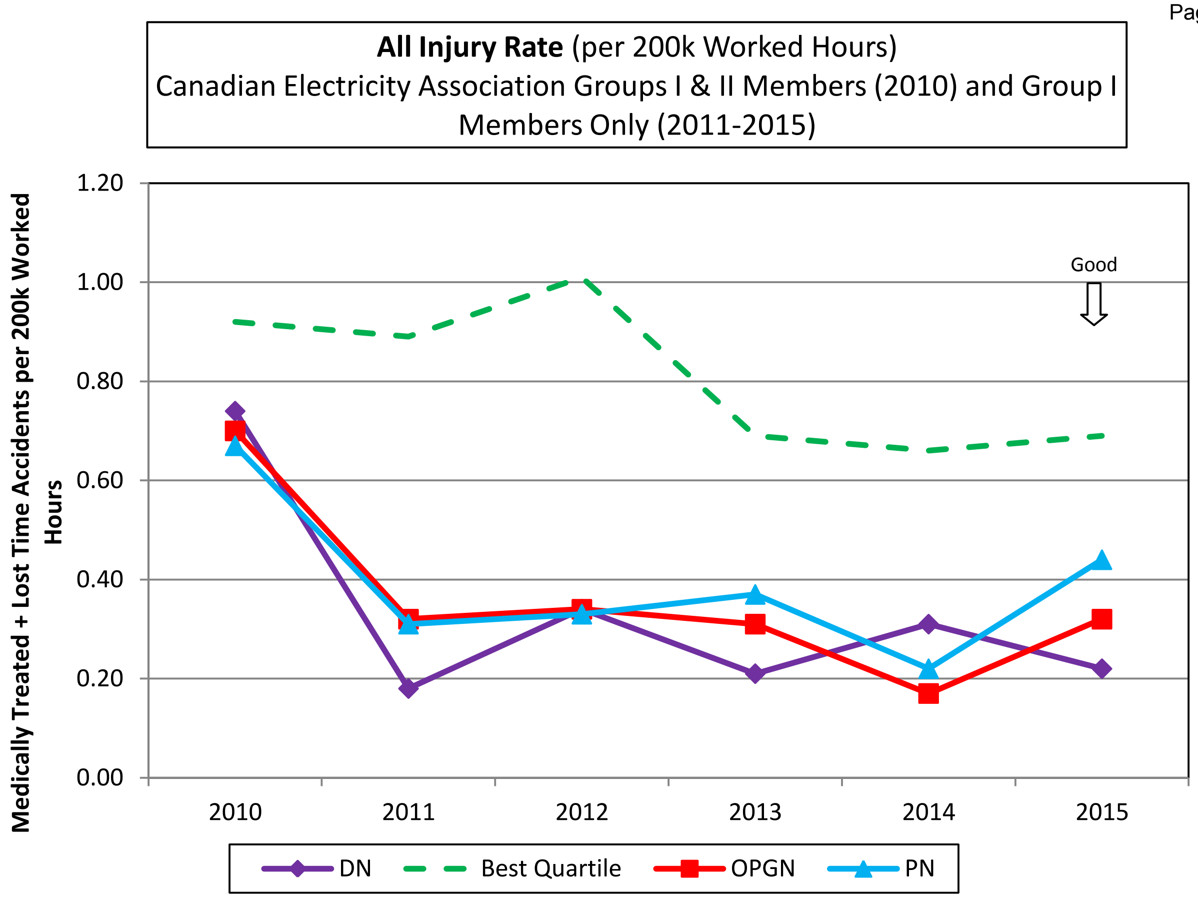
All Injury Rate



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Observations – All Injury Rate (AIR) (Canadian Electricity Association – CEA)

2015 (Annual Value)

- Pickering, Darlington, and OPG Nuclear as a fleet all performed better than the CEA top quartile of 0.69.
- Darlington's AIR injuries decreased from four in 2014 to three in 2015 resulting in an improved AIR from 0.31 in 2014 to 0.22 in 2015.
- Pickering's AIR injuries increased from four in 2014 to eight in 2015 resulting in a setback in AIR from 0.22 in 2014 to 0.44 in 2015. Four out of the eight AIR injuries seen in 2015 are associated with routine activities or situational awareness. Initiatives to improve performance in these areas are shown under 'Factors Contributing to Performance'
- OPG benchmarks against CEA Group 1 (a sub-set of all CEA members), which incorporates 10 organizations with more than 1500 employees, including most provincial utilities.

Trend

- While the industry Best Quartile has improved steadily over the review period; it has not improved to the same extent as Pickering, Darlington and OPG Nuclear.
- OPG Nuclear recorded its best AIR performance in the company's history in 2014. Its AIR performance has regressed in 2015 but it continues to demonstrate steady improvement when extended over the six year review period.
- Pickering, Darlington and OPG Nuclear as a fleet have all shown significant improvements in performance since 2010.
- Pickering Nuclear had a successful WANO evaluation in 2015 and Darlington Nuclear in 2016 with zero areas for improvement found for Industrial Safety.

Factors Contributing to Performance

- OPG encourages a proactive reporting culture that seeks to identify hazards and addresses them, before they lead to employee injuries. Proactive reporting is tracked, trended and managed via the Station Condition Record process.
- OPG Nuclear continues to utilize and promote its "Situational Awareness" program which works to support employees in identifying and addressing changing and/or distracted work conditions that could lead to hazardous situations.
- OPG launched the Total Health Program in 2014, which supports employees and their families in their efforts to achieve an optimal level of health and functioning, primarily through health education, health promotion, disease and injury prevention, and crisis intervention. The Total Health Program incorporates mental health as a key component.
- To further improve performance, OPG Nuclear is implementing an initiative in 2016 to address injuries that can result from 'routine activities.' Routine activities are being defined as those injuries that did not occur at a job site or while engaged in specific work task activities. The actions from this initiative aim to reduce distractions so that employees continue their focus on safety at all times.

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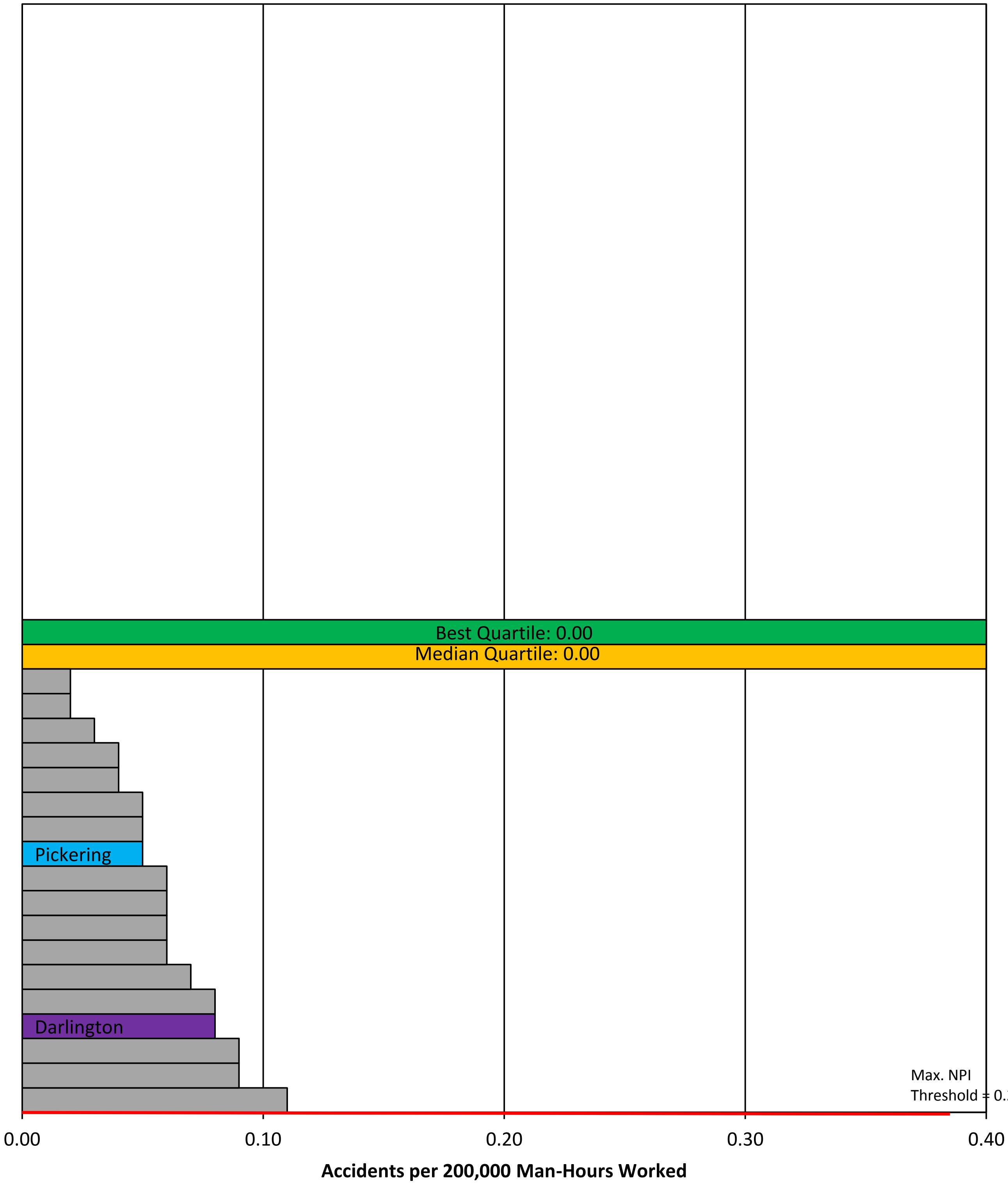
Rolling Average Industrial Safety Accident Rate

2015 Rolling Average Industrial Safety Accident Rate (per 200,000 man-hours worked)
North American PWR & PHWR Plant Level Benchmarking



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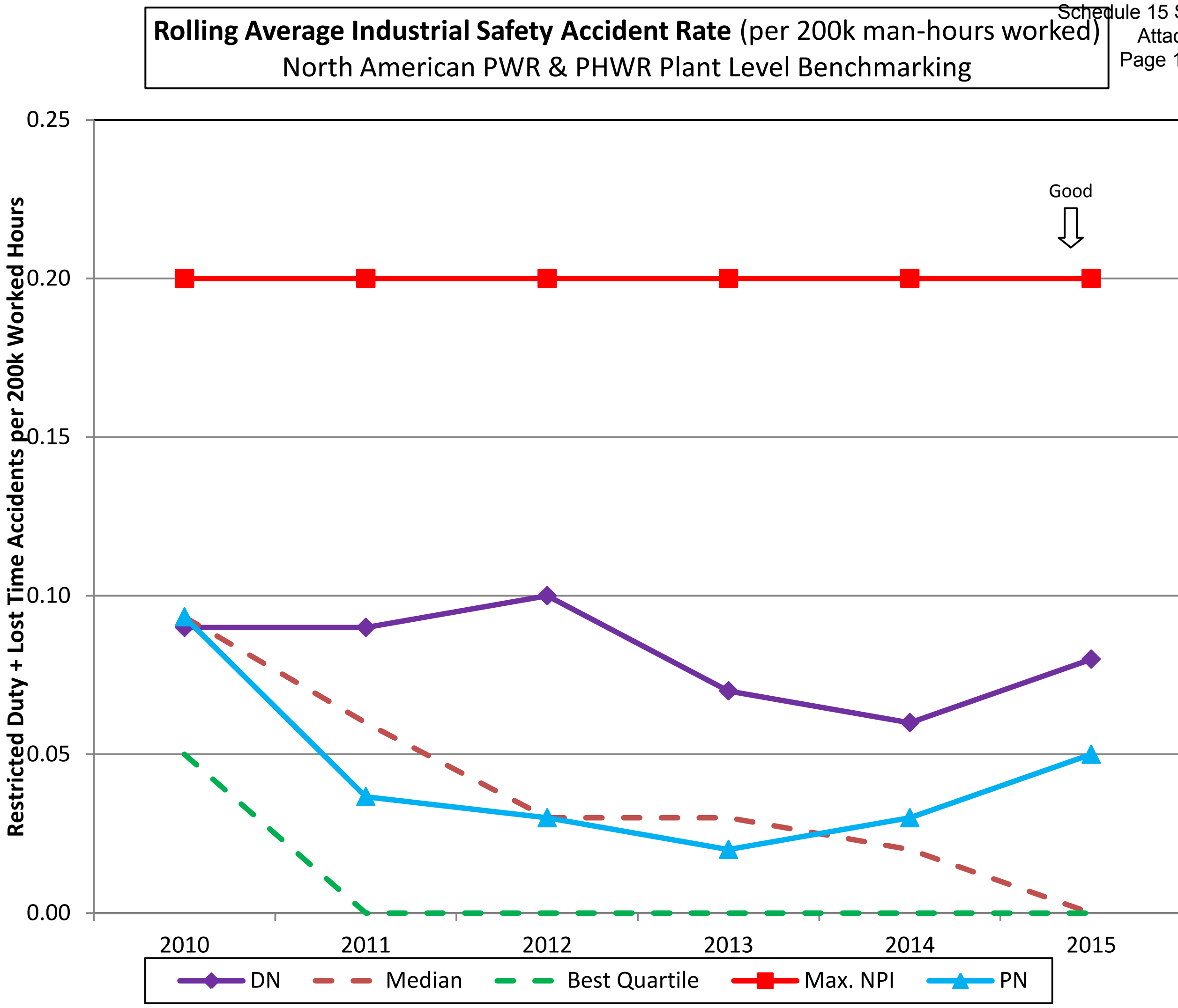

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Observations – Rolling Average Industrial Safety Accident Rate (ISAR) (World Association of Nuclear Operators - WANO)

2015 (Rolling 2 Year Average Pickering, Rolling 3 Year Average Darlington)

- The Industrial Safety Accident Rate (ISAR) incorporates all lost time injuries and restricted work injuries incurred by OPG employees working on the site.
- For reporting the ISAR, a 2-year rolling average was used for all panel members with the exception of the Darlington station which follows a 3-year outage cycle. This is consistent with the World Association of Nuclear Operators (WANO) Nuclear Performance Index (NPI) reporting guidelines.
- WANO top quartile in 2015 remained unchanged from 2014 at 0.00 (i.e. zero ISAR events). Median performance was 0.00, which was an improvement from 0.02 in 2014.
- Both Pickering and Darlington achieved maximum NPI points for the ISAR in 2015.
- Pickering ISAR performance degraded from 2014 to 2015 (0.03 to 0.05).
- Darlington ISAR performance degraded from 2014 to 2015 (0.06 to 0.08).
- Darlington and Pickering ISAR did not meet the WANO median or top quartile in 2015.

Trend

- The ISAR median and best quartile has improved over the past six years. The industry best quartile has maintained the value of zero for the past five years and the median is at zero for the first time.
- Darlington's ISAR rolling average has increased slightly to 0.08 but continues to show general improved performance over the past four years.
- Pickering's ISAR rolling average increased slightly to 0.05 in 2015 due to the one ISAR injury in that year compared to zero injuries in 2013.

Factors Contributing to Performance

- ISAR is a measure of "permanent utility personnel" and does not include contractors. Many of the utilities in the benchmarking group utilize contractors to a greater extent than OPG Nuclear for higher risk work activities (e.g. outages). Therefore this can negatively impact OPG Nuclear's ISAR in comparison to the reported industry benchmark quartiles.
- OPG Nuclear continues to monitor performance trends in the area of conventional safety and implements action plans to support continuous improvement. A new initiative to address injuries from 'routine activities' defined as those injuries that did not occur at a job site or while engaged in specific work task activities is underway for 2016.
- Additionally, an ongoing major initiative is to improve "Situational Awareness", which works to support employees in identifying and addressing changing and/or distracted work conditions that could lead to hazardous situations.

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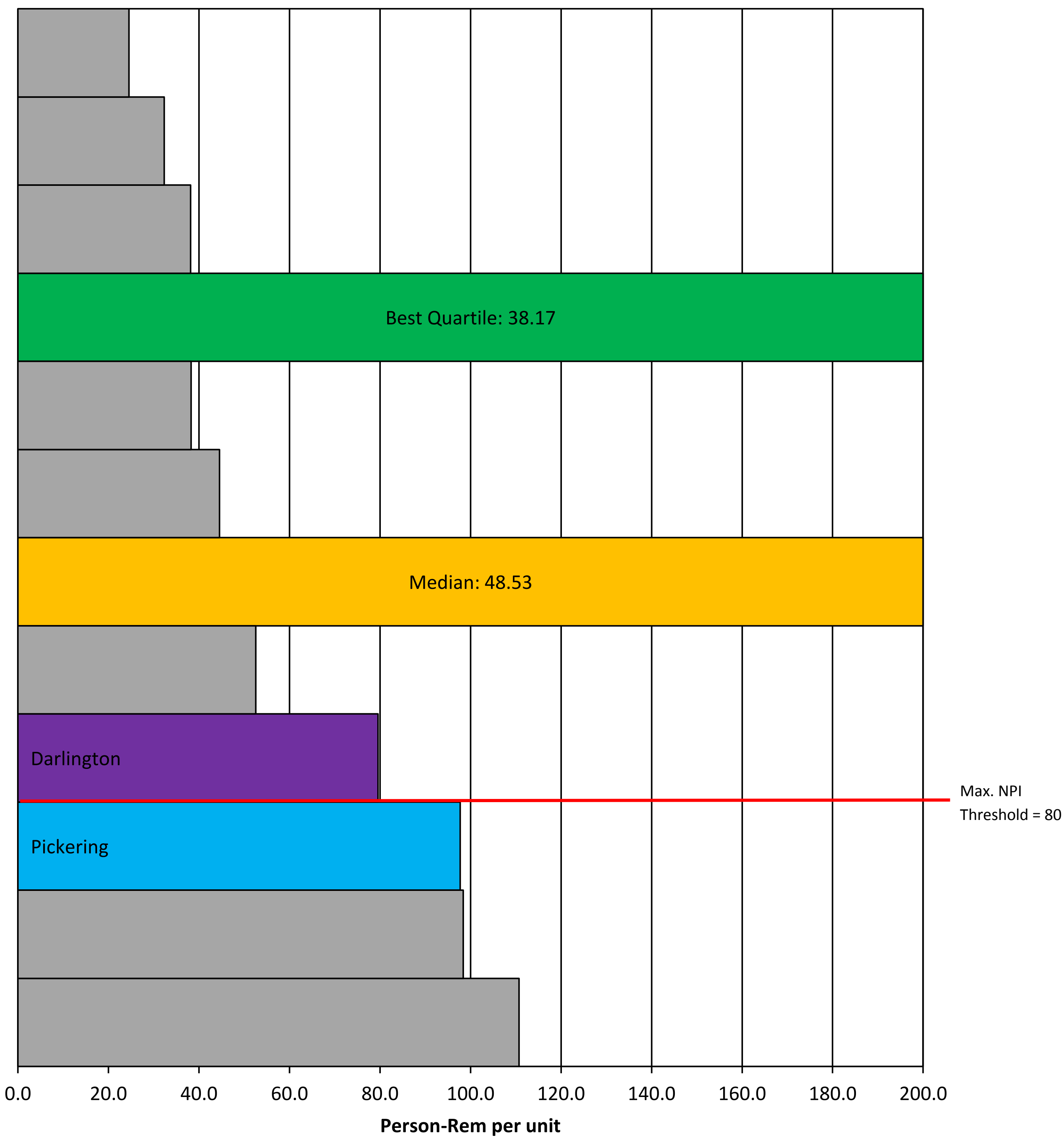
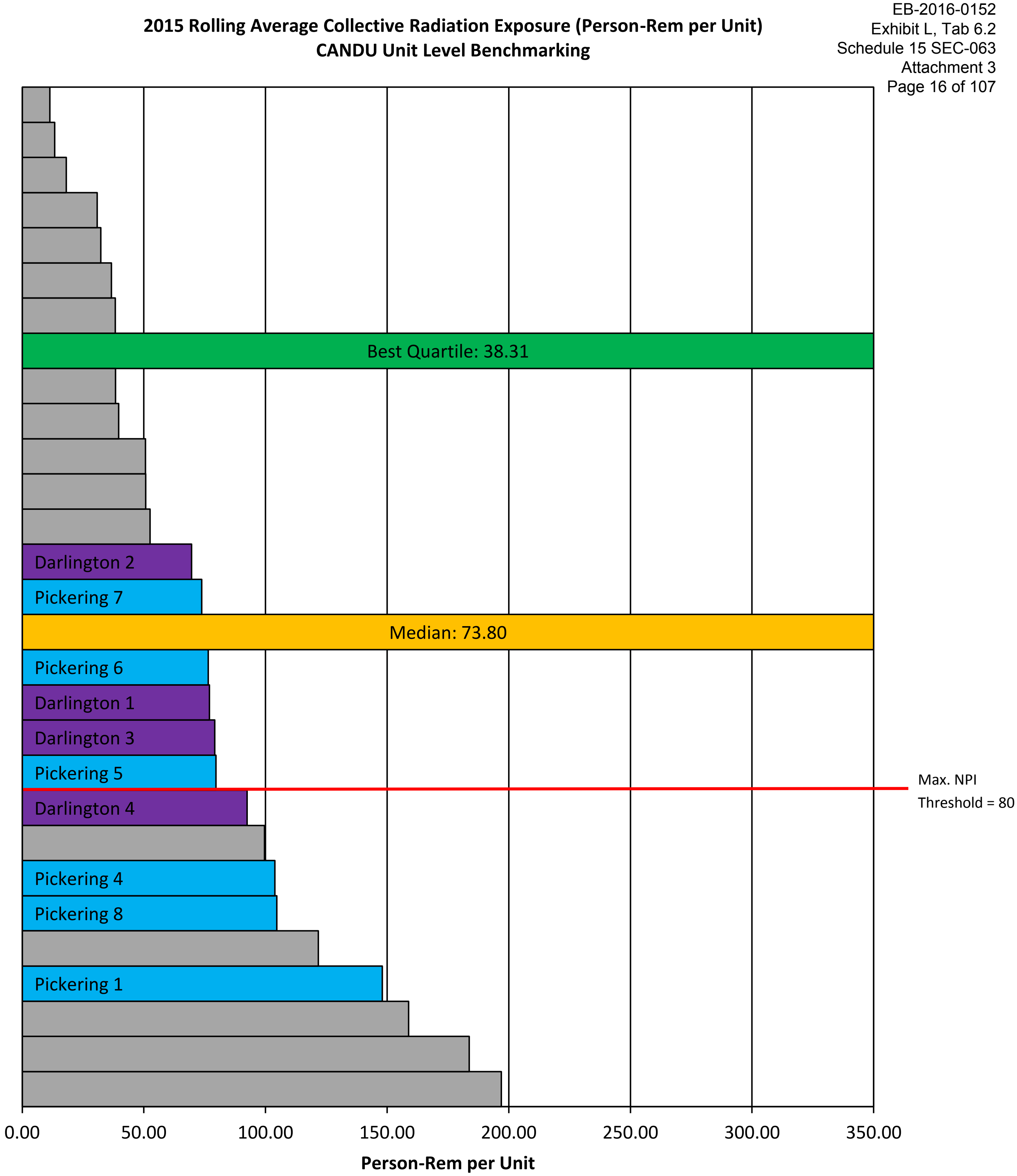
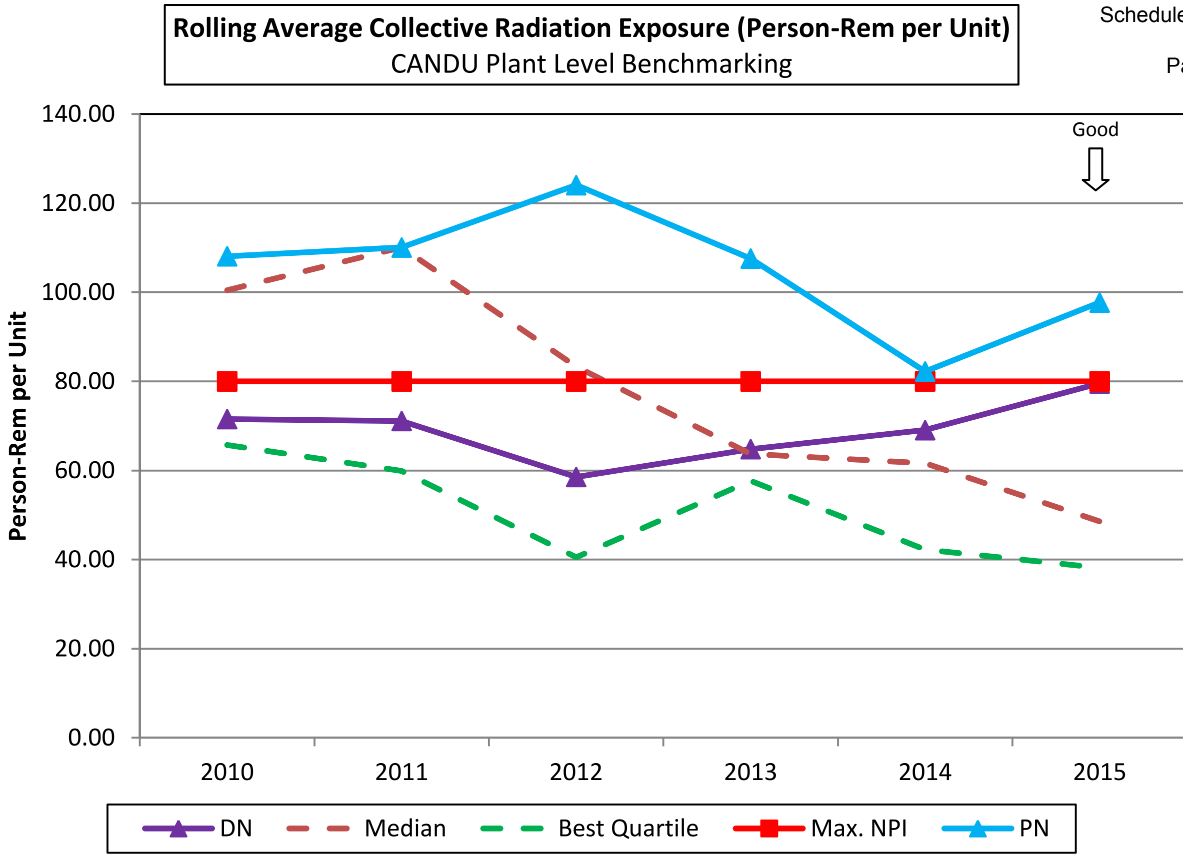
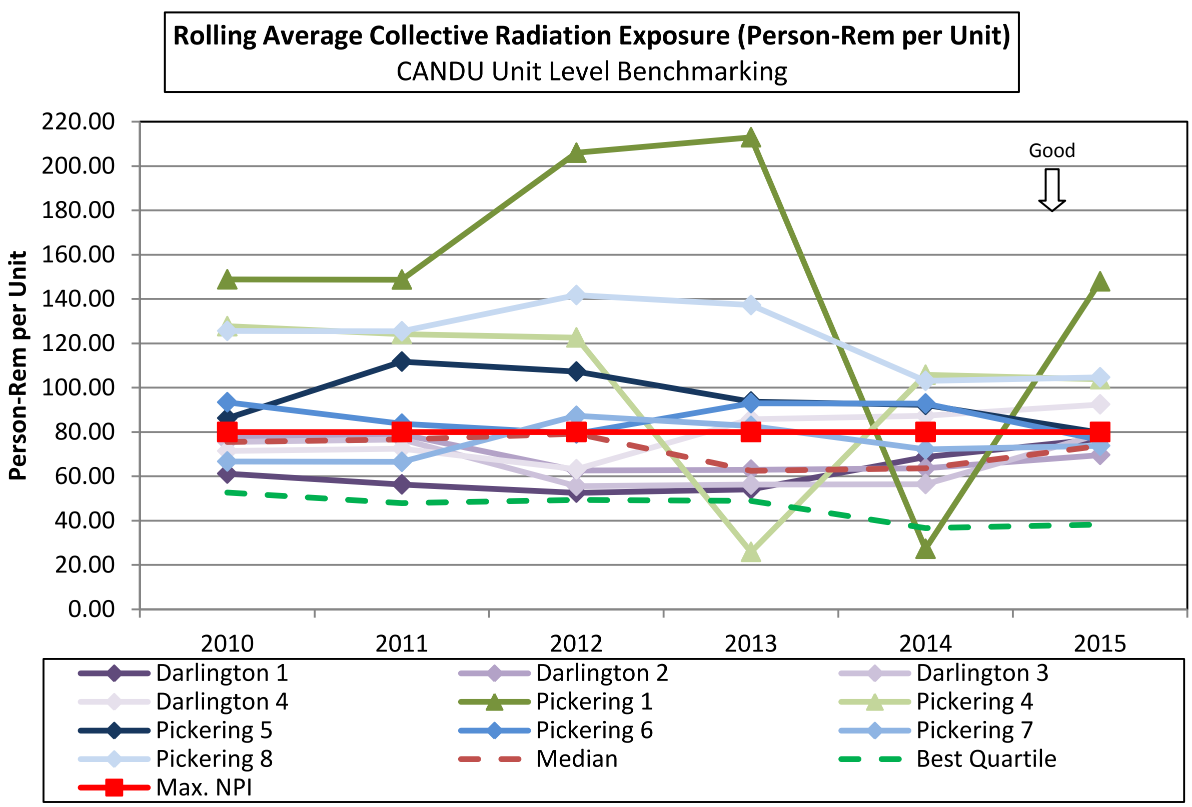
Rolling Average Collective Radiation Exposure

2015 Rolling Average Collective Radiation Exposure (Person-Rem per Unit)
CANDU Plant Level Benchmarking




2015 Rolling Average Collective Radiation Exposure (Person-Rem per Unit)
CANDU Unit Level Benchmarking
Best Quartile: 38.31
Darlington 2
Pickering 7
Median: 73.80
Pickering 6
Darlington 1
Darlington 3
Pickering 5
Max. NPI
Threshold = 80
Darlington 4
Pickering 4
Pickering 8
Pickering 1
0.00
50.00
100.00
150.00
200.00
250.00
300.00
350.00
Person-Rem per Unit


Rolling Average Collective Radiation Exposure (Person-Rem per Unit)
CANDU Plant Level Benchmarking
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Person-Rem per Unit
Good
2010
2011
2012
2013
2014
2015
DN
Median
Best Quartile
Max. NPI
PN


Rolling Average Collective Radiation Exposure (Person-Rem per Unit)
CANDU Unit Level Benchmarking
220.00
200.00
180.00
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Person-Rem per Unit
Good
2010
2011
2012
2013
2014
2015
Darlington 1
Darlington 2
Darlington 3
Darlington 4
Pickering 1
Pickering 4
Pickering 5
Pickering 6
Pickering 7
Pickering 8
Median
Best Quartile
Max. NPI

Observations – Rolling Average Collective Radiation Exposure (CANDU)

- Collective Radiation Exposure (CRE) is an industry composite indicator encompassing external and internal collective whole body radiation dose.
- The industry uses a two or three year rolling average (based on the site outage cycle) to define the CRE performance for a given year. Darlington follows a 3-year outage cycle and Pickering and other panel members are on a 2-year outage cycle. The following factors play a significant role in the CANDU reactors' CRE performance: the number of planned outages, outage scope and duration, tritiated ambient air in accessible and access controlled areas, effectiveness of mitigation measures and initiatives being implemented to reduce identified sources of radiological hazards, and human performance during execution of radiological tasks.

2015 (Rolling 2 Year Average Pickering, Rolling 3 Year Average Darlington)

- The Pickering plant-level rolling average dose performance value of 97.72 person-rem/unit was worse than the industry plant-level median value of 48.53 person-rem/unit.
- The Pickering unit-level rolling average performance was worse than the industry unit- level median value of 73.80 person-rem/unit for five Pickering units while one unit achieved median performance.
- The number of planned outages, as well as scope and duration significantly contributed to this level of plant and unit rolling average CRE performance. In general, Pickering has three major planned outages per year; Darlington averages 1.3 outages per year over the three year outage cycle.
- The Darlington plant-level rolling average dose performance value of 79.55 person-rem/unit achieved maximum NPI points of 80.0 person-rem/unit. This result is worse than the industry plant-level median value of 48.53 person-rem/unit.
- The Darlington unit-level rolling average dose performance was worse than the industry unit-level median value of 73.80 person-rem/unit for three Darlington units while one unit achieved median performance.

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Trend

- Pickering plant-level performance has improved sharply and steadily from 2012 to 2014, while performance declined in 2015. The rolling average is still worse than median due to scope increases during outages and long outage duration.
- Pickering unit-level performance has remained relatively flat over the review period.
- The Darlington plant-level dose has been increasing since 2012 and because the median value dose has significantly decreased in the same time period, Darlington now finds itself above the industry median. This performance is due to increased outage scope, including both planned and unplanned outages as well as prerequisite work associated with refurbishment activities.
- Darlington units as a whole have performed near the industry median over the review period.

Factors Contributing to Performance Rolling Average Collective Radiation Exposure (CANDU)

Best Practices

- The following list represents common practices that demonstrate continuous improvement and help maintain good CRE performance for CANDU type reactors:
    - Robust Site As Low as Reasonably Achievable (ALARA) Committee, chaired by Facility Senior Vice President.
    - Reactor face shielding to reduce dose rates.
    - Use of full size vault platforms to improve workflow.
    - Teledosimetry.
    - Process fluid detritiation.
    - Use of Munters driers to enhance existing measures to minimize ambient airborne tritium levels.
    - Optimization of Fuelling Machine purification using Ion Exchange with annual resin replacement and/or sub-micron filters.
    - Sub-micron filtration in the Primary Heat Transport system.
    - Use of independent radiological oversight for higher risk work to improve human performance during execution of radiological tasks.
    - Daily accounting of dose, and work group focus on Radiation Protection Fundamentals.
- OPG establishes internal administrative dose limits to ensure that dose to each exposed individual is managed and maintained well below individual regulatory limits.

Initiatives

- OPG Nuclear fleet-wide and site specific initiatives have been implemented to incorporate the industry best practices noted above.
- Specific key initiatives are described below.

Pickering

- Source term reduction, including improvements to process fluid filtration, a dose reducing resin trial, and detritiation.
- Source term mitigation, including optimization of shielding for reactor face work, improvements to the shielding canopy for reactor face work, and dryer modifications for improved performance and reliability.
- Human performance, including involvement and oversight by Radiation Protection (RP) staff of work with elevated radiation risk.
- Focus on dose to the individual through implementation of daily dose goals.
- Improving RP worker practices by driving individual accountability.
- Work Group specific dose reduction plans are being developed and implemented by line management with ALARA support.

Darlington

- The early efforts in source term reduction are generating lasting effects. A reduction of coolant pH factors from 10.8 to 10.1 minimizes crud migration from boilers to inlet feeders. The installation of sub micron heat transport filters effectively reduces the dose rates in our heat transport system and has contributed the success of Darlington's external dose.
- Developed and implemented a reactor face shielding strategy to reduce dose while at the same time minimize the risks of personnel injury during shielding installation.
- Implemented an improved feeder ice jacket including the application of long handled tools for jacket installation and remote data acquisition.
- Effectively utilized Teledosimetry to reduce Radiation Protection Coordinator dose. Utilized Teledosimetry as a coaching tool to improve worker radiation protection practices and reduce dose.
- Tritium mitigation strategies have been developed and implemented to reduce air-borne tritium concentrations inside containment and confinement rooms.
- Developed and implemented X-ray Fluorescence (XRF) spectroscopy to identify cobalt residues in an effort to reduce cobalt deposits in the moderator system during valve overhaul activities thus reducing overall radiation dose.
- Work Group specific dose reduction initiatives have been developed and implemented by line management.

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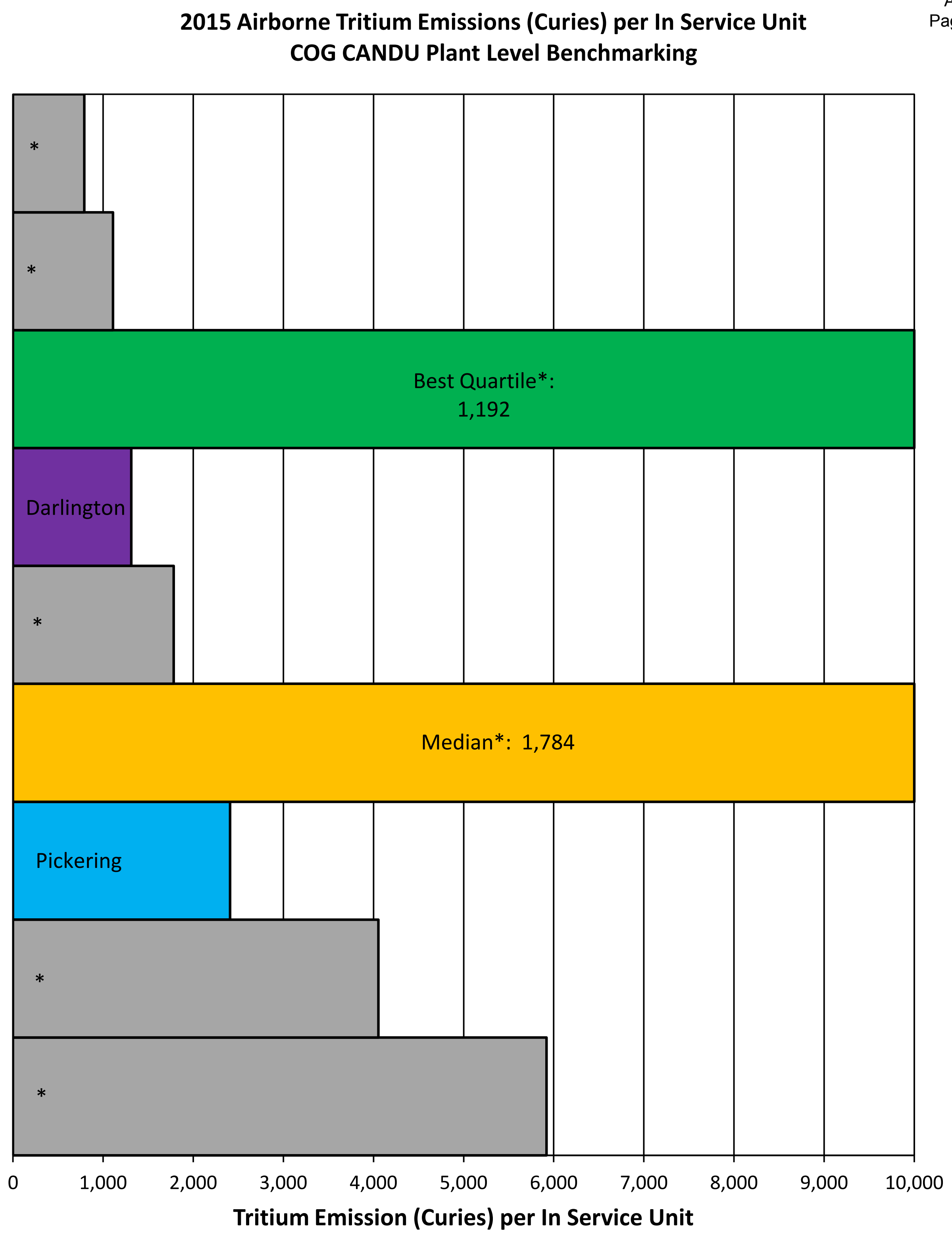
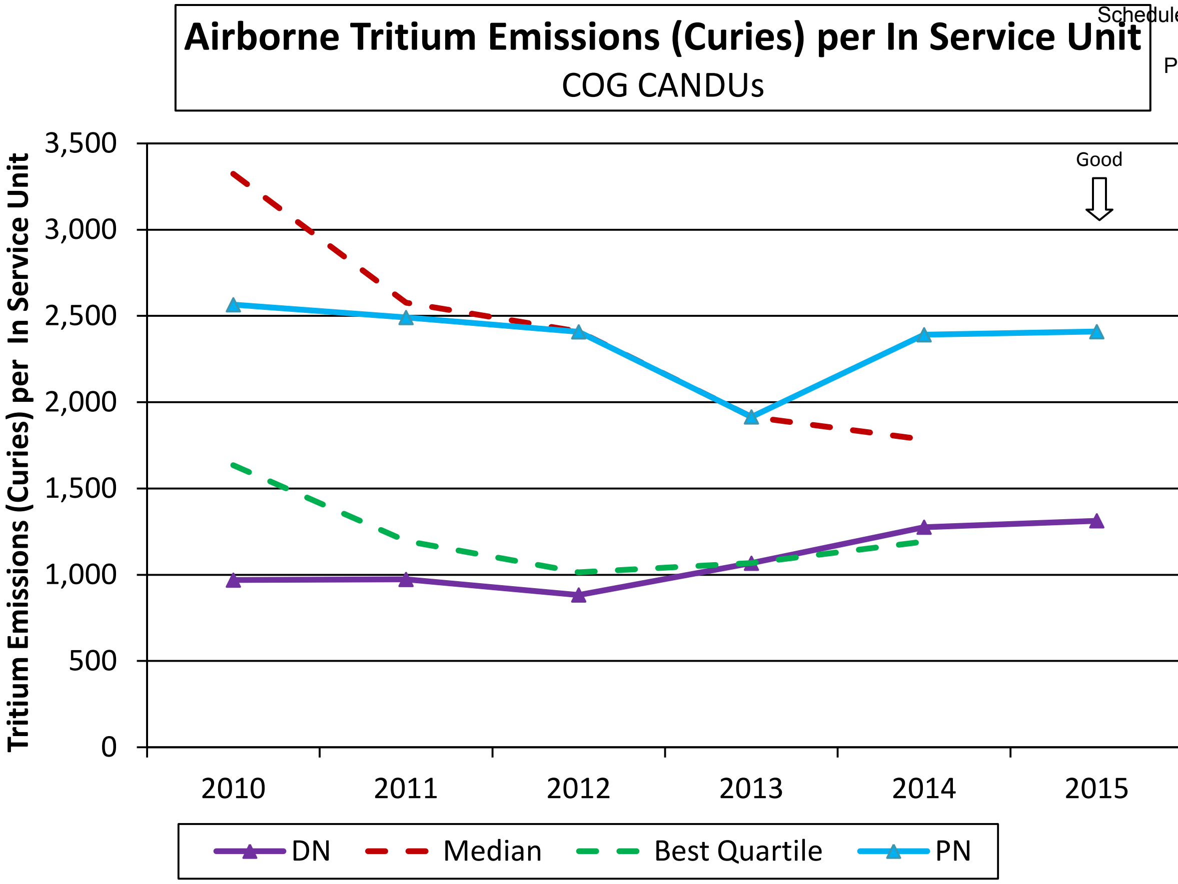
Airborne Tritium Emissions per In Service Unit



* Industry data based on 2014 as it is the best available information at the time. Pickering and Darlington results are 2015.



Notes:

- Median and Best Quartiles are plotted till 2014 as the 2015 results were unavailable at the time of benchmarking.
- Darlington values have retroactively modified as of 2013 to exclude Tritium Removal Facilities emissions consistent with COG benchmarking results.

Observations – Airborne Tritium Emissions (Curies) per In Service Unit

2015 (Annual Value)

- Pickering achieved its best Airborne Tritium Emissions performance in 2013 as a result of increased focus on dryer performance, leak management and source term reduction.
- The 2014 industry results collected by the CANDU Owners Group (COG) are included in this report as the most up-to-date figures available for benchmarking performance. As of 2013, tritium emissions from Tritium Removal Facilities (TRF) are no longer included in COG benchmarking results.
- Airborne Tritium Emissions from each OPG facility for 2015 are compared per in service reactor unit.
- Curies per in service unit at top quartile CANDU plants was 1,192 or lower.
- Darlington performed better than the industry median threshold of 1,784 Curies per in service unit. Performance slipped from best quartile performance in 2013 to second quartile performance in 2014 and 2015.
- Pickering performed worse than the industry median threshold. Performance slipped from second quartile performance in 2013 to third quartile performance in 2014 and 2015.

Trend

- In 2014 and 2015, a worsening trend in performance at both Pickering and Darlington was observed due to heavy water leaks, poor vapour recovery dryer performance and unavailability of the Tritium Removal Facility (see below).
- The industry trend line graph shows that industry best quartile performance has worsened slightly since 2012. Industry median performance continues to improve.
- Darlington and Pickering tritium emissions to air continue to be less than one per cent of the regulatory limits.

Factors Contributing to Performance

- Key factors affecting performance at Darlington and Pickering include the following:
  - leaks within containment requiring outages for repair,
  - poor vapour recovery dryer performance,
  - operational issues of the Tritium Removal Facility impacting its availability,
  - increased unit tritium source term.
- Station focus on tritium emission reduction initiatives include dedicated teams to ensure daily emissions monitoring, sustaining and improving dryer performance, heavy water leak minimization, tritium program development and innovations, and availability and performance of the Tritium Removal Facility at the Darlington site.
- Other improvement initiatives include OPG's ongoing participation in COG environmental benchmarking of participating CANDU stations to determine best environmental practices.

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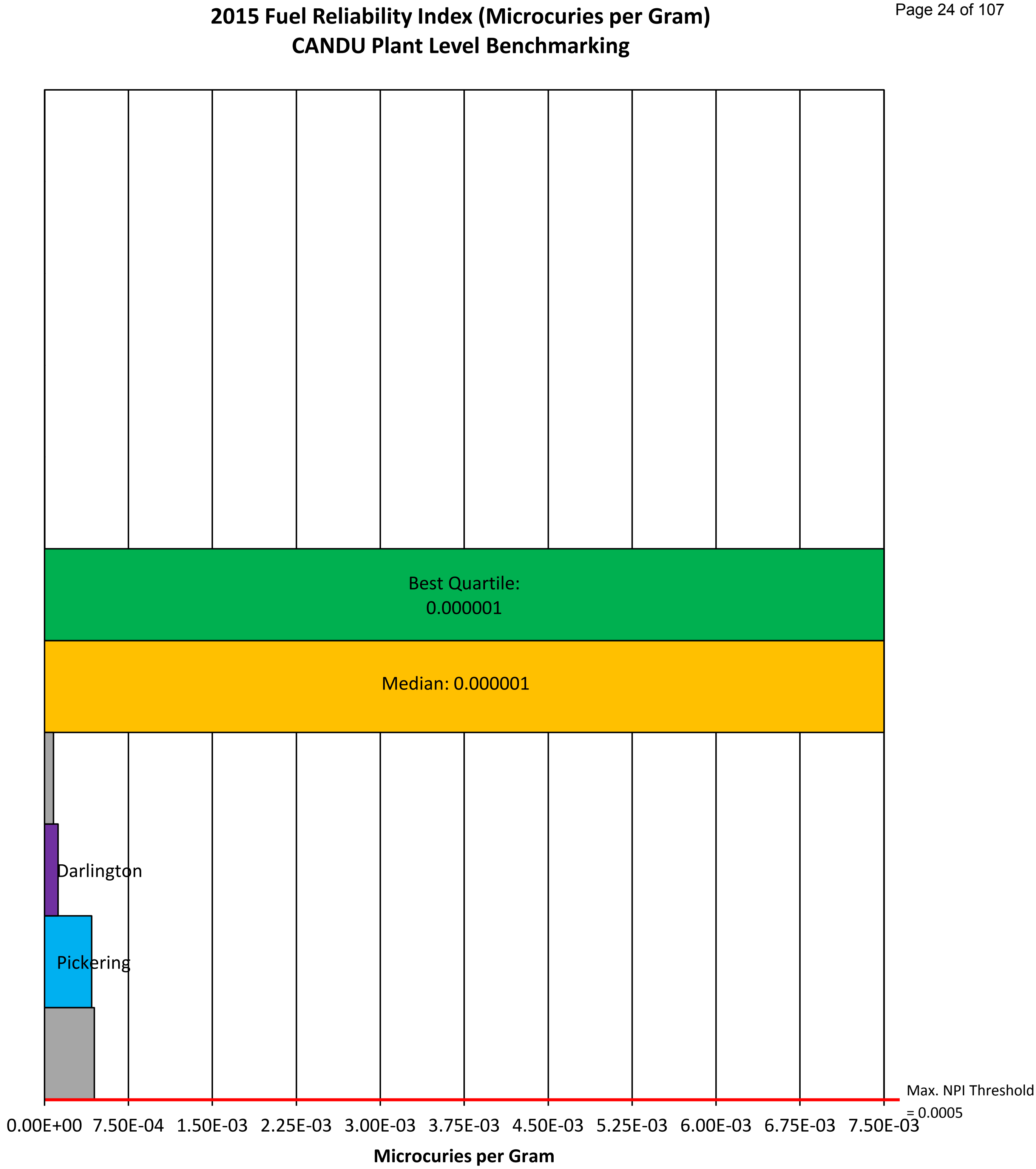
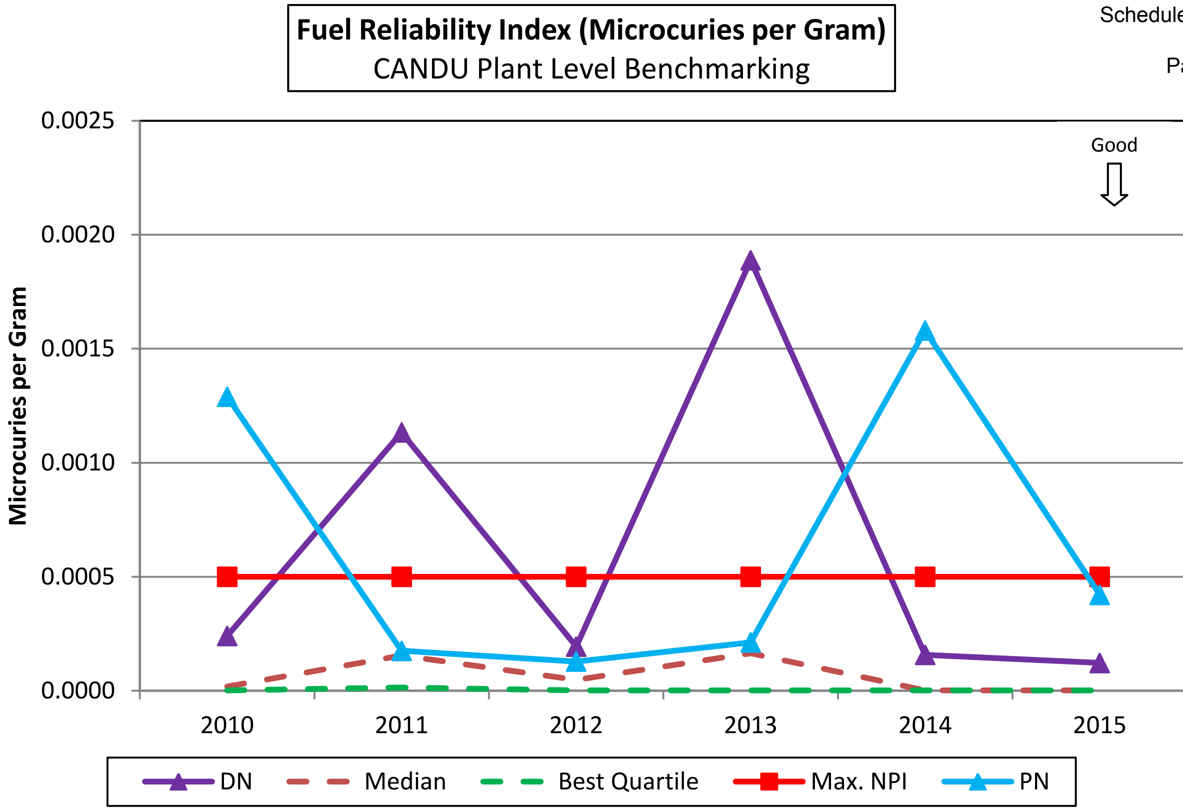
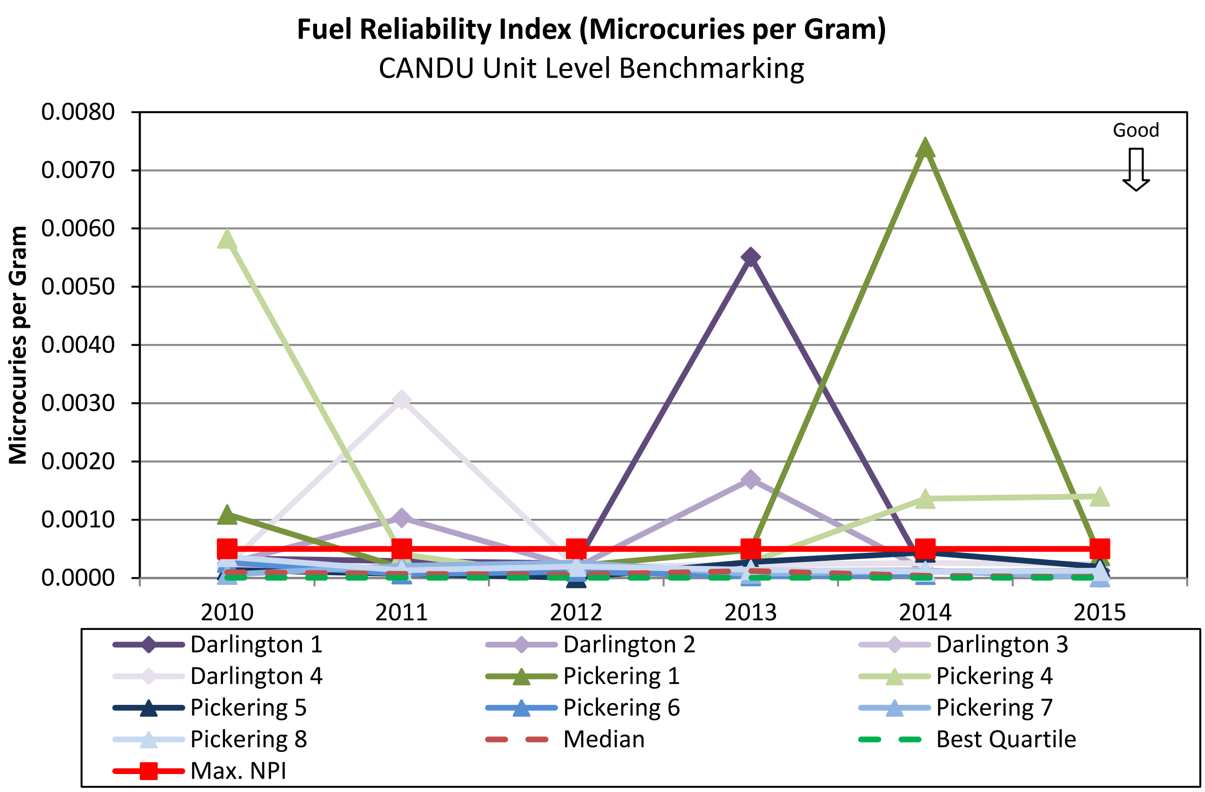
Fuel Reliability Index




Fuel Reliability Index (Microcuries per Gram)
CANDU Plant Level Benchmarking
Good
Microcuries per Gram
0.0025
0.0020
0.0015
0.0010
0.0005
0.0000
2010
2011
2012
2013
2014
2015
DN
Median
Best Quartile
Max. NPI
PN


Fuel Reliability Index (Microcuries per Gram)
CANDU Unit Level Benchmarking
Good
Microcuries per Gram
0.0080
0.0070
0.0060
0.0050
0.0040
0.0030
0.0020
0.0010
0.0000
2010
2011
2012
2013
2014
2015
Darlington 1
Darlington 2
Darlington 3
Darlington 4
Pickering 1
Pickering 4
Pickering 5
Pickering 6
Pickering 7
Pickering 8
Median
Best Quartile
Max. NPI

Observations – Fuel Reliability Index (CANDU - FRI)

2015 (Most Recent Operating Quarter)

- The best quartile and median values for Fuel Reliability Index (FRI) performance for CANDU plants were 0.000001. For individual CANDU units, the best quartile was 0.000001 and the median value was 0.000015.
- The Pickering plant level FRI performance at 0.000421 was worse than the CANDU plant median, but still achieved maximum NPI points.
- The Darlington plant level FRI performance at 0.000122 was worse than the CANDU plant median, but still achieved maximum NPI points.
- Post-discharge fuel inspections for Pickering indicated that the overall condition of fuel inspected was acceptable and consistent with previous years. Fuel inspections for Pickering confirmed two fuel defects in 2015.
- Post-discharge fuel inspections for Darlington indicated that the overall condition of fuel inspected was acceptable and consistent with previous years. Darlington was free of fuel defects in 2015. No fuel issues of significance arose at Darlington in 2015.

Trend

- The best quartile for CANDU plants remained relatively consistent at 0.000001 from 2010. The median values for CANDU plants has generally improved from 2010 and remained at 0.000001 since 2014.
- The Pickering station FRI performance has generally improved since 2010 despite a spike in 2014 due to increasing incidents of fuel defects. In 2015, the FRI performance has drastically improved with the reduction in fuel defect incidents, and as a result achieved maximum NPI points.
- The Darlington station FRI performance has generally improved since 2010 despite spikes in 2011 and 2013. The reactors were defect-free in 2015, which was an improvement from 2014 and remained to achieve maximum NPI points.

Factors Contributing to Performance

Fuel defects existed in the three units in Pickering in 2014. A team was formed to investigate the fuel defects incidents and a corrective action plan has been prepared to address the problem, which resulted in a reduction of defects totaling to two fuel defects in 2015.

Actions that were taken that drove this improvement since 2014 include:

- Developing a fuel defect guideline for Pickering,
- Increasing scope of Heat Transport System (HTS) grab sampling and analysis,
- Assessing and comparing Units 1, 4 and 5 to 8 power ramps,
- Assessing impact of adjuster burn-out during operation,
- Assessing impact of pressure tube creep on fuel performance,
- Improving the methods of surveillance and elimination of the possibility of foreign materials entrance into the HTS due to Fuel Handling and Outage practices,
- Fuel bundle manufacturing assessment,
- 3rd party examinations of unirradiated Pickering fuel bundle,

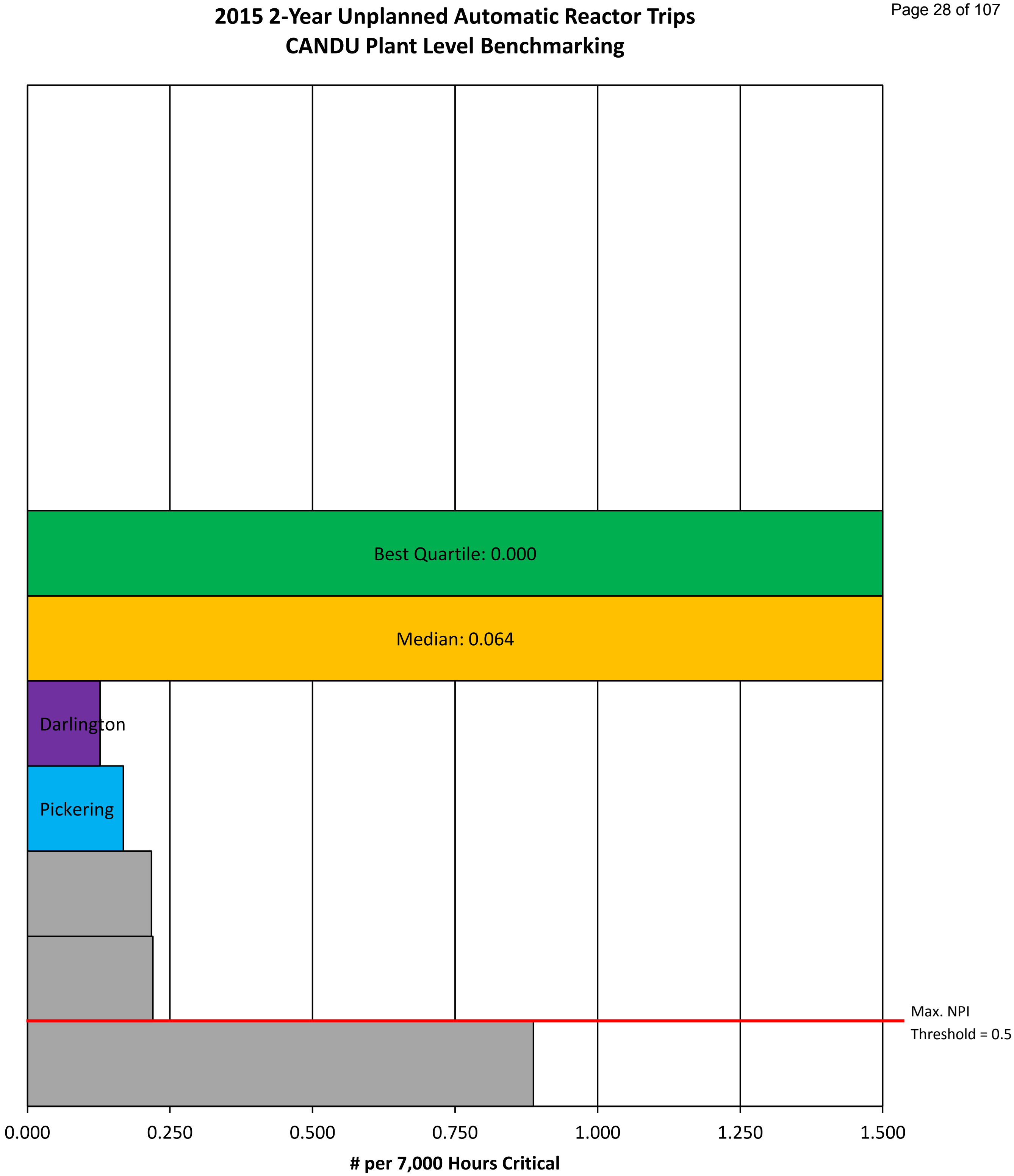
Observations – Fuel Reliability Index (CANDU - FRI)

- Irradiated fuel inspections and examinations,
- Improving capability of detecting the defected fuel bundles during the discharge from the fuelling machines, and
- Improving the capability of the in-bay inspection of the suspected fuel bundles to be defected.

Darlington has been defect free in 2015. The steps taken that have led to improved FRI performance and prevent the potential of fuel defects are the following:

- New fuel with tighter tolerances for mass was received and is currently being used,
- Installed a new fuel inspection facility and completed inspections in East Fuelling Facility Auxiliary Area; confirmed defects in all suspect bundles and all fuel defects originated from one batch of 2786 bundles,
- OPG-supplier co-operation resulted in installation of an automatic loader of fuel pallets complete with a “go/no go” pallet diameter monitor,
- Close monitoring of existing fuel bundle inventory and core load, and
- Projects in progress on Gaseous Fission Products (GFP) and feeder scanners to improve ability to locate defects on power and during outages.

2-Year Unplanned Automatic Reactor Trips



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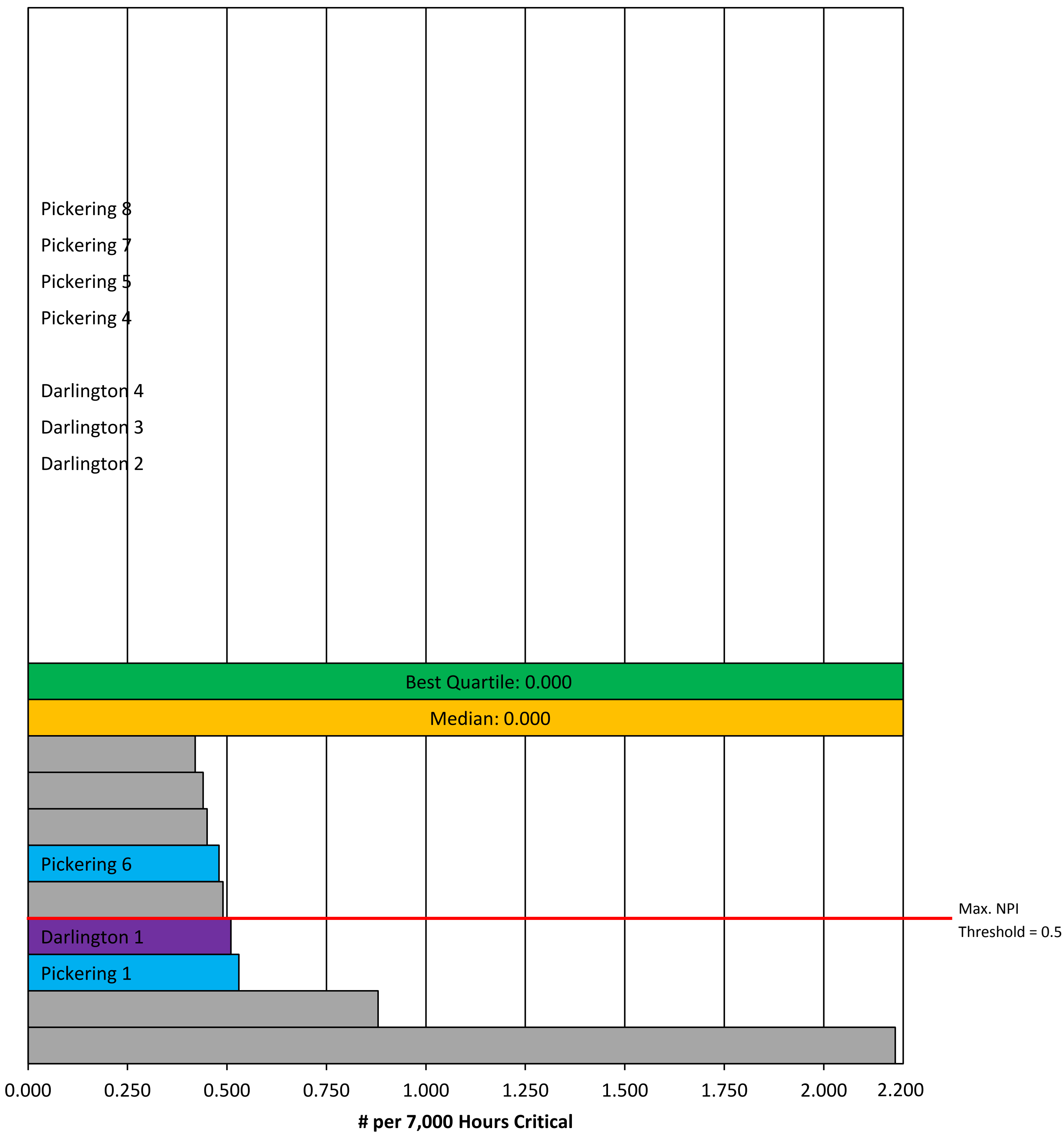
2015 2-Year Unplanned Automatic Reactor Trips
CANDU Unit Level Benchmarking



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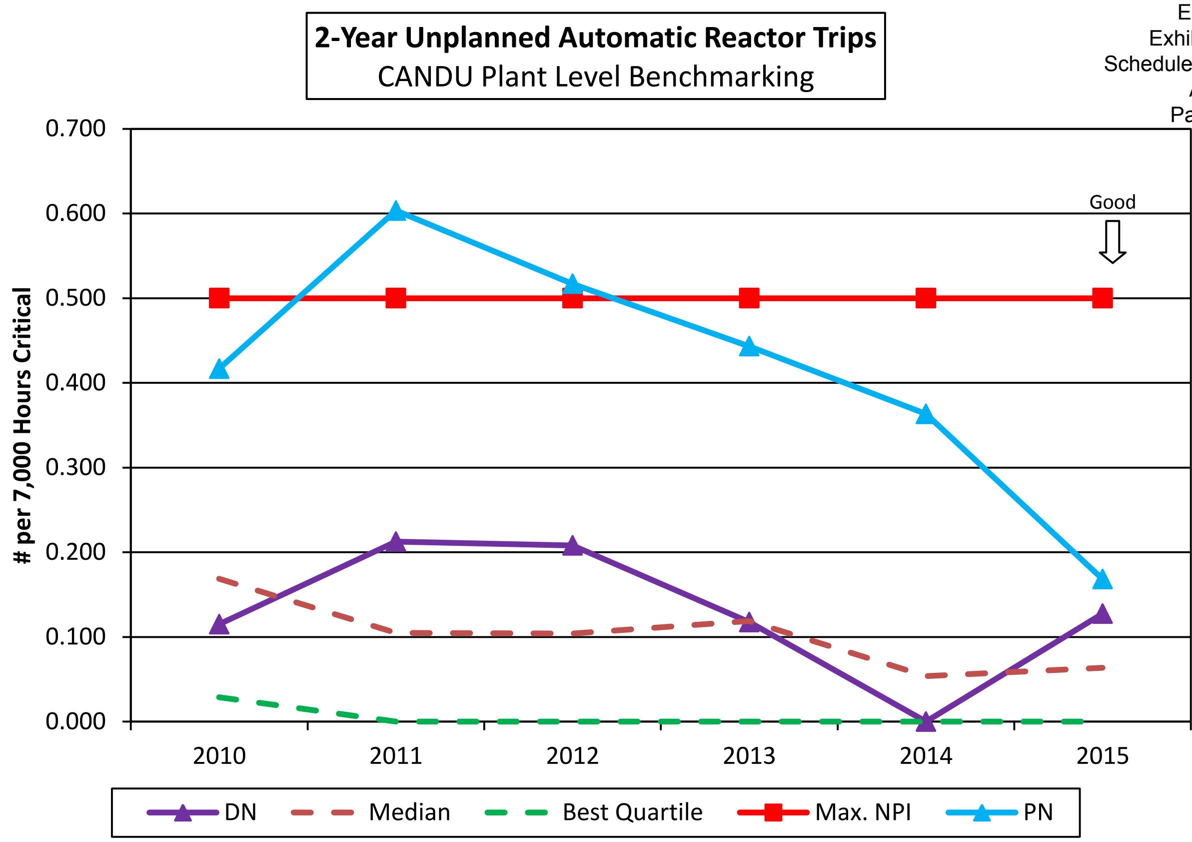

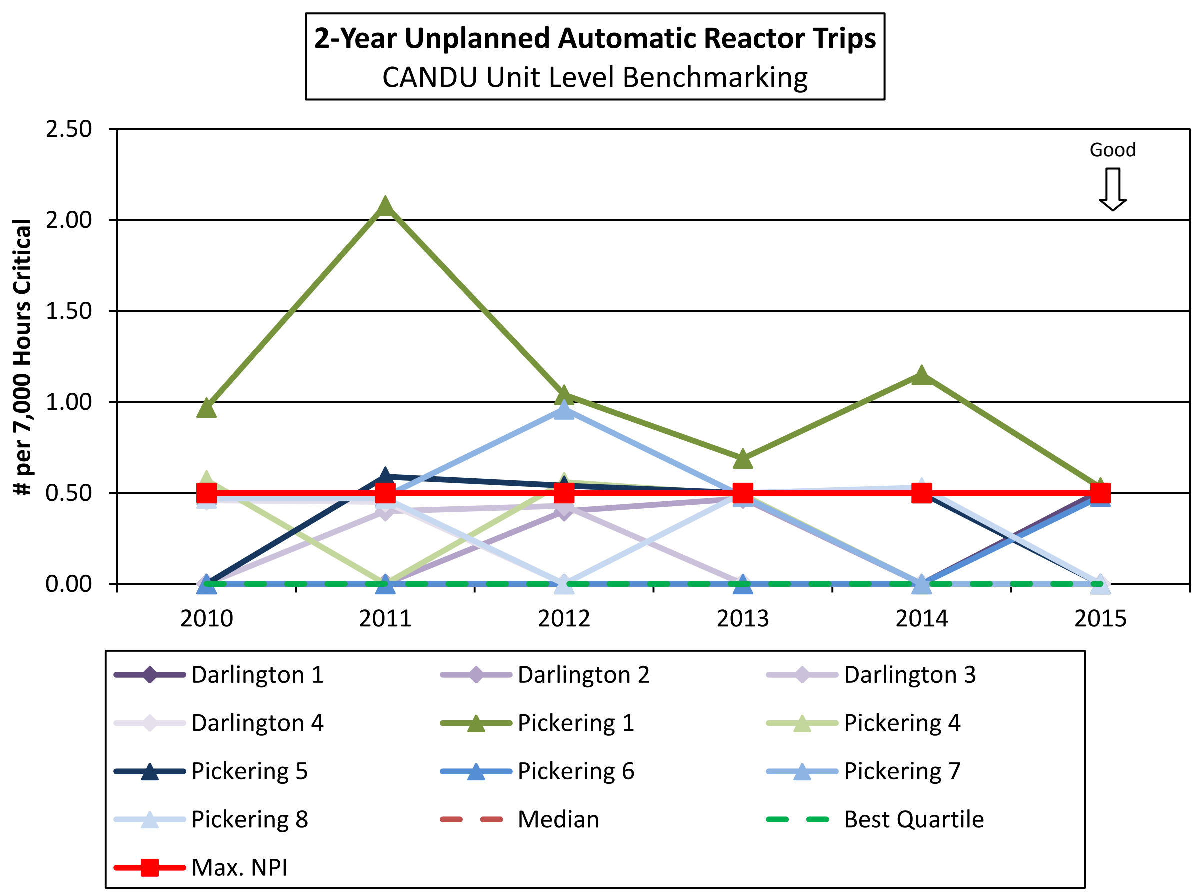

Observations – 2-Year Unplanned Automatic Reactor Trips (CANDU)

2015 (2-Year Rolling Average)

- The 2-year rolling average unplanned automatic reactor trip best quartile for CANDU plants was zero with a median of 0.064. For individual CANDU units, the best quartile and median values for unplanned reactor trip were zero.
- At the plant level, Pickering's trip rate of 0.168 was better than the maximum NPI threshold value of 0.50. On an individual unit basis, Units 4, 5, 7, and 8 with trip rate of zero, were at best quartile. Unit 6, with trip rate of 0.48 and Unit 1, with trip rate of 0.53, were worse than the third quartile threshold of 0.45 and significantly better than the highest value in the benchmark of 2.18.
- At the plant level Darlington's trip rate of 0.13 was better than the maximum NPI threshold value of 0.50. On an individual unit basis, Units 2, 3, and 4, with trip rates of zero, performed at the best quartile level. Unit 1, with trip rate of 0.51 was worse than the third quartile threshold of 0.45 and significantly better than the highest value in the benchmark of 2.18.

Trend

- The unplanned automatic reactor trip best quartile for CANDU plants has been zero since 2011. The median value improved from 2010 to 2012, performance declined in 2013, but improved in 2014 and declined in 2015 again. On an individual unit basis, the industry best quartile and median has remained at zero since 2010.
- At the plant level, Pickering station performance has continued to significantly improve from 2011. On an individual unit basis, Unit 1 performance has improved from 2011 to 2013, but decreased in 2014, and improved again in 2015. Unit 4 performance has decreased from 2011 to 2012, slightly improved in 2013, and achieved best performance in 2014 and 2015 with a zero trip rate. Unit 5 performance has been trending downwards since 2011, achieving a zero trip rate in 2015. Unit 6 has consistently performed at a zero trip rate since 2009, but decreased in 2015. Unit 7 performance improved from 2012 to 2013 and achieved the best performance in 2014 and 2015 with a zero trip rate. Unit 8 performance remained flat around 0.50, and in 2014 slightly decreased to 0.53, but the best performance with a zero trip rate was in 2012 and 2015.
- At the plant level, Darlington station performance has been improved since 2011, achieving the best result of a zero trip rate in 2014, but decreased in 2015. On an individual unit basis, Unit 1 has consistently performed at a zero trip rate since 2009, but the performance decreased in 2015. Units 3 and 4 performed at a zero trip rate in 2013 to 2015 with both units improving from previous years' performance. Unit 2 performance has significantly improved in 2014 and 2015 from 2012 and 2013.

Factors Contributing to Performance

- Key performance drivers for this metric include: general equipment reliability, material condition, and human performance.
- In 2015, Pickering had 1 unplanned automatic reactor trip (1 on Unit 6).
  In 2015, Darlington had 1 unplanned automatic reactor trip (1 on Unit 1).

- On-going due diligence by Station Operations, Engineering and Maintenance organizations. Operating Experience (OPEX) from each event has been shared at Pickering, Darlington and at external summits. Where necessary, training material has been revised based on OPEX. To improve human performance, technical procedures have been revised. To improve equipment reliability, where possible, like-for-like parts replacement has taken place. System health teams are involved in obsolescence issues.

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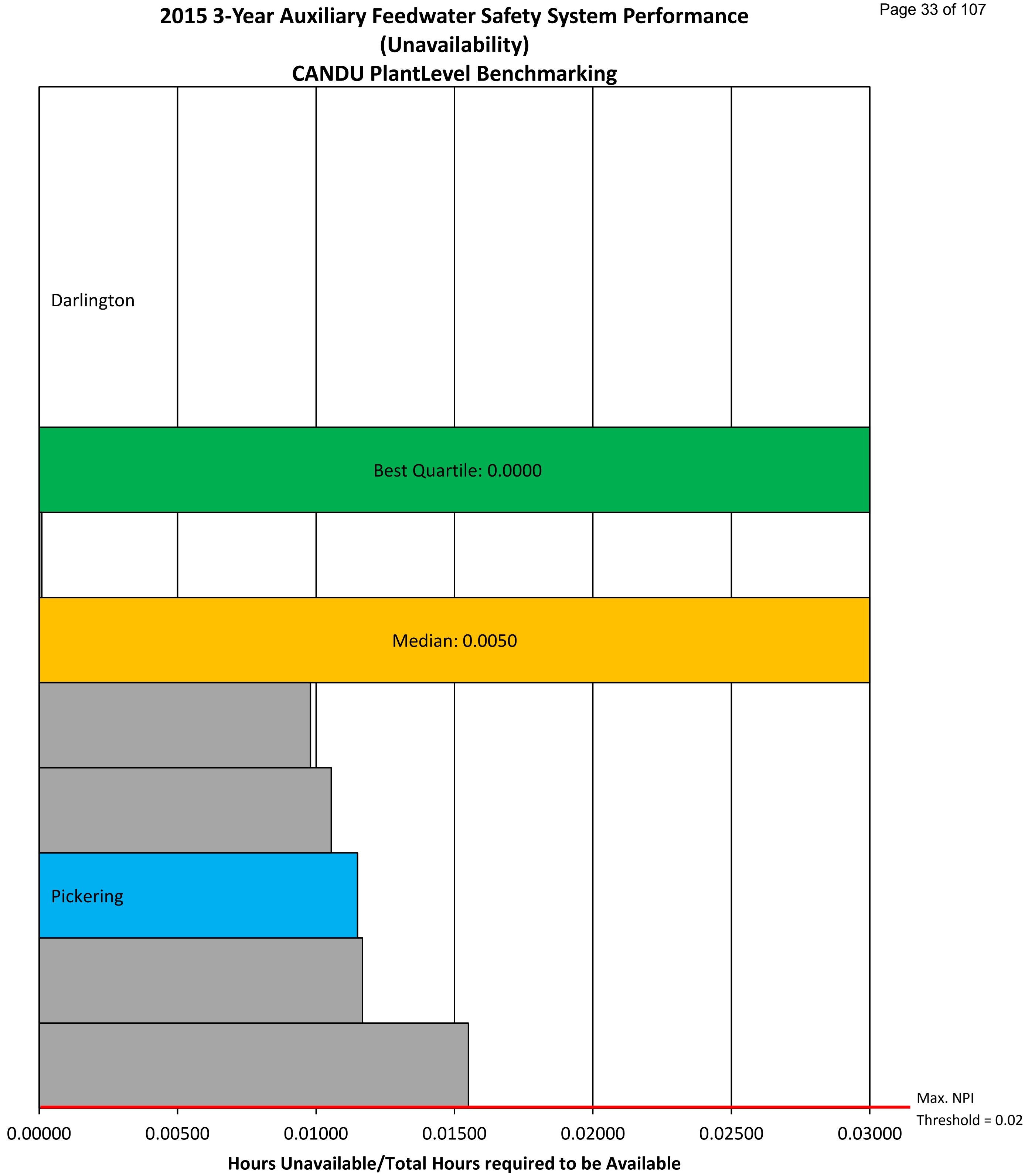
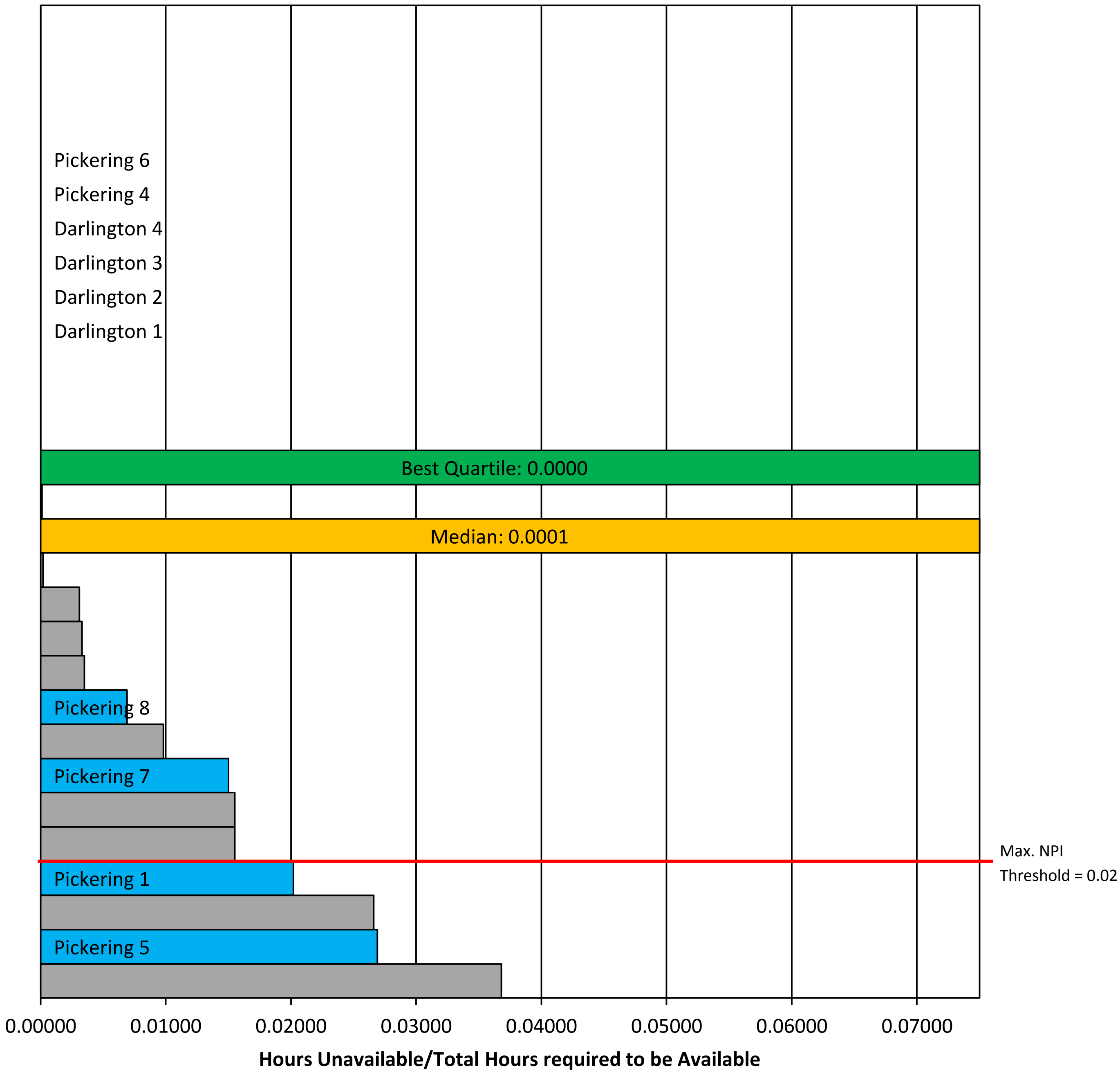
3-Year Auxiliary Feedwater Safety System Unavailability



2015 3-Year Auxiliary Feedwater Safety System Performance (Unavailability)
CANDU Unit Level Benchmarking



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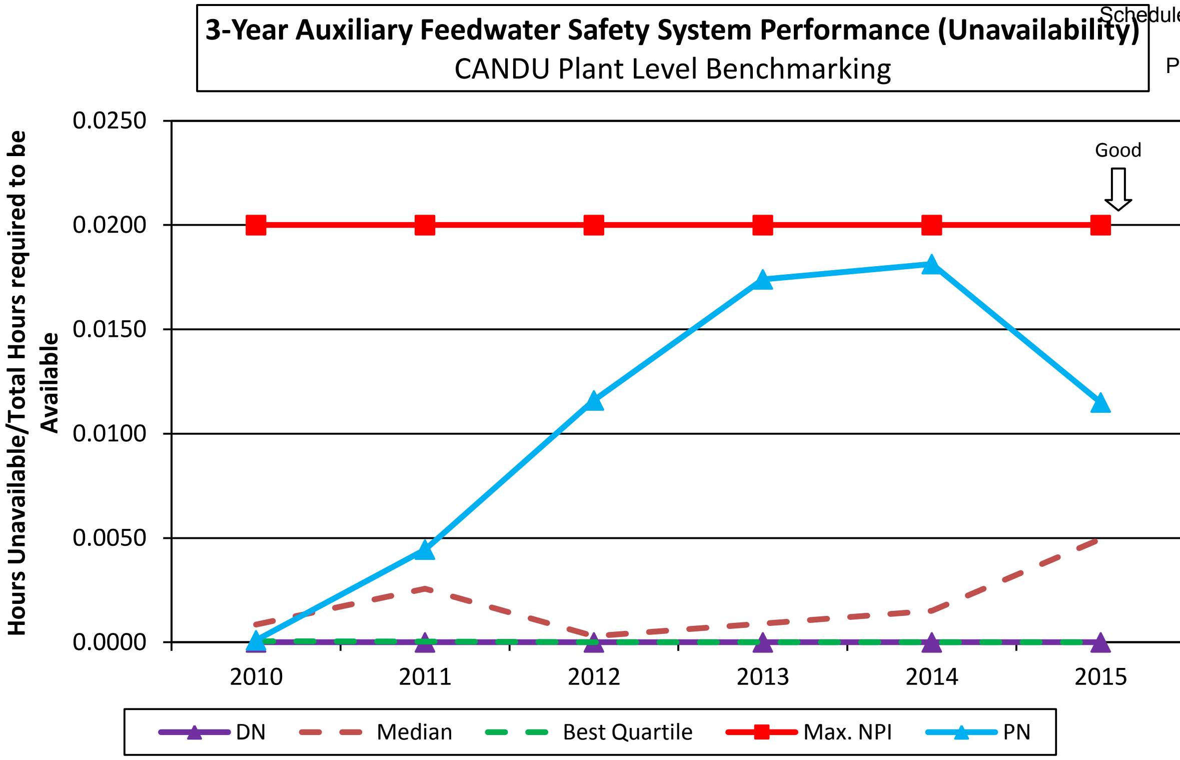

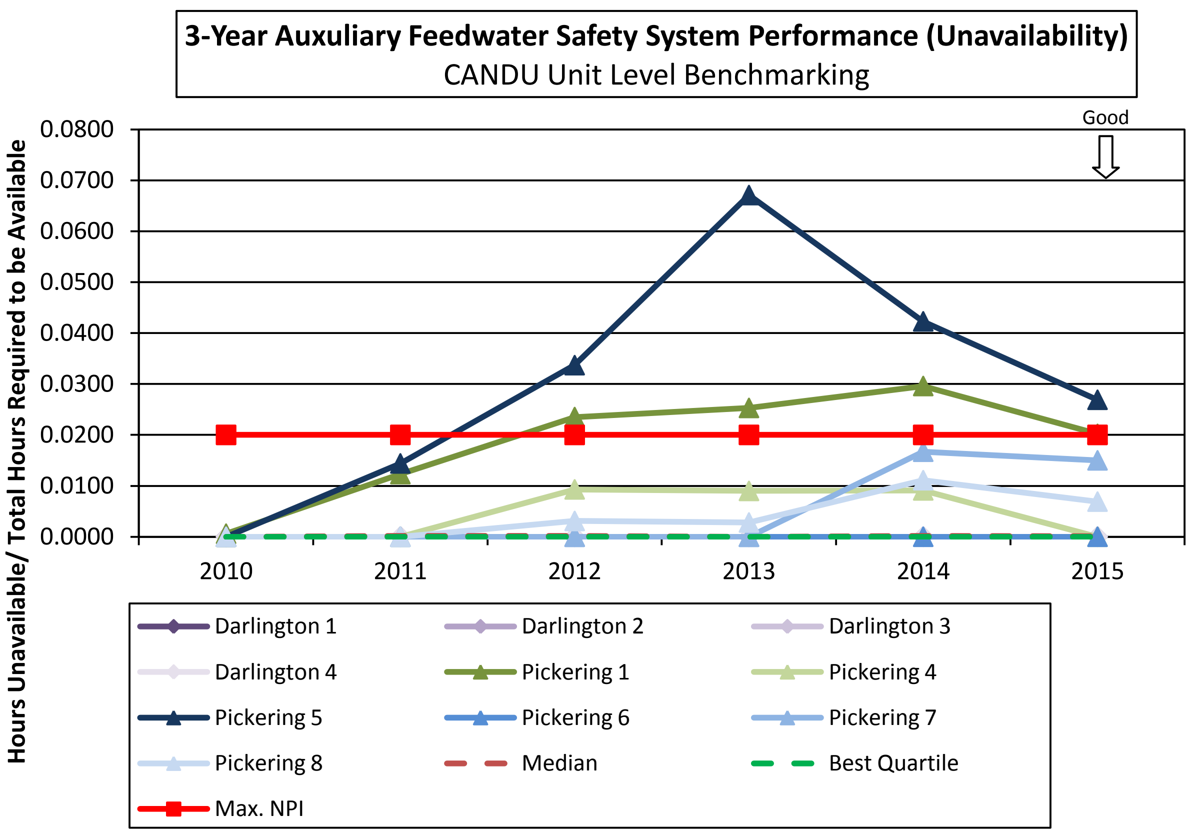

Observations – 3-Year Auxiliary Feedwater System (CANDU)

2015 (3-Year Rolling Average)

- The best quartile auxiliary feedwater (AFW) safety system performance for CANDU plants was zero with a median value of 0.0050. For individual CANDU units, the best quartile was zero with a median of 0.0001.
- At the plant level, Pickering station, with an unavailability of 0.0115 is below maximum NPI threshold value of 0.0200. On an individual unit basis, Units 4, 6, 7 and 8 achieved maximum NPI points for AFW unavailability. Units 1 and 5 unavailability is above the NPI maximum threshold.
- Darlington station achieved best quartile performance of zero unavailability at both the station and unit levels in 2015.

Trend

- The 3-Year Auxiliary Feedwater unavailability best quartile performance of CANDU plants improved from 2010 and maintained zero unavailability from 2011 to 2015. The plant level industry median value has fluctuated slightly over the review period but has remained well below the NPI maximum threshold. At the unit level, the industry best quartile has remained at zero over the review period and the median value at or close to zero over the review period.
- At the plant level, Pickering station performance has declined since 2010 and approached the NPI maximum threshold in 2014, but improved in 2015. On an individual unit basis, Unit 6 has consistently performed at a zero unavailability rate over the review period. Unit 1 performance declined in 2014, but improved in 2015. Unit 4 performance was at zero unavailability rate in 2010 and 2011, decreased slightly in 2012 to 2014, and improved to zero unavailability in 2015. Unit 5 performance improved from 2013, but still remained below maximum NPI threshold. Unit 7 performances has consistently performed at a zero unavailability rate since 2009, but declined in 2014 and improved in 2015. Unit 8 performance declined from 2012 but improved in 2015.
- Darlington station and unit performance has been at zero unavailability since 2010.

Factors Contributing to Performance

- Key performance drivers for this metric include: general equipment reliability, material condition, and human performance.
- No Auxiliary Feedwater Safety System unavailability occurred during 2015 which led to improved performance relative to previous years.

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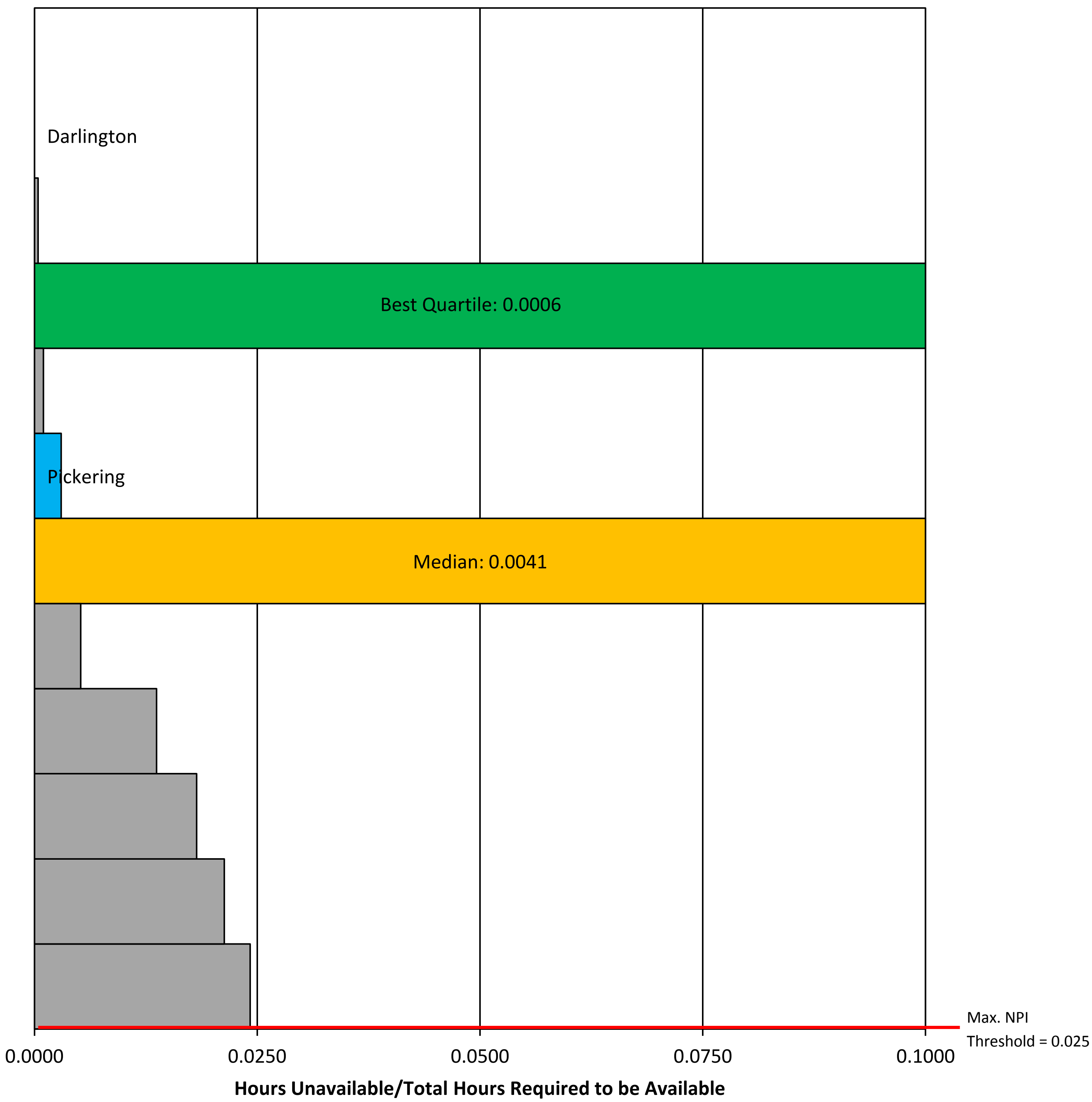
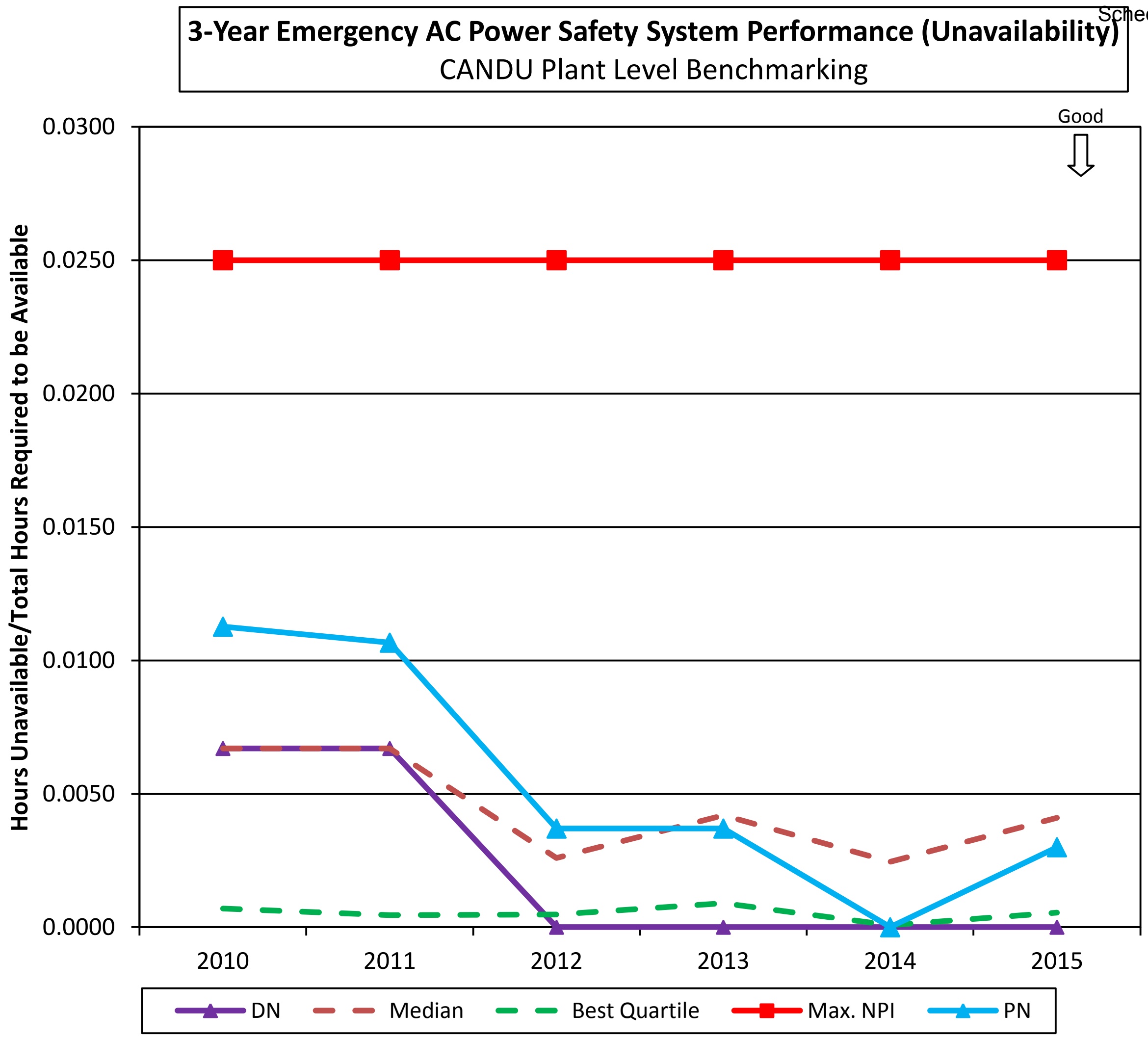
3-Year Emergency AC Power Safety Unavailability

2015 3-Year Emergency AC Power Safety System Performance (Unavailability)
CANDU Plant Level Benchmarking




3-Year Emergency AC Power Safety System Performance (Unavailability)
CANDU Plant Level Benchmarking
Hours Unavailable/Total Hours Required to be Available
0.0300
0.0250
0.0200
0.0150
0.0100
0.0050
0.0000
Good
2010
2011
2012
2013
2014
2015
DN
Median
Best Quartile
Max. NPI
PN

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Observations – 3-Year Emergency AC Power Safety System (CANDU)

2015 (3-Year Rolling Average)

- 3-Year Emergency AC Power Safety System performance at best quartile CANDU plants was 0.0006. The industry median value was 0.0041.
- At the plant level, Pickering station, with an unavailability of 0.0030 is below of maximum NPI threshold of 0.0250.
- Darlington was one of the best performing stations in the CANDU peer group, achieving zero unavailability, best quartile performance and maximum NPI results.

Trend

- The 3-year Emergency AC Power Safety System unavailability industry best quartile for CANDU plants has steadily improved since 2010, with slight declines in 2013 and 2015. The industry median value improved over the review period, with slight declines in 2013 and 2015.
- Pickering station performance has improved over the review period, reaching its best performance in 2014 achieving zero unavailability, but station performance declined in 2015.
- Darlington station and unit performance improved from 2011, achieving zero unavailability in the last four years 2012 to 2015.

Factors Contributing to Performance

- Key performance drivers for this metric include: general equipment reliability, material condition, and human performance.
- On February 15, 2015, Pickering 'Ready to Start' light extinguished due to malfunction of exhaust gas temperature input module in extreme cold ambient temperature. The reason being that the module was not configured to the design requirement of -30˚C. It was concluded after investigation that it was not affecting 'standby' mode of operation and, hence, standby generator (SG) 056-SG1 was available for emergency operation. This affected all 3 SGs on 056 Bank and 078-SG1 on 078 SG Bank. It did not impact 078-SG3 and the other SG; 078-SG2 was in outage.
- On March 12, 2015, Pickering 056-SG1 was taken out of service for gas producer swap. During post-maintenance testing, the issue of low generator voltage was discovered and it was diagnosed that Automatic Voltage Regulator tune up and adjustment was required prior to returning to service. However, 056-SG1 could not be returned to service in the first quarter of 2015 due to resource constraints, and was returned to service in the first week of second quarter of 2015.

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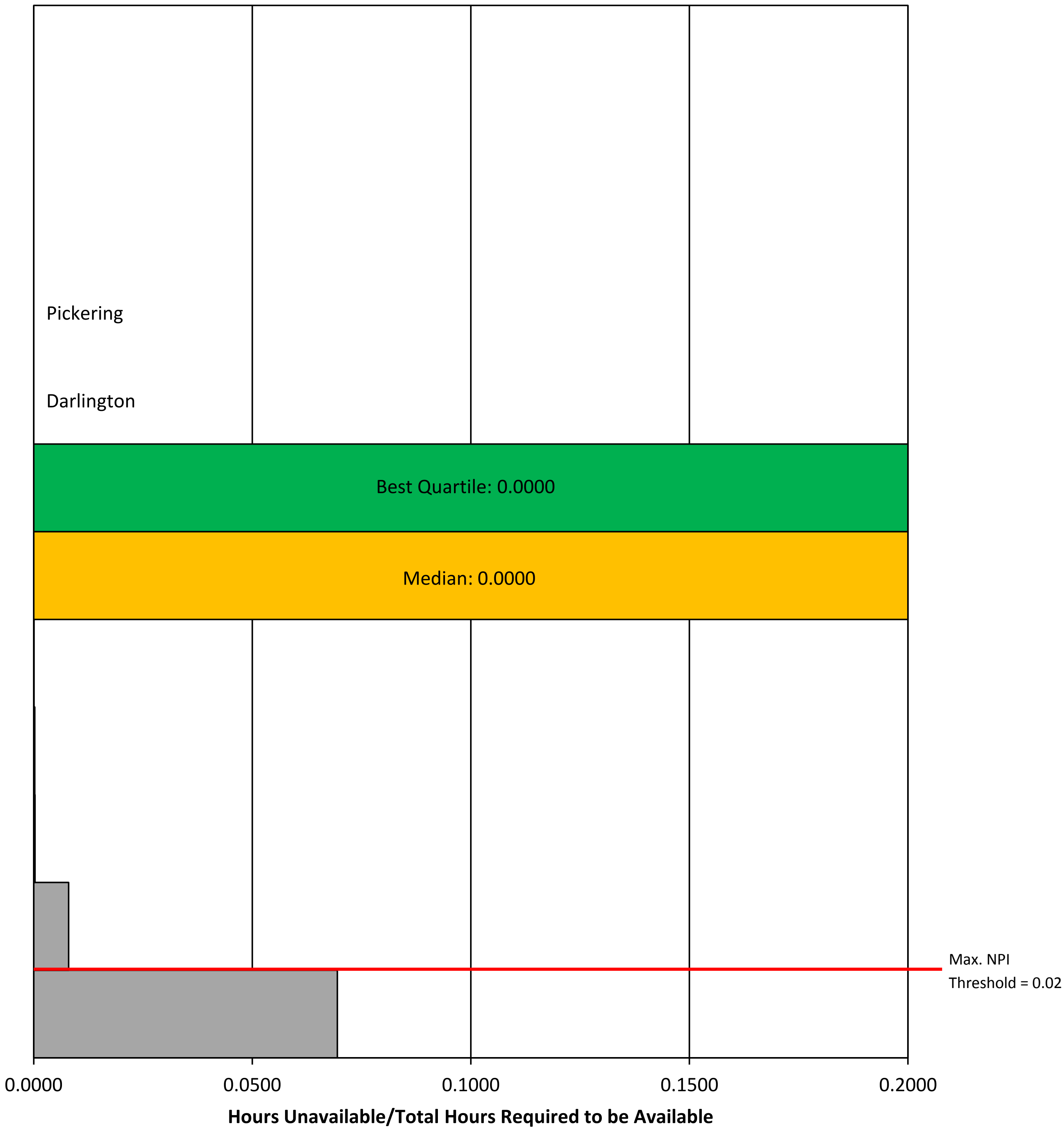
3-Year High Pressure Safety Injection

2015 3-Year High Pressure Injection (ECI) Safety System Performance (Unavailability)
CANDU Plant Level Benchmarking



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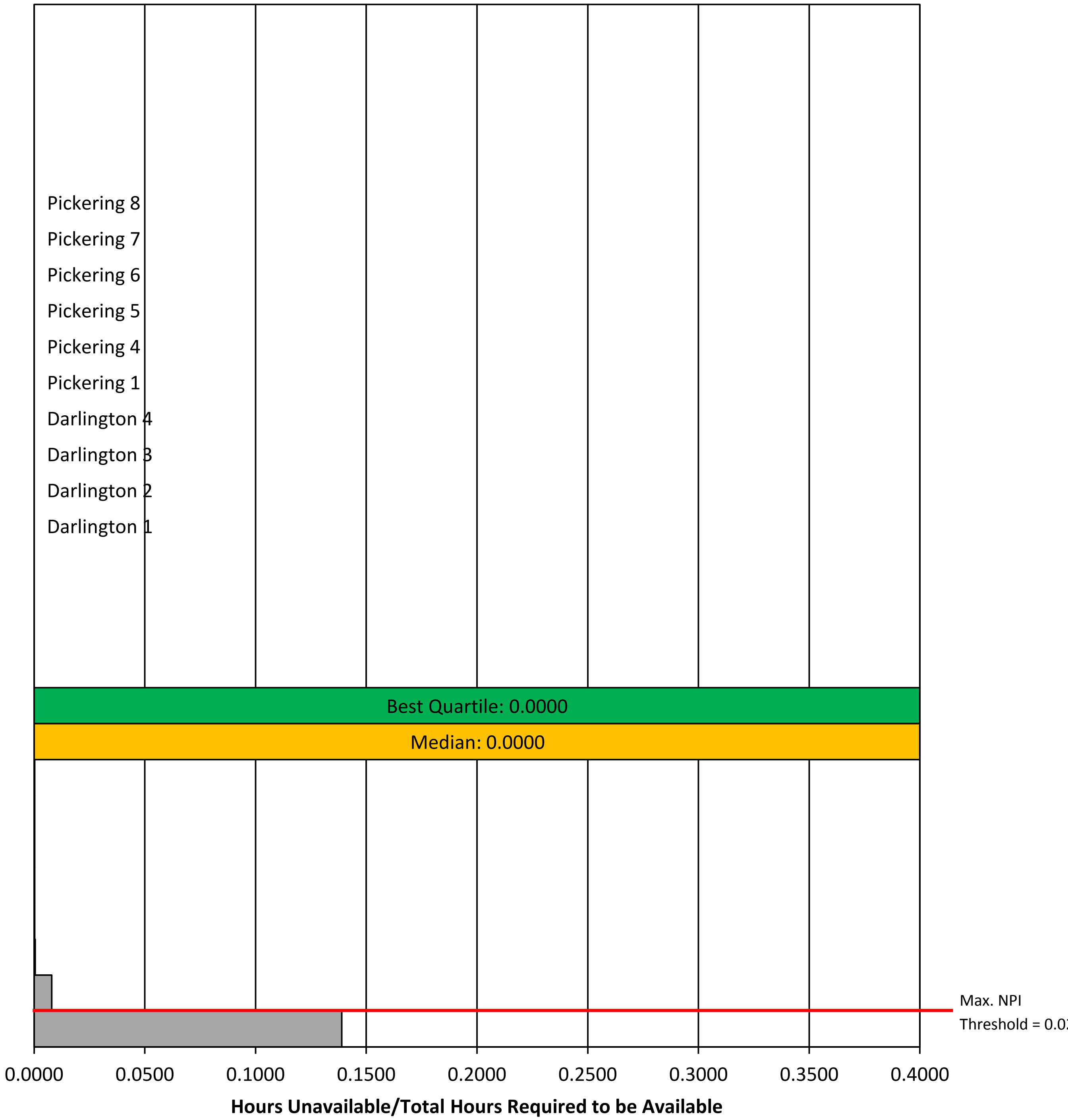
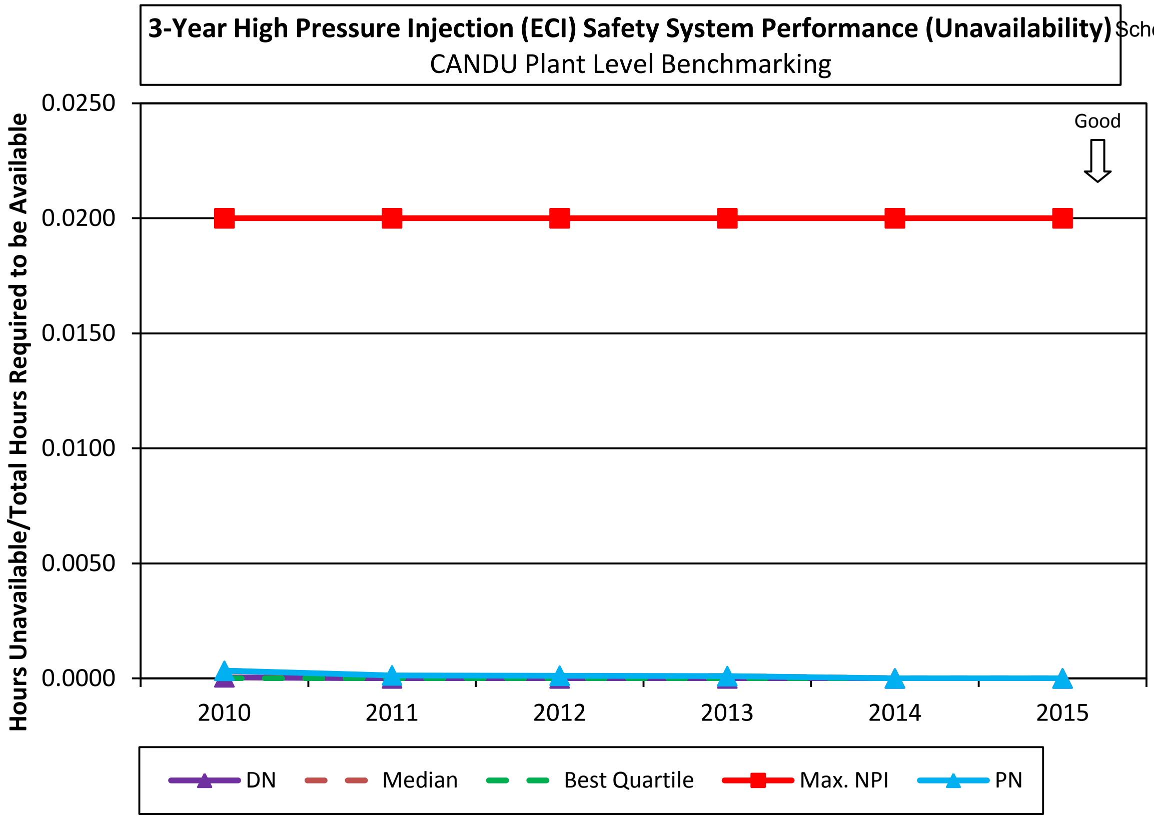
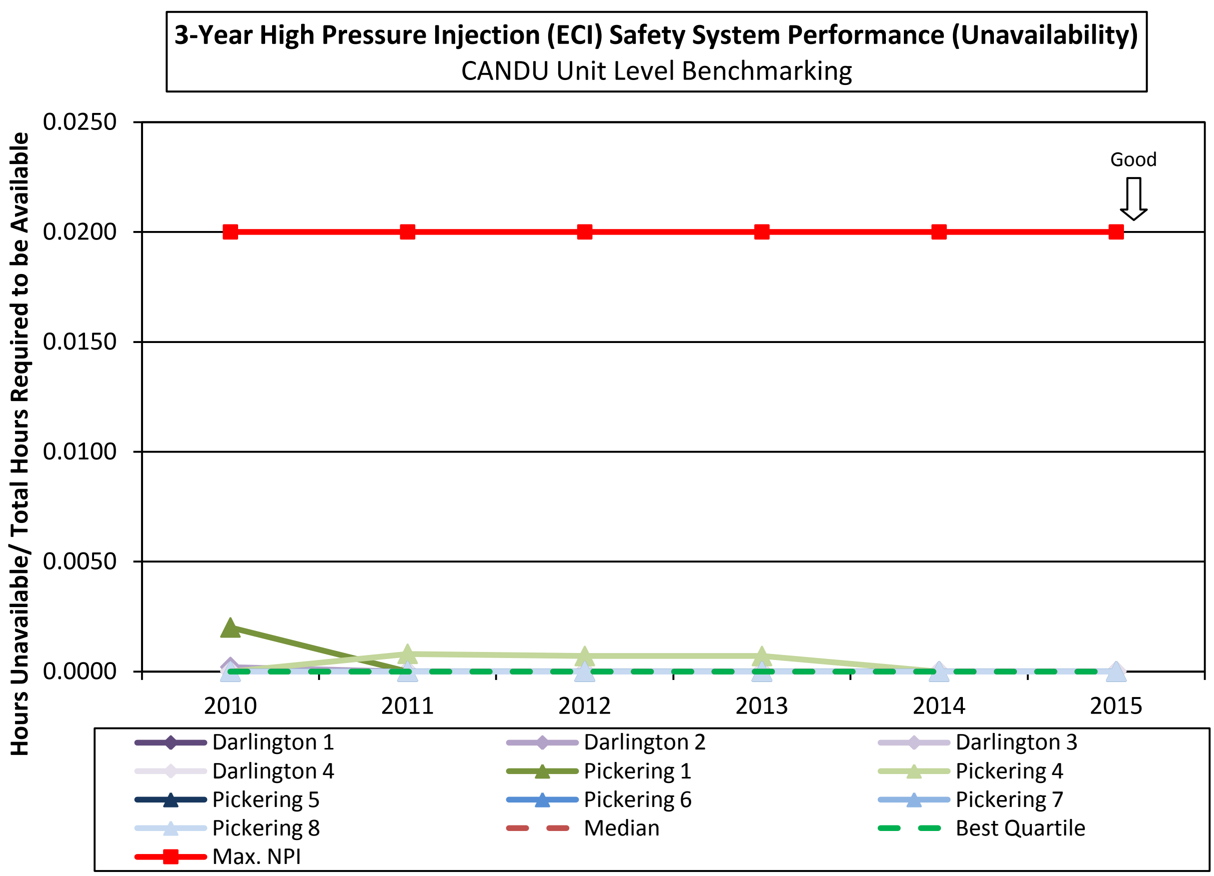
2015 3-Year High Pressure Injection (ECI) Safety System Performance (Unavailability)
CANDU Unit Level Benchmarking




3-Year High Pressure Injection (ECI) Safety System Performance (Unavailability)
CANDU Plant Level Benchmarking
Hours Unavailable/Total Hours Required to be Available
0.0250
0.0200
0.0150
0.0100
0.0050
0.0000
2010
2011
2012
2013
2014
2015
Good
DN
Median
Best Quartile
Max. NPI
PN


3-Year High Pressure Injection (ECI) Safety System Performance (Unavailability)
CANDU Unit Level Benchmarking
Hours Unavailable/ Total Hours Required to be Available
0.0250
0.0200
0.0150
0.0100
0.0050
0.0000
2010
2011
2012
2013
2014
2015
Good
Darlington 1
Darlington 2
Darlington 3
Darlington 4
Pickering 1
Pickering 4
Pickering 5
Pickering 6
Pickering 7
Pickering 8
Median
Best Quartile
Max. NPI

Observations – 3-Year High Pressure Safety Injection Unavailability (CANDU)

2015 (3-Year Rolling Average)

- The best quartile and median values for the 3-Year High Pressure Safety Injection Unavailability performance for CANDU plants were zero. For individual CANDU units, both the best quartile and median value were zero.
- Pickering achieved best quartile performance of zero unavailability at both the station and unit levels in 2015.
- Darlington achieved best quartile performance of zero unavailability at both the station and unit levels in 2015.

Trend

- The 3-Year High Pressure Safety Injection unavailability best quartile performance of CANDU plants has been zero since 2010. The plant level industry median performance improved since 2010 and achieved zero unavailability in 2014 and 2015. At the unit level, the industry best quartile and median value have remained at zero over the review period.
- At the plant level, Pickering station performance has consistently improved over the review period achieving zero unavailability in 2014 and 2015. On an individual unit basis, Unit 1 has improved from 2010, achieving zero unavailability from 2011 to 2015. Unit 4 performance improved from 2011 and achieving zero unavailability in 2014 and 2015. Units 5, 6, 7, and 8 have been at the best quartile since 2010.
- At the plant level, Darlington station performance has improved since 2010 and has maintained best quartile performance from 2011 to 2015. On an individual unit basis, Units 1, 3, and 4 have been at the best quartile since 2010, while Unit 2 has been at the best quartile since 2011.

Factors Contributing to Performance

- Key performance drivers for this metric include: general equipment reliability, material condition, and human performance.
- On February 6, 2015, Pickering Unit 6 Emergency Coolant Injection (ECI) Level 2 Impairment was declared due to heat tracing alarm which resulted in 25 minutes of unavailability. This did not impact the numerical value of the NPI because the system unavailability was declared for a very short period of time.
- Key performance drivers for this metric include the continuous implementation and utilization of:
    - Modifications and key initiatives such as the Parts Improvement Initiative ensuring parts availability.
    - Plant Reliability Lists work programs to drive work execution.
    - Dashboard at Plant Health to provide coordination and support work completion from a cross-functional team.
    - Procedural Updates to continuously incorporate Operating Experience and to mitigate human performance events.
    - Enhanced System Health Team Focus and Effectiveness.

3.0 RELIABILITY

Methodology and Sources of Data

The majority of reliability metrics were calculated using the data from WANO. Any data labelled as invalid by WANO was excluded from all calculations. Indicator values of zero are not plotted or included in calculations except in cases where zero is a valid result. Complete data for the review period was obtained and averages are as provided by WANO.

The two backlog metrics, On-line Deficient and Corrective maintenance, are also included within this section and the data comes from an industry sponsored INPO AP-928 subcommittee. Data points benchmarked on backlogs are a single point in time, not a rolling average. All of the data is self-reported. Industry backlog benchmark standards changed with Revision 3 of AP-928 Work Management Practices at INPO in June of 2010. The new standard created an alignment between engineering criticality coding and backlog classification that allows improved focus on the more critical outstanding work. This standard also sets a more consistent foundation for classification of backlogs such that comparisons between utilities will be more meaningful. All OPG nuclear stations converted to the new standard on January 24, 2011. The On-line Deficient and Corrective maintenance backlog industry data was collected from INPO for 2015.

Discussion

The primary metric within the reliability section is the WANO Nuclear Performance Index (NPI). The WANO NPI is an operational performance indicator comprised of 10 metrics, three of which are analyzed in this section: Forced Loss Rate, Unit Capability Factor, and Chemistry Performance Indicator. The remainder of the WANO NPI components are analyzed in the safety section (Section 2.0).

Darlington quartile rankings for the Corrective and Deficient Maintenance Backlogs dropped to the third quartile while Unit Capability Factor dropped to the fourth quartile in 2015. Industry best quartile performance for NPI significantly improved in 2015. Darlington's scores for the NPI metric fell overall and the station ranking fell from the median quartile in 2014 to the third quartile in 2015.

The Pickering station performed at the same quartile rankings when compared to 2014 except for the Chemistry Performance Indicator and Deficient Maintenance Backlogs, which fell to the fourth quartile in 2015. All other Pickering Reliability metrics are in the fourth quartile.

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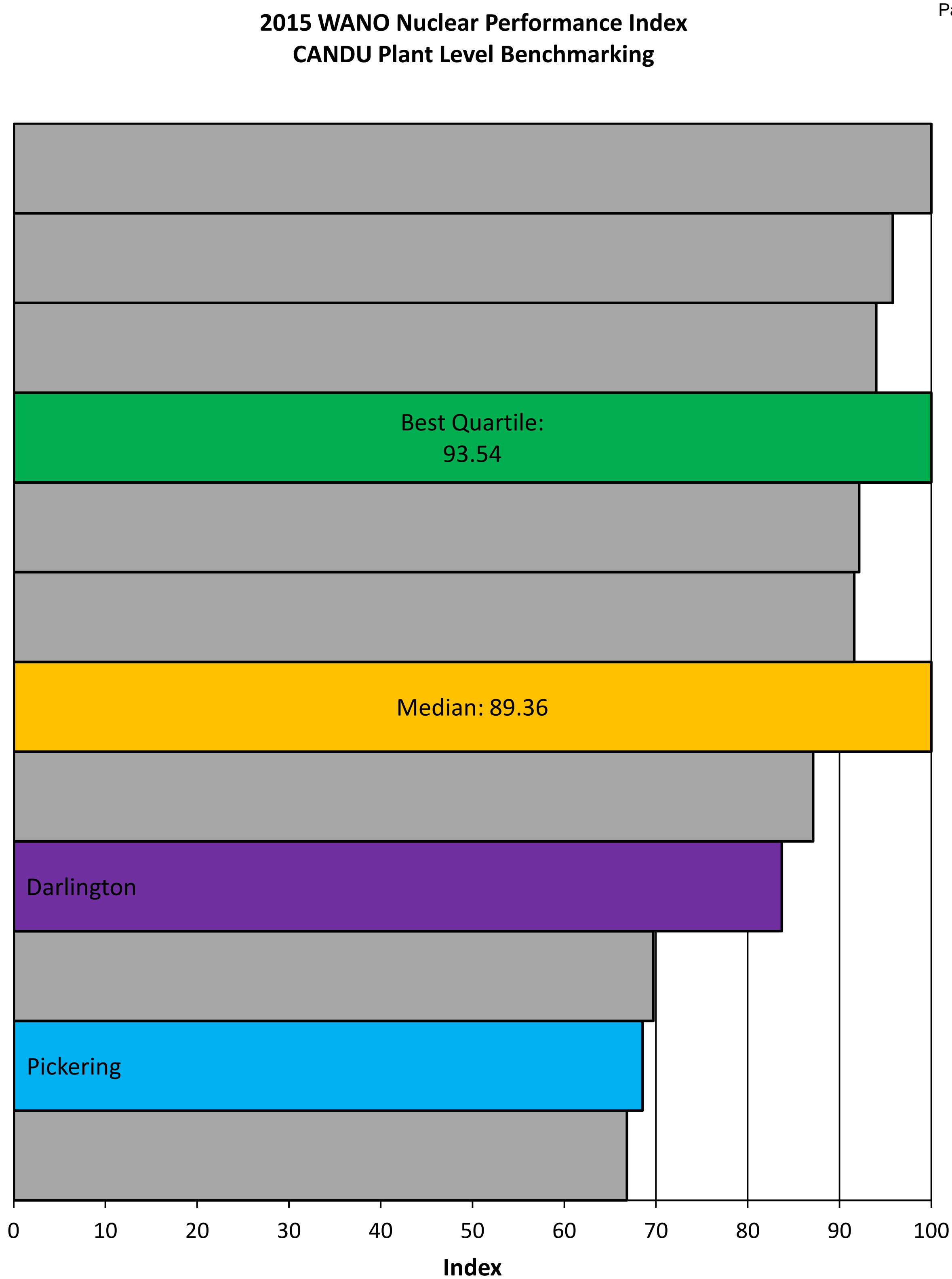
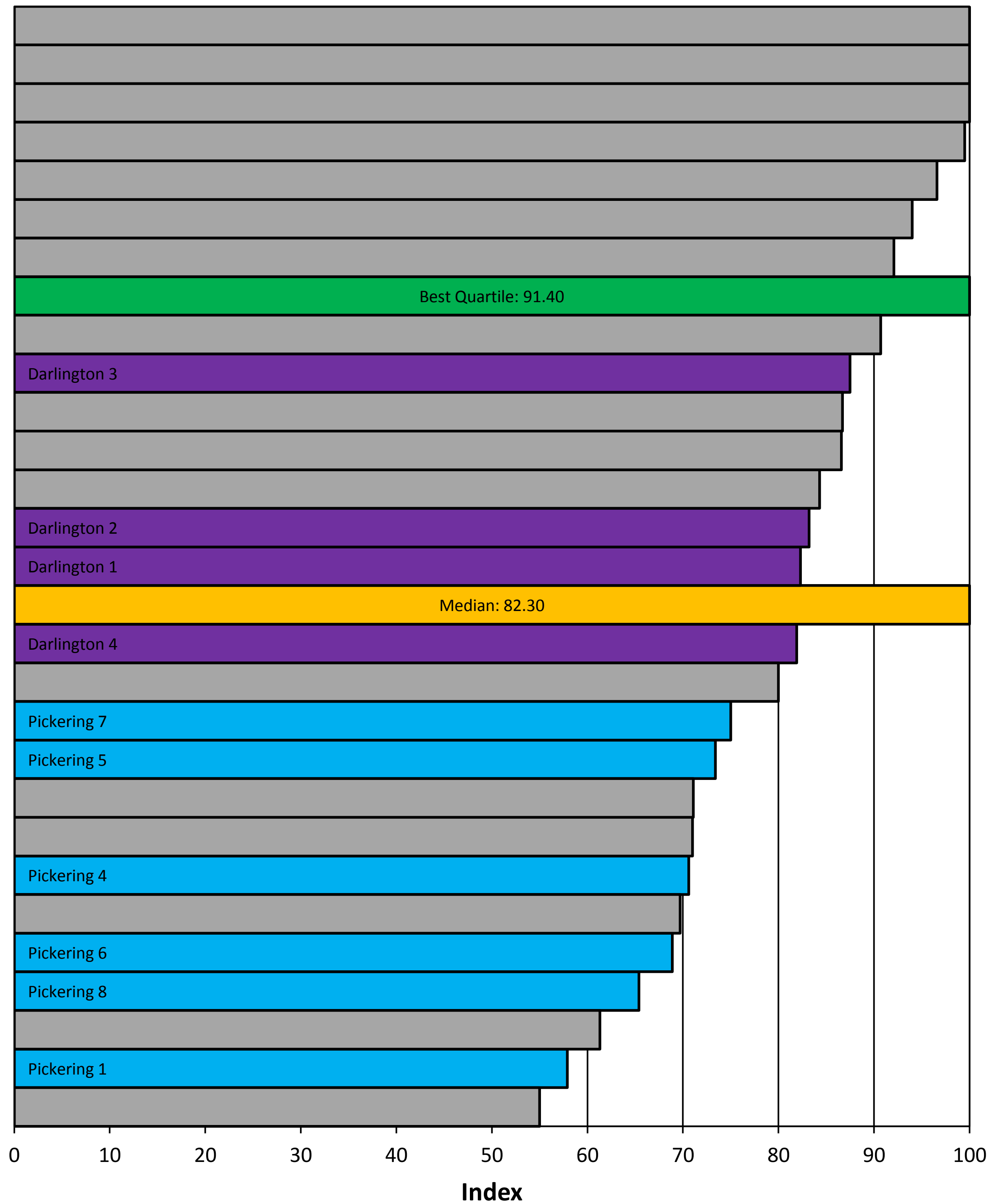
WANO Nuclear Performance Index



2015 WANO Nuclear Performance Index
CANDU Unit Level Benchmarking



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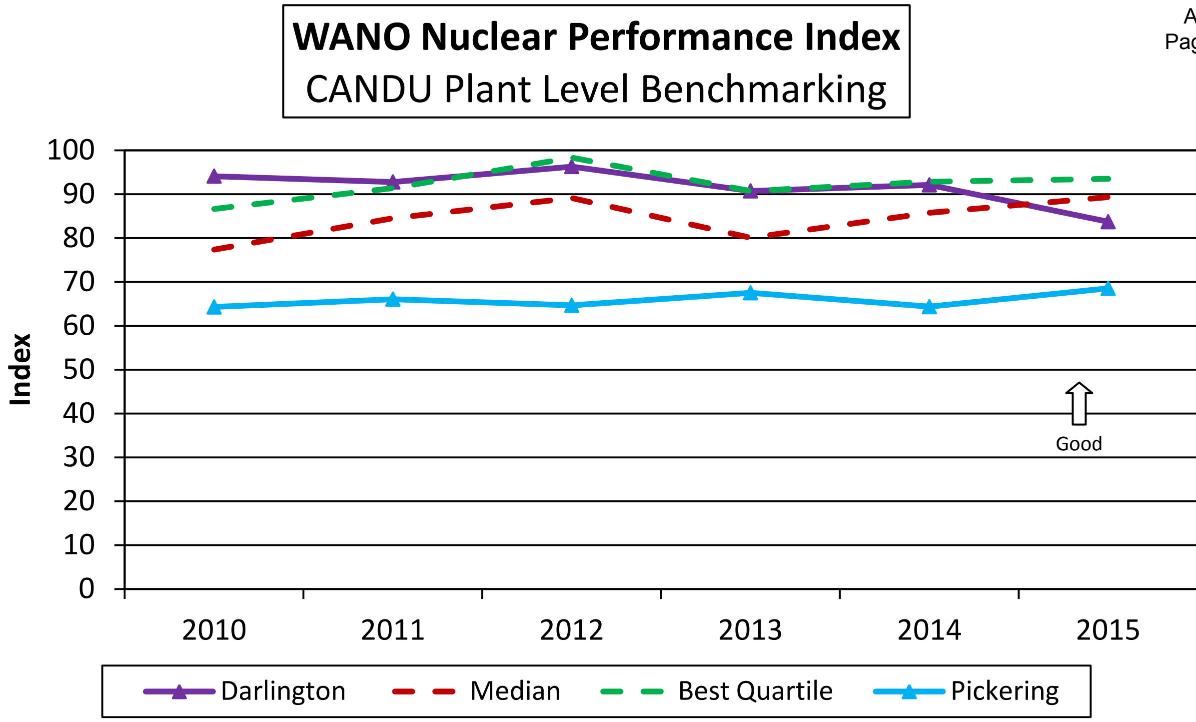

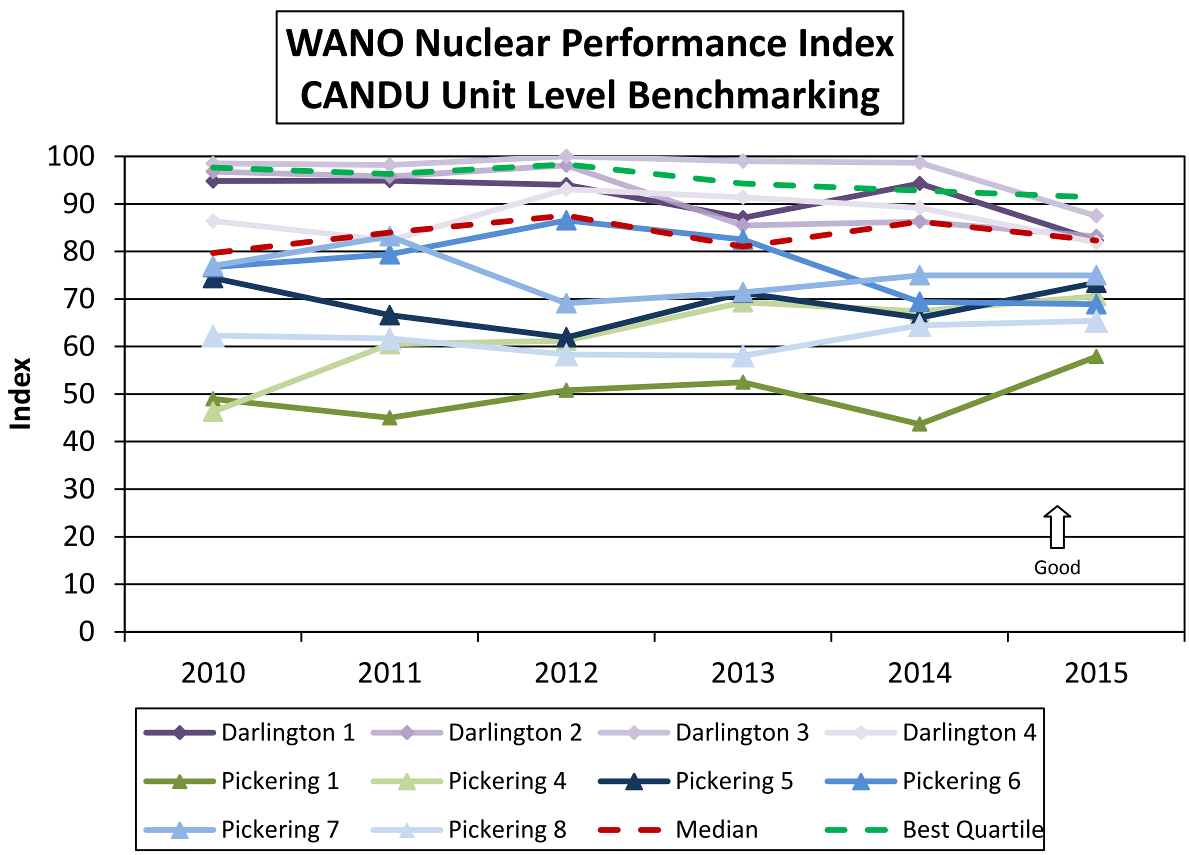

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Observations – WANO Nuclear Performance Index (NPI) (CANDU)

2015

- The 2015 best quartile of the CANDU plant comparison panel for WANO NPI is 93.5. This represents a 0.6 point increase above the 2014 best quartile.
- The median of the CANDU plant comparison panel rose 3.6 points, compared to last year, to 89.4 in 2015.
- At the plant level, both Darlington and Pickering scored below median NPI performance in 2015.
- In 2015, Darlington had three units in the second quartile, and one unit in the third quartile. Pickering had two units in the third quartile and four units in the bottom quartile.

Trend

- The best quartile of the CANDU plant comparison panel rose from 2010 to 2012, with the best quartile performance rising to its highest level in 2012. While this was not sustained in subsequent years, the best quartile results for the past 3 years remain in the low 90's.
- The median value of the CANDU plant comparison panel continued to rise from 2010 to 2012, indicating that the performers in the lower quartiles are performing better. This performance was not sustained in 2013, but did recover in 2014 and 2015.
- Pickering has performed consistently below median over the review period.
- As the strongest OPG performer, Darlington achieved best quartile performance over the majority of the review period, ranking just below top quartile in 2014, but performance declined in 2015 due to the station vacuum building containment outage for planned regulatory maintenance and higher FLR.

Factors Contributing to Performance

- The WANO NPI is a composite index reflecting the weighted sum of the scores of 10 separate performance measures. A maximum score of 100 is possible. All of the sub-indicators in this index are reviewed separately in this benchmarking report.

Pickering

- Pickering's NPI performance is negatively impacted by the need for long outages to accommodate fuel channel inspection programs.
- These long outages negatively impact both the unit capability factor and collective radiation exposure metrics.
- For 2015, Pickering achieved maximum scores for 3 out of 10 NPI sub-indicators.
- For the key safety system related metrics of high pressure injection and emergency alternating current (AC) power, the station received 10 of 10 points.
- Pickering also achieved a perfect score for industrial safety accident rate (5 of 5).
- Pickering earned 9.9 of 10 points for reactor trip rates.
- Pickering achieved 3.7 of 5 points for chemistry performance, 7.0 of 10 points for collective radiation exposure, 9.7 of 10 points for fuel reliability and 8.8 of 10 points for auxiliary feedwater.
- Pickering received 0.2 of 15 points for unit capability factor and 4.2 of 15 points for forced loss rate due to forced outages, longer planned outages related to life extension, and planned outage extensions.

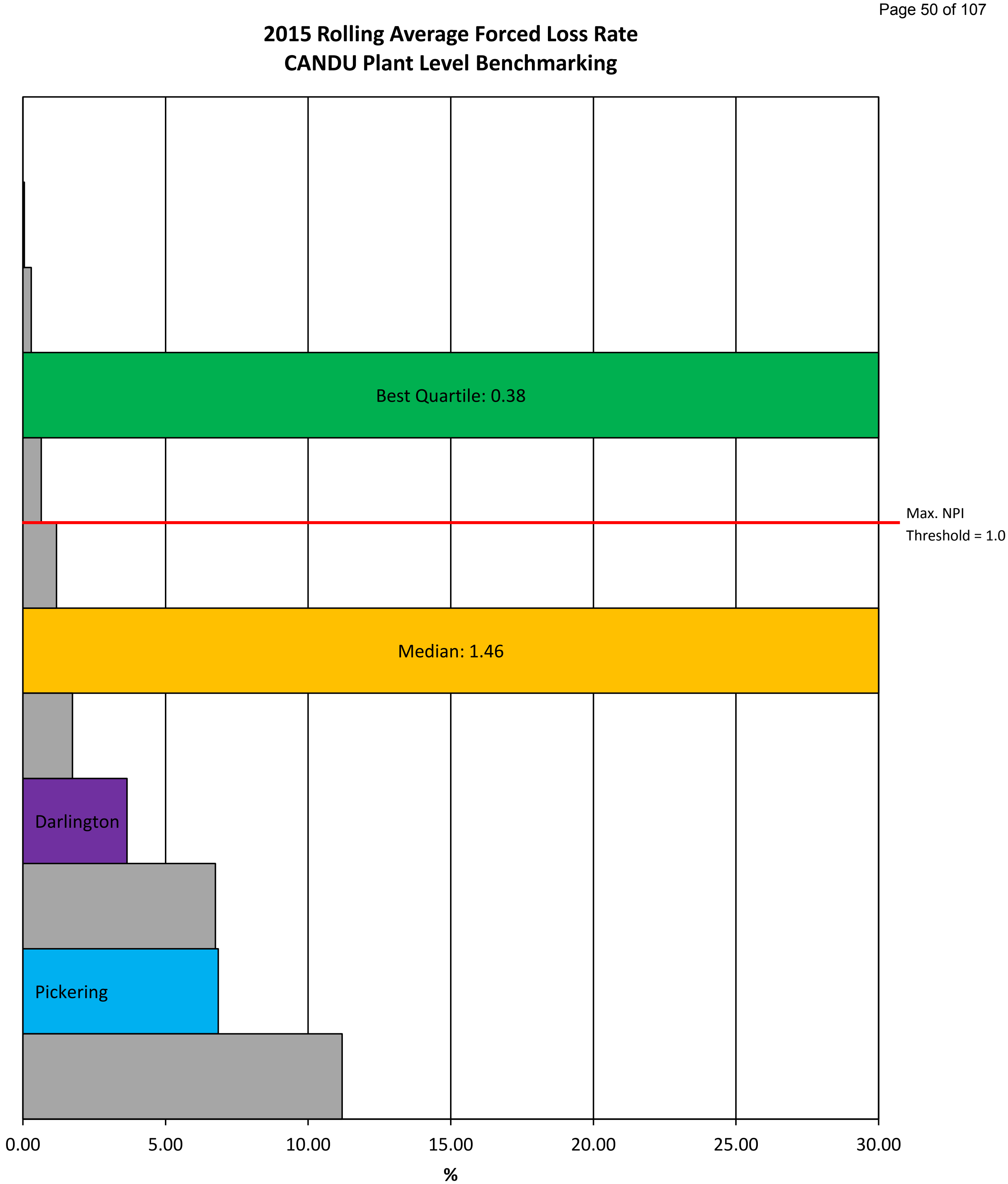
Factors Contributing to Performance (CONT'D)

Darlington

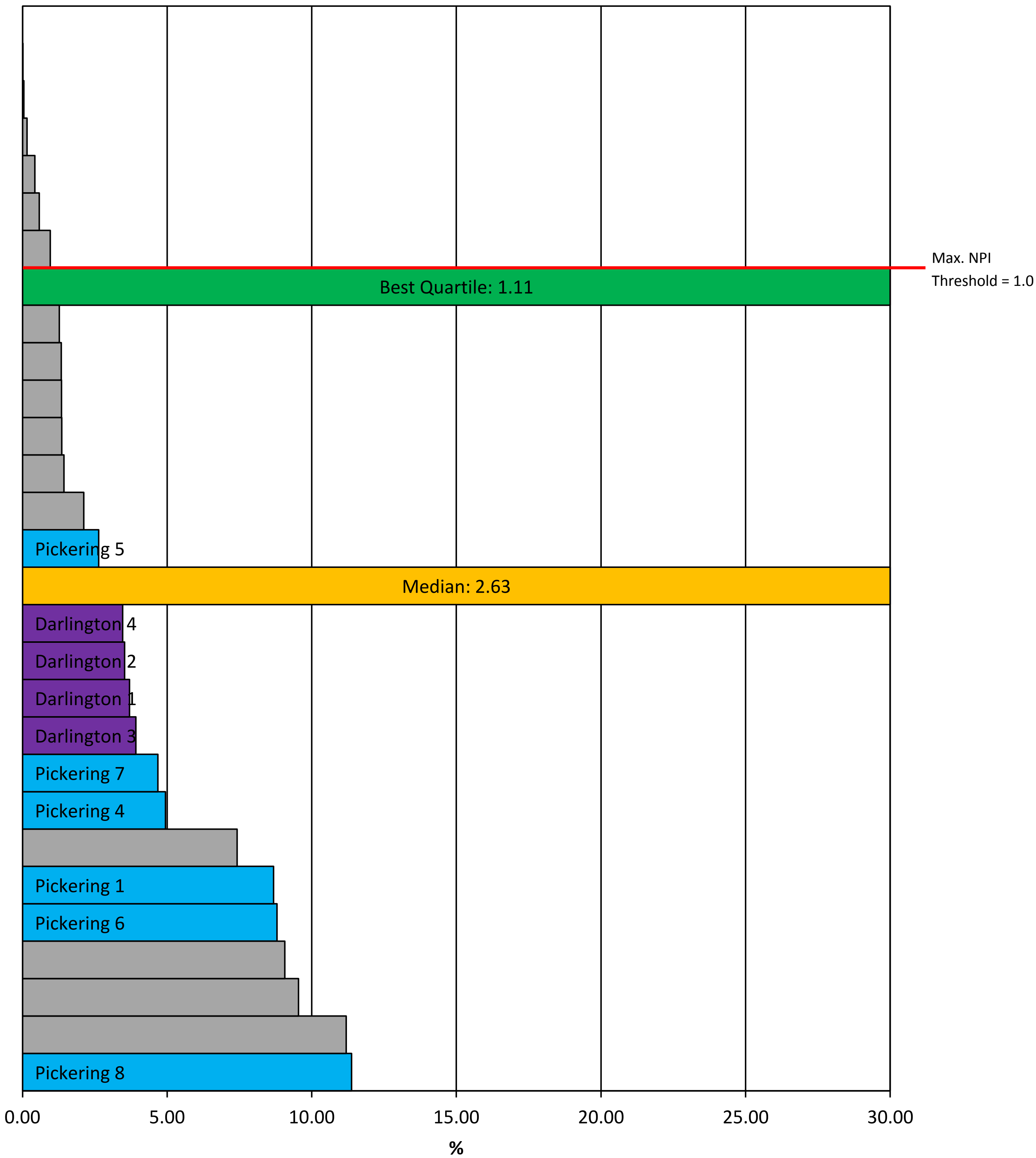
- Darlington's NPI performance has been impacted by higher forced loss rate and by a lower unit capability factor due to the 4 unit VBO shutdown in 2015.
- For 2015, Darlington achieved maximum scores for 7 out of 10 NPI sub-indicators.
- For each of the key safety system related metrics, high pressure injection, auxiliary feedwater, and emergency alternating current (AC) power, Darlington received 10 of 10 points.
- Darlington also achieved perfect scores for reactor trip rate (10 of 10), fuel reliability (10 of 10), chemistry performance (5 of 5), and industrial safety accident rate (5of 5).
- Darlington earned 9.5 out of 10 points for collective radiation exposure.
- Darlington achieved 5.0 out of 15 points for unit capability factor and 9.3 out of 15 points for forced loss rate

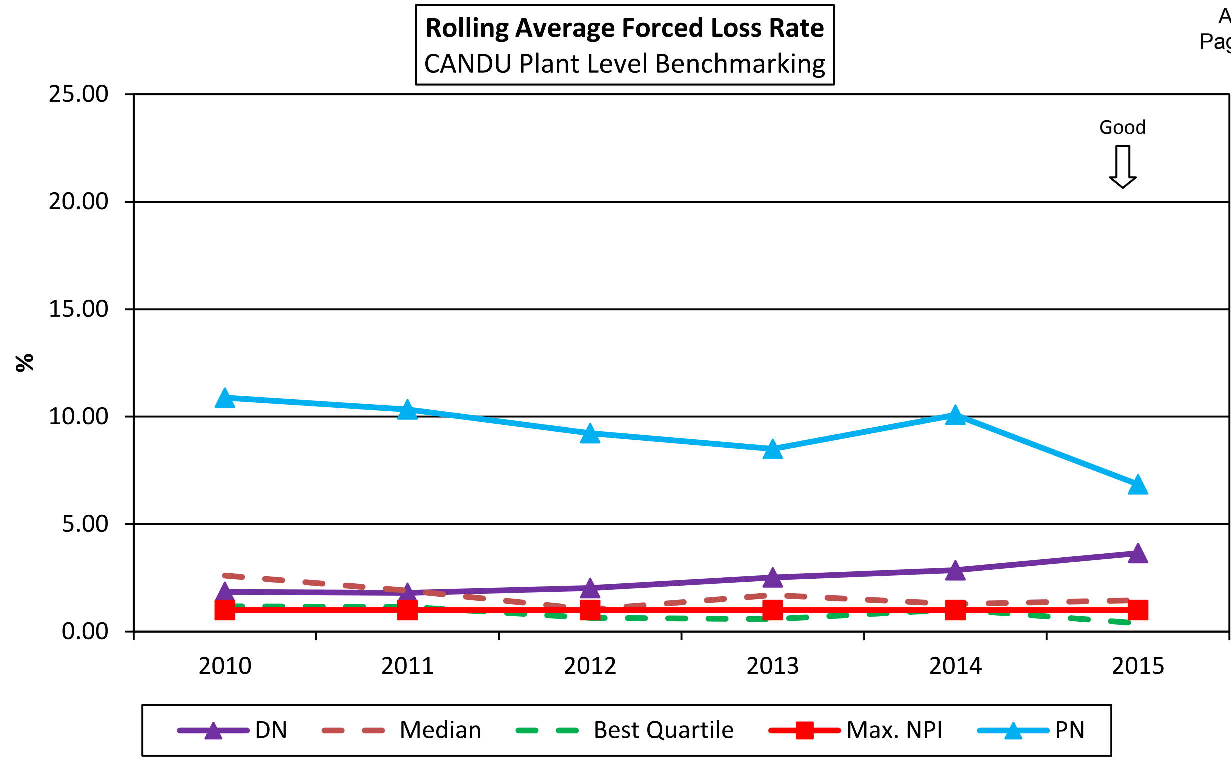
Please refer to Table 13 of the Appendix for an NPI plant level performance summary of OPG nuclear stations against the North American panel.

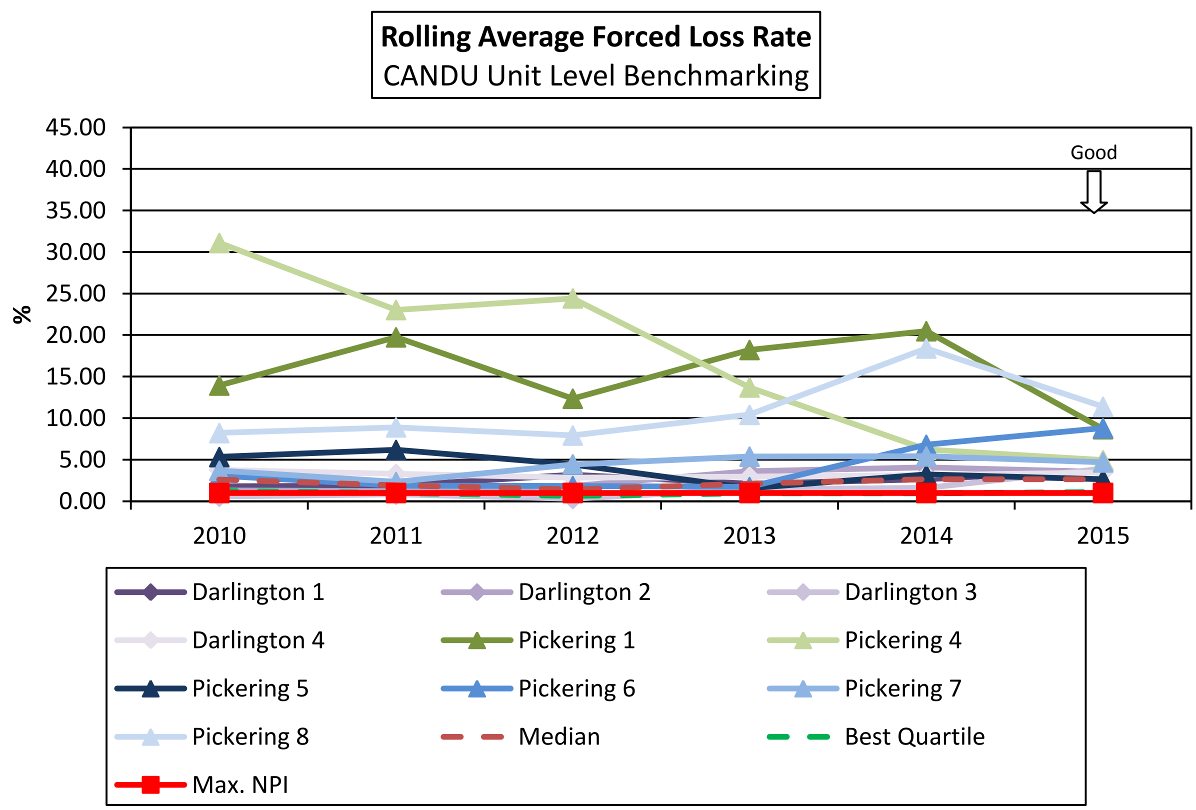
Rolling Average Forced Loss Rate



2015 Rolling Average Forced Loss Rate
CANDU Unit Level Benchmarking




Rolling Average Forced Loss Rate
CANDU Plant Level Benchmarking
25.00
20.00
15.00
10.00
5.00
0.00
%
Good
2010
2011
2012
2013
2014
2015
DN
Median
Best Quartile
Max. NPI
PN


Rolling Average Forced Loss Rate
CANDU Unit Level Benchmarking
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
%
Good
2010
2011
2012
2013
2014
2015
Darlington 1
Darlington 2
Darlington 3
Darlington 4
Pickering 1
Pickering 4
Pickering 5
Pickering 6
Pickering 7
Pickering 8
Median
Best Quartile
Max. NPI

Observations – Rolling Average Forced Loss Rate (CANDU)

2015 (Rolling 2 Year Average, Pickering %; Rolling 3 Year Average, Darlington %)

- At the plant level, Pickering Forced Loss Rate (FLR) performance was 6.85, which was worse than industry median (1.46). At the unit level, one Pickering unit was above median (2.63) in the second quartile. All remaining 5 Pickering units were ranked in the third and fourth quartile.
- At the plant level, Darlington FLR performance was 3.65, which was also worse than median (1.46). At the unit level, all Darlington units were below median, positioned in the third quartile. This is declining performance, as Darlington previously had 2 units performing above median unit FLR threshold in 2014.

Trend

- Industry plant median FLR trend continues to improve over the same period, from 2.60 in 2010 to 1.29 in 2014, with minor up-tick to 1.46 in 2015. Industry best quartile has also improved during the period, from 1.18 in 2010 to 1.03 in 2014 and down to 0.38 in 2015.
- Pickering's FLR performance over the 5 year review period, has been improving. The equipment reliability improvements at Pickering have been the main drivers for the favourable improvement in FLR performance. FLR performance appreciably improved in 2015 by a reduction in station FLR (6.85) from 2014 FLR (10.08).
- Darlington's overall FLR performance decreased slightly from 2.85 in 2014 to 3.65 in 2015. Over the 5 year review period, there has been a general trend of minor decline in FLR performance, with increasing FLR (about 1.85%) from 1.80 in 2011 to 3.65 in 2015.

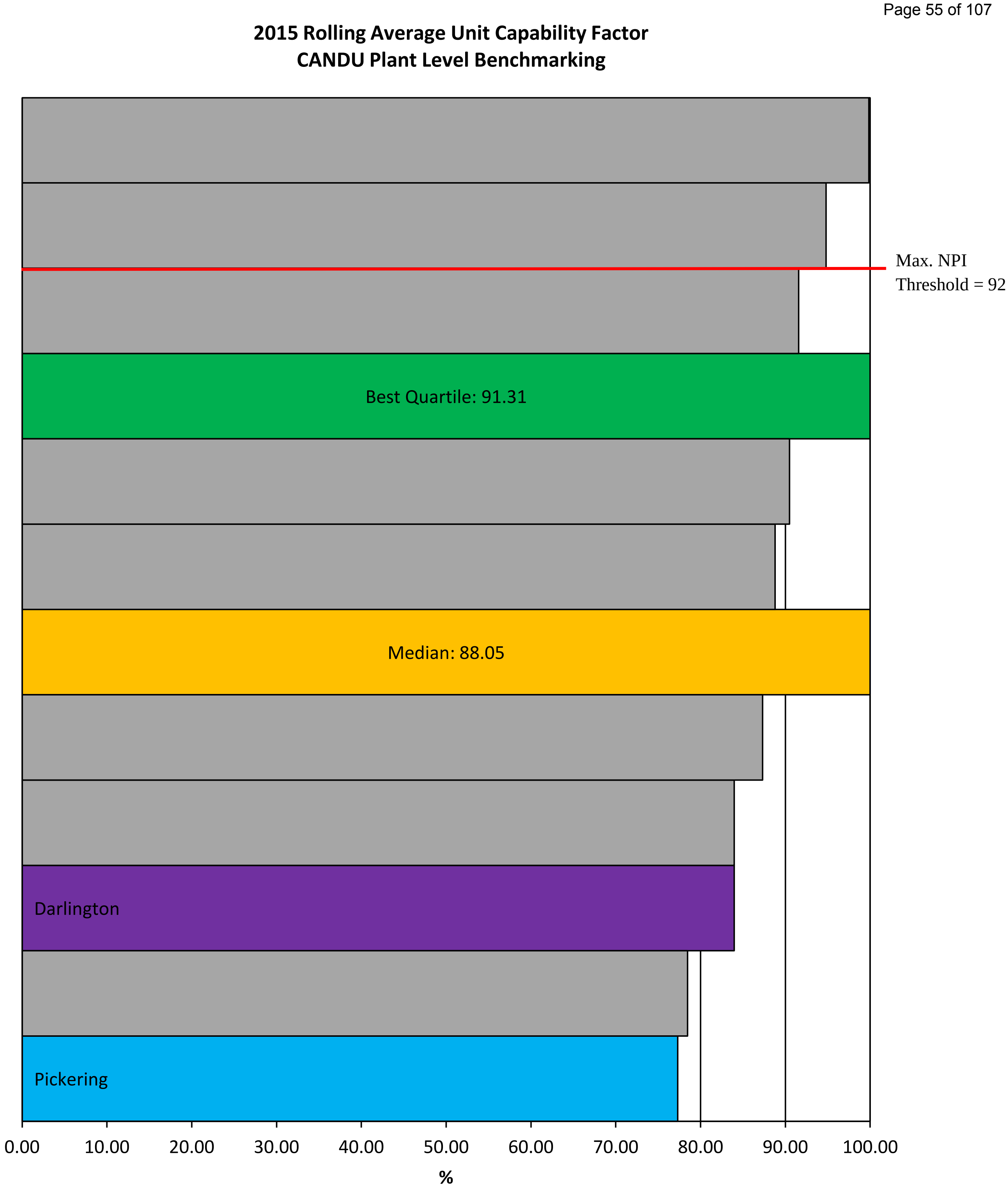
Factors Contributing to Performance

- Equipment reliability, work order backlog and human performance are the key contributors to the FLR performance gap at Pickering.
- Pickering's 2015 FLR was impacted by 5 unplanned outages due to failures from the reactor and turbine side totaling 25.5 days of lost production. Equipment issues with the Boiler and Liquid Zone Control systems were the main contributors for the forced outages.
- Pickering continues to execute a list of high priority work orders (PRL-plant reliability list) to improve equipment reliability and reduce operator burden.
- Pickering continues reducing corrective and deficient work order backlogs through a reduction of incoming emergent work orders by proactive equipment replacements and minor modifications to improve/correct system and equipment performance.
- Pickering is also implementing equipment reliability projects to put new equipment in the plant to prevent forced loss events. Single point vulnerability (SPV) reviews have been completed and elimination and mitigation actions are being implemented or dispositioned for outstanding items.

Observations – Rolling Average Forced Loss Rate (CANDU) (CONT'D)

- The main contributors to Darlington's Forced Loss in 2015 were equipment mechanical issues relating to turbine oil leaks and the system main circulating pump motor electrical production trip. Only 5% of the FLR impact is from human performance. There were 7 forced outages in 2015.
- Darlington continues to drive plant reliability improvements via the system health improvement process and recovery actions. The Plant Reliability List of important work orders are implemented to improve system health. Incoming work reduction and Preventive Maintenance interval stretch have been leveraged for improvements.
- Improvements in equipment reliability, high Equipment Reliability Index performance and effective mitigation of SPVs in plant production systems are common practices of top operating plants.
- NFI-04 Equipment Reliability fleet initiative was launched in 2015 to improve OPG fleet performance over 2016-2018. Site equipment reliability Excellence Plans were developed as part of NFI-04 and locally focused ER improvement initiatives are being executed. An SPV mitigation program is being implemented at both sites.

Rolling Average Unit Capability Factor



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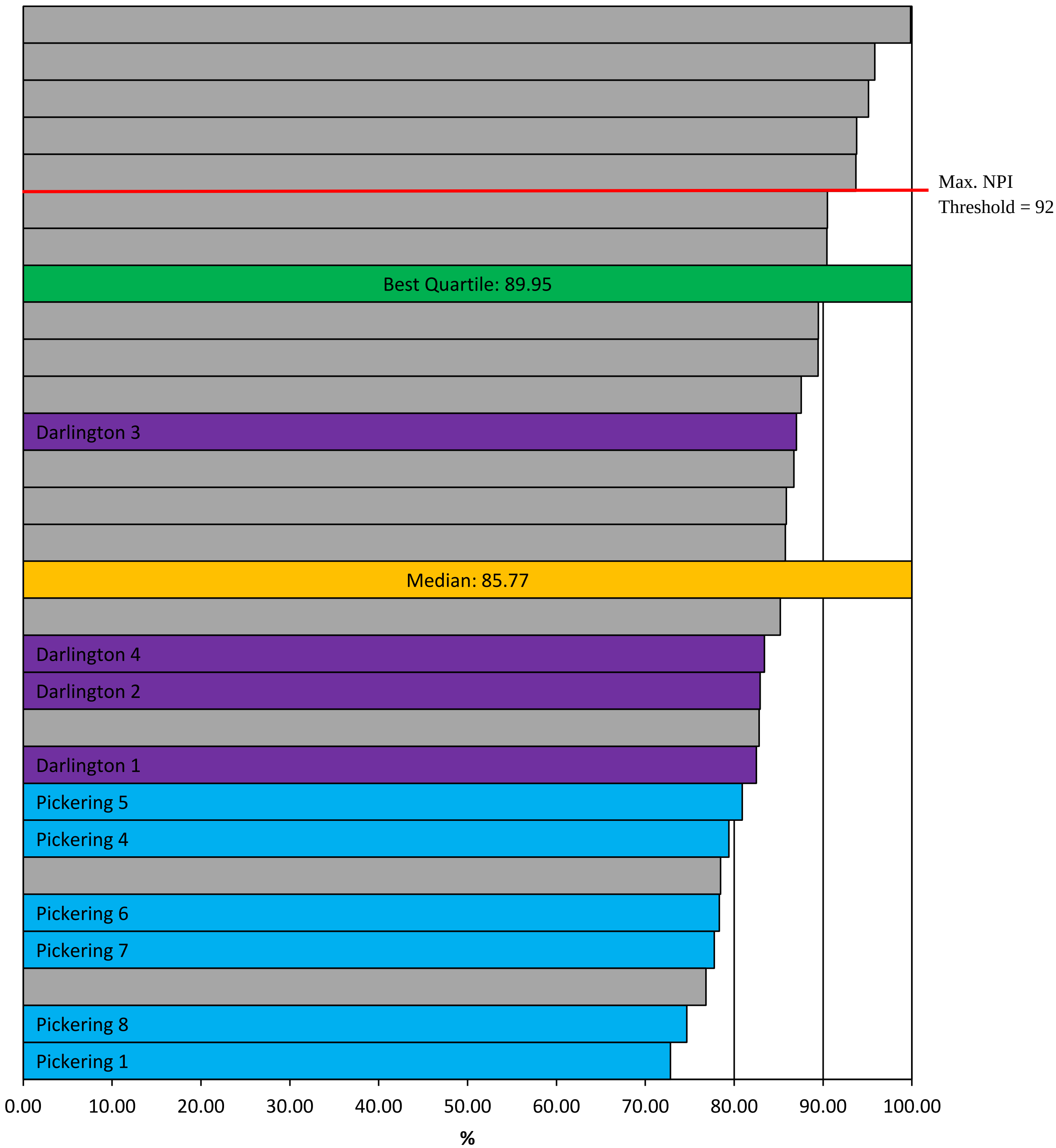
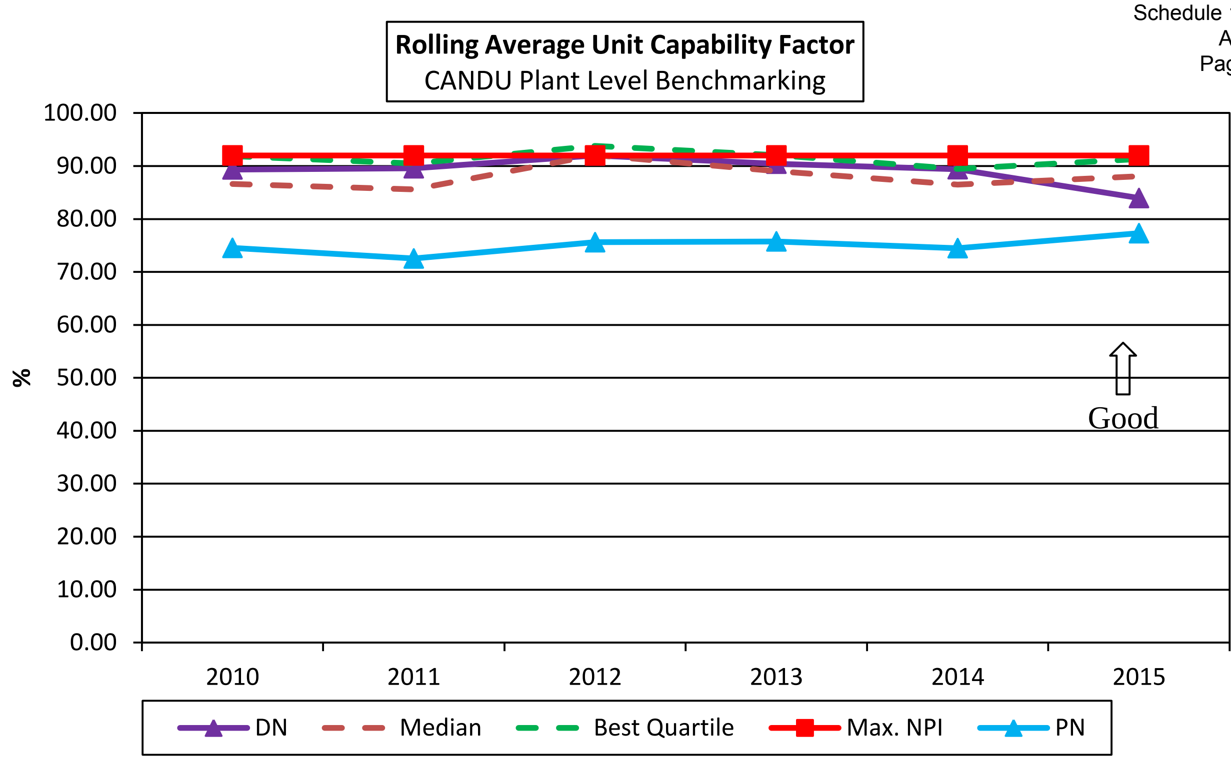
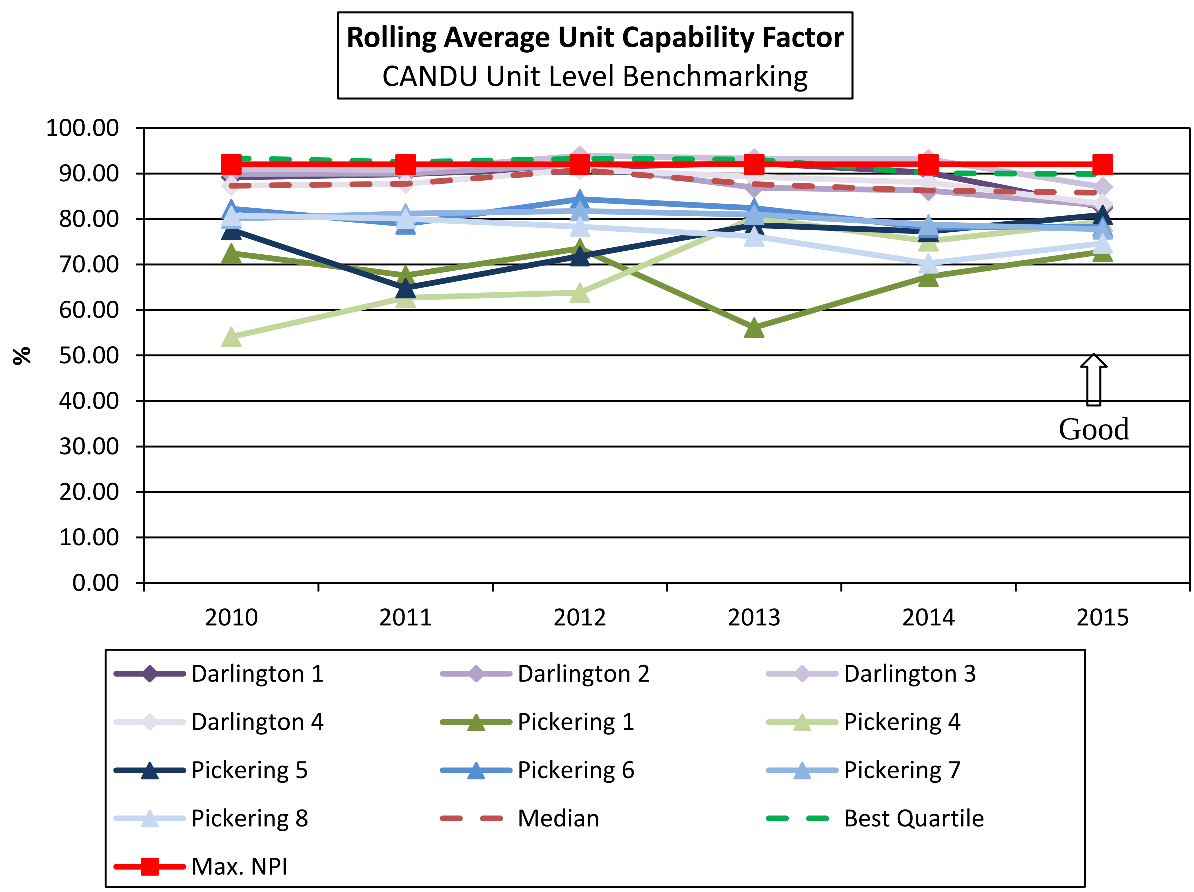
2015 Rolling Average Unit Capability Factor
CANDU Unit Level Benchmarking




Rolling Average Unit Capability Factor
CANDU Plant Level Benchmarking
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
%
Good
2010
2011
2012
2013
2014
2015
DN
Median
Best Quartile
Max. NPI
PN


Rolling Average Unit Capability Factor
CANDU Unit Level Benchmarking
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
%
Good
2010
2011
2012
2013
2014
2015
Darlington 1
Darlington 2
Darlington 3
Darlington 4
Pickering 1
Pickering 4
Pickering 5
Pickering 6
Pickering 7
Pickering 8
Median
Best Quartile
Max. NPI

Observations – Rolling Average Unit Capability Factor-UCF (CANDU)

2015 (Rolling 2 Year Average, Pickering %; Rolling 3 Year Average, Darlington %)

- Pickering performed below median at both the plant and unit level UCF.
- Darlington UCF performance was 83.96, which was below plant median (88.05). At the unit level, only one Darlington unit was better than median (85.77) and the remaining 3 Darlington units were in the third quartile.
- Pickering's gap to best quartile plant UCF was 13.99; and to median UCF was 10.73.
- Darlington's gap to best quartile plant UCF was 7.35; and to median UCF was 4.09.

Trend

- Pickering's UCF performance over the 5 year period, generally had been improving modestly, and in 2015 improved favourably to 77.32 vs 74.50 in 2014. The equipment reliability improvements at Pickering have been favourable for improvement in recent UCF performance.
- Darlington's plant UCF has been declining for the past 4 years (92.01, 90.44, 89.41, 83.96). Coupled with UCF benchmark improving in the past year, Darlington's gap to reach both the best quartile and median thresholds has widened.
- Industry plant median and best quartile UCF benchmarks both improved in 2015 and this is a reversal to the declining trend since 2012. This contributes to a slightly increased challenge in reaching top performance levels for both Pickering and Darlington.

Factors Contributing to Performance

- The primary factors impacting UCF are longer outages to accommodate reactor component inspections necessary for extended life at Pickering and the four unit Vacuum Building Outage at Darlington as well as forced outages at both stations and forced extensions to planned outages at Pickering.
- Darlington had 7 forced outages in 2015. Pickering had 5 forced outages in 2015.
- Pickering had 350.1 days of planned outage in 2015 and Darlington had 266.9 days (includes 4 unit VBO outage). Pickering had 40.6 days of forced extension to planned outage and Darlington had 7.7 days. Higher number of planned outage days and forced extension to planned outages contribute to lower UCF compared to CANDU peers.
- The issues and causes for degrading FLR performance also negatively impact UCF. Significant improvements in equipment reliability are expected to correlate into improved FLR and UCF performance.

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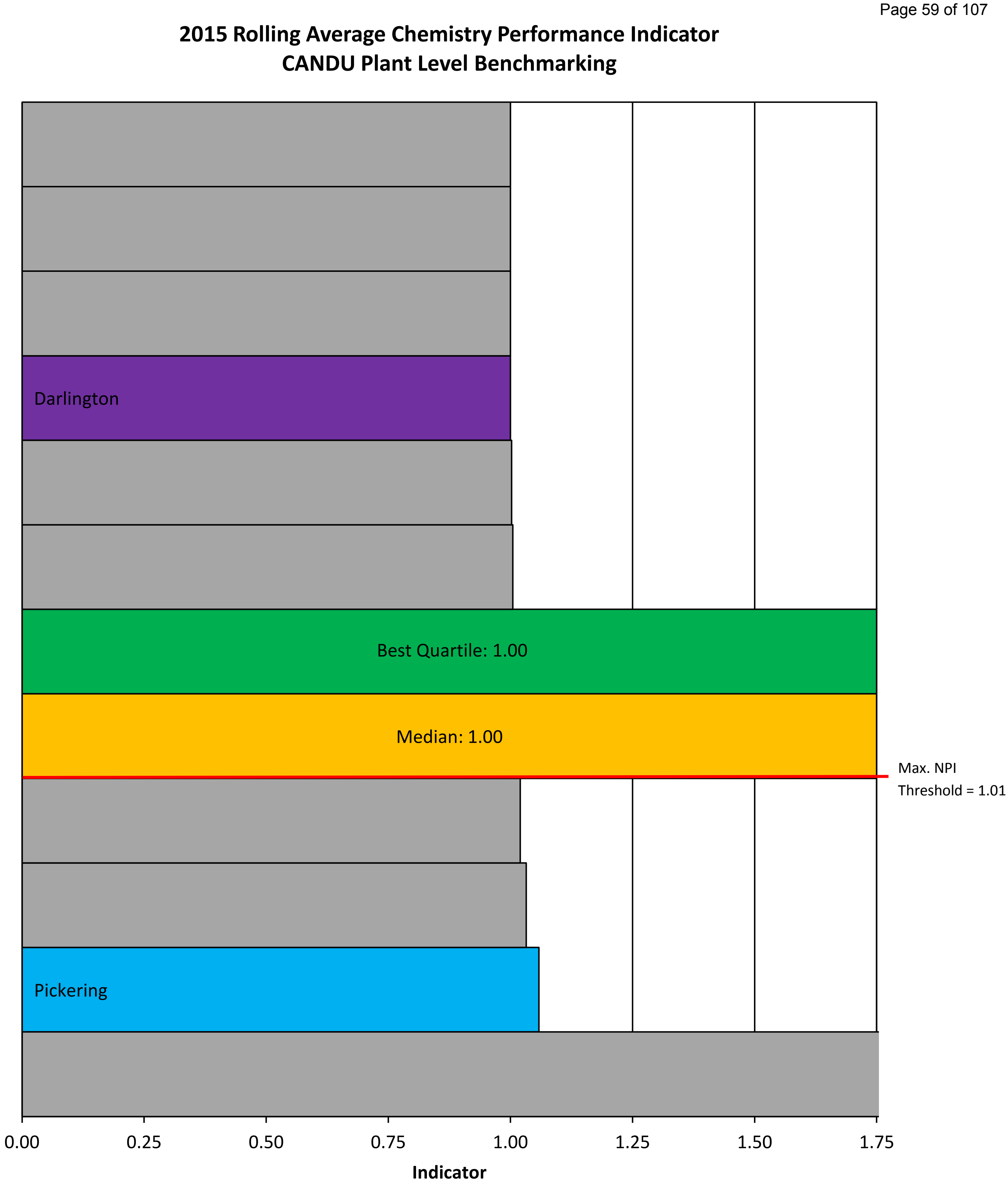
Rolling Average Chemistry Performance Indicator



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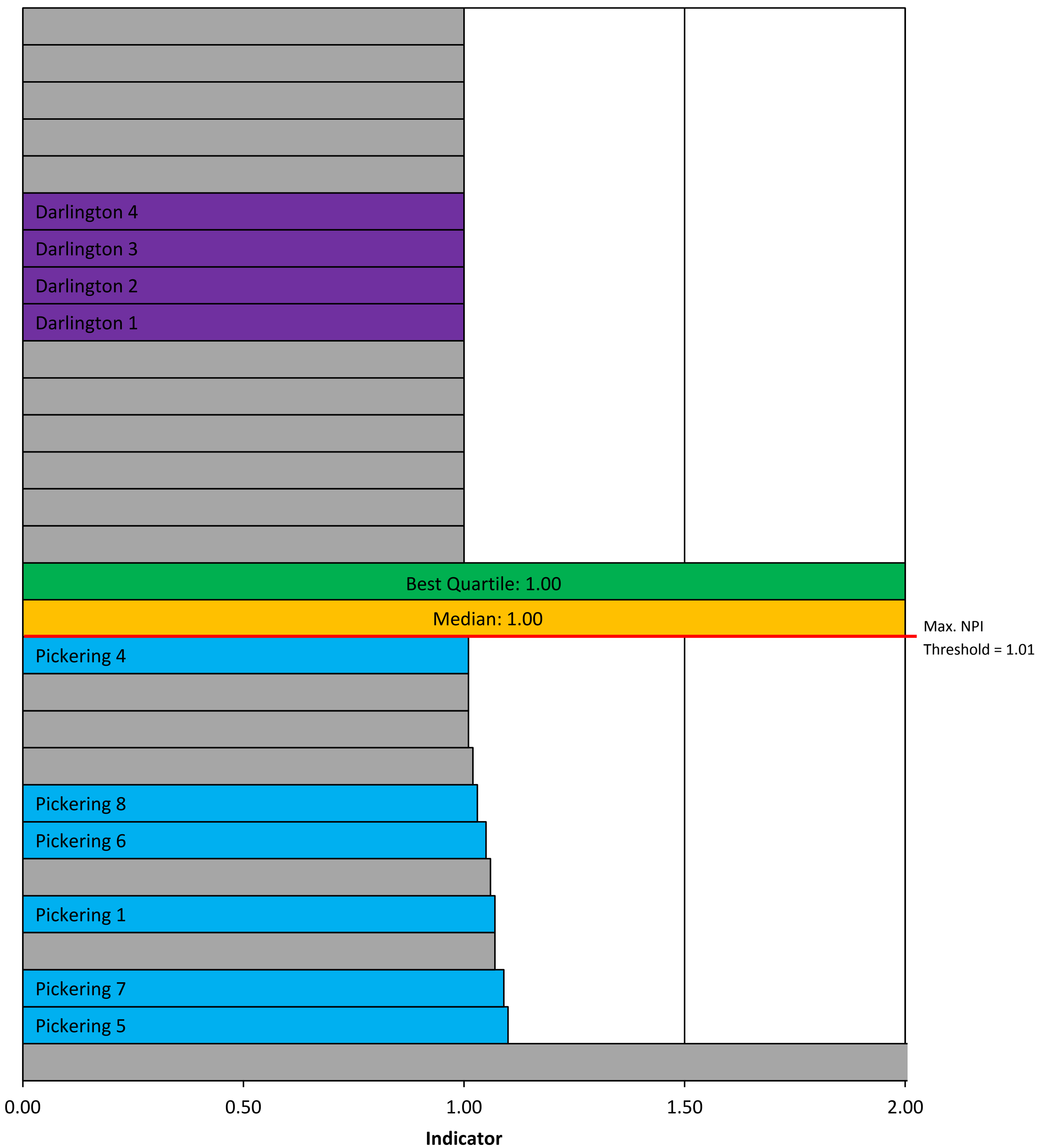
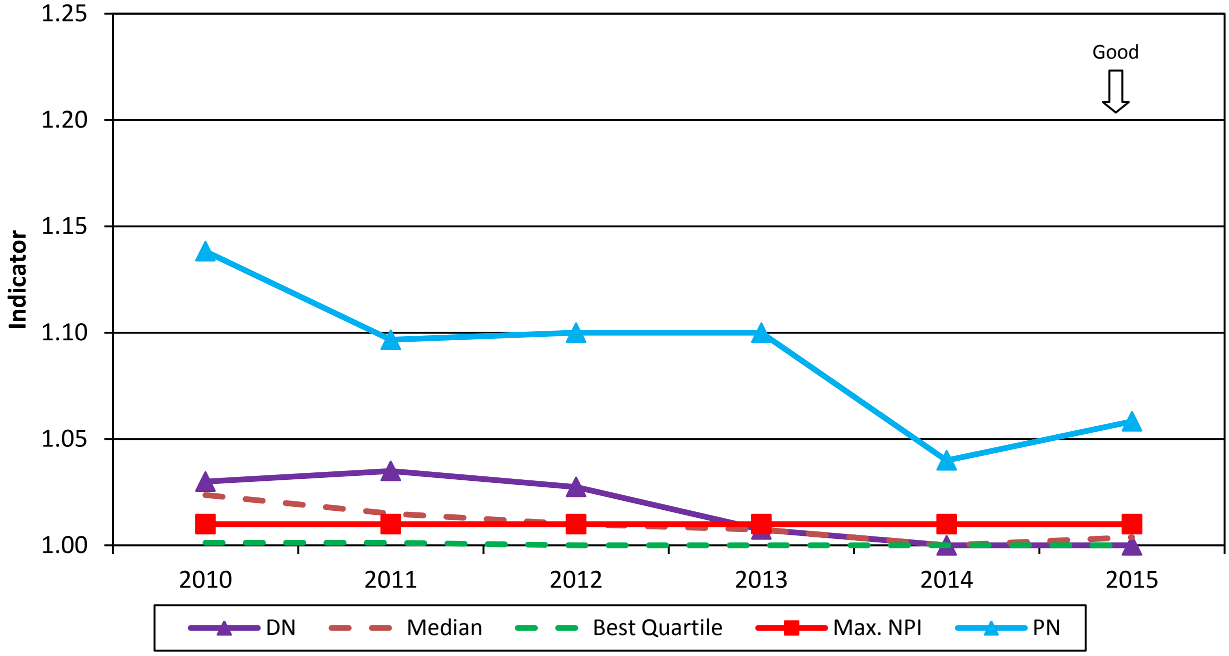
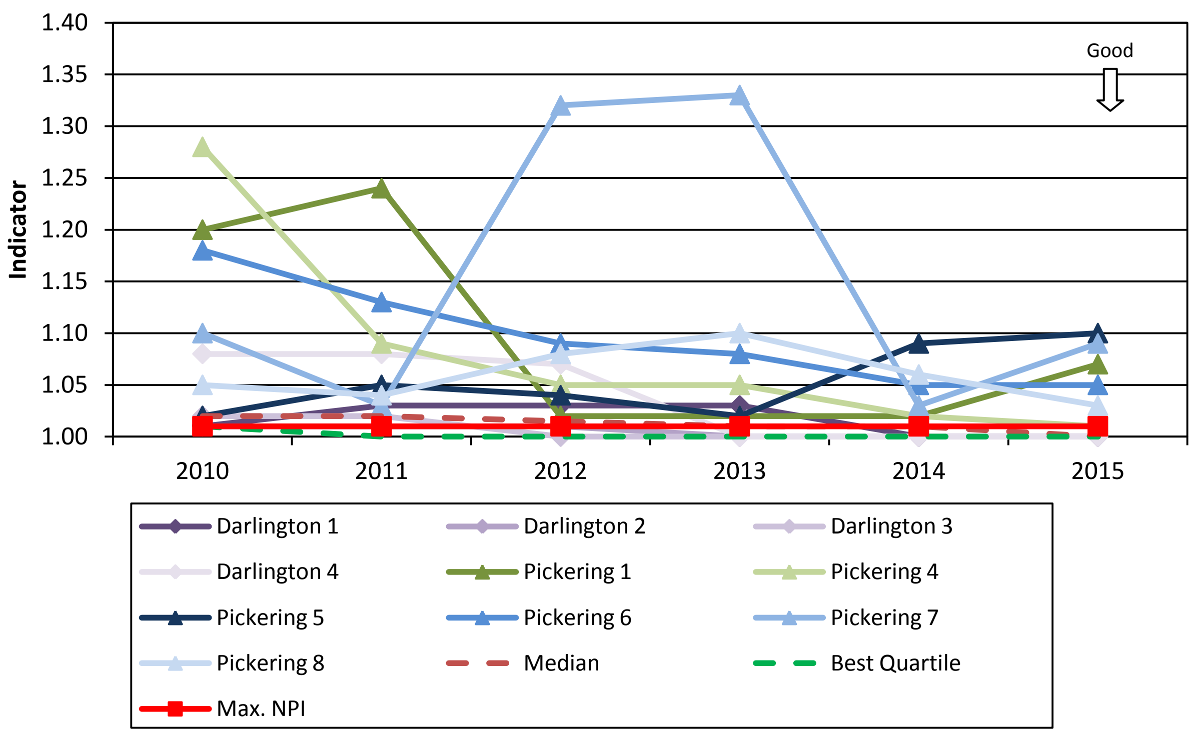
2015 Rolling Average Chemistry Performance Indicator
CANDU Unit Level Benchmarking



Rolling Average Chemistry Performance (CPI)
CANDU Plant Level Benchmarking



Rolling Average Chemistry Performance Indicator
CANDU Unit Level Benchmarking



Observations – Rolling Average Chemistry Performance Indicator (CANDU)

2015 (Rolling 2 Year Average Pickering, Rolling 3 Year Average Darlington)

- The CANDU plant median and top quartile values are both 1.00.
- The CANDU unit median and top quartile values are both 1.00.
- CPI is calculated using data during normal operation (> 30% Full Power).
- The Pickering plant level of performance was worse than the CANDU plant median CPI (1.06 vs 1.00).
- The Pickering unit levels of performance were all worse than the CANDU unit level median CPI (1.01 to 1.10 vs 1.00).
- Pickering plant performance in 2015 declined to 1.06 from 1.04 in 2014.
- Pickering CPI in 2015 improved on Units 4 and 8 whereas performance on Unit 6 remained constant and declined for Units 1, 5, and 7. The CPI results were impacted primarily as a result of three outages with extended clean-up time for boiler impurities. Persistent elevated boiler sodium following restart from the planned outage on Unit 1 was a result of foreign material (high in sodium) introduced during turbine maintenance and elevated sulphate on Units 5 and 7 was attributed to sulphate transferred to boilers (from recent condenser tube leaks in 2012, 2013, and 2014) and, to a lesser extent, a larger latent inventory of sulphate-containing resin (from the 2006 Water Treatment Plant resin event).
- Darlington plant performance in 2015 was equivalent to the CANDU plant level median and best quartile performance (1.00).
- Darlington unit performance in 2015 was equivalent to the CANDU plant level best quartile performance (1.00) and equivalent to the median level performance (1.00).

Trend

- Pickering overall plant performance improved from 2011-2014 (1.10, 1.10, 1.10, and 1.04, respectively), but start up issues have adversely affected CPI in 2015 (1.06).
- Darlington overall plant performance has improved over the last 5 years (1.03, 1.03, 1.01, 1.00, and 1.00 for 2011-2015 respectively).

Factors Contributing to Performance

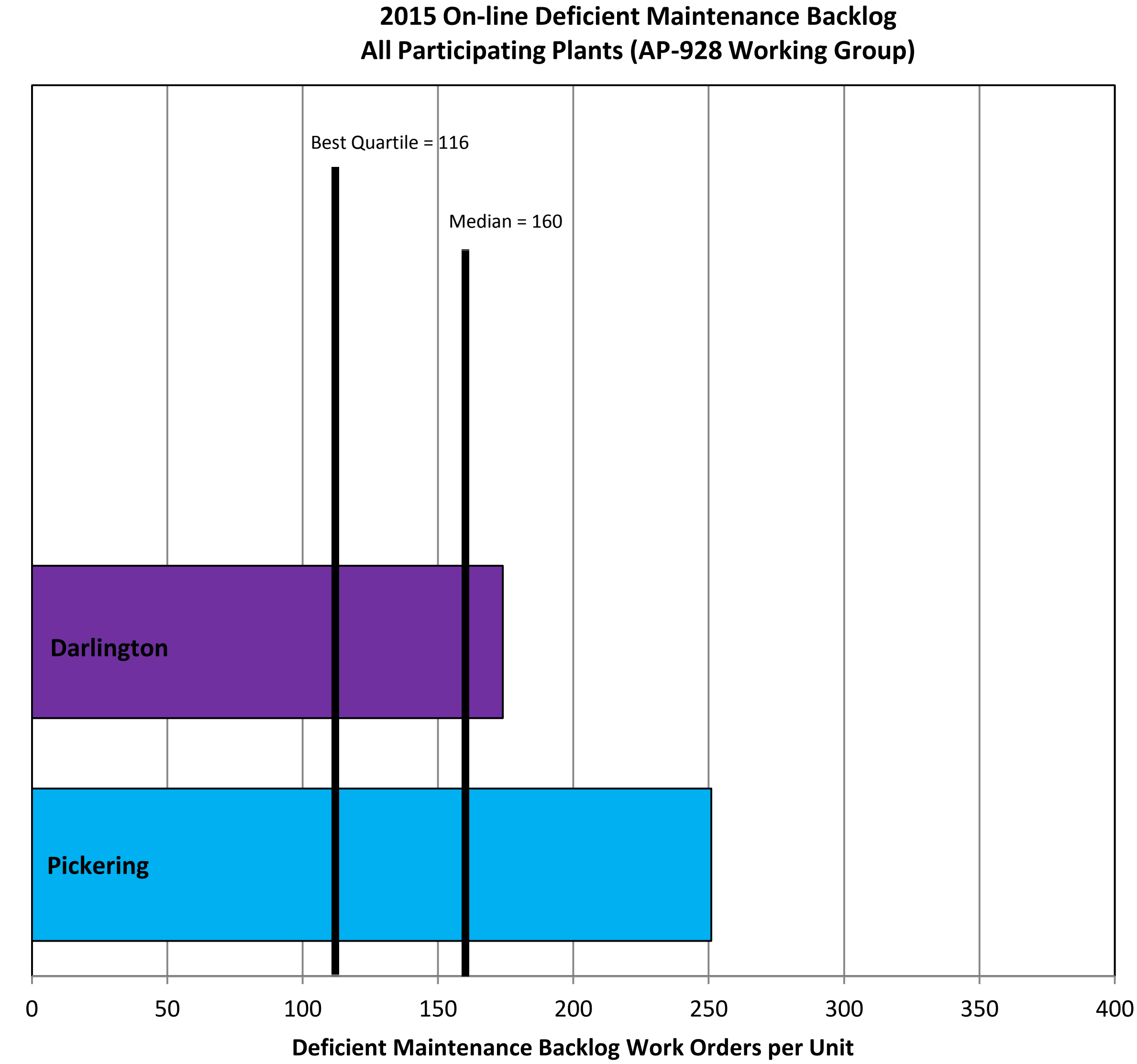
- Chemistry Performance at Pickering is hindered by numerous unit power transients (planned or forced outages), which tend to result in increased corrosion product transport throughout the heat transport system negatively impacting the chemistry performance.
- Pickering is one of the older sites and boiler ion specifications were much higher in the past. Consequently, there is a large inventory of sludge in the boilers, in addition to lakewater salts from prior chronic condenser water in-leakage, which contribute to boiler ions desorption/adsorption phenomenon and increases concentrations above the WANO limiting values for certain ions (most significantly, sulphate).

Observations – Rolling Average Chemistry Performance Indicator (CANDU)

Factors Contributing to Performance (continued)

- Pickering boilers have a different design from other plants (e.g. lower blowdown capacity than Darlington, 12 boilers per unit, mixed-alloy feedtrain for Units 1-4, Monel-400 boiler tubes compared to Alloy 800 at Darlington etc.), and WANO limiting values used in calculating CPI (6 parameters at Pickering) are three times less than Darlington.
- Best practices among top performing plants include use of dispersants to reduce corrosion product transport to boilers, condenser inspections and, cleaning to remove a source of iron and copper transport (CPT) to boilers during start-ups. These inspections and cleans are now being performed at both Pickering and Darlington to minimise CPT. Darlington has implemented morpholine addition to reduce iron transport (Pickering already employs morpholine addition). Darlington's corrosion product reduction plan also includes startup condensate filtration, boilers lay-up practices and sampling improvements.
- Fleetwide and station initiatives which have or are expected to improve performance include:
  - Boiler blowdown piping improvements and enhanced tracking of blowdowns at Pickering per the procedure,
  - Condenser cleaning during planned outages (which has resulted in improvement in Darlington CPI performance),
  - Ongoing use of local portable feedwater dissolved oxygen analyzer carts (commissioned on Pickering Units 5-8) to ensure dissolved oxygen remains in specification,
  - Ongoing oversight of water treatment plant product water quality to meet boiler makeup water specifications, and
  - Investigation of Film Forming Amine (FFA) technology to control CPT to boilers.

1-Year On-line Deficient Maintenance Backlog



Observations – On-Line Deficient Maintenance Backlog (AP-928 Working Group)

2015 (Annual Value)

- The industry Best Quartile and Median Thresholds were 116 and 160 work orders per unit respectively for On-Line Deficient Maintenance (DM) backlog.
    - Darlington DM backlogs were at 174 Work Orders per unit for 2015 which is third quartile performance.
    - Pickering DM backlogs were at 251 Work Orders per unit which is fourth quartile performance.

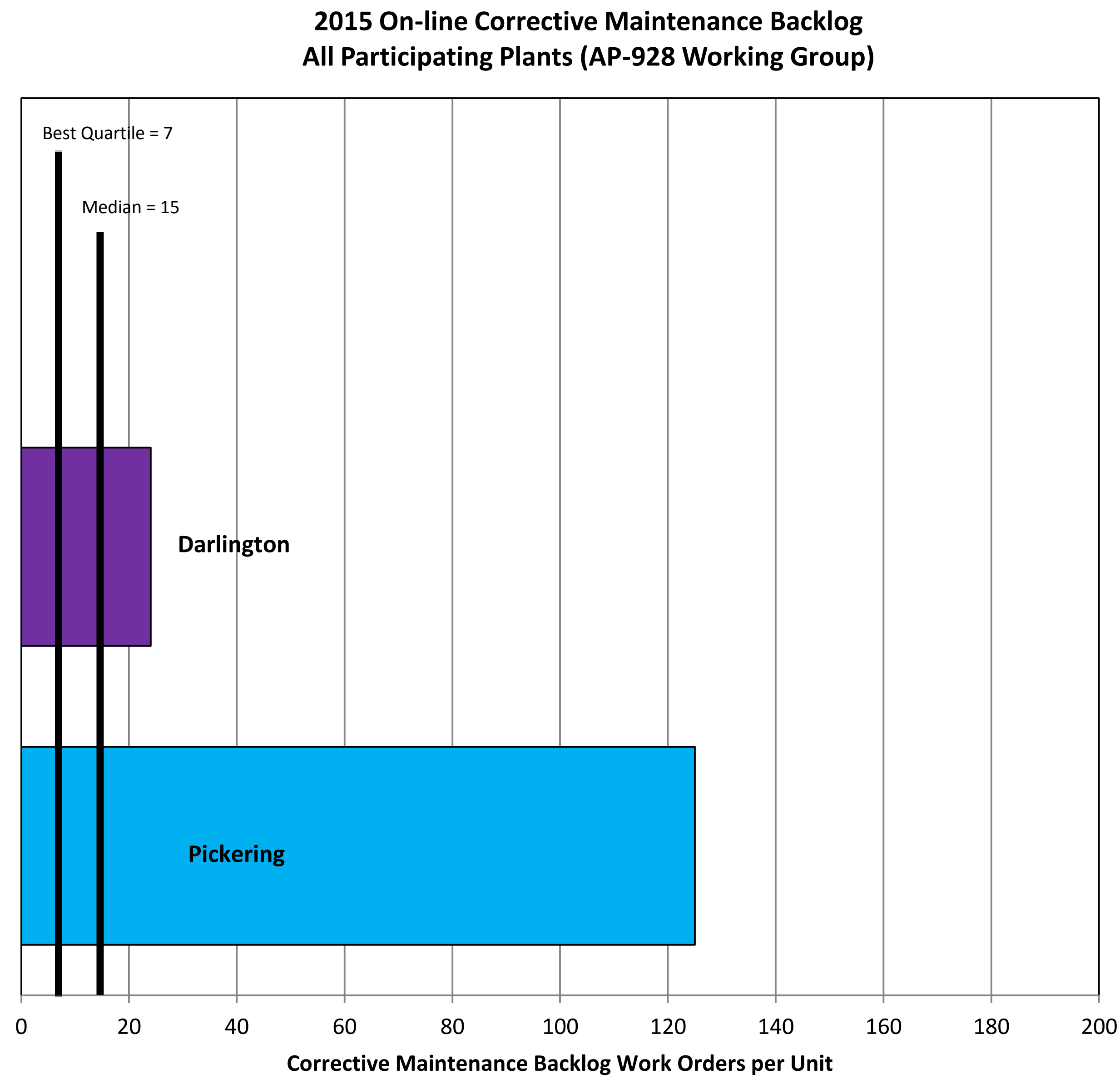
Trend

- In comparison to the 2014 data:
    - Darlington performance in 2015 has improved from 176 to 174 work orders per unit
    - Pickering performance in 2015 improved from 276 to 251 work orders per unit
- Darlington has shown backlog improvement from 2011 through 2015.
- Pickering has shown backlog improvement from 2011-2013, a decline in 2014 and improvement again in 2015.

Factors Contributing to Performance

- For Darlington and Pickering the factors that impact the deficient maintenance backlogs include the following:
    - Forced outages and outage extensions which negatively impact the backlog reduction efforts by reducing the resources available to perform the planned work.
    - Gaps in the work package preparation, scheduling and parts availability
- To improve performance there is a fleet wide initiative to improve parts availability, which involves adherence to the work management process, reduction in the amount of work removed from the schedule and improvements to the process for in-house repair of components removed from systems. Implementation is ongoing and initiative completion is targeted for 2017.
- In addition to the fleet wide initiatives, both stations have made improvements to the Fix-It-Now teams to improve work execution efficiency and better address emergent work.

1-Year On-line Corrective Maintenance Backlog



Observations – 1 Year On-line Corrective Maintenance Backlog (AP-928 Working Group)

2015 (Annual Value)

- The industry Best Quartile and Median thresholds were 7 and 15 work orders per unit respectively for On-line Corrective Maintenance (CM) backlog.
    - Darlington CM backlogs were at 24 Work Orders per unit for 2015, which is in the third quartile.
    - Pickering CM backlogs were at 125 Work Orders per unit, which is in the worst quartile.

Trend

- In comparison to the 2014 data:
    - Darlington performance in 2015 declined from 20 to 24 work orders per unit
    - Pickering performance in 2015 improved from 160 to 125 work orders per unit
- Darlington has shown backlog improvement from 2011 through 2014.
- Pickering has shown backlog improvement from 2011-2012 and declined in 2013-2014.

Factors Contributing to Performance

- Refer to the factors contributing to performance discussed above in the 1 Year On-line Deficient Maintenance Backlog.

4.0 VALUE FOR MONEY

Methodology and Sources of Data

The Electric Utility Cost Group (EUCG) database is the source for cost benchmarking data. Data was collected for three-year rolling averages for all financial metrics covering the review period from 2010-2015. Zero values for cost indicators are excluded from all calculations. All data submitted to and subsequently extracted from EUCG by OPG is presented in Canadian dollars.

EUCG automatically applies a purchasing power parity (PPP) factor to adjust all values across national borders. The primary function of the PPP value is to adjust for currency exchange rate fluctuations but it also adjusts for additional cross-border factors which may impact purchasing power of companies in different jurisdictions. As a result, cost variations between plants are limited, as much as possible, to real differences and not due to advantages of utilizing one currency over another.

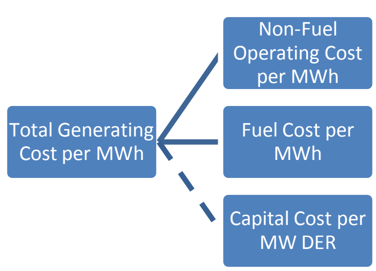
The benchmarking panel utilized for value for money metrics is made up of all North American plants reporting to EUCG. Bruce Power is the only other CANDU technology plant reporting within that panel. The remaining plants are Boiling Water Reactors or Pressurized Water Reactors. For that reason, some of the gaps in performance are associated with technology differences rather than comparable performance.

All metrics include cost information normalized by some factor (MWh or MW DER (Design Electrical Rating)) to allow for comparison across plants.

Discussion

Four value for money metrics are benchmarked in this report. They are the Total Generating Cost per MWh, Non-Fuel Operating Cost per MWh, Fuel Cost per MWh, and Capital Cost per MW DER. The relationship underlying the value for money metrics is shown in the illustration below. The Total Generating Cost per MWh is the sum of Non-Fuel Operating Cost, Fuel Cost and Capital Cost measured on a per MWh basis for benchmarking purposes. Given the differences between OPG's nuclear generating stations and most North American plants with respect to both fuel costs and the different treatments of non-fuel and capital costs, the best overall financial comparison metric for OPG facilities is the Total Generating Cost per MWh.

Diagram of Summary Relationship of Value for Money Metrics



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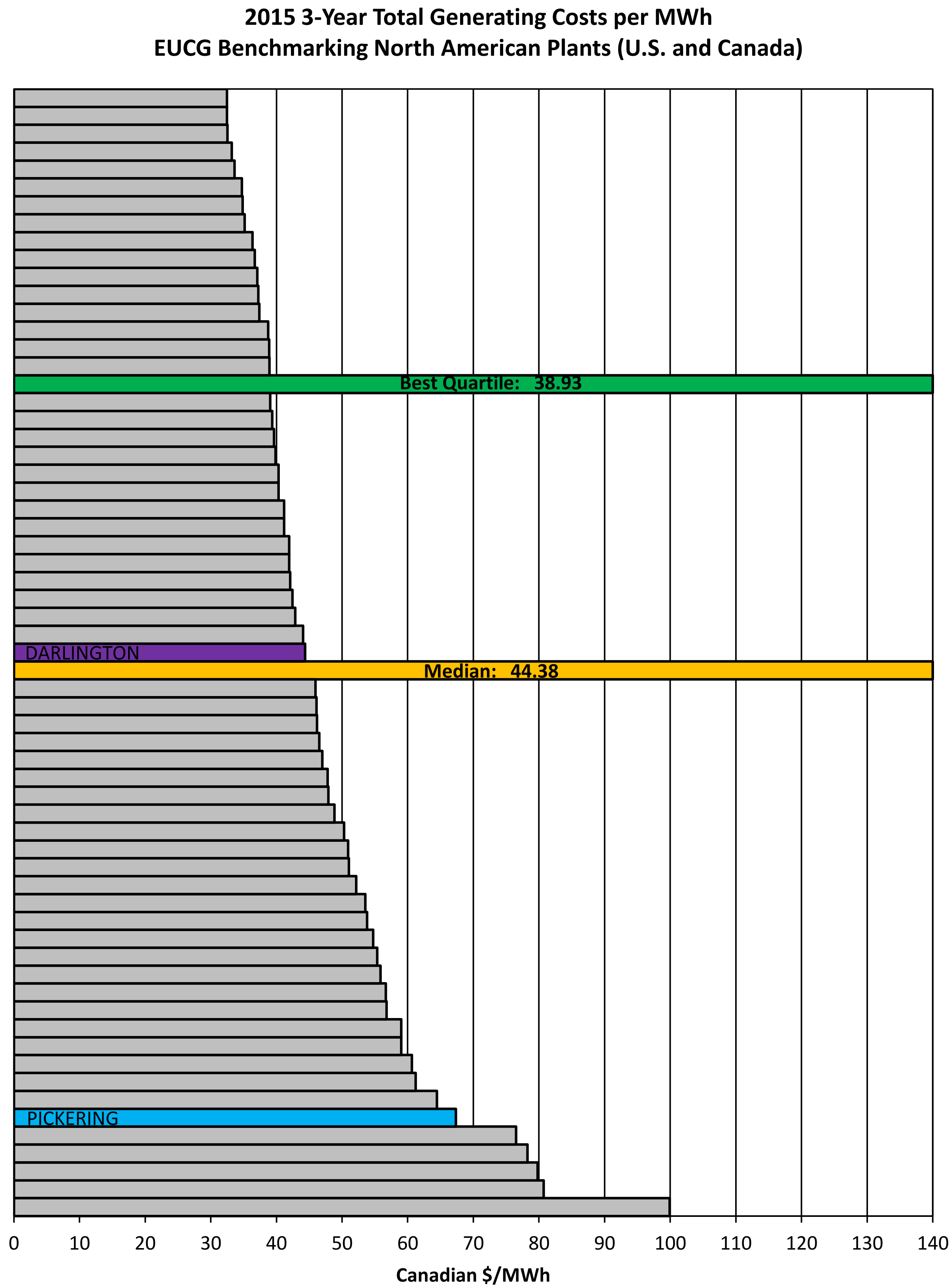
3-Year Total Generating Cost per MWh



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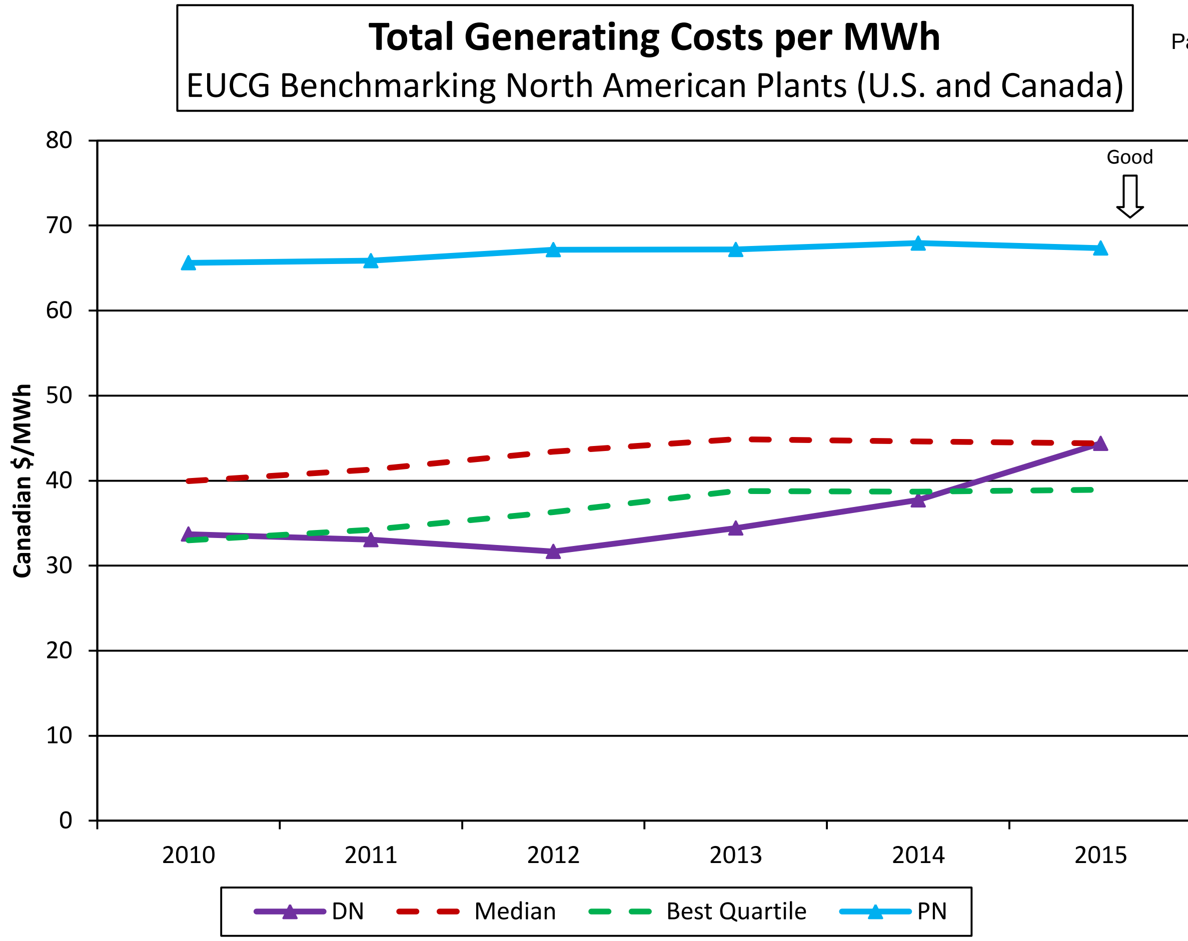

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Observations – 3-Year Total Generating Cost per MWh (All North American Plants)

2015 (3-Year Rolling Average)

- The best quartile level for Total Generating Cost per MWh (TGC/MWh) among North American EUCG participants was $38.93/MWh while the median level was $44.38/MWh.
- Darlington TGC/MWh was $44.38/MWh, equal to the median of $44.38/MWh.
- Pickering TGC/MWh was $67.36/MWh, worse than the median of $44.38/MWh.

Trend

- Over the 2010 to the 2015 period, the best quartile cost rose by $5.95/MWh while the median cost rose by $4.45/MWh.
- Darlington rose by $10.66/MWh and Pickering rose by $1.73/MWh.
- Both best quartile and median levels increased over the 2010-2015 period with a compound annual growth rate of 3.4% for best quartile and 2.1% for median.
- Darlington annual compound growth rate was 5.7%, higher than the median annual compound growth rate. Pickering was relatively flat with an annual compound growth rate of 0.5%.

Factors Contributing to Performance

- For technological reasons, Fuel Costs per MWh is an advantage for all CANDUs and the OPG plants performed within the best quartile.
- Non-Fuel Operating Cost per MWh, for all OPG plants, yielded results that are worse than the median for the most recent data point compared to the North American EUCG panel.
- OPG Capital Costs are below industry levels. Capital expenditures reported by the peer group include costs for life extension, reactor head replacement, steam generator replacement, uprates, and spent fuel storage. These are costs not incurred by OPG to the extent as its peers.

Darlington

- The 3-Year Rolling Average for Darlington from 2014 to 2015 rose $6.65/MWh. The primary drivers at Darlington were lower generation (4,998 GWh) and higher total costs of approximately $319M. The higher total costs were primarily attributable to higher Operating, Maintenance & Administrative (OM&A) costs of $212M and Capital costs of $129M, partially slightly offset by lower Fuel Costs of $22M .
- Lower generation at Darlington was primarily due to higher planned outage days and increased forced outages. Outage days at Darlington increased by 234 days for 2015 period versus 2014 mainly due to the Darlington Vacuum Building Outage in 2015.

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Observations – 3-Year Total Generating Cost per MWh (All North American Plants) (CON'T)

- OM&A costs increased mainly due to the Darlington Vacuum Building Outage in 2015 with increased outage costs (51%) along with smaller increases in project costs (20%), nuclear support (18%) and allocated corporate costs (10%), partially offset by smaller reductions in plant base costs. Labour, material and purchased services differential was mainly due to the increased planned outage days, and were accompanied by smaller increases in OM&A labour including payroll burden, overtime and other costs. The increased overtime, labour escalation and increased use of temporary staff were partially offset by reduced head count. The OM&A Project differential in 2015 over 2014 period includes project cancellation and asset removal costs.
- Capital costs have almost tripled at Darlington from 2012 – 2015 with Capital Portfolio and Minor Fixed Assets rising due to aging plant equipment, refurbishment support and regulatory requirements for extended life at Darlington. Labour capital has increased due to increased regular, overtime and temporary staff consistent with increased capital program at Darlington.
- Fuel spending is lower due to decreased energy production.
- Darlington performed within the best quartile for Fuel Cost per MWh and Capital Cost per MW DER while performing at the fourth quartile for the Non-Fuel Operating Cost per MWh.
- For Non-Fuel Operating Cost, CANDU technology is a large performance gap driver for Darlington during the review period. The larger equipment inventory in a CANDU unit compared to the pressurized water reactor's and boiling water reactor's units represents a net increase in maintenance and operations workload which requires additional staff.

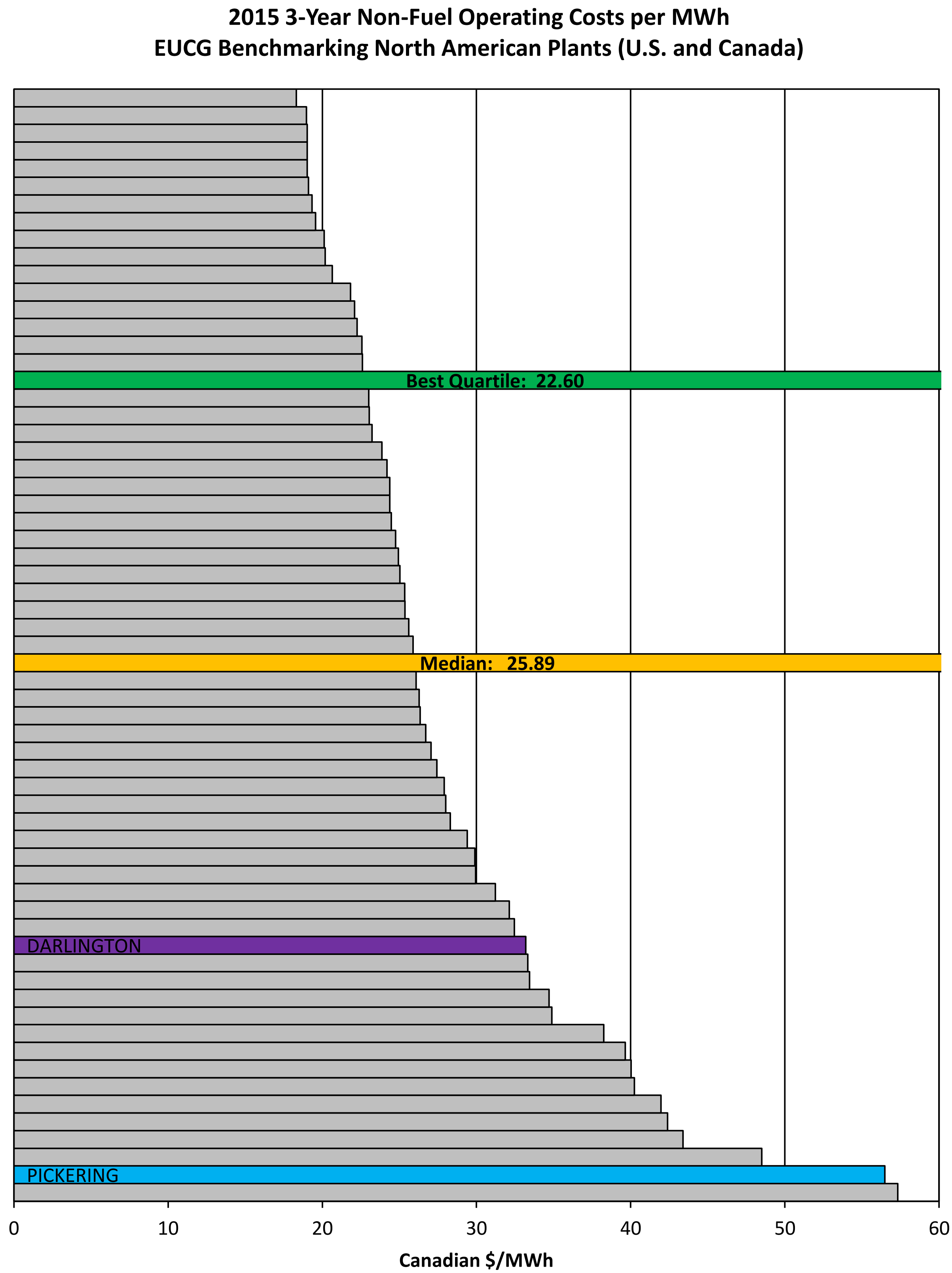
Pickering

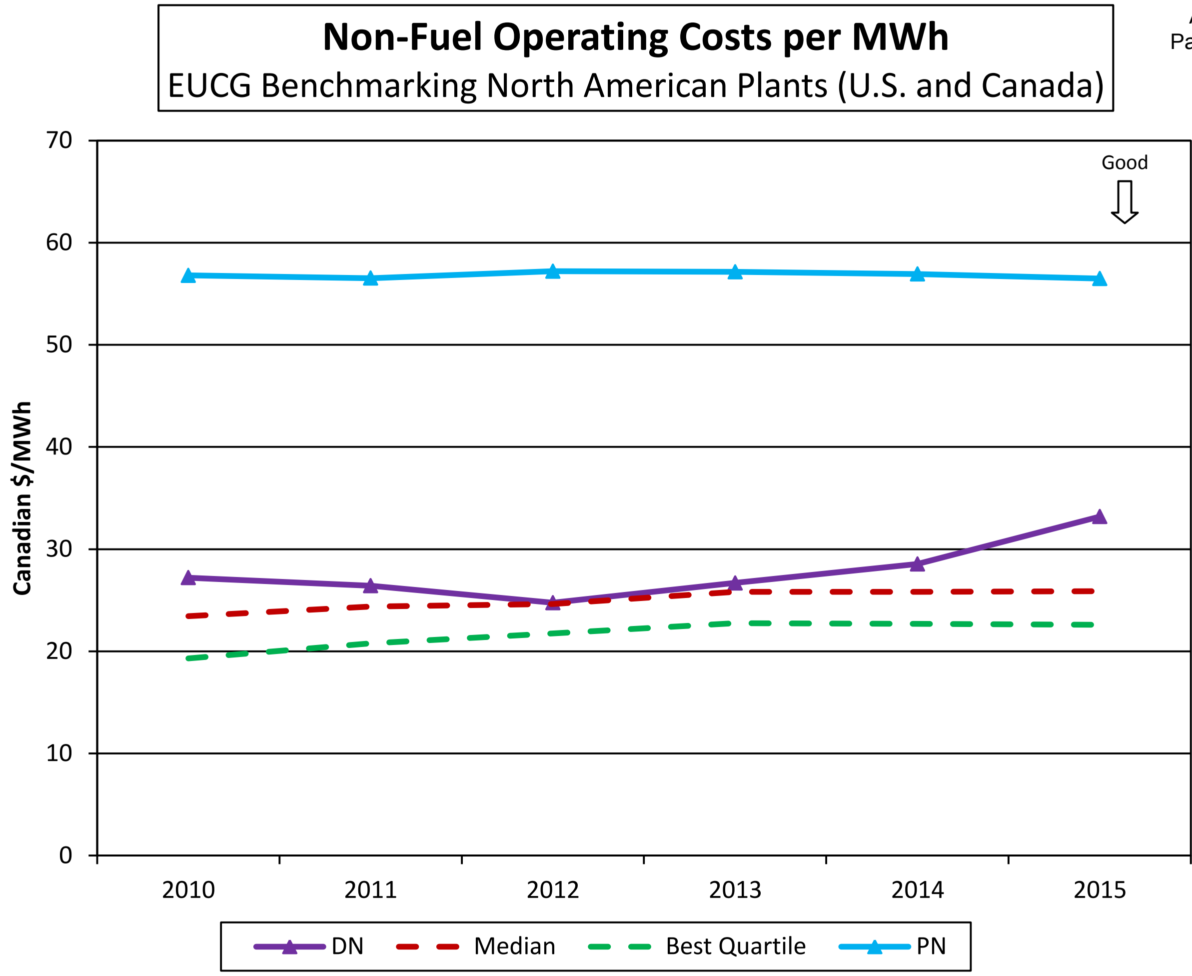
- The 3-Year Rolling Average for Pickering from 2014 to 2015 decreased by $0.57/MWh. The primary drivers at Pickering are higher generation (485 GWh) and lower total costs $2.1M. The lower total costs were primarily attributable to lower capital costs of $3.3M, partially offset by higher OM&A costs of $0.3M and Fuel Costs of $0.9M.
- Outage days for Pickering decreased by 48 days for 2015 versus 2014 leading to lower outage costs. Higher electricity production levels were also due to the successful implementation of equipment reliability program improvement initiatives and strategic investments to resolve degraded or obsolete equipment issues which helped reduce Pickering's forced loss rate.
- OM&A Costs have decreased slightly mainly due to decreases in project costs, outage costs (purchased service and overtime) and allocated corporate costs, partially offset by increased nuclear support costs and base costs.

Observations – 3-Year Total Generating Cost per MWh (All North American Plants) (CON'T)

- Capital spending at Pickering has decreased slightly from the 2012-2014 period to the 2013-2015 period since OPG is reducing capital spending in advance of End of Life (EOL) at Pickering. Same comment as DN above.
- Fuel spending is higher due to increased energy production.
- Pickering performed within the best quartile for Fuel Cost per MWh and Capital Cost per MW DER while performing worse than the median for Non-Fuel Operating Cost per MWh.

3-Year Non-Fuel Operating Cost per MWh




Non-Fuel Operating Costs per MWh
EUCG Benchmarking North American Plants (U.S. and Canada)
Good
Canadian $/MWh
70
60
50
40
30
20
10
0
2010
2011
2012
2013
2014
2015
DN
Median
Best Quartile
PN

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Observations – 3-Year Non-Fuel Operating Cost per MWh (All North American Plants)

2015 (3-Year Rolling Average)

- Best quartile plants had Non-Fuel Operating Costs per MWh (NFOC/MWh) at or below $22.60.
- The median plant level threshold was $25.89/MWh.
- Compared to North American EUCG plants, the Non-Fuel Operating Costs per MWh of all participating Canadian CANDU plants are worse than industry median performance.
- Darlington's costs, at $33.19/MWh, were $10.59/MWh higher than best quartile and $7.30/MWh higher than the median.
- Pickering's costs, at $56.49/MWh, were $33.89/MWh higher than best quartile and $30.60/MWh higher than median.

Trend

- Both best quartile and median levels increased over the 2010-2015 period with a compound annual growth rate of approximately 3.2% for the best quartile and approximately 2.0% for the median.
- Darlington annual compound growth rate was 4.1% and Pickering's effectively did not change.
- Pickering 3-yr NFOC/MWh increased from 2010 ($56.79/MWh) to 2012 ($57.21/MWh) then decreased by 2015 ($56.49/MWh). Please see 2015 TGC per MWh discussion regarding total Pickering costs and production. Higher electricity production levels are largely due to the successful implementation of equipment reliability program improvement initiatives and strategic investments to resolve degraded or obsolete equipment issues which helped reduce Pickering's forced loss rate.
- Pickering's 3-yr NFOC/MWh had a slight reduction from 2010 to 2015 as compared to the annual compound growth rates of 3.2% for best quartile and 2.0% for median levels due to slightly lower costs and higher production.
- Pickering's annual Non-Fuel Operating Cost, over the 2010-2015 review period, is being managed through the continuous pursuit of efficiency improvements enabled by initiatives such as the amalgamation of the Pickering A and Pickering B stations into one Pickering site. The company-wide business transformation project launched in 2011 is also helping streamline, eliminate and reduce work to leverage attrition profiles while sustaining safety and reliability performance excellence.
- Over the 2010-2015 review period, Darlington's Non-Fuel Operating Cost increased from 2010 ($27.22/MWh) to 2015 ($33.19/MWh). Please see 2015 TGC per MWh discussion regarding total Darlington costs and production.
- Darlington's 3-yr NFOC/MWh had an annual compound growth rate of 4.1% from 2010 to 2015 as compared to 3.2% for best quartile and 2.0% for median levels. The 2015 increase in Darlington's 3-yr NFOC/MWh from 2014 is due to primarily to lower generation from the Darlington VBO and higher FLR, and higher OM&A spending.

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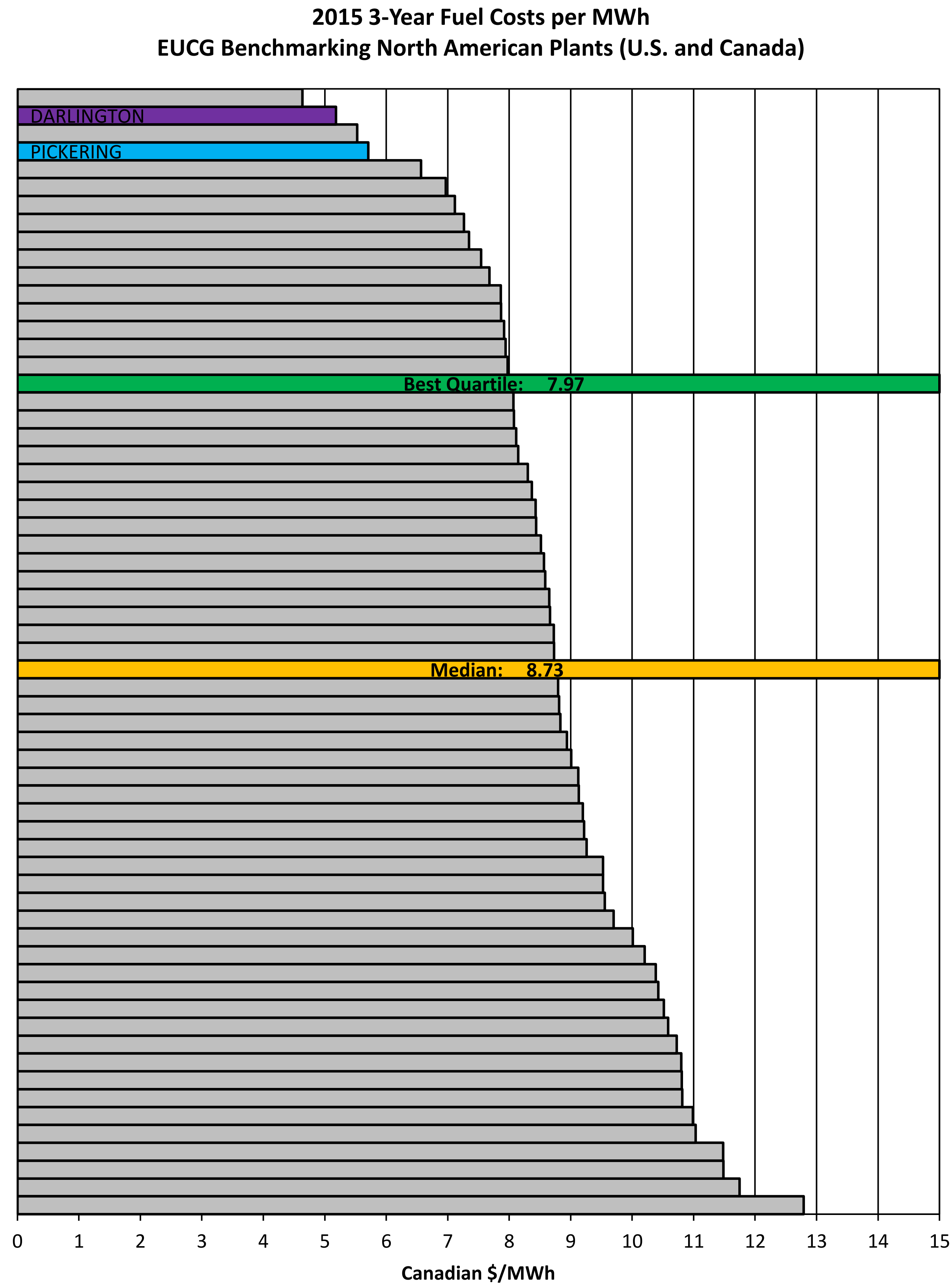
Factors Contributing to Performance – 3-Year Non-Fuel Operating Cost per MWh (CONT'D)

Factors Contributing to Performance

- Performance in Non-Fuel Operating Cost per MWh drives the majority of OPG's financial performance. The most significant performance gap drivers are CANDU technology, capability factor, station size, age of the plant, corporate cost allocations and capitalization policy. The biggest drivers are further expanded below:
  - The 'capability factor' driver is related specifically to generation performance of the station in relation to the overall potential for the station (results are discussed under the Reliability section within the Rolling Average Unit Capability Factor metric).
  - The 'station size' driver is the combined effect of number of units and size of units which can have a significant impact on plant cost performance.
  - The 'CANDU technology' driver relates specifically to the concept that CANDU technology results in some specific cost disadvantages related to the overall engineering, maintenance, and inspection costs. While OPG's ten nuclear units are all CANDU reactors, they reflect three generations of design philosophy and technology which impacts the extent and nature of operations and maintenance activity. In addition, this factor is influenced by the fact that CANDU plants have less well-developed user groups to share and adopt competitive advantage information, than do longer-established user groups for Pressurized Water Reactors (PWR) and Boiling Water Reactors (BWR). Though quantification of CANDU technology impact to cost remains most difficult of all drivers, a staff benchmarking analysis recognized a significant reduction in the gap between OPG staff levels and the industry benchmark. OPG undertook a staffing study through a third-party consultant which concluded that technology, design and regulatory differences exist between CANDU and PWR reactor units and that such factors drive staffing differences. The study established that CANDU technology was a contributor to explaining higher staffing levels for CANDU versus PWR plants which also contributed to OPG's performance in Non-Fuel Operating Cost.
  - The 'corporate cost allocations' driver relates directly to the allocated corporate support costs charged to the nuclear group.
  - Capitalization policy can be an indirect contributing factor when benchmarking Non-Fuel Operating Cost due to variations in "repair vs. replace strategies.", i.e. a strategy to repair versus replace will increase non fuel operating cost versus option to replace. The impact of differing capitalization policies is removed when looking at Total Generating Cost per MWh (i.e., the sum of Non-Fuel Operating Cost, Fuel Cost, and Capital Cost).

3-Year Fuel Cost per MWh



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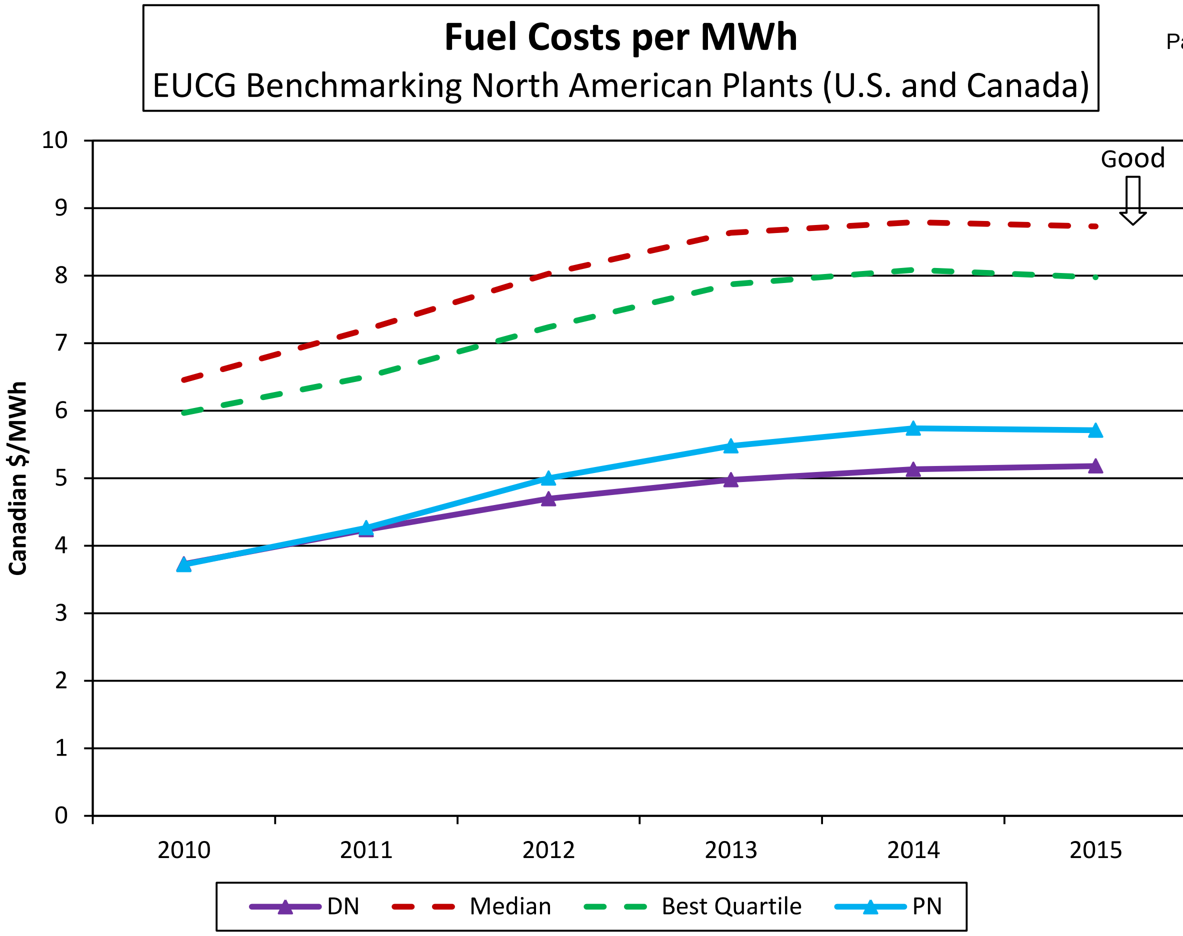

Observations – 3-Year Fuel Cost per MWh (All North American Plants)

2015 (3-Year Rolling Average)

- Fuel Cost per MWh for all Canadian CANDU plants are better than the best quartile threshold ($7.97/MWh) for the panel of North American EUCG plants.
- The two OPG plants ranked as the top four lowest fuel cost plants in the North American panel with Darlington ($5.18/MWh) at second and Pickering ($5.71/MWh) at fourth.

Trend

- The best quartile 3-year Fuel Cost per MWh has remained flat over 2014 and 2015.
- From 2010 to 2012, Fuel Cost per MWh for all OPG plants had been rising and has since stabilized over the last three years, a trend similarly experienced by the nuclear industry. The rate of increase in the Fuel Cost per MWh has moderated since 2012, due primarily to lower input uranium costs offset by rising used fuel storage and disposal costs, which have increased well above the rate of inflation from 2014 to 2015.
- The Darlington Generating Station would rank the lowest among the CANDU plants in the peer panel ranked group if used fuel storage and disposal provision costs were excluded from the calculation with a 3-year rolling average fuel cost per MWh of $4.20/MWh. Similarly, Pickering would rank second with an average 3-year rolling average fuel cost per MWh of $4.25/MWh.

Factors Contributing to Performance

- Fuel costs, primarily driven by the technological differences in CANDU technology, are lower for OPG than all North American Pressurized Water Reactors or Boiling Water Reactors (PWR/BWR) reactors as CANDUs do not require enriched uranium like BWRs and PWRs. This provides a significant advantage for OPG and other CANDUs in this cost category.

Best quartile fuel cost performance noted above is due to the following factors:

- Uranium fuel costs: Raw uranium is processed directly into uranium dioxide to make fuel pellets, without the cost and process complexity of enriching the fuel as required in light water reactors. Fuel costs also include transportation, handling and shipping costs.
- Reactor core efficiency: CANDU is the most efficient of all reactors in using uranium, requiring about 15% less uranium than PWRs for each megawatt hour of electricity.

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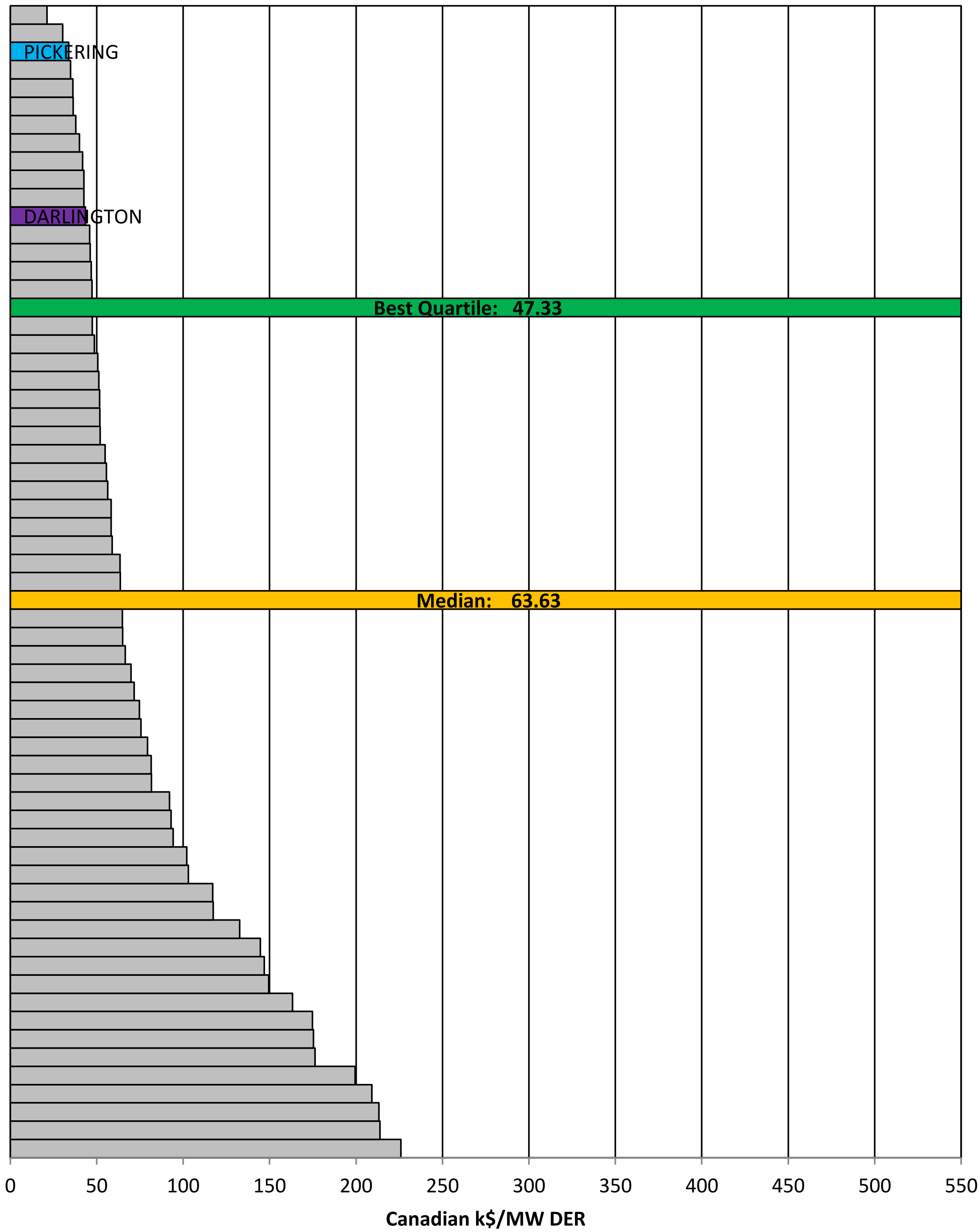
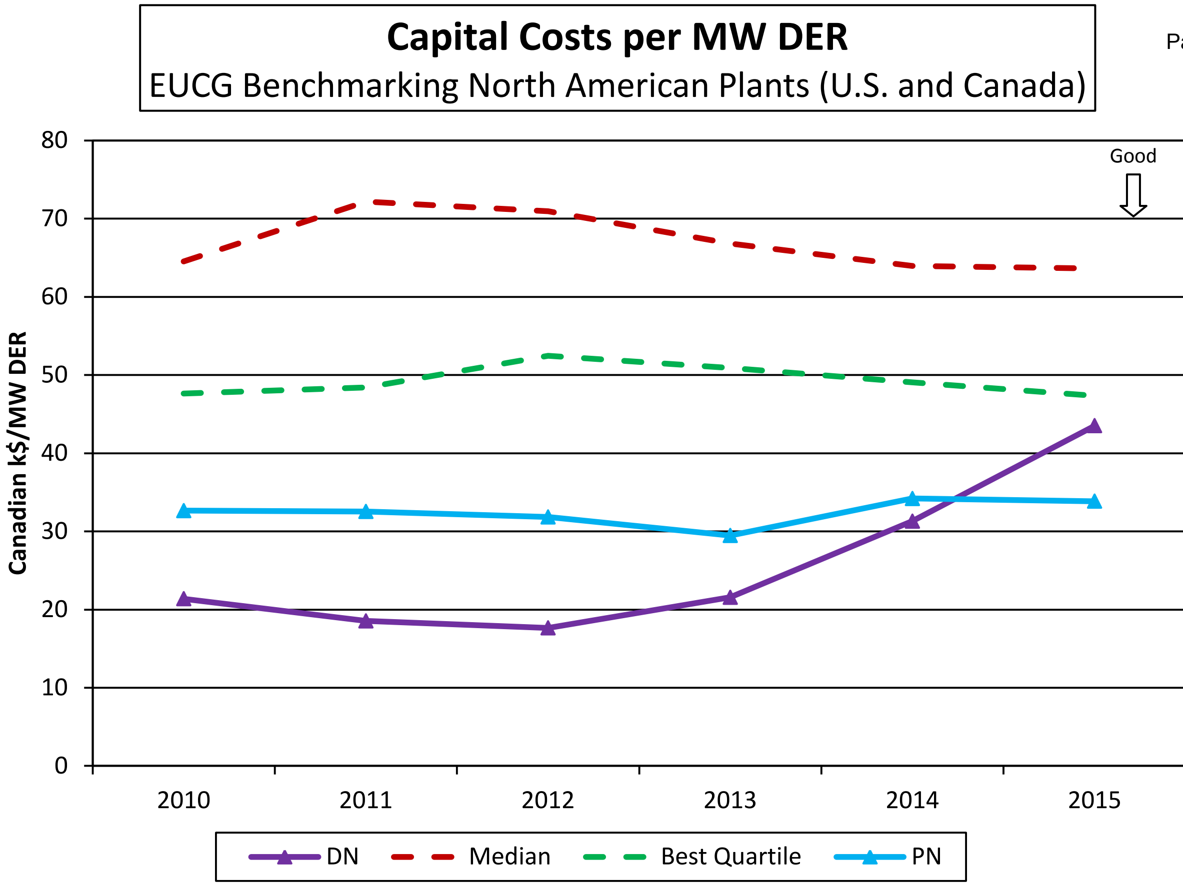
3-Year Capital Cost per MW DER (Design Electrical Rating)

2015 3-Year Capital Costs per MW DER
EUCG Benchmarking North American Plants (U.S. and Canada)




Capital Costs per MW DER
EUCG Benchmarking North American Plants (U.S. and Canada)
Good
80
70
60
50
40
30
20
10
0
Canadian k$/MW DER
2010
2011
2012
2013
2014
2015
DN
Median
Best Quartile
PN

Observations – 3-Year Capital Cost per MW DER (All North American Plants)

2015 (3-Year Rolling Average)

- The best quartile threshold for Capital Cost per MW DER across the North American EUCG peer panel plants was k$47.33/MW DER.
- Median cost for the panel was k$63.63/MW DER.
- Both Pickering and Darlington had lower capital cost/MW DER than the best quartile threshold.

Trend

- The best quartile threshold declined to approximately the same as the 2010 rolling average. This is due to continuing reductions in life extension, uprates and steam generator replacement spending. These reductions are offset by increased Fukushima response and sustaining capital investment.
- Also driving the quartile thresholds down are reduced capital spending at plants slated for permanent shutdown in the coming years or are at risk of permanent shutdown due to economic factors. These units are reducing their Capital spending as they approach their planned or anticipated shutdown dates.
- Darlington's Capital Cost per MW DER increased in 2015 due to increased spending on to support post-refurbishment operations, reliability improvements, non-power block infrastructure, sustaining and Fukushima response.
- Pickering's Capital Cost per MW DER declined slightly in 2015 due to a reduction in reliability improvements and other regulatory costs. These were offset by increased sustaining and performance improvement spending as well as higher Fukushima response costs.

Factors Contributing to Performance

- Both Darlington and Pickering are performing in the best quartile overall for the period.
- This performance is due to best and median quartile spending performance on information technology, enhancements, regulatory and sustaining investments.
- Fukushima costs at Darlington and Pickering are significantly lower than their American peers, contributing to the second quartile ranking for regulatory spending. Only units slated for permanent shutdown in the US have incurred similar expenditures. The difference in approach to Fukushima response between the Canadian and American utilities has resulted in lower costs.
- The favourable ranking in enhancements spending is due primarily to costs incurred by the peer group (Reactor vessel head replacements, steam generator replacements and Uprates) that would not be incurred by OPG due to technological differences.
- Spending on sustaining investments at Darlington is in the second quartile despite having increased period over period to support operations following the refurbishment commencing 2016. Pickering sustaining investments declined as projects to support operations to 2020 approaches completion.

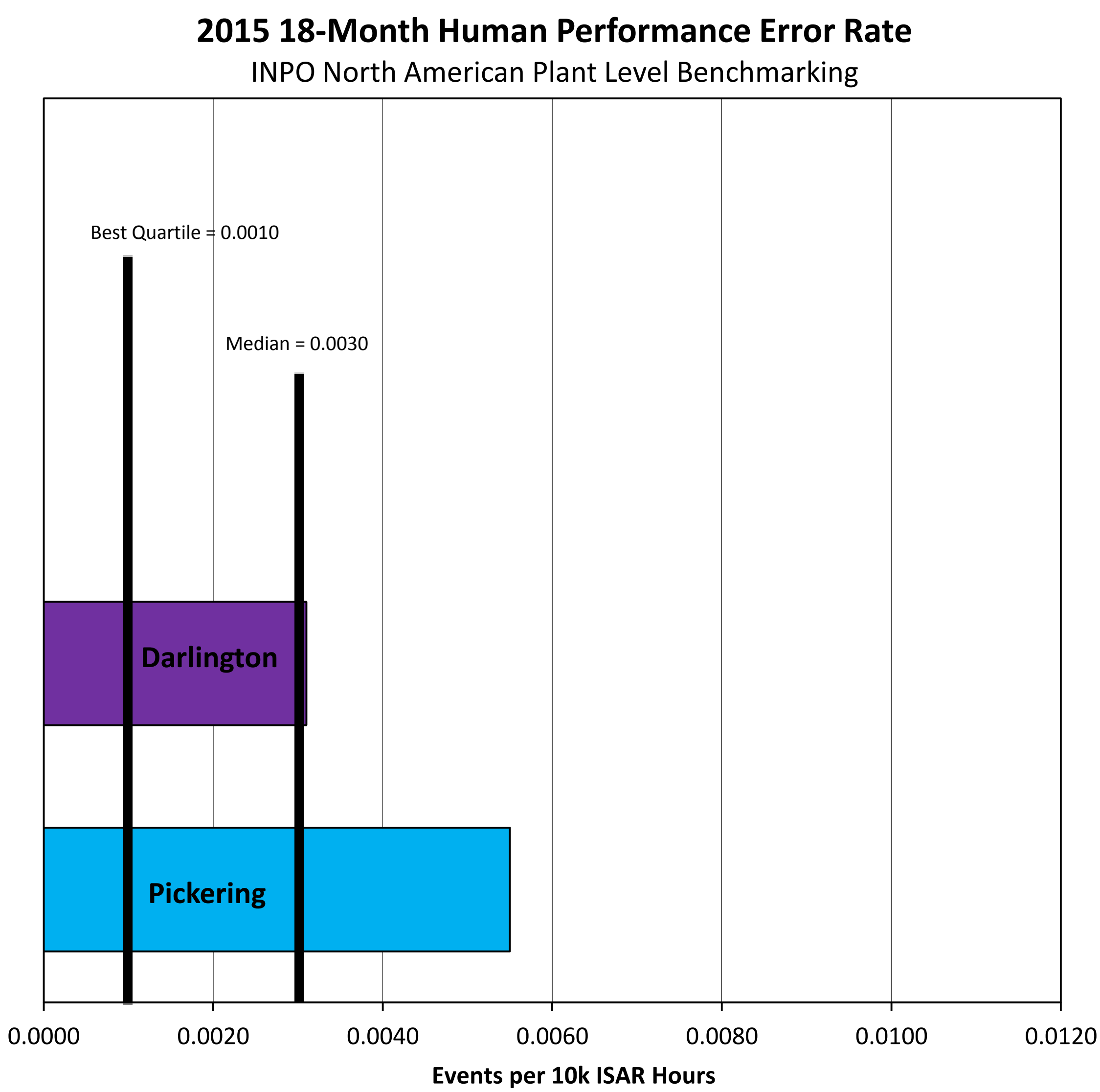
- The performance in these areas is offset by third and fourth quartile spending in non-power block infrastructure and capital spares.
- Non-power block infrastructure spending at Darlington to support post-refurbishment operations continues to be higher than the majority of its peers.
- Investment in capital spares at both Darlington and Pickering has increased to support overhauls of aging equipment and support safe and reliable operations.

5.0 HUMAN PERFORMANCE

Methodology and Sources of Data

The Human Performance Error Rate metric has been selected to benchmark the performance of OPG's Nuclear fleet against other INPO utilities in the area of Human Performance. This will ensure a continued focus on improving Human Performance by comparing OPG Nuclear stations to industry quartiles through the use of consistent and comparable data.

18-Month Human Performance Error Rate



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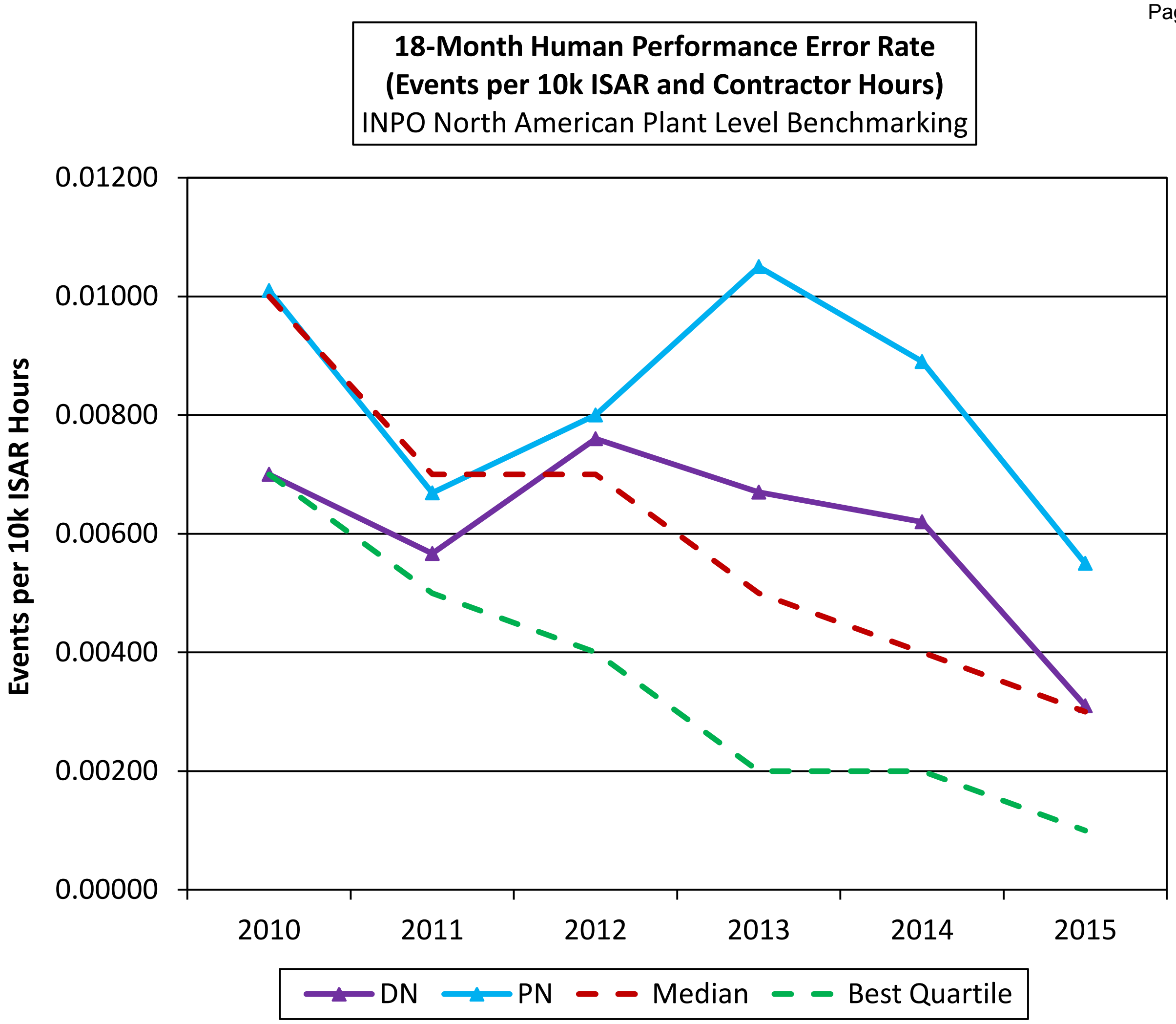


Observations – 18 Month Human Performance Error Rate (INPO North American Plants)

2015 (18 Month Rolling Average)

- The 2015 18-month Human Performance Error Rate (HPER) continues to indicate improved year over year performance. The 2015 INPO best quartile was 0.0010 and the median quartile 0.0030 both of which were improved from 2014 HPER when the INPO best quartile was 0.0020, and the median quartile was 0.0040.
- Compared to the INPO peer group, at the end of 2015 the Darlington station (HPER 0.0031) remained in the third quartile (from .0062 in 2014) and the Pickering station (HPER 0.0055) moved to the third quartile (from 0.0089 in 2014).

Trend

- Darlington and Pickering have shown improved performance with Pickering station HPER moving up to the next quartile performance, while Darlington just missing the median ranking.
- Industry performance continues to improve year-over-year with respect to both top quartile and median quartile results with the exception of 2014, where the top quartile benchmark remained unchanged from 2013 (HPER 0.002) while the median quartile improved in 2014 to 0.0040 from 0.0050 in 2013.
- While high level indicators show improved performance, evaluations and event investigations show that there are areas for improvement including: setting, communicating or reinforcing of standards and expectations through effective coaching in the field; providing sufficient positive reinforcement to ensure that good behaviours are reinforced and performance shortfalls addressed.

Factors Contributing to Performance

- Characteristic of organizations that achieve top quartile performance in this benchmark area:
  - Field workers who understand and are focused on the task and ingrain good human performance behaviours in their work habits.
  - Supervisor/managers who positively shape field worker behaviours by providing effective coaching; and identify and address challenges to proficiency or unexpected conditions.
  - Standardized Department Event Day Reset criteria aligned to the industry and used as a performance indicator to identify moderate consequential events and enable performance comparisons and benchmarking opportunities.
  - Leveraging lower tier reporting as an opportunity to rectify underlying causal factors that may contribute to a potential ‘high consequence’ loss-of-control event.
  - Leaders who provide candid and timely feedback, reinforce positive behaviors, correct shortfalls, nurture ownership and create a culture of healthy accountability to improve performance and expectations.

- In 2015, human performance at OPG Nuclear continued to receive significant focus. The Human Performance peer team worked to align the stations around common initiatives to drive improved performance. A fleet strategic plan was approved. The focus of the strategy is to improve coaching culture, establish consistent reinforcement of procedures and standards, and introduce a culture in which front-line workers and others are not penalized for actions, omissions or decisions taken by them which are commensurate with their experience and training, but where gross negligence, willful violations and destructive acts are not tolerated.
- As stated above, the stations have demonstrated improvement in 2015. Ongoing monitoring of performance will provide evidence that performance continues to improve and will serve as a feedback mechanism to allow for adjustment of initiatives as appropriate.

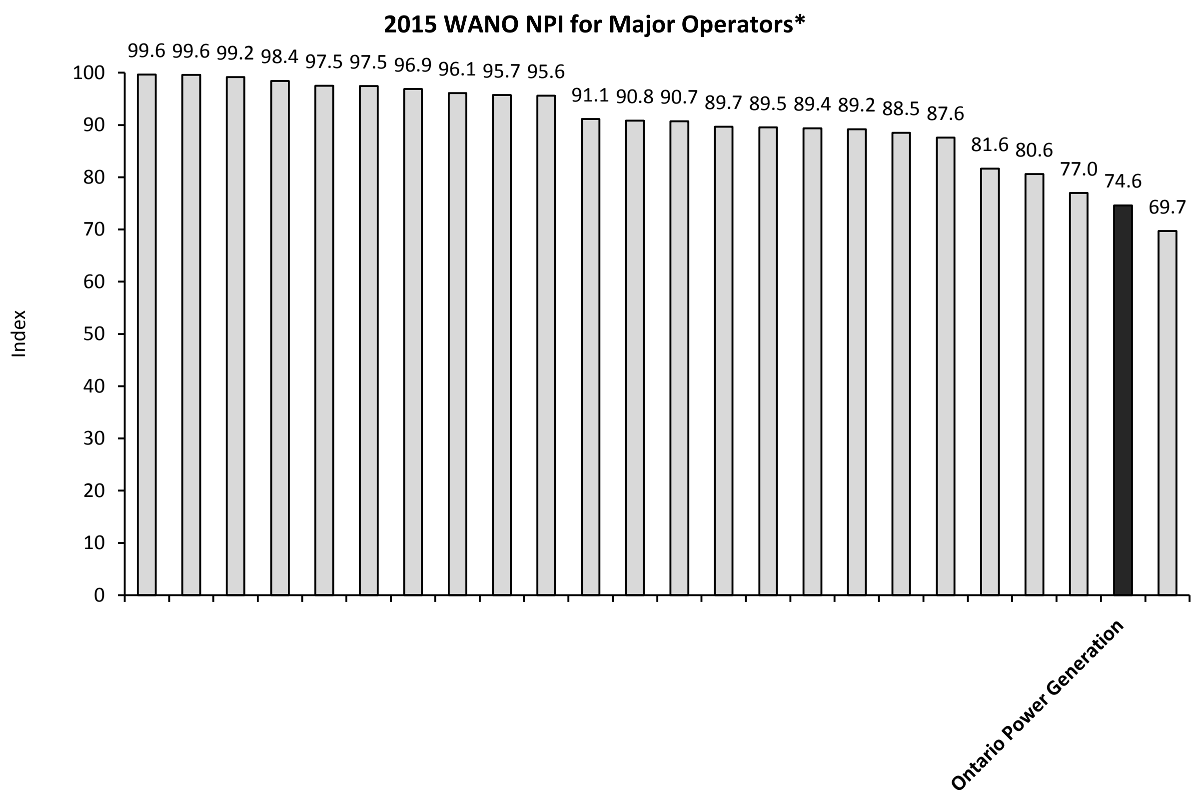
6.0 MAJOR OPERATOR SUMMARY

Purpose

This section supplements the Executive Summary, providing more detailed comparison of the major operators of nuclear plants for three key metrics: WANO Nuclear Performance Index (NPI), Unit Capability Factor (UCF), and Total Generating Cost (TGC) per MWh. Although the benchmarking study has been primarily focused on operational performance comparison to COG CANDUs, this section of the report contemplates the larger industry by capturing OPG Nuclear's performance against North American PWR and PHWR operators in addition to the international CANDU panel. Operator level summary results are the average (mean) of the results across all plants managed by the given operator. These comparisons provide additional context, but the detailed data in the previous sections provide a more complete picture of plant by plant performance. The WANO NPI and UCF are calculated as the mean of all unit performance for a specific operator. The TGC per MWh is the mean of plant level data because costs are not allocated to specific units within the EUCG industry panel.

WANO Nuclear Performance Index Analysis

The WANO Nuclear Performance Index (NPI) results for the operators in 2015 are illustrated in the graph below. OPG Nuclear performance ranking fell from 2014 shown in Table 3.



*See Table 7 in the Appendix for listing of operators and plants.

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**OPG Nuclear unit values averaging to a WANO NPI of 74.6 in 2015 are shown below:

Unit	2015 WANO NPI
Pickering 1	57.9
Pickering 4	70.6
Pickering 5	73.4
Pickering 6	68.9
Pickering 7	75.0
Pickering 8	65.4
Darlington 1	82.3
Darlington 2	83.2
Darlington 3	87.5
Darlington 4	81.9

In 2015, OPG ranked 23rd, with an NPI of 74.6. OPG's NPI performance slightly decreased by 0.85 and dropped by one compared to the 2014 ranking. Darlington performed better overall than Pickering. In 2015, Darlington's NPI performance was unfavourably impacted by the 2015 Vacuum Building station containment outage and higher FLR. Refer to Section 3.0 for further information.

The NPI rankings of the major operators from 2010 to 2015 are listed in Table 3. The list and ranking of operators has been updated to reflect any industry developments if applicable.

Table 3: Average WANO NPI Rankings

Operator	2010	2011	2012	2013	2014	2015
	10	5	2	12	16	1
	6	6	18	8	9	2
	1	4	17	16	8	3
	13	19	10	13	2	4
	9	20	22	10	5	5
	3	8	6	5	4	6
	24	27	24	23	19	7
	2	1	5	6	10	8
	14	10	3	1	13	9
	7	7	7	4	7	10
	15	11	15	19	11	11
	17	16	13	17	15	12
	16	3	4	2	14	13
	4	13	19	14	1	14
	20	21	23	24	3	15
	18	14	12	9	12	16
	22	9	8	7	6	17
	8	17	9	20	23	18
	11	18	21	3	17	19
	12	2	1	18	20	20
	19	15	11	15	18	21
	21	23	20	21	21	22
Ontario Power Generation	23	24	25	22	22	23
	28	NA*	27	25	24	24
	25	22	16	11	NA	NA
	5	12	14	NA	NA	NA
	27	25	26	NA	NA	NA
	26	26	26	NA	NA	NA

*NA: Not applicable due to multi-year refurbishment of the generating Station.

Note: Four operators are no longer ranked in 2015 (reason for 28 ranked operators in 2010 vs. 24 in 2015). These operators were removed as a result of plant acquisitions or closures. All 2010-2014 rankings and numbers are carried over from previous Benchmarking reports.

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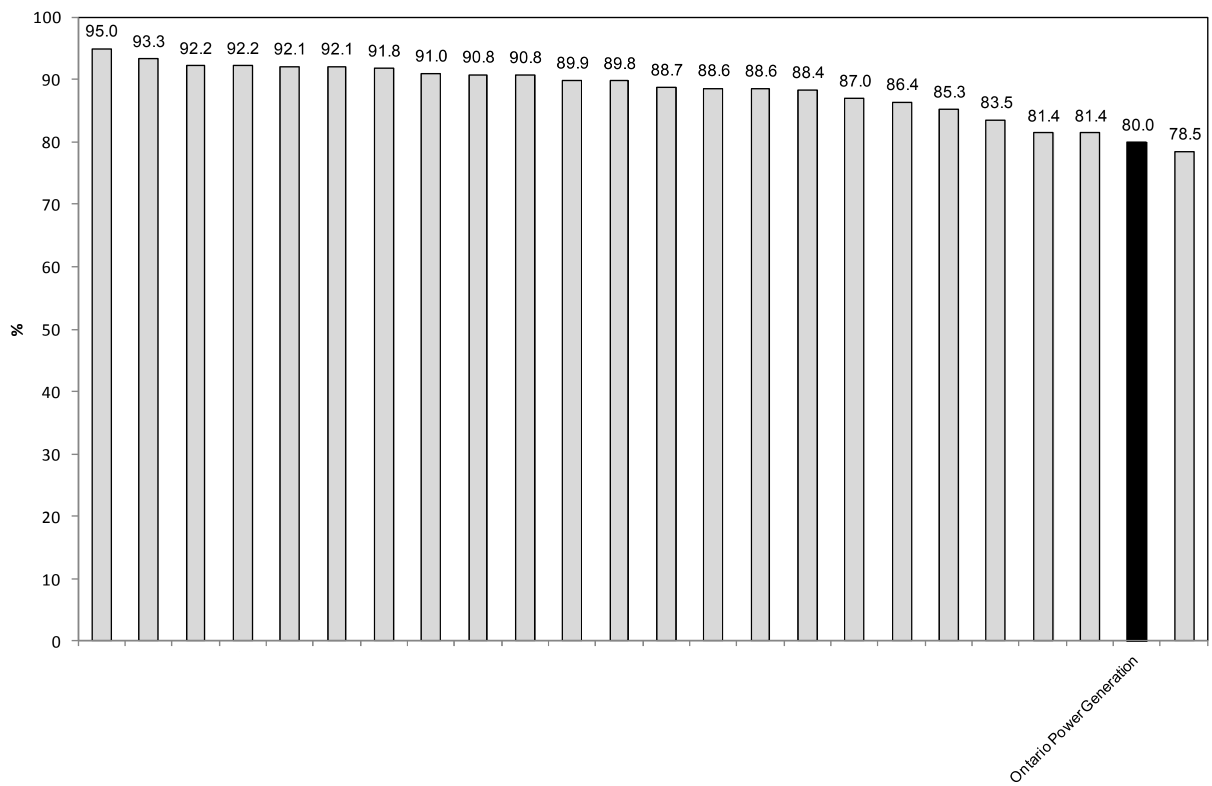
Unit Capability Factor Analysis

Unit Capability Factor (UCF) is the ratio of available energy generation over a given time period to the reference energy generation of the same time period, expressed as a percentage. Reference energy generation is the energy that could be produced if the unit were operating continuously at full power under normal conditions. Since nuclear generation plants are large fixed assets, the extent to which these assets generate reliable power is the key to both their operating and financial performance.

A comparison of UCF values for major nuclear operators is presented in the graph below. UCF is expressed as a two-year average for all operators except for OPG Nuclear, which includes a three-year average for the Darlington station and a two-year average for Pickering to reflect each plant's respective outage cycle. OPG Nuclear achieved a rolling average UCF of 80.0% and ranked 23 out of 24 operators in the WANO data set. The list and ranking of operators has been updated to reflect any industry developments if applicable.

2015 Rolling Average Unit Capability Factor Ranking for Major Operators*



* See Table 7 in the Appendix for listing of operators and plants.

**OPG unit values averaging to a rolling average UCF of 80.0% in 2015 are shown below:

Unit	2015 Rolling Average UCF
Pickering 1	72.8
Pickering 4	79.4
Pickering 5	80.9
Pickering 6	78.3
Pickering 7	77.8
Pickering 8	74.7

Unit	2015 Rolling Average UCF
Darlington 1	82.5
Darlington 2	82.9
Darlington 3	87.0
Darlington 4	83.4

Rankings for the major operators for UCF over the past six years are provided in Table 4 below.

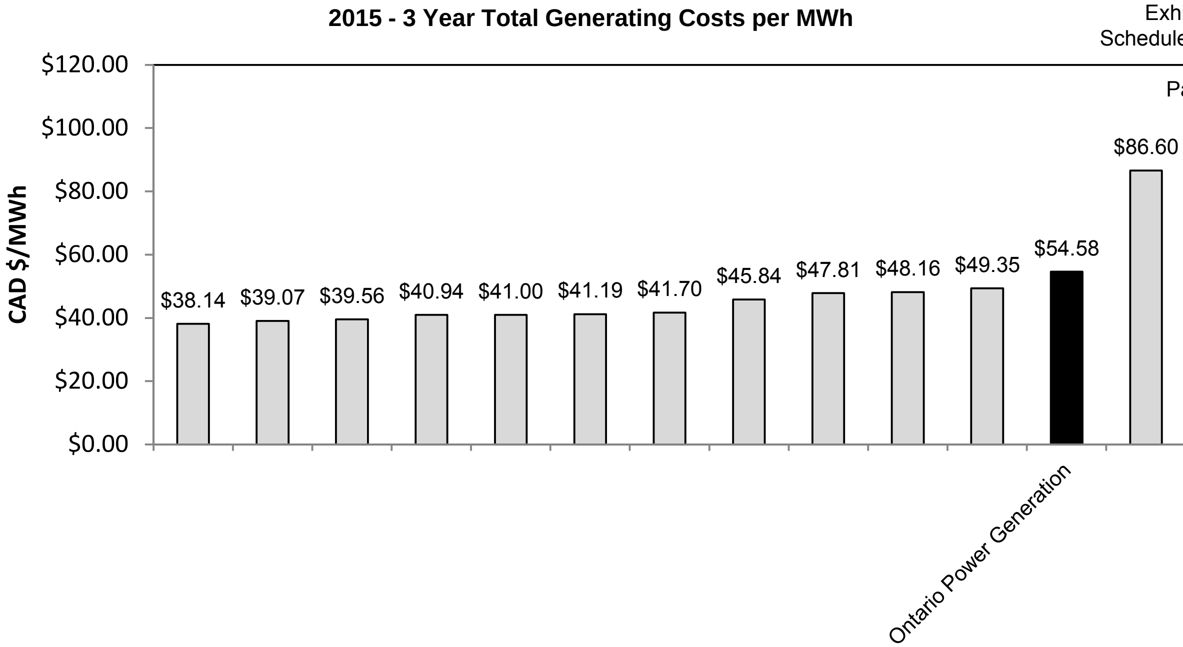
Table 4: Rolling Average Unit Capability Factor Rankings

Operator	2010	2011	2012	2013	2014	2015
	4	2	4	4	1	1
	17	14	12	10	7	2
	22	22	9	14	17	3
	14	19	2	13	19	4
	6	7	1	2	6	5
	5	9	15	8	8	6
	10	21	22	6	2	7
	27	16	3	3	9	8
	13	13	10	7	4	9
	1	4	5	1	5	10
	8	8	14	16	11	11
	20	1	6	12	13	12
	12	11	16	15	3	13
	18	18	13	9	10	14
	21	20	24	23	16	15
	7	10	26	25	24	16
	11	15	20	21	20	17
	19	17	17	17	15	18
	3	12	8	5	14	19
	9	5	19	20	18	20
	15	6	18	11	12	21
	16	24	23	22	23	22
Ontario Power Generation	23	25	21	19	21	23
	28	28	27	24	22	24
	25	27	7	18	NA	NA
	2	3	11	NA	NA	NA
	24	23	25	NA	NA	NA
	26	26	NA	NA	NA	NA

Note: Four operators are no longer ranked in 2015 (reason for 28 ranked operators in 2010 vs. 24 in 2015). These operators were removed as a result of plant acquisitions or closures. All 2010-2014 rankings and numbers are carried over from previous Benchmarking reports.

Total Generating Cost/MWh Analysis

The 3-year Total Generating Cost results for the major operators in 2015 are displayed in the graph below. Total Generating Costs are defined as total operating costs plus capital costs and fuel costs of all plants that the operator operates in 2013-2015. This value is divided by the total net generation of all plants that the operator operates for the same period and is provided as a three-year average. OPG Nuclear ranked 12th, with a 3-year Total Generation Cost of \$54.58 per MWh.



*OPG plant values of 3-year rolling average TGC per MWh are shown below:

Unit	2015 3-Year TGC
Darlington	$44.38/MWh
Pickering	$67.36/MWh

Table 5: Three-Year Total Generating Cost per MWh Rankings

	2010	2011	2012	2013	2014	2015
	9	7	4	1	1	1
	4	4	5	4	4	2
	1	2	2	6	5	3
	3	1	1	2	2	4
	2	3	3	3	3	5
	10	8	7	7	6	6
	NA	NA	NA	11	7	7
	14	13	14	14	12	8
	5	5	6	5	8	9
	11	11	11	9	9	10
	7	9	9	10	11	11
Ontario Power Generation	12	12	10	8	10	12
	13	14	13	13	13	13
	8	10	12	12	NA	NA
	6	6	8	NA	NA	NA

Note: Two operators have been removed due to acquisitions by the other operators in the panel (reason for 14 ranked operators in 2010 vs. 13 in 2015).

Total Generating Cost is comprised of: (a) Non-Fuel Operating Costs, plus (b) Fuel Costs, plus (c) Capital Costs. Table 6 below shows the relative contribution of these cost components to Total Generating Cost and compares OPG's costs to those of all EUCG operators.

Table 6: EUCG Indicator Results Summary (Operator Level)

EUCG Indicator Results Summary	OPG Average	EUCG Major Operators*		Units
		Median	Best Quartile	
Value for Money Performance				
3-Yr. Non-Fuel Operating Costs per MWh	$ 43.53	$ 24.64	$ 23.63	CAD $/MWh
3-Yr. Fuel Costs per MWh	$ 5.42	$ 9.04	$ 8.04	CAD $/MWh
3-Yr. Capital Costs per MWh	$ 5.63	$ 7.38	$ 6.60	CAD $/MWh
3-Yr. Total Generating Costs per MWh	$ 54.58	$ 41.70	$ 40.94	CAD $/MWh

*See Table 8 in the appendix for list of operators included.

Notes: This summary contains the average of all plant results per operator. The calculation of the EUCG 3-Yr Total Generating Costs per MWh median and best quartiles has been modified. Previously, 3-Yr TGC/MWh was derived by summing the quartile rankings of the three sub-components of TGC/MWh. The revised approach derives the 3-Yr TGC/MWh by reference to actual quartile performance.

7.0 APPENDIX

Acronyms

Acronym	Meaning
ALARA	As Low As Reasonably Achievable
BWR	Boiling Water Reactor
CANDU	CANada Deuterium Uranium (type of PHWR)
CEA	Canadian Electricity Association
COG	CANDU Owners Group
DER	Design Electrical Rating
EUCG	Electric Utility Cost Group
INPO	Institute of Nuclear Power Operators
OPG	Ontario Power Generation
PHWR	Pressurized Heavy Water Reactor
PWR	Pressurized Water Reactor
WANO	World Association of Nuclear Operators

Safety and Reliability Definitions

The following definitions are summaries extracted from industry peer group databases.

All Injury Rate is the average number of fatalities, total temporary disabilities, permanent total disabilities, permanent partial disabilities and medical attention injuries per 200,000 hours worked.

Industrial Safety Accident Rate is defined as the number of accidents for all utility personnel (permanently or temporarily) assigned to the station, that result in one or more days away from work (excluding the day of the accident) or one or more days of restricted work (excluding the day of the accident), or fatalities, per 200,000 man-hours worked. The selection of 200,000 man-hours worked or 1,000,000 man-hours worked for the indicator will be made by the country collecting the data, and international data will be displayed using both scales. Contractor personnel are not included for this indicator.

Collective Radiation Exposure, for purposes of this indicator, is the total external and internal whole body exposure determined by primary dosimeter (thermoluminescent dosimeter (TLD) or film badge), and internal exposure calculations. All measured exposure should be reported for station personnel, contractors, and those personnel visiting the site or station on official utility business.

Visitors, for purposes of this indicator, include only those monitored visitors who are visiting the site or station on official utility business.

Airborne Tritium Emissions per Unit: Tritium emissions to air are one of the sites' leading components of dose to the public. By specific tracking of tritium emissions, the sites can maintain or reduce dose. Reducing OPG Nuclear's dose to the public demonstrates continuous improvement in operations.

Fuel Reliability Index is inferred from fission product activities present in the reactor coolant. Due to design differences, this indicator is calculated differently for different reactor types. For PHWR's, the indicator is defined as the steady-state primary coolant iodine-131 activity (Becquerels/gram or Microcuries/gram), corrected for the tramp uranium contribution and power level, and normalized to a common purification rate.

Unplanned automatic reactor trips (SCRAMS) is defined as the number of unplanned automatic reactor trips (reactor protection system logic actuations) that occur per 7,000 hours of critical operation. The indicator is further defined as follows:

- Unplanned means that the trip was not an anticipated part of a planned test.
- Trip means the automatic shutdown of the reactor by a rapid insertion of negative reactivity (e.g., by control rods, liquid injection shutdown system, etc.) that is caused by actuation of the reactor protection system. The trip signal may have resulted from exceeding a set point or may have been spurious.
- Automatic means that the initial signal that caused actuation of the reactor protection system logic was provided from one of the sensors' monitoring plant parameters and conditions, rather than the manual trip switches or, in certain cases described in the clarifying notes, manual turbine trip switches (or pushbuttons) provided in the main control room.
- Critical means that, during the steady-state condition of the reactor prior to the trip, the effective multiplication factor ($k_{eff)}$ was essentially equal to one.
- The value of 7,000 hours is representative of the critical hours of operation during a year for most plants, and provides an indicator value that typically approximates the actual number of scrams occurring during the year.

The **safety system performance indicator** is defined for the many different types of nuclear reactors within the WANO membership. To facilitate better understanding of the indicator and applicable system scope for these different type reactors a separate section has been developed for each reactor type.

Also, because some members have chosen to report all data on a system train basis versus the "standard" overall system approach, special sections have also been developed for those reactor types where train reporting has been chosen. (The resulting indicator values resulting from these methods are essentially the same.)

Each section is written specifically for that reactor type and reporting method. If a member desires to understand how a different member is reporting or wishes to better understand that member's indicator, it should consult the applicable section.

The safety systems monitored by this indicator are the following:

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PHWRs

Although the PHWR safety philosophy considers other special safety systems to be paramount to public safety, the following PHWR safety and safety-related systems were chosen to be monitored in order to maintain a consistent international application of the safety system performance indicators:

- Auxiliary boiler feedwater system
- Emergency AC power
- High pressure emergency coolant injection system

These systems were selected for the safety system performance indicator based on their importance in preventing reactor core damage or extended plant outage. Not every risk important system is monitored. Rather, those that are generally important across the broad nuclear industry are included within the scope of this indicator. They include the principal systems needed for maintaining reactor coolant inventory following a loss of coolant, for decay heat removal following a reactor trip or loss of main feedwater, and for providing emergency AC power following a loss of plant off-site power. (Gas cooled reactors have an additional decay heat removal system instead of the coolant inventory maintenance system)

Except as specifically stated in the definition and reporting guidance, no attempt is made to monitor or give credit in the indicator results for the presence of other systems at a given plant that add diversity to the mitigation or prevention of accidents. For example, no credit is given for additional power sources that add to the reliability of the electrical grid supplying a plant because the purpose of the indicator is to monitor the effectiveness of the plant's response once the grid is lost.

The **Nuclear Performance Index** Method 4 is an INPO sponsored performance measure, and is a weighted composite of ten WANO Performance Indicators related to safety and production performance reliability.

The NPI is used for trending nuclear station and unit performance, and comparing the results to the median or quartile values of a group of units, to give an indication of relative performance. The quarterly NPI has also been used to trend the performance and monitor the effectiveness of various improvement programs in achieving top quartile performance and allows nuclear facilities to benchmark their achievements against other nuclear plants worldwide.

The **Forced Loss Rate (FLR)** is defined as the ratio of all unplanned forced energy losses during a given period of time to the reference energy generation minus energy generation losses corresponding to planned outages and any unplanned outage extensions of planned outages, during the same period, expressed as a percentage.

Unplanned energy losses are either unplanned forced energy losses (unplanned energy generation losses not resulting from an outage extension) or unplanned outage extension of planned outage energy losses.

Unplanned forced energy loss is energy that was not produced because of unplanned shutdowns or unplanned load reductions due to causes under plant management control when the unit is considered to be at the disposal of the grid dispatcher. Causes of forced energy losses are considered to be unplanned if they are not scheduled at least four weeks in advance. Causes considered to be under plant management control are further defined in the clarifying notes.

Unplanned outage extension energy loss is energy that was not produced because of an extension of a planned outage beyond the original planned end date due to originally scheduled work not being completed, or because newly scheduled work was added (planned and scheduled) to the outage less than four weeks before the scheduled end of the planned outage.

Planned energy losses are those corresponding to outages or power reductions which were planned and scheduled at least four weeks in advance (see clarifying notes for exceptions).

Reference energy generation is the energy that could be produced if the unit were operated continuously at full power under reference ambient conditions throughout the given period. Reference ambient conditions are environmental conditions representative of the annual mean (or typical) ambient conditions for the unit.

Unit Capability Factor is defined as the ratio of the available energy generation over a given time period to the reference energy generation over the same time period, expressed as a percentage. Both of these energy generation terms are determined relative to reference ambient conditions.

Available energy generation is the energy that could have been produced under reference ambient conditions considering only limitations within control of plant management, i.e., plant equipment and personnel performance, and work control.

Reference energy generation is the energy that could be produced if the unit were operated continuously at full power under reference ambient conditions.

Reference ambient conditions are environmental conditions representative of the annual mean (or typical) ambient conditions for the unit.

The **Chemistry Performance Indicator** compares the concentration of selected impurities and corrosion products to corresponding limiting values. Each parameter is divided by its limiting value, and the sum of these ratios is normalized to 1.0. For BWRs and most PWRs, these limiting values are the medians for each parameter, based on data collected in 1993, thereby reflecting recent actual performance levels. For other plants, they reflect challenging targets. If an impurity concentration is equal to or better than the limiting value, the limiting value is used as the concentration. This prevents increased concentrations of one parameter from being masked by better performance in another. As a result, if a plant is at or below the limiting value for all parameters, its indicator value would be 1.0, the lowest chemistry indicator value attainable under the indicator definition. The following is used to determine each unit's chemistry indicator value:

- PWRs with recirculating steam generators and VVERs
  - Steam generator blowdown chloride
  - Steam generator blowdown cation conductivity
  - Steam generator blowdown sulphate
  - Steam generator blowdown sodium

- Final feedwater iron
- Final feedwater copper (not applicable to PWRs with I-800 steam generator tubes)
- Condensate dissolved oxygen (only applicable to PWRs with I-800 steam generator tubes)
- Steam generator molar ratio target range (by reporting the upper and lower range limits (as "from" and "to" values when using molar ratio control)
- Steam generator actual molar ratio (if reporting molar ratio control data)
- Feedwater oxygen
- Feedwater pH value at 270deg. C

- PWRs with once through steam generators
  - Final feedwater chloride
  - Final feedwater sulfate
  - Final feedwater sodium
  - Final feedwater iron
  - Final feedwater copper
  -
- Pressurized heavy water reactors (PHWRs)
  - *Inconel-600 or Monel tubes
    - Steam generator blowdown chloride
    - Steam generator blowdown sulfate
    - Steam generator blowdown sodium
    - Final feedwater iron
    - Final feedwater copper
    - Final feedwater dissolved oxygen
  - Incoloy-800 tubes
    - Steam generator blowdown chloride
    - Steam generator blowdown sulfate
    - Steam generator blowdown sodium
    - Final feedwater iron
    - Final feedwater dissolved oxygen

- PHWRs on molar ratio control
  - Steam generator blowdown chloride
  - Steam generator blowdown sulfate
  - Final feedwater iron
  - Final feedwater copper
  - Feedwater dissolved oxygen
  - Steam generator molar ratio target range (by reporting the upper and lower range limits (as "from" and "to" values)
  - Steam generator actual molar ratio

Online Deficient Maintenance Backlog is the average number of active on-line maintenance work orders per operating unit classified as Deficient Critical (DC) or Deficient Non-Critical

(DN) that can be worked on without requiring the unit shutdown. This metric identifies deficiencies or degradation of plant equipment components that need to be remedied, but which do not represent a loss of functionality of the component or system.

Online Corrective Maintenance Backlog is the average number of active on-line maintenance work orders per operating unit classified as Corrective Critical (CC) or Corrective Non-Critical (CN) that can be worked on without requiring the unit shutdown. This metric identifies deficiencies or degradation of components that need to be remedied, and represents a loss of functionality of a major component or system.

On-line maintenance is maintenance that will be performed with the main generator connected to the grid.

<u>Value for Money Definitions</u>

The following definition summaries are taken from the *January 2013 EUCG Nuclear Committee Nuclear Database Instructions*.

Capital Costs ($)

All costs associated with improvements and modifications made during the reporting year. These costs should include design and installation costs in addition to equipment costs. Other miscellaneous capital additions such as facilities, computer equipment, moveable equipment, and vehicles should also be included. These costs should be fully burdened with indirect costs, but exclude AFUDC (interest and depreciation).

Fuel ($)

The total cost associated with a load of fuel in the reactor which is burned up in a given year.

Net Generation (Gigawatt Hours)

The gross electrical output of the unit measured at the output terminals of the turbine-generator minus the normal station service loads during the hours of the reporting period, expressed in Gigawatt hours (GWh). Negative quantities should not be used.

Design Electrical Rating (DER)

The nominal net electrical output of a unit, specified by the utility and used for plant design (DER net expressed in MWe). Design Electrical Rating should be the value that the unit was certified/designed to produce when constructed. The value would change if a power uprate was completed. After a power uprate, the value should be the certified or design value resulting from the uprate.

Operating Costs ($)

The operating cost is to identify all relevant costs to operate and maintain the nuclear operations in that company. It includes the cost of labour, materials, purchased services and other costs, including administration and general.

Total Generating Costs ($)

The sum of total operating costs and capital costs as above.

Total Operating Costs ($)
The sum of operating costs and fuel costs as above.

Note: Capital costs, fuel costs, operating costs and Total Generating Costs are divided by net generation as above to obtain per MWh results. Capital costs are also divided by MW DER to obtain MW results.

Human Performance Definitions

The following definition summary is taken from the Institute of Nuclear Power Operations (INPO) database.

Human Performance Error Rate (# per ISAR and Contractor Hours)
. The Human Performance Error Rate metric represents the number of site level human performance events in an 18-month period per 10,000 ISAR hours worked (including on site supplemental personnel). The formula used is:

{(# of S-EFDRs) / (Total ISAR Hours + Total Contractor Hours)} x 10,000 Hours (Calculated as an 18-month rolling average)

INPO guidelines define non utility personnel to include contractor, supplemental personnel assigned to perform work activities on site or at other buildings that directly support station operation. This includes personnel who deliver and receive equipment, deliver fuel oil, remove trash and radioactive waste, and provide building and grounds maintenance within the owner-controlled areas or facilities that support the station.

INPO defines an event to occur as a result of the following:

An initiating action (error) by an individual or group of individuals (event resulting from an active error) or an initiating action (not an error) by an individual or group of individuals during an activity conducted as planned (event resulting from a flawed defense or latent organizational weakness). They may be related to Nuclear Safety, Radiological Safety, Industrial Safety, Facility Operations or considered to be a Regulatory Event reportable to a regulator or governing agency. OPG Nuclear's criteria for defining station event free day resets have been developed based on INPO guidelines. However, the definition may differ slightly due to adaptation resulting from technological differences.

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Panels

Table 7: WANO Panel

Operator	Plant
Ameren Missouri	Callaway
American Electric Power Co.	Cook
Arizona Public Service Co.	Palo Verde
Bruce Power	Bruce A Bruce B
Dominion Generation	Millstone North Anna Surry
Duke Energy	Catawba Harris Mcguire Oconee Robinson
Entergy Nuclear	Arkansas Nuclear One Indian Point Palisades Waterford
Exelon Generation Co.	Braidwood Byron Three Mile Island Calvert Cliffs Ginna
FirstEnergy Nuclear Operating Co.	Beaver Valley Davis-Besse
Florida Power & Light Co.	St. Lucie Turkey Point

Operator	Plant
International CANDU	Cernavoda Embalse Qinshan 3 Wolsong A Wolsong B
Luminant Generation	Comanche Peak
New Brunswick Power	Point Lepreau
NextEra Energy Resources	Point Beach Seabrook
Northern States Power Company	Prairie Island
Omaha Public Power District	Fort Calhoun
Ontario Power Generation	Darlington Pickering
Pacific Gas & Electric Co.	Diablo Canyon
Public Service Enterprise Group Nuclear	Salem
South Carolina Electric & Gas Co.	V.C. Summer
Southern Nuclear Operating Co.	Farley Vogtle
STP Nuclear Operating Co.	South Texas
Tennessee Valley Authority	Sequoyah Watts Bar
Wolf Creek Nuclear Operating Corp.	Wolf Creek

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Table 8: EUCG Panel

Major Operator	Plant
Bruce Power	Bruce A Bruce B
Dominion Generation	Millstone North Anna Surry
Duke Energy	Brunswick Catawba Harris Mcguire Oconee Robinson
Entergy Nuclear	Arkansas Nuclear One Fitzpatrick Grand Gulf Indian Point Palisades Pilgrim River Bend Waterford
Exelon Generation Co.	Braidwood Byron Calvert Cliffs Clinton Dresden Lasalle Limerick Nine Mile Oyster Creek Peach Bottom Quad Cities Ginna Three Mile Island
FirstEnergy Nuclear Operating Co.	Beaver Valley David-Besse Perry

Major Operator	Plant
Florida Power & Light Co.	St Lucie Turkey Point
NextEra Energy Resources	Duane Arnold Point Beach Seabrook
Northern States Power Company	Monticello Prairie Island
Ontario Power Generation	Darlington Pickering
Public Service Enterprise Group Nuclear	Hope Creek Salem
Southern Nuclear Operating Co.	Farley Hatch Vogtle
Tennessee Valley Authority	Browns Ferry Sequoyah Watts Bar

Remaining EUCG Members

Operator	Plant	Operator	Plant
AmerenUE	Callaway	Nebraska Public Power District	Cooper
American Electric Power Co. Inc.	Cook	Pacific Gas & Co.	Diablo Canyon
Arizona Public Service Co.	Palo Verde	Talen Energy	Susquehanna
DTE Energy	Fermi	South Carolina Electric & Gas Company (SCE&G)	V.C. Summer
Energy Northwest	Columbia	STP Nuclear Operating Co.	South Texas
Luminant Generation	Comanche Peak	Wolf Creek Nuclear Operations Corp.	Wolf Creek

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Table 9: COG CANDUs

Operator	Plant
Bruce Power	Bruce A Bruce B
China (CNNP)	Qinshan 3
NASA	Embalse
Korea (KHNP)	Wolsong A Wolsong B
New Brunswick Power	Point Lepreau
OPG	Darlington Pickering
Romania	Cernavoda

Table 10: CEA Members

Companies
AltaLink
ATCO Electric
ATCO Power
BC Hydro and Power Authority
Brookfield Renewable Energy Group
Capital Power Corporation
City of Medicine Hat, Electric Utility
Columbia Power Corporation
Emera Inc.
ENMAX
EnWin
EPCOR
FortisAlberta Inc.
FortisBC Inc.
Horizon Utilities Corp
Hydro One
Hydro Ottawa

Companies
Hydro Quebec
Manitoba Hydro
Maritime Electric Company
Nalcor Energy
New Brunswick Power
Newfoundland Power
Northwest Territories Power Corp.
Nova Scotia Power
Oakville Hydro Corp.
Ontario Power Generation
PowerStream
Saint John Energy
Saskatoon Light & Power
SaskPower
Toronto Hydro Corp.
TransCanada
Yukon Energy Corp.

Table 11: INPO Members for Human Performance Error Rate

Plant	
Arkansas Nuclear One (ANO)	Millstone
Beaver Valley	Monticello
Braidwood	Nine Mile Point
Browns Ferry	North Anna
Brunswick	Oconee
Byron	Oyster Creek
Callaway	Palisades
Calvert Cliffs	Palo Verde
Catawba	Peach Bottom
Clinton	Perry
Columbia Gen	Pilgrim
Comanche Peak	Point Beach
Cook	Prairie Island
Cooper	Quad Cities
Davis-Besse	River Bend
Diablo Canyon	Robinson
Dresden	Salem
Duane Arnold	Seabrook
Farley	Sequoyah
Fermi 2	South Texas
Fitzpatrick	St. Lucie
Fort Calhoun	Summer
Ginna	Surry
Grand Gulf	Susquehanna
Harris	Three Mile Island
Hatch	Turkey Point
Hope Creek	Vermont Yankee
Indian Point	Vogtle
LaSalle	Waterford
Limerick	Watts Bar
McGuire	Wolf Creek

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Table 12: INPO Members for On-Line Maintenance Backlogs

Plant	
Arkansas Nuclear One (ANO)	Monticello
Beaver Valley	Nine Mile Point
Braidwood	North Anna
Browns Ferry	Oconee
Brunswick	Oyster Creek
Byron	Palisades
Callaway	Palo Verde
Calvert Cliffs	Peach Bottom
Catawba	Perry
Clinton	Pilgrim
Columbia Gen	Point Beach
Comanche Peak	Prairie Island
Cook	Quad Cities
Cooper	River Bend
Davis-Besse	Robinson
Diablo Canyon	Salem
Dresden	Seabrook
Duane Arnold	Sequoyah
Farley	South Texas
Fermi 2	St. Lucie
Fitzpatrick	Summer
Ginna	Surry
Grand Gulf	Susquehanna
Harris	Three Mile Island
Hatch	Turkey Point
Hope Creek	Vermont Yankee
Indian Point	Vogtle
LaSalle	Waterford
Limerick	Watts Bar
McGuire	Wolf Creek
Millstone	

Table 13: NPI Plant Level Performance Summary (North American Panel)

	2015 Actuals				
Indicator	**NPI Max**	**Best Quartile**	**Median**	**Pickering**	**Darlington**
Rolling Average Industrial Safety Accident Rate (#/200k hours worked)	0.20	0.00	0.00	0.05	0.08
Rolling Average Collective Radiation Exposure (person-rem per unit)	80.00	32.08	47.75	97.72	79.55
Fuel Reliability Index (microcuries per gram)	0.000500	0.000001	0.000008	0.000421	0.000122
2-Year Reactor Trip Rate (# per 7,000 hours)	0.50	0.00	0.21	0.17	0.13
3-Year Auxiliary Feedwater System Unavailability (#)	0.0200	0.0028	0.0041	0.0115	0.0000
3-Year Emergency AC Power Unavailability (#)	0.0250	0.0102	0.0133	0.0030	0.0000
3-Year High Pressure Safety Injection Unavailability (#)	0.0200	0.0019	0.0032	0.0000	0.0000
Rolling Average Forced Loss Rate (%)	1.00	0.58	1.30	6.85	3.65
Rolling Average Unit Capability Factor (%)	92.00	92.61	90.00	77.32	83.96
Rolling Average Chemistry Performance Indicator (Index)	1.01	1.00	1.00	1.06	1.00
WANO NPI (Index)	Not Applicable	98.7	92.6	68.5	83.7

SEC Interrogatory #72

Issue Number: 6.6
Issue: 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?

Interrogatory

Reference:
[F4/3/1, p.8]

Please provide a breakdown of the cost impact (additional cost and/or savings) for each of the negotiated collective agreements with the PWU and the Society, for each of the following time periods: i) the term of the current collective agreement, ii) the test period, and iii) the total impact if the change extends beyond the test period. Please detail all assumptions made and the full calculations.

Response

The negotiated changes to collective agreements are detailed in Ex. L-06.6-15 SEC-071. Chart 1 and Chart 2 below provide the estimated cost impacts (for the nuclear facilities) arising from the negotiated collective agreements with each of the PWU and the Society, respectively, for the term of the agreements. This information is split out between the period preceding the IR Term and the period included within the IR Term. Information beyond the current terms of the collective agreements is not provided, as the collective agreements may change beyond this timeframe based on future bargaining (see Ex. L-06.6-15 SEC-70). Information beyond 2021 is not provided because it is not relevant to the OEB's determination of the revenue requirement and payment amounts in this proceeding.

The impacts of pension reform related items are shown separately in each of the two charts. The costs/savings related to pension reform were not considered as part of achieving the Government mandate of ensuring any compensation issues would reflect an overall net neutral cost to the electricity ratepayers. As such, any changes to pension contributions and benefits could not count as offsets for the purposes of calculating net zero (see L-06.6-1 Staff 147, Attachment 1 and Ex. F4-3-1, p.15, lines 16-23).

While allocations were made to present information below for the nuclear facilities for the purposes of the rate application, the Government assessed the results from the collective bargaining on a total OPG basis, determined at the time of bargaining.

Chart 1
PWU Collective Agreement Impacts (Attributed to Nuclear)

Item	**Costs / (Savings) $M**		
Numbers may not add due to rounding	**Apr 1, 2015 to Dec 31, 2016** (a)	**Jan 1, 2017 to Mar 31, 2018** (b)	**Apr 1, 2015 to Mar 31, 2018** (c)=(a)+(b)
Non-Pension Reform Related Items:	[redacted]		
3-Year Wage Increases at 1%/year[1]			
250-Hour Purchased Services Threshold[2]			
Nuclear Outage Purchased Services Agreement[3]			
Radiation Protection Technician (RPT) Appendix A Midterm[4]			
Project Technician Purchased Services Agreement[5]			
Temporary Work Headquarters Travel Time Provisions[6]			
Minor Benefit Improvements			
Pension Reform Related Items:			
Increased Employee Pension Contributions[7]			
Lump Sum Payments[8]			
Hydro One Share Performance Plan[9]			

Numbers may not add due to rounding

Notes:

[redacted]

[redacted]

Chart 2
Society Collective Agreement Impacts (Attributed to Nuclear)

Item	Costs / (Savings) $M		
	Jan 1 to Dec 31, 2016 (a)	**Jan 1, 2017 to Dec 31, 2018** (b)	**Jan 1, 2016 to Dec 31, 2018** (c)=(a)+(b)
Non-Pension Reform Related Items:	[redacted]		
3-Year Wage Increases at 1%/year[1]			
Purchased Services Agreement LOU #193[2]			
Overtime PWU Rate Equivalency[3]			
Hours of Work Averaging Permit[4]			
Minor Benefit Improvements			
Elimination of Band N Goal Sharing Equivalent Payment			
Other Miscellaneous Items			
Pension Reform Related Items:			
Increased Employee Pension Contributions[5]			
Lump Sum Payments[6]			
Hydro One Share Performance Plan[7]			

Numbers may not add due to rounding

Notes:
[redacted]

[redacted]

Board Staff Interrogatory #170

Issue Number: 6.7
Issue: Are the corporate costs allocated to the nuclear businesses appropriate?

Interrogatory

Reference:
Ref: Exh F3-1-1 page 14

One of the corporate functions benchmarked by Hackett was executive and corporate services (ECS) function. Footnote 11 on page 14 lists the 11 sub-categories within ECS.

a) Are some of the groups within ECS included in those that were not benchmarked in the Towers report at Exh F4-3-1 Attachment 2?

b) Are some of the groups within ECS included in those that were not benchmarked in the Goodnight report at Exh F2-1-1 Attachment 4?

c) ECS cost in 2010 and 2014 is provided as a % of revenue. Please provide the ECS costs in dollars for 2010 and 2014.

d) Please provide the 2010 and 2014 ECS costs allocated to the nuclear business. Please provide the forecast ECS costs allocated to the nuclear business for each year 2017-2021.

Response

a) No, all of the groups within ECS were included in the Towers report at Ex. F4-3-1, Attachment 2.

b) Yes, some of the groups within ECS are included in those that were not benchmarked in the Goodnight report at Ex. F2-1-1, Attachment 2. For example, Corporate Support not directly supporting the Nuclear Program, such as the Law Division and Enterprise Risk Management, was excluded from the Goodnight report. The inclusion of these groups within ECS is consistent with the Hackett group benchmark methodology (Ex. F3-1-1, Attachment 1, p. 6); and similarly, the exclusion of these groups is consistent with Goodnight Consulting benchmarking methodology (Ex. F2-1-1, Attachment 2, p. 14). The difference in methodology is expected, as the Hackett Group and Goodnight benchmarking were performed for different objectives (see Ex. F3-1-1, Attachment 1, p. 5 and Ex. F2-1-1, Attachment 2, p. 3, respectively). Furthermore, each methodology ensures OPG is compared to peers on an apples to apples basis.

c) The ECS costs for OPG's regulated operations in dollars for 2010 and 2014 can be found at Ex. F3-1-1, Attachment 1, p. 11.

d) Referring to the 2014 ECS cost at Ex. F3-1-1, Attachment 1, p. 11 and forecasted corporate costs in Ex. F3-1-1, OPG has completed a high level estimate of the ECS costs allocated to nuclear business for 2017-2021: $99M in 2017; $99M in 2018; $99M in 2019; $99M in 2020; and $100M in 2021.

As in L-06.6-1 Staff-169, it should be further noted that these values represent an estimate based on information available to OPG. The values above have not been derived using the Hackett Group's taxonomy applied to 2010 and 2014 costs, or otherwise vigorously vetted by a similar taxonomy, as this is not an exercise OPG performs in its normal course of business. Furthermore, although ECS cost as a percentage of revenue was higher than peer in the Hackett Study, driven by OPG specific requirements (see Ex. F3-1-1, p. 15, lines 7-24), OPG HR cost per employee was comparable to peer and OPG IT cost per end user was better than peer (Ex. F3-1-1, p.14, lines 14-17).

AMPCO Interrogatory #147

Issue Number: 8.1
Issue: 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?

Interrogatory

Reference:
Ref: C2-1-1

Preamble: The evidence discusses amounts recorded in OPG's financial statements as due to or due from the Province in accordance with generally accepted accounting principles.

a) Please provide the amounts recorded in OPG's financial statements as due to or due from the Province for the years 2013 to 2015 and forecast for 2016 to 2021.

b) Please confirm the first year that OPG recorded an amount due to province in its financial statements.

c) Please provide the regulations, rules, guidelines or any other relevant documents with specific references that govern when and how amounts due to or due from the Province are managed.

Response

a) The total "Due to Province" amounts recorded in OPG's audited consolidated financial statements as at December 31 for 2013-2015 and reflected in pre-filed evidence projections as at December 31 for 2016-2021 are as follows:

$M	**2013 Actual**	**2014 Actual**	**2015 Actual**	**2016 Proj'n**	**2017 Proj'n**	**2018 Proj'n**	**2019 Proj'n**	**2020 Proj'n**	**2021 Proj'n**
Used Fuel Fund	990	1,429	1,703	1,791	1,883	1,980	2,082	2,189	2,302
Decommissioning Fund	624	1,100	1,285	1,351	1,421	1,494	1,571	1,652	1,737

Refer to Ex. L-8.1-15 SEC-091 part (d) for discussion of how the forecasted funded status of the Decommissioning Fund is derived.

b) OPG recorded the first "Due to Province" amount in its 2004 financial statements. The first "Due from Province" amount was recorded in the 2003 financial statements.

c) Section 3.7.1 of the Ontario Nuclear Funds Agreement (ONFA) governs the determination of the Used Fuel Fund "Due to Province" or "Due from Province" amount related to the guaranteed the rate of return earned for the portion of the Used Fuel Fund attributed to the first 2.23 million used fuel bundles. In conjunction with Section 2.2 and as applicable Section 3.10.3 and Section 4.7.3, Section 8.2 of the ONFA governs OPG's right to the Decommissioning Fund and the Used Fuel Fund, and therefore provides the basis for the "Due to Province" amounts related to the excess of the value of fund assets over the corresponding ONFA liability.[1] A copy of the ONFA is found at Ex. L-8.1-15 SEC-091 Attachment 1.

The description of the accounting treatment of the "Due to Province" and "Due from Province" amounts can be found in OPG's audited consolidated financial statements. For example, refer to the 2015 audited consolidated financial statement at Ex. A2-1-1, Att. 3, p. 144.

From an OPG rate-setting perspective, the OEB explicitly addressed the matter of the "Due to Province" amounts for the ONFA funds in its EB-2013-0321 Decision with Reasons, p. 110:

> *The Board will not direct OPG to use the excess earnings in the Decommissioning and Used Fuel funds to decrease the revenue requirement by $28.5M as proposed by AMPCO as the funds are "Due to Province" as stipulated in the Ontario Nuclear Funds Agreement reference plan. The Board is satisfied that the current over funding position will not result in a cash withdrawal from the fund to the Province. In addition, given the long-term nature of the fund, it is appropriate for any periodic over earning to be retained within the fund to offset future potential under earning*.

[1] Further details with respect to the Decommissioning Fund can be found in EB-2013-0321 Ex. J11.8

AMPCO Interrogatory #150

Issue Number: 8.1
Issue: 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?

Interrogatory

Reference:
Ref: C2-1-1 Table 1
Preamble: The total revenue requirement impact of OPG's nuclear liabilities (Prescribed Facilities and Bruce) are $454.3 million in 2017, $450.1 million in 2018, $439.1 million in 2019, $506 in 2020 and $444 million in 2021.

a) Please provide any relevant documents (including without limitation regulations, statutes, MOUs) and highlight the specific references that proscribe the circumstances under which OPG must pay the province any amounts from the segregated funds.

b) Please provide any relevant documents (including without limitation regulations, statutes, MOUs) and highlight the specific references that proscribe the calculation of the amounts OPG must pay the province from the segregated funds under the circumstances defined in a)

c) Provide a table showing the amounts to be paid to the province from the segregated funds each year 2016-2021 and show the supporting calculations.

d) Please provide the revenue requirement impact if the amounts calculated as due to the province are retained by OPG.

Response

OPG understands that the question is in reference to the "Due to Province" amounts related to the segregated funds.

a) and b) The document that describes the circumstances under which the Province would be entitled to withdraw amounts from the segregated funds and the calculation of such amounts is the Ontario Nuclear Funds Agreement (ONFA). The ONFA can be found at Ex.L-8.1-15 SEC-091 Attachment 1. The sections of the ONFA describing the payout circumstances and related calculations of the "Due To Province" amounts are set out in Ex. L-8.1-2 AMPCO-147 part (c).

c) The projected total year-end "Due to Province" amounts for 2016-2021 are provided in Ex. L-8.1-2 AMPCO-147 part (a). These amounts were based on the actual amounts reported in OPG's 2015 audited consolidated financial statements (Ex. A2-1-1 Attachment 3, p. 145) and were determined in accordance with the ONFA requirements. OPG is not providing the requested supporting calculations for the reasons set out in part (d) below.

d) OPG is not providing the hypothetical calculations requested in part (d) or the calculations requested in part (c), as this information is not relevant to the determination of payment amounts for OPG's prescribed assets. The OEB previously found in the EB-2013-0321 Decision with Reasons that "[t]he Board will not direct OPG to use the excess earnings in the Decommissioning and Used Fuel funds to decrease the revenue requirement by $28.5M as proposed by AMPCO as the funds are "Due to Province" as stipulated in the Ontario Nuclear Funds Agreement reference plan," noting that "[t]he Board has no authority over the segregated funds or the reference plan for nuclear liabilities established by the Ontario Nuclear Funds Agreement." (p. 110)

SEC Interrogatory #91

Issue Number: 8.1
Issue: 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?

Interrogatory

Reference:
[C2/1/1, p.5]

With respect to the Ontario Nuclear Fund Agreement:

a. Please provide a copy of the Ontario Nuclear Funds Agreement.

b. Please provide a copy of the current Ontario Nuclear Funds Agreement Reference Plan.

c. What percentage funded is the Decommissioning Fund?

d. What is the forecast percentage funded of the Decommissioning Fund for each year between 2017 and 2021?

e. Please provide a copy of the latest financial statements of the segregated funds.

Response

a. The Ontario Nuclear Funds Agreement (ONFA) is provided in Attachment 1.

b. The current ONFA Reference Plan was the one approved to be effective January 1, 2012 (the 2012 ONFA Reference Plan). The full 2012 ONFA Reference Plan is a voluminous document approximately 4,000 pages long and containing highly detailed technical evaluations and cost estimating information for thousands of work program elements. It is also a confidential document. In order to present this information in a more practical and meaningful way, in Attachment 2, OPG provides non-confidential summary level reports for each of the five nuclear liability programs (see Ex. C2-1-1, section 3.1.1) and for the ONFA liabilities overall. These reports, which form part of the 2012 ONFA Reference Plan, total approximately 175 pages and provide the key outputs and assumptions.

c. As at June 30, 2016, the date of OPG's most recent issued interim consolidated financial statements, the Decommissioning Fund was approximately 118% funded.

d. As explained at Ex. C2-1-1 p. 7, lines 1-19, OPG limits the Decommissioning Fund earnings it recognizes in accordance with US GAAP such that the balance of the fund is equal to the current ONFA decommissioning liability (referred to in ONFA as the Decommissioning Balance to Complete Cost Estimate), plus the portion of the excess funding available to OPG to transfer to the Used Fuel Fund under the ONFA. As both the Decommissioning Fund balance and the ONFA decommissioning liability are assumed to grow at the rate of 5.15% per annum based on the approved ONFA Reference Plan, the forecast funded status of the Decommissioning Fund, in percentage terms, is the same as the actual funded status at the time the forecast is developed and, in dollar terms, increases at the rate of 5.15% per annum over the projection period.

The specific forecasted funded status does not affect the forecasted earnings or balance of the Decommissioning Fund as long as the fund is between 100% and 120% funded at the time the forecast is developed because OPG does not have the right or access to that excess funding.[1]

Since the 2017-2021 forecast in the pre-filed evidence was based on the December 31, 2015 actual funded position, it reflects the December 31, 2015 funded status of slightly less than 120%.

e. The audited 2015 Used Fuel Fund financial statements are provided in Attachment 3 and the audited 2015 Decommissioning Fund financial statements are provided in Attachment 4.

[1] If the Decommissioning Fund were to be over 120% funded at the time the forecast is developed, the specific forecasted funded status would affect the forecasted earnings and balance of the Decommissioning Fund to the extent that the Used Fuel Fund is underfunded, as OPG has the right to direct up to 50 per cent of the excess over 120 per cent to the Used Fuel Fund, up to the amount that the Used Fuel Fund is underfunded. OPG can direct such a transfer upon approval of a new ONFA Reference Plan only, with the Province entitled to receive an amount from the Decommissioning Fund that is equal to the amount transferred to the Used Fuel Fund.

IMPACT STATEMENT

1.0 PURPOSE

The purpose of this exhibit is to show the impact of certain material changes that have occurred since OPG submitted its pre-filed evidence in this Application on May 27, 2016, consistent with the requirements of paragraph 11.02 of the OEB's *Rules of Practice and Procedure*. These changes impact the revenue requirement for the nuclear facilities and result from (i) OPG's 2017-2019 business plan (the "2017-2019 Business Plan"), which includes an updated forecast of pension and other post-employment benefit ("OPEB") cash amounts, projected cost impacts of the 2017 to 2021 ONFA Reference Plan approved by the Province in December 2016 (the "2017 ONFA Reference Plan")[1], and new Canadian Nuclear Safety Commission ("CNSC") requirements; (ii) an updated forecast of used fuel and low and intermediate level ("L&ILW") revenues under the Bruce lease and associated agreements ("Bruce Lease") that was finalized subsequent to the approval of the 2017-2019 Business Plan; and (iii) the Return on Equity ("ROE") value of 8.78% published by the Ontario Energy Board ("OEB") on October 27, 2016 for use in 2017 custom IR applications (collectively, the "Drivers").[2]

The Application was filed based on OPG's 2016-2018 Business Plan, which also included a financial projection for the 2019-2021 period (Ex. A2-2-1). The 2017-2019 Business Plan was approved by OPG's Board of Directors ("OPG Board") on November 10, 2016 and includes a financial projection for the 2020-2021 period. The five-year planning information included in the 2017-2019 Business Plan was developed as part of the 2017-2019 business planning cycle, applying a consistent process for all years. A copy of the 2017-2019

[1] See Attachment 4 for a copy of the letter from the Province approving the 2017-2021 ONFA Reference Plan.

[2] See Ontario Energy Board Web Posting, "*Cost of Capital Parameter Updates for 2017 Cost of Service and Custom Incentive Rate-setting Applications*", dated October 27, 2016 at http://www.ontarioenergyboard.ca/oeb/_Documents/2017EDR/OEB_Ltr_Cost_of_Capital_Update_20161027.pdf

Business Plan is provided in Attachment 1[3]. Attachment 1 is being filed in accordance with the requirements of the OEB's practice directions on confidential filings.

2.0 SUMMARY

This update to the Application reflects material changes in costs for the nuclear facilities in the 2017 to 2021 IR period resulting from the Drivers. In determining items to be included as part of this update, OPG evaluated changes with reference to a materiality threshold of an average $10M per year over the IR period. As shown in Chart 2.0 below, the changes in this update result in an overall net increase in the nuclear revenue requirement of approximately $7M in total for the IR period. The updated cost forecasts were determined using the same rigour and, unless otherwise noted in this Impact Statement, using the same methodologies as the original pre-filed evidence. OPG is not updating its nuclear production forecast, as there is no material change to that forecast in the 2017-2019 Business Plan. An updated Revenue Requirement Work Form reflecting the changes identified in this Impact Statement is attached as Attachment 2.

The update to the revenue requirement does not impact OPG's smoothing proposal of a constant 11 percent per year nuclear base rate increase. There are also no changes to the proposed deferral and variance account amortization amounts. As a result, OPG is not updating its request for smoothed nuclear payment amounts or riders, and there is no change to the annualized residential consumer impact of OPG's Application.

In addition to revenue requirement items, OPG is updating its forecast of pension and OPEB accrual costs attributed to the nuclear facilities for the IR period provided in the Application, to reflect the 2017-2019 Business Plan. As discussed in Ex. F4-3-2, OPG proposes to continue recording the difference between actual accrual costs and actual cash amounts for pension and OPEB in the Pension & OPEB Cash Versus Accrual Differential Deferral Account, pending the outcome of the OEB's EB-2015-0040 consultation.

[3] A copy of OPG's 2017-2019 Business Planning Instructions can be found at Ex. L-1.2-1 Staff-003.

OPG is proposing to update the 2017 to 2021 nuclear revenue requirement in the following five areas, as discussed in greater detail in section 3.0:

- changes to forecast pension and OPEB cash amounts, including the impact of the latest filed pension funding valuation as of January 1, 2016 and an assumed subsequent valuation as of January 1, 2019 (see section 3.1);
- changes to forecast costs associated with OPG's liabilities for nuclear waste management and decommissioning ("nuclear liabilities"), including the projected impact of the 2017 ONFA Reference Plan effective January 1, 2017[4], as well as the income tax impacts of changes to forecast cash expenditures on nuclear waste management and decommissioning and corresponding disbursements from the nuclear segregated funds (see section 3.2);
- changes to Bruce Lease net revenues and related tax effects as a result of an updated forecast of used fuel and L&ILW revenues, under the amended Bruce Lease, for changes in revenue rates reflecting the 2017 ONFA Reference Plan cost estimates and new waste volume forecasts provided by Bruce Power LP (see section 3.3);
- an update to the forecast ROE amounts and related tax effects to reflect the most recent OEB-published Cost of Capital parameters (see section 3.4); and
- an increase in forecast Nuclear base OM&A costs resulting from new Fitness for Duty requirements from the CNSC (see section 3.5).

There are two consequential changes to the nuclear revenue requirements, also presented in Chart 2.0, as a result of the five changes identified above:

- an increase in nuclear stretch factor dollars as a result of the changes in Nuclear OM&A included in this Impact Statement; and
- the elimination of IR period regulatory tax loss carry forwards, as a result of the changes in regulatory taxable income arising from the items included in this Impact Statement (see section 3.6).

[4] Any difference between the projected impacts and the final impacts for the prescribed facilities arising from the approved 2017 ONFA Reference Plan will be recorded in the Nuclear Liability Deferral Account. Any such differences related to the Bruce facilities will be recorded in the Bruce Lease Net Revenues Variance Account.

Chart 2.0

Summary of Changes to Proposed Nuclear Revenue Requirement* ($M)

Line No.		2017	2018	2019	2020	2021	Total
1	Pension and OPEB Cash Amounts	19.1	18.3	53.8	81.0	79.3	251.5
2	Nuclear Liabilities	(40.3)	(57.2)	(21.0)	(121.2)	(156.0)	(395.6)
3	Used Fuel and Waste Services Bruce Lease Revenue	35.1	35.6	36.5	37.6	34.9	179.8
4	Return on Equity Value	(9.0)	(9.4)	(9.2)	(20.1)	(21.3)	(69.0)
5	New CNSC Requirements (Base OM&A)	0.5	0.5	16.7	11.7	11.7	41.0
6	Nuclear Stretch Dollars**	-	(0.0)	(0.1)	(0.1)	(0.2)	(0.5)
7	Tax Carryforwards	6.4	(15.2)	(52.0)	60.8	-	(0.0)
8	**Total Revenue Requirement Change**	11.9	(27.4)	24.6	49.6	(51.6)	7.1

*all amounts shown are inclusive of any income tax impacts; positive values are increases to revenue requirement and negative values are decreases
**reflects changes in Nuclear base OM&A due to new CNSC requirements and changes in nuclear liabilities costs

The updated nuclear requirement is provided in Ex. N1-1-1 Table 1. In order to minimize the impact on the proceeding schedule and to keep the Impact Statement to a manageable size, OPG is limiting the update to the changes described above.

The change in forecast pension and OPEB cash amounts for the nuclear facilities increases the nuclear revenue requirement by approximately $252M over the IR period. This is due to higher payments for pension deficit funding projected in the 2017-2019 Business Plan, primarily as a result of a decrease in discount rates relative to the pre-filed evidence. The forecast nuclear pension and OPEB accrual costs decrease by approximately $21M over the IR period. The 2017 to 2021 forecast excess of pension and OPEB accrual costs over cash amounts decreases to approximately $130M for the nuclear facilities, compared to approximately $403M in the pre-filed evidence.

Changes in forecasts related to nuclear liabilities decrease the IR period nuclear revenue requirement by approximately $396M, which consists of a decrease of approximately $551M related to the changes in nuclear liabilities costs for the Bruce facilities, an increase of approximately $280M associated with the changes in nuclear liabilities costs for the prescribed facilities, and a decrease of approximately $124M in income tax impacts related to changes in forecast cash expenditures on nuclear waste management and decommissioning and associated disbursements from the nuclear segregated funds.

The change in Bruce Lease net revenues as a result of updated used fuel and L&ILW revenue forecasts increases the nuclear revenue requirement by approximately $180M over the IR period, which consists of a $135M reduction in Bruce Lease net revenues and $45M in increased income tax impacts.

OPG is updating its ROE for all years of the IR period using the prevailing 2017 ROE as specified by the OEB[5]. The 2017 ROE value is 8.78%, which is 0.41% lower than the ROE value underpinning the pre-filed evidence. The change in ROE decreases the 2017 to 2021 nuclear revenue requirement by approximately $69M, inclusive of the related income taxes.

The new CNSC Fitness for Duty regulatory requirements will create an obligation for OPG to design and implement a Fitness for Duty program. OPG expects to incur Nuclear base OM&A costs of approximately $41M for implementation of this program during the IR period. Based on the regulatory significance of this new CNSC requirement, OPG has included this item as part of its update. These costs exceed $10M per year, for each year compliance is assumed to be required by the CNSC during the IR period (2019-2021).

As discussed in section 4.0, the above changes impact the nuclear revenue requirement and nuclear rate base approvals sought by OPG in Ex. A1-2-2, as well as the resulting portion of the annual nuclear revenue requirement OPG proposes to defer in the Rate Smoothing Deferral Account over the IR period.

3.0 ITEMS INCLUDED IN THE IMPACT STATEMENT

This section provides additional detail on each of the five changes reflected in the revised nuclear revenue requirement requested for the IR period. In addition, it presents the change in forecast pension and OPEB accrual costs for the period, to provide a forecast of the

[5] See footnote 1.

impact on the Pension & OPEB Cash Versus Accrual Differential Deferral Account. Each of the following sections covers the amount of the change and the reason(s) for the change.

3.1 Pension and OPEB

3.1.1 <u>Pension and OPEB Cash Amounts</u>

OPG is forecasting an overall increase of $251.5M in pension and OPEB cash amounts attributed to the nuclear facilities over the IR period, as detailed in Chart 3.1.1A below. This increase is primarily due to higher forecast pension contributions for 2019 to 2021, as a result of lower discount rates, partly offset by a decrease in forecast OPEB payments. The updated forecast of OPG's total pension and OPEB cash amounts was determined by its independent actuary, Aon Hewitt ("Aon"), using the same methodology as in the pre-filed evidence. Aon's report on the updated forecast of pension and OPEB cash amounts and accrual costs for 2017-2021 is provided in Attachment 2. As discussed in Ex. F4-3-2 and Ex. H1-1-1, OPG proposes to continue recording the difference between actual and forecast pension and OPEB cash amounts in the Pension & OPEB Cash Payment Variance Account.

Chart 3.1.1A

Revenue Requirement Changes – Nuclear Pension and OPEB Cash Amounts ($M)

Line No.		Reference	2017	2018	2019	2020	2021
	Pension:						
1	Original Submission	Ex. F4-3-2, Chart 1	171.1	175.5	180.3	157.2	162.1
2	N1 Update		200.0	202.9	243.5	247.9	250.6
3	Revenue Requirement Impact of Update	line 2 - line 1	28.9	27.4	63.2	90.7	88.5
	OPEB:						
4	Original Submission	Ex. F4-3-2, Chart 1	100.9	104.9	109.2	114.1	117.8
5	N1 Update		91.1	95.7	99.9	104.3	108.5
6	Revenue Requirement Impact of Update	line 5 - line 4	(9.8)	(9.2)	(9.3)	(9.8)	(9.3)
7	Total Revenue Req'ment Impact of Update	line 3 + line 6	19.1	18.3	53.8	81.0	79.3

In line with the 2017-2019 Business Plan, the updated forecast of cash amounts reflects the latest filed actuarial valuation of the OPG registered pension plan ("RPP") as of January 1, 2016, which sets out the minimum employer funding requirements for 2016 to 2018. The valuation was prepared and certified by Aon, and was filed with the Financial Services Commission of Ontario on September 30, 2016. As discussed in Ex. L-6.6-1 Staff-156, OPG made the decision to advance this valuation from January 1, 2017, in response to a decrease in long-term bond yields observed since the beginning of the year. The decrease in bond yields increased the likelihood of higher 2017 and 2018 contributions under a January 1, 2017 valuation, compared to a January 1, 2016 valuation. In addition, the January 1, 2016 valuation decreased OPG's 2016 pension contributions attributed to the nuclear facilities by approximately $80M. Further details and a copy of the January 1, 2016 funding valuation can be found at Ex. L-6.6-1 Staff-156.

The 2017-2019 Business Plan also reflects the projected results of the next funding valuation of the RPP as of the latest permitted date of January 1, 2019, which would set the minimum employer funding requirements for 2019 to 2021. Aon projected the results of this valuation by extrapolating information from, and using the same actuarial assumptions as, the January 1, 2016 filed valuation, updated for the decrease in solvency discount rates observed since the beginning of 2016.

As discussed in Ex. F4-3-2, minimum employer funding requirements pursuant to actuarial valuations of registered pension plans comprise current service cost (also known as normal cost), as well as going concern and solvency special payments towards the deficit, if required. The updated forecast reflects increased special payments over the IR period, as shown in Chart 3.1.1B below, mainly in the form of higher solvency special payments in 2019 to 2021 included in the 2017-2019 Business Plan based on the results of the January 1, 2019 projected valuation. In addition, the 2017-2019 Business Plan includes higher going concern special payments in 2017 and 2018, reflecting the results of the January 1, 2016 valuation.

Chart 3.1.1B

Components of Forecast Nuclear Pension Contributions ($M)

Line No.		Reference	2017	2018	2019	2020	2021
	Original Submission:						
1	Employer Normal Cost		157.2	161.6	166.3	157.2	162.1
2	Special Payments		13.9	13.9	14.0	-	-
3	Total Pension Contribution	Ex. F4-3-2, Chart 1	171.1	175.5	180.3	157.2	162.1
	N1 Update:						
4	Employer Normal Cost		155.8	158.6	161.7	166.1	170.9
5	Special Payments		44.3	44.3	81.8	81.8	79.8
6	Total Pension Contribution	Chart 3.1.1A, line 2	200.0	202.9	243.5	247.9	250.6
	Net Increase (Decrease):						
7	Employer Normal Cost	line 4 - line 1	(1.4)	(3.0)	(4.6)	8.9	8.8
8	Special Payments	line 5 - line 2	30.3	30.3	67.8	81.8	79.8
9	Total Pension Contribution	line 6 - line 3	28.9	27.4	63.2	90.7	88.5

The higher forecast special payments for 2019 to 2021 primarily result from a decrease in discount rates used to project solvency special payments. These rates are based on prescribed discount rates in effect at the time the projection is prepared. As noted in Ex. F4-3-2, p. 9, lines 18 to 21 and footnote 10, the discount rates for solvency valuations must be determined in accordance with specific standards of practice issued by the Canadian Institute of Actuaries, reflecting government of Canada bond yields and annuity purchase rates determined using information provided by insurance companies. The solvency discount rates reflected in the pre-filed evidence were based on end of 2015 information, as follows: 2.10% per annum for the first ten years and 3.70% per annum thereafter for commuted values and 3.20% per annum for annuity purchases. The updated forecast uses discount rates of 1.88% per annum for the first 10 years and 3.32% per annum thereafter for commuted values and 3.02% per annum for annuity purchases, determined as of mid-2016.[6] This decrease in the discount rates reflects the decline in long-term bond yields observed during the first half of 2016.

The updated forecast of OPEB payments for the IR period is lower than in the pre-filed evidence. As in the pre-filed evidence, cash amounts for OPEB represent forecast benefit payments to retirees and dependants in accordance with the provisions of the plans, and are based on estimated future cash flows used to project the corresponding benefit obligations. The lower forecast payments mainly result from lower per capita expected health care benefit costs and updated plan membership data as of January 1, 2016, both of which are included in the comprehensive accounting valuation discussed in section 3.1.2 below.

3.1.2 Pension and OPEB Accrual Costs

OPG is forecasting a net decrease of $21.2M in pension and OPEB accrual costs attributed to the nuclear facilities during the IR period, as detailed in Chart 3.1.2 below. OPG's total accrual costs for this period were determined by Aon in accordance with US GAAP, as detailed in Aon's report in Attachment 2. Other than the adoption of the Full Yield Curve

[6] The solvency discount rates used in the updated forecast reflect the assumed application of a smoothing (averaging) mechanism permitted under the *Pension Benefits Act* (Ontario). Smoothing has the effect of increasing discount rates used in the January 1, 2019 projected valuation and reducing the resulting projected solvency special payments for 2019 to 2021, relative to a solvency valuation without smoothing.

Approach to determining certain components of the pension and OPEB costs starting in 2017, discussed in section 3.1.2.1 below, the updated forecast was prepared using the same methodology as in the pre-filed evidence. The economic assumptions and pension plan asset values underpinning the updated forecast reflect market conditions as at June 30, 2016.

The updated forecast of the costs reflects an estimate of the impact of a new comprehensive accounting valuation to determine OPG's year-end 2016 plan obligations. As discussed in EB-2013-0321, comprehensive accounting valuations are conducted periodically to incorporate current demographics of plan membership, and update applicable assumptions to represent the current best estimate based on plan experience and current expectations.[7] The new comprehensive accounting valuation is triggered by the availability of more current information as a result of performing the January 1, 2016 funding valuation, and will ensure that OPG's accounting obligations continue to be fairly stated in accordance with US GAAP. The changes reflected as part of the new comprehensive accounting valuation are outlined in Aon's report in Attachment 2.

Chart 3.1.2

Updated Forecast of Nuclear Pension and OPEB Accrual Costs ($M)

Line No.		Reference	2017	2018	2019	2020	2021
	Pension:						
1	Original Submission	Ex. F4-3-2, Chart 1	222.8	167.5	153.0	140.0	131.4
2	N1 Update		214.4	174.0	166.2	163.5	163.8
3	Impact of Update	line 2 - line 1	(8.4)	6.5	13.2	23.5	32.4
	OPEB:						
4	Original Submission	Ex. F4-3-2, Chart 1	194.6	195.0	196.0	197.0	198.3
5	N1 Update		169.8	174.5	178.5	182.7	187.0
6	Impact of Update	line 5 - line 4	(24.8)	(20.5)	(17.5)	(14.3)	(11.3)
7	Total Impact of Update	line 3 + line 6	(33.2)	(13.9)	(4.3)	9.2	21.2

[7] For example, see EB-2013-0321 Ex. N1-1-1, section 2.2.1.

The overall decrease in the accrual costs compared to the pre-filed evidence reflects lower OPEB costs, partly offset by higher pension costs. The main factors contributing to the higher forecast pension costs include lower discount rates, the largely offsetting impact of adopting the Full Yield Curve Approach, actual asset performance during the first half of 2016, and updated membership data and other changes resulting from the new comprehensive accounting valuation. The decrease in projected OPEB costs is mainly driven by lower expected per capita health care benefit costs, reflecting lower costs of prescription drugs, as part of the comprehensive accounting valuation. This is partly offset by the impact of updated membership data and other changes in OPEB costs from the comprehensive accounting valuation. The effect of lower discount rates on OPEB costs is offset by the adoption of the Full Yield Curve Approach.

3.1.2.1 Discount Rates and Full Yield Curve Approach

To date, OPG has been determining the current service and interest cost components of pension and OPEB costs using the weighted-average discount rate reflected in the calculation of the plan benefit obligations, based on a AA corporate bond yield curve (the "Traditional Approach").[8] In particular, the current service cost is calculated by discounting the underlying future cash flows at the weighted-average interest rate implicit in the entire benefit obligation, and the interest cost is calculated by multiplying the benefit obligation by that same rate. This has been the generally accepted approach to determining pension and OPEB costs in accordance with US GAAP.

The pension and OPEB cost forecast in the pre-filed evidence was determined using the Traditional Approach, based on the December 31, 2015 yield curve. The resulting weighted-average discount rates used to project the costs for the IR period were 4.10% per annum for pension, 4.20% per annum for other post-retirement benefits, and 3.40% per annum for long-term disability benefits (Ex. F4-3-2, p. 17, Chart 5). As of June 30, 2016, these discount rates, determined using the same approach, decreased to 3.60%, 3.70%

[8] The components of pension and OPEB costs are described in Ex. F4-3-2, section 5.0.

and 2.80%, respectively. Under the Traditional Approach, this would have caused an increase in the forecast pension and OPEB costs relative to the pre-filed evidence.

Recently, the Full Yield Curve Approach has emerged as an acceptable alternative to the Traditional Approach under US GAAP, with a view to more precisely measuring the current service and interest cost components.[8a] While the same yield curve is used under both approaches, the Full Yield Curve Approach determines current service cost by applying individual spot interest rates from the yield curve to each future year's underlying projected benefit payments, and interest cost by multiplying individual spot rates from the yield curve by each year's present values of future projected benefit payments.[9]

OPG believes that the Full Yield Curve Approach will result in a more precise measurement of pension and OPEB costs and is adopting it starting with the 2017 fiscal year costs and the 2017-2019 Business Plan. OPG's external auditors, Ernst & Young LLP, have indicated that the adoption of the Full Yield Curve Approach will be acceptable as a prospective change in accordance with US GAAP. With an upward sloping yield curve and the pattern of OPG's estimated future benefit cash flows, the adoption of the Full Yield Curve Approach is expected to lower OPG's current service and interest cost components, reducing the overall projected pension and OPEB costs in the initial years following adoption, including during the IR period.[10]

8[a] The U.S. Securities and Exchange Commission ("SEC") staff has indicated that they will not object to the use of the spot rate approach (i.e. the Full Yield Curve Approach) for setting accounting discount rate under US GAAP. The SEC staff also stated that they would not object if the change from the single weighted-average rate approach to the spot rate approach is treated as a change in accounting estimate, which would support prospective application of the change. See Remarks before the 2015 AICPA National Conference on Current SEC and PCAOB Developments dated December 9, 2015, found at the following link: https://www.sec.gov/news/speech/remarks-at-2015-aicpa-conference-wright.html

[9] At page 7, Aon's report in Attachment 2 shows the single weighted average discount rates implicit in the current service cost and interest cost calculations under the Full Yield Curve Approach, which expectedly are different from the single weighted average discount rate shown for the overall obligation. Aon's report makes a further distinction under the Full Yield Curve Approach between the interest cost for the projected benefit obligation at the beginning of the period and the interest cost for the current service cost recorded during the period.

[10] As the Full Yield Curve Approach does not change the calculation of the benefit obligation, the decrease in the current service and interest cost components will give rise to offsetting reductions in actuarial gains (or an increase in actuarial losses). These offsetting impacts will be recognized in OPG's pension and OPEB costs over time, through amortization of actuarial gains/losses under the corridor approach in accordance with US GAAP. As a result, the overall net effect of the Full Yield Curve Approach on pension and OPEB costs is expected to diminish in the longer term.

3.1.3 Pension and OPEB Cash to Accrual Differential

Compared to the pre-filed evidence, the forecast excess of pension and OPEB accrual costs over cash amounts for the nuclear facilities is reduced by $272.4M for the IR period, mainly due to the higher pension contributions discussed above. As detailed in Chart 3.1.3 below, total IR period forecast pension cash amounts for the nuclear facilities are now higher than accrual amounts by $262.9M, while total forecast OPEB cash amounts are $393.0M lower than the accrual costs.

Chart 3.1.3

Updated Forecast of Nuclear Pension and OPEB Accrual to Cash Differential* ($M)

Line No.		2017	2018	2019	2020	2021
1	Pension	14.4	(28.9)	(77.2)	(84.4)	(86.8)
2	OPEB	78.7	78.8	78.6	78.4	78.5
3	**Total**	**93.1**	**49.9**	**1.4**	**(6.0)**	**(8.3)**

*positive values represent excess of accrual costs over cash amounts

3.2 Nuclear Liabilities

3.2.1 Summary of Revenue Requirement Changes

OPG is now seeking to recover a total after-tax revenue requirement impact of $2,022.2M in respect of the nuclear liabilities costs for both prescribed and Bruce facilities over the IR period, which reflects the 2017 ONFA Reference Plan effective January 1, 2017. As detailed in Chart 3.2.1, line 8 below, this represents a decrease of $271.2M compared to the pre-filed evidence, consisting of an increase of $279.6M for the prescribed facilities and a decrease of $550.8M for the Bruce facilities. The increase for the prescribed facilities is primarily due to an increase in regulatory income taxes associated with the expected reduction in segregated fund contributions as a result of lower Used Fuel Disposal program[11] cost estimates, and the accounting impact of higher Decommissioning cost estimates. The decrease for the Bruce facilities is driven primarily by the accounting impact of the lower Used Fuel Disposal program cost estimates.

[11] The five nuclear waste management and decommissioning programs are described at Ex. C2-1-1, p. 3.

The lower Used Fuel Disposal program costs estimates reflect 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 increased cost estimates associated with Decommissioning primarily relate to a better definition of work required during the preparation for safe storage after station shutdown, including de-watering and de-fueling of reactors, and a higher volume of waste forecast to be generated during decommissioning.

In addition to the above, as detailed in Chart 3.2.1, line 17 below, OPG is reducing the amount of regulatory income taxes sought for recovery over the IR period by $124.4M, as a result of an increase in forecast cash expenditures on nuclear waste management and decommissioning attributed to the prescribed facilities and changes in associated segregated fund disbursements, in line with the 2017-2019 Business Plan.[12] As discussed in Ex. F4-2-1, sections 3.2.3 and 3.2.4, cash expenditures incurred and charged against the nuclear liabilities represent an income tax deduction for OPG, while disbursements from the segregated funds are taxable. The higher forecast expenditures attributed to the prescribed facilities are consistent with the projected cost flows underpinning the 2017 ONFA Reference Plan.

[12] There are no changes in the proposed revenue requirement on account of changes in nuclear liability expenditures and associated segregated fund disbursements attributed to the Bruce facilities because these changes result in equal and offsetting changes in the current and deferred income tax expense components of Bruce Lease net revenues, with no net effect.

Chart 3.2.1

Summary of Revenue Requirement Changes – Nuclear Liabilities ($M)

Line No.		Refererence	2017	2018	2019	2020	2021
	Nuclear Liabilities Costs						
	Original Submission:						
1	Prescribed Facilities	Ex. C2-1-1 Table 1, line 8	144.9	137.7	120.6	180.4	137.5
2	Bruce Facilities	Ex. C2-1-1 Table 1, line 17	309.4	312.4	318.5	325.6	306.5
3	Total Revenue Requirement Impact of Nuclear Liabilities Costs	line 1 + line 2	454.3	450.1	439.1	506.0	444.0
	N1 Update:						
5	Prescribed Facilities	Ex. N1-1-1 Table 2, line 8	222.8	216.8	231.3	211.0	118.8
6	Bruce Facilities	Ex. N1-1-1 Table 2, line 17	208.6	200.5	204.1	210.3	198.1
7	Total Revenue Requirement Impact of Nuclear Liabilities Costs	line 5 + line 6	431.4	417.3	435.4	421.2	316.9
8	Revenue Requirement Impact of Update	line 7 - line 3	(22.9)	(32.8)	(3.7)	(84.8)	(127.0)
	Expenditures on Nuclear Waste Management and Decommissioning and Segregated Fund Disbursements						
	Original Submission:						
9	Expenditures on Nuclear Waste Management and Decommissioning *(deduction for regulatory tax purposes)*	Ex. F4-2-1 Table 3a, line 13	166.0	177.4	200.6	230.7	228.0
10	Segregated Fund Disbursements *(addition for regulatory tax purposes)*	Ex. F4-2-1 Table 3a, line 4	85.0	108.3	140.0	208.4	191.6
11	Regulatory Taxable Income impact	line 10 - line 9	(80.9)	(69.0)	(60.6)	(22.3)	(36.5)
12	Income Tax Impact	line 11 x 25% / (1-25%)	(27.0)	(23.0)	(20.2)	(7.4)	(12.2)
	N1 Update:						
13	Expenditures on Nuclear Waste Management and Decommissioning *(deduction for regulatory tax purposes)*	Ex. N1-1-1 Table 3, line 8	217.5	227.9	232.8	283.6	317.0
14	Segregated Fund Disbursements *(addition for regulatory tax purposes)*	Ex. N1-1-1 Table 3, line 15	84.4	85.7	120.4	152.0	193.7
15	Regulatory Taxable Income impact	line 13 + line 14	(133.1)	(142.2)	(112.4)	(131.6)	(123.3)
16	Income Tax Impact	line 15 x 25% / (1-25%)	(44.4)	(47.4)	(37.5)	(43.9)	(41.1)
17	Revenue Requirement Impact of Update	line 16 - line 12	(17.4)	(24.4)	(17.3)	(36.4)	(29.0)
18	Total Revenue Requirement Impact of Updates Related to Nuclear Liabilities	line 8 + line 17	(40.3)	(57.2)	(21.0)	(121.2)	(156.0)

3.2.2 Accounting and Revenue Requirement Impacts of Changes in Nuclear Liabilities Costs

The revenue requirement impact of changes in forecast nuclear liabilities costs is shown in Ex. N1-1-1 Table 2. These changes reflect the accounting impacts of the 2017 ONFA Reference Plan in accordance with US GAAP. These include a year-end 2016 projected adjustment to reduce the carrying balance of OPG's asset retirement obligation ("ARO") and asset retirement costs ("ARC") by $1,529.7M, comprising $237.9M for the prescribed facilities and $1,291.8M for the Bruce facilities.[13] This adjustment is detailed, by station and program, in Ex. N1-1-1 Table 5.

The year-end 2016 adjustment will represent the seventh tranche of OPG's ARO balance. Each tranche is calculated using a discount rate determined at the time of the adjustment. Unlike previous ARO adjustments, the projected year-end 2016 adjustment represents an overall downward revision in the undiscounted estimated cash flows underlying the obligation. As such, the adjustment will be calculated using the weighted average discount rate of the existing tranches, rather than a credit-adjusted risk-free rate determined as of the date of the ARO revision. The weighted average accretion rate of the total ARO balance after the adjustment is projected at approximately 4.95%.

The projected revenue requirement impact of changes in nuclear liabilities costs also reflects a projected reduction in segregated fund contributions, effective in 2017, based on the 2017 ONFA Reference Plan lifecycle liabilities and a projection of year-end 2016 segregated fund balances. The expected reduction in the contributions is due to an overall decrease in Used Fuel Disposal lifecycle liability estimates. The new segregated fund contributions are subject to confirmation by the Province.

[13] In addition, OPG expects to record an ARO increase of $4.4 million on December 31, 2016 (Ex. N1-1-1 Table 3, line 3 and Table 4, line 3) in relation to changes to cost estimates related to the implementation of 2012 CNSC requirements to include certain facilities with Waste Nuclear Substance Licenses. Although these facilities were not included in the 2012 ONFA Reference Plan (see Ex. C2-1-1 Table 2, Note 6), they are included in the 2017 ONFA Reference Plan. In accordance with GAAP, the ARO adjustment will be expensed in 2016 (i.e. not included in ARC), as it relates to a legacy facility not used to support OPG's current operations.

The changes in the 2017 to 2021 revenue requirement impacts of the nuclear liabilities costs are itemized in Ex. N1-1-1 Table 6. The methodologies applied in deriving these impacts are unchanged from those applied in the pre-filed evidence as well as previous proceedings. Updated continuity schedules showing the opening, closing and average balances of the segregated funds, ARO, unfunded nuclear liability and ARC are provided in Ex. N1-1-1 Table 3 (for the prescribed facilities) and Table 4 (for the Bruce facilities).

The changes in the revenue requirement impacts of the nuclear liabilities costs arise primarily as a result of the following:

- Higher ARC depreciation for the prescribed facilities reflecting an increase in the Pickering ARC depreciation, partly offset by a reduction in the Darlington ARC depreciation;
- Lower return on rate base for the prescribed facilities due to the net reduction in the projected ARC balance and a lower weighted average accretion rate;
- Lower ARC depreciation for the Bruce facilities due to the reduction in the projected ARC balance;
- Lower accretion expense for the Bruce facilities due to the decrease in the projected ARO balance;
- Higher L&ILW variable expenses for both prescribed and Bruce facilities, mainly due to higher per cubic metre cost rates reflecting an overall increase in L&ILW storage and disposal baseline cost estimates per the 2017 ONFA Reference Plan, and a lower accounting discount rate. The projected discount rate used to determine variable expenses in the 2017-2019 Business Plan is 2.63%, compared to 3.21% reflected in the pre-filed evidence based on December 31, 2015 information;[14]

[14] As incremental variable expenses represent increases in undiscounted cash flows underlying the ARO, they are calculated using a credit-adjusted risk-free rate as of the date of the latest ARO adjustment. This approach is followed irrespective of whether the latest ARO adjustment was calculated using a credit-adjusted risk-free rate or a weighted average discount rate of the existing tranches (i.e. depending on the direction of change in the underlying undiscounted cash flows). Therefore, the final L&ILW and used fuel variable cost rates will be calculated using the credit-adjusted risk-free discount rate determined as of December 31, 2016 (using the methodology described in Ex. L-8.2-1 Staff-207).

- Lower segregated fund earnings for the Bruce facilities due to lower forecast segregated fund contributions over the period;[15] and
- Higher income taxes for the prescribed facilities due to lower forecast segregated fund contributions and above noted increases in prescribed facilities' depreciation and L&ILW variable expenses.

3.3 Used Fuel and Waste Services Revenue under Bruce Lease

As discussed in Ex. G2-2-1, under the terms of the amended Bruce Lease, the used fuel revenue rate per fuel bundle (i.e. supplemental rent) and the L&ILW revenue rate per cubic metre of waste are based on prevailing ONFA cost estimates and are recalibrated in conjunction with each ONFA Reference Plan update. The updated used fuel and L&ILW rates effective January 1, 2017 were finalized by OPG subsequent to the OPG Board approval of the 2017-2019 Business Plan. Overall, the updated revenue rates are lower than those reflected in the pre-filed evidence, due to a reduction in the underlying cost estimates to manage these wastes based on the 2017 ONFA Reference Plan. Another key driver of the lower L&ILW revenues over the IR period is a reduction in forecast waste volumes provided by Bruce Power. The revenue requirement impact of the lower projected used fuel and L&ILW revenues during the IR period is shown in Chart 3.3 below.

[15] Segregated fund earnings continue to be forecast at 5.15% per annum consistent with the growth rate in the 2017 ONFA Reference Plan submitted to the Province.

Chart 3.3

Revenue Requirement Changes – Used Fuel and L&ILW Bruce Lease Revenues ($M)

Line No.		Refererence	2017	2018	2019	2020	2021
	Original Submission:						
1	Supplemental Rent Revenue (Used Fuel Fees)	Ex. G2-2-1 Table 2, line 6	184.5	176.0	187.5	200.7	161.2
2	Low and Intermediate Level Waste Services Revenue	Ex. G2-2-1 Table 2, line 2	28.9	32.5	31.2	30.0	35.5
3	Bruce Facilities' Current Income Taxes	(line 1 + line 2) x 25%	(53.3)	(52.1)	(54.7)	(57.7)	(49.2)
4	Bruce Lease Net Revenues Impact	line 1 + line 2 + line 3	160.0	156.3	164.0	173.1	147.5
5	Income Tax Impact	line 4 x 25% / (1-25%)	53.3	52.1	54.7	57.7	49.2
6	Revenue Requirement Impact	line 4 + line 5	213.4	208.5	218.7	230.8	196.7
	N1 Update:						
7	Supplemental Rent Revenue (Used Fuel Fees)		160.4	153.0	163.0	174.5	140.1
8	Low and Intermediate Level Waste Services Revenue		17.8	19.8	19.2	18.6	21.6
9	Bruce Facilities' Current Income Taxes	(line 7 + line 8) x 25%	(44.6)	(43.2)	(45.5)	(48.3)	(40.4)
10	Bruce Lease Net Revenues Impact	line 7 + line 8 + line 9	133.7	129.6	136.6	144.9	121.3
11	Income Tax Impact	line 10 x 25% / (1-25%)	44.6	43.2	45.5	48.3	40.4
12	Revenue Requirement Impact	line 10 + line 11	178.3	172.8	182.2	193.1	161.8
13	Revenue Requirement Impact of Update	line 6 - line 12	35.1	35.6	36.5	37.6	34.9

For comparative purposes, in Ex. N1-1-1 Tables 7 and 7a, OPG provides an updated view of total forecast Bruce Lease net revenues for the IR period that incorporates the above changes in used fuel and L&ILW revenues, as well as the changes in forecast nuclear liabilities costs outlined in section 3.2. The updated forecast of Bruce Lease net revenues over the IR period (Ex. N1-1-1 Table 7, line 30) is an increase of approximately $278M over the pre-filed evidence (Ex. G2-2-1 Table 1, line 9), which results in a reduction in the nuclear revenue requirement.

3.4 Return on Equity

OPG's pre-filed evidence reflects ROE calculated using the OEB's Cost of Capital parameters issued on October 15, 2015. The Application also proposes to set the final ROE for 2017 using the prevailing ROE value established by the OEB, and to use that value to determine the revenue requirement for 2018-2021 (Ex. C1-1-1, p.2, lines 24-30). On October 27, 2016, the OEB issued an update to the allowable ROE for 2017, lowering the rate from 9.19% to 8.78%. OPG has updated for this change by way of this Impact Statement, which results in an after-tax reduction of $69M to the requested 2017-2021 nuclear revenue requirement. Chart 3.4 below provides the details of this impact, by year.

Chart 3.4

Revenue Requirement Changes – Return on Equity ($M)

Line No.		Refererence	2017	2018	2019	2020	2021
1	Component of Nuclear Rate Base Financed by Common Equity	Ex. I1-1-1 Table 1, line 7	1,638.7	1,721.8	1,690.4	3,672.1	3,899.9
	Original Submission:						
2	Return on Equity (%)	Ex. C1-1-1 Tables 1-5, line 5	9.19%	9.19%	9.19%	9.19%	9.19%
3	Return on Equity	Ex. I1-1-1 Table 1, line 12	150.6	158.2	155.3	337.5	358.4
4	Income Tax Impact	line 3 x 25% / (1-25%)	50.2	52.7	51.8	112.5	119.5
5	Return on Equity Incl. Income Taxes	line 3 + line 4	200.8	211.0	207.1	450.0	477.9
					.		
	N1 Update:						
6	Return on Equity (%)		8.78%	8.78%	8.78%	8.78%	8.78%
7	Return on Equity	line 1 x line 6	143.9	151.2	148.4	322.4	342.4
8	Income Tax Impact	line 7 x 25% / (1-25%)	48.0	50.4	49.5	107.5	114.1
9	Return on Equity Incl. Income Taxes	line 7 + line 8	191.8	201.6	197.9	429.9	456.6
10	Revenue Requirement Impact of Update	line 9 - line 5	(9.0)	(9.4)	(9.2)	(20.1)	(21.3)

3.5 New CNSC Requirements

The 2017-2019 Business Plan includes Nuclear base OM&A costs for new regulatory requirements from the CNSC relating to Fitness for Duty. The CNSC will be publishing its formal Regulatory Document on Fitness for Duty related to employee drug, alcohol, psychological and physical testing (expected March 2017). The CNSC Regulatory Document has undergone a public comment period. This Regulatory Document will require OPG to design and implement a Fitness for Duty program with a scope that is anticipated to address testing for cause, pre-employment, post incident and random testing for workers in certain positions at OPG's nuclear plants. The 2017-2019 Business Plan assumes full compliance with the Regulatory Document to be required by 2019. These costs have been included in this update because they are driven by a regulatory requirement that is outside of OPG's control and exceed $10M per year for each year compliance is required (2019-2021).

The costs included in this update represent expected costs to implement the required Fitness for Duty initiative, including design, set up and implementation of a testing program, as well as for the ongoing operation of a testing program. The expected costs are $0.5M in 2017, $0.5M in 2018, $16.7M in 2019, $11.7M in 2020 and $11.7M in 2021.

3.6 Summary of Regulatory Income Tax Impacts

Changes in regulatory income taxes associated with each of the items included in this update are identified in the calculation of these items' impacts on the revenue requirement. For comparative purposes, in Ex. N1-1-1 Tables 8 and 8a, OPG provides an updated calculation of total nuclear regulatory income taxes for each year of the IR period, reflecting the changes associated with all of the updated items.

As shown at Ex. N1-1-1 Table 8, line 20, OPG projects nuclear regulatory taxable income for each year of the IR period, whereas the forecasts in the pre-filed evidence gave rise to nuclear regulatory tax losses in certain years (Ex. F4-2-1, Table 3a, line 20). These losses were carried back or forward, as appropriate, reducing regulatory income taxes in other IR period years, such that the losses were fully utilized by 2021 (Ex. F4-2-1, Table 3a, line 21). As a result of the elimination of the tax loss carry forwards in this update, the regulatory income taxes in individual IR period years change relative to the pre-filed evidence. These inter-period revenue requirement impacts are shown in Chart 2.0, line 7; they do not impact the total nuclear revenue requirement over the 2017-2021 period.

4.0 SUMMARY OF CHANGES IN APPROVALS SOUGHT

The items identified in this Impact Statement result in amendments to the following approvals sought by OPG in this Application for the IR period: (i) nuclear revenue requirements, (ii) nuclear rate base, and (iii) portion of the nuclear revenue requirements deferred under rate smoothing. The updated approvals are detailed below. Prior to the oral hearing, OPG will file with the OEB an amendment to Ex. A1-2-2 Approvals to reflect these changes and to Ex. A1-3-4 Drivers of Deficiency to reflect the changes in the drivers of revenue deficiency for the nuclear facilities over the IR period. As noted above, OPG is not updating its request for smoothed nuclear payment amounts or riders, and therefore there is no change to the annualized residential consumer impact of OPG's Application.

Nuclear Revenue Requirement

1. The approval of the following revised revenue requirements for the nuclear facilities, net of the nuclear stretch factor, for each year of the IR period:

Period	Revenue Requirement
January 1, 2017 through December 31, 2017	$3,201.8M
January 1, 2018 through December 31, 2018	$3,222.5M
January 1, 2019 through December 31, 2019	$3,309.6M
January 1, 2020 through December 31, 2020	$3,824.4M
January 1, 2021 through December 31, 2021	$3,437.8M

Nuclear Rate Base

2. The approval of the following revised rate base values for the nuclear facilities for each year of the IR period:[16]

Year	Rate Base
2017	$3,868.4M
2018	$3,960.6M
2019	$3,819.3M
2020	$7,786.2M
2021	$8,208.6M

[16] The changes to rate base values from the pre-filed evidence represent changes in forecast ARC balances, as a result of the projected year-end 2016 ARO/ARC adjustment to reflect changes in the nuclear liabilities related to the 2017 ONFA Reference Plan.

Deferred Nuclear Revenue Requirement

3. The approval of the deferred amounts resulting from the revised nuclear revenue requirements identified in item 1 above of $694M, $412M, $145M, $462M and $(97)M in 2017, 2018, 2019, 2020 and 2021, respectively, and as further illustrated below:

	2017	2018	2019	2020	2021
Proposed Revenue Requirement ($M)	$ 3,202	$ 3,223	$ 3,310	$ 3,824	$ 3,438
Forecast Production (TWh)	38.10	38.47	39.03	37.36	35.38
Smoothed Rate ($/MWh)	$ 65.81	$ 73.05	$ 81.09	$ 90.01	$ 99.91
Smoothed Revenue ($M)	$ 2,507	$ 2,810	$ 3,165	$ 3,362	$ 3,535
Deferred Revenue Requirement ($M)	$ 694	$ 412	$ 145	$ 462	$ (97)

LIST OF ATTACHMENTS

Attachment 1	OPG's 2017-2019 Business Plan
Attachment 2	Aon Hewitt Report on OPG's Estimated Pension and OPEB Costs for 2017-2021
Attachment 3	Updated Revenue Requirement Work Form
Attachment 4	Letter regarding Ontario Nuclear Funds Agreement Reference Plan

Filed December 19 2016

EB-2016-0152
Revenue Requirement Work Form

Ontario Power Generation

Ontario Power Generation

EB-2016-0152 Revenue Requirement Work Form

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Ontario Power Generation

EB-2016-0152 Revenue Requirement Work Form

Legend / Colour Scheme

Yellow	OPG Proposed Amounts
Light blue	Adjustment Input Cells For OEB Use
Green	Automatically Generated Calculations

OEB Adjustment Input Sheet

Total Generating Facilities

Line No.	Description	2017				2018			
		OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Capital Structure								
1	Common Equity	49.0%	49.0%		49.0%	49.0%	49.0%		49.0%
2	Debt	51.0%	51.0%	0.0%	51.0%	51.0%	51.0%	0.0%	51.0%
	Cost of Capital								
3	Short-Term Debt Facility Cost ($M)	2.6	2.6		2.6	2.6	2.6		2.6
4	Short-Term Debt Interest Cost ($M)	0.6	0.6		0.6	1.1	1.1		1.1
5	Short-Term Debt Cost ($M)	2.9	2.9		2.9	3.4	3.4		3.4
6	Regulated Portion of Short-Term Debt Cost Rate	92.67%	92.67%		92.67%	92.67%	92.67%		92.67%
7	Existing and Planned Long-Term Debt Cost Rate	4.89%	4.89%		4.89%	4.60%	4.60%		4.60%
8	Other Long-Term Debt Provision Cost Rate	4.89%	4.89%		4.89%	4.60%	4.60%		4.60%
9	Common Equity Cost Rate ROE	9.19%	8.78%		8.78%	9.19%	8.78%		8.78%
10	Adjustment for Lesser of UNL/ARC Cost Rate	5.11%	4.95%		4.95%	5.11%	4.95%		4.95%
	Capitalization ($M)								
11	Short-Term Debt Principal	37.1	37.1		37.1	37.1	37.1		37.1
12	Existing and Planned Long-Term Debt Principal	2,878.4	2,878.4		2,878.4	3,168.1	3,168.1		3,168.1
13	Adjustment for Lesser of UNL/ARC	775.4	524.0		524.0	725.1	446.7		446.7

Line No.	Description	2019				2020				2021			
		OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Capital Structure												
1	Common Equity	49.0%	49.0%		49.0%	49.0%	49.0%		49.0%	49.0%	49.0%		49.0%
2	Debt	51.0%	51.0%	0.0%	51.0%	51.0%	51.0%	0.0%	51.0%	51.0%	51.0%	0.0%	51.0%
	Cost of Capital												
3	Short-Term Debt Facility Cost ($M)	2.6	2.6		2.6	2.6	2.6		2.6	2.6	2.6		2.6
4	Short-Term Debt Interest Cost ($M)	1.5	1.5		1.5	1.5	1.5		1.5	1.5	1.5		1.5
5	Short-Term Debt Cost ($M)	3.8	3.8		3.8	3.8	3.8		3.8	3.8	3.8		3.8
6	Regulated Portion of Short-Term Debt Cost Rate	92.67%	92.67%		92.67%	92.67%	92.67%		92.67%	92.67%	92.67%		92.67%
7	Existing and Planned Long-Term Debt Cost Rate	4.52%	4.52%		4.52%	4.49%	4.49%		4.49%	4.48%	4.48%		4.48%
8	Other Long-Term Debt Provision Cost Rate	4.52%	4.52%		4.52%	4.49%	4.49%		4.49%	4.48%	4.48%		4.48%
9	Common Equity Cost Rate ROE	9.19%	8.78%		8.78%	9.19%	8.78%		8.78%	9.19%	8.78%		8.78%
10	Adjustment for Lesser of UNL/ARC Cost Rate	5.11%	4.95%		4.95%	5.11%	4.95%		4.95%	5.11%	4.95%		4.95%
	Capitalization ($M)												
11	Short-Term Debt Principal	37.1	37.1		37.1	37.1	37.1		37.1	37.1	37.1		37.1
12	Existing and Planned Long-Term Debt Principal	3,489.7	3,489.7		3,489.7	3,527.6	3,527.6		3,527.6	3,406.0	3,406.0		3,406.0
13	Adjustment for Lesser of UNL/ARC	674.9	369.5		369.5	624.6	292.2		292.2	590.1	249.6		249.6

Nuclear Facilities

Line No.	Description	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Rate Base ($M)								
14	Gross Plant at Cost	7,627.1	7,389.1		7,389.1	8,122.9	7,885.0		7,885.0
15	Accumulated Depreciation/Amortization	4,218.8	4,232.3		4,232.3	4,581.6	4,622.1		4,622.1
16	Cash Working Capital	11.0	11.0		11.0	11.0	11.0		11.0
17	Materials and Supplies	448.7	448.7		448.7	444.5	444.5		444.5
18	Nuclear Fuel Inventory	251.9	251.9		251.9	242.2	242.2		242.2
19	**Total**	**4,119.8**	**3,868.4**	**-**	**3,868.4**	**4,239.0**	**3,960.6**	**-**	**3,960.6**
	Expenses ($M)								
20	OM&A	2,318.6	2,346.0		2,346.0	2,327.1	2,351.4		2,351.4
21	Fuel	219.9	218.2		218.2	222.0	219.9		219.9
22	Depreciation/Amortization	346.9	373.9		373.9	378.7	405.7		405.7
23	Property Taxes	14.6	14.6		14.6	14.9	14.9		14.9
24	**Total**	**2,900.0**	**2,952.6**	**-**	**2,952.6**	**2,942.8**	**2,991.9**	**-**	**2,991.9**
	Other Revenues ($M)								
25	Bruce Lease Revenues Net of Direct Costs	(66.1)	(16.9)		(16.9)	(74.3)	(17.1)		(17.1)
26	Ancillary and Other Revenue	31.7	31.7		31.7	22.0	22.0		22.0
27	**Total**	**(34.5)**	**14.8**	**-**	**14.8**	**(52.4)**	**4.9**	**-**	**4.9**
28	**Forecast Production** (TWh)	**38.1**	**38.1**		**38.1**	**38.5**	**38.5**		**38.5**

Line No.	Description	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Rate Base ($M)												
14	Gross Plant at Cost	8,416.1	8,178.2		8,178.2	12,887.2	12,649.3		12,649.3	13,763.5	13,525.6		13,525.6
15	Accumulated Depreciation/Amortization	4,962.9	5,030.4		5,030.4	5,417.3	5,511.8		5,511.8	5,848.8	5,951.4		5,951.4
16	Cash Working Capital	11.0	11.0		11.0	11.0	11.0		11.0	11.0	11.0		11.0
17	Materials and Supplies	436.3	436.3		436.3	427.0	427.0		427.0	415.0	415.0		415.0
18	Nuclear Fuel Inventory	224.2	224.2		224.2	210.7	210.7		210.7	208.6	208.6		208.6
19	**Total**	**4,124.7**	**3,819.3**	**-**	**3,819.3**	**8,118.6**	**7,786.2**	**-**	**7,786.2**	**8,549.2**	**8,208.6**	**-**	**8,208.6**
	Expenses ($M)												
20	OM&A	2,347.9	2,425.1		2,425.1	2,368.0	2,469.0		2,469.0	2,248.7	2,349.1		2,349.1
21	Fuel	233.1	232.1		232.1	228.2	224.4		224.4	212.7	209.1		209.1
22	Depreciation/Amortization	384.0	411.0		411.0	524.9	551.9		551.9	338.1	327.3		327.3
23	Property Taxes	15.3	15.3		15.3	15.7	15.7		15.7	17.0	17.0		17.0
24	**Total**	**2,980.3**	**3,083.5**	**-**	**3,083.5**	**3,136.7**	**3,261.0**	**-**	**3,261.0**	**2,816.5**	**2,902.5**	**-**	**2,902.5**
	Other Revenues ($M)												
25	Bruce Lease Revenues Net of Direct Costs	(85.9)	(27.4)		(27.4)	(82.1)	(23.8)		(23.8)	(93.1)	(38.1)		(38.1)
26	Ancillary and Other Revenue	22.7	22.7		22.7	22.2	22.2		22.2	22.9	22.9		22.9
27	**Total**	**(63.2)**	**(4.7)**	**-**	**(4.7)**	**(59.9)**	**(1.6)**	**-**	**(1.6)**	**(70.2)**	**(15.1)**	**-**	**(15.1)**
28	**Forecast Production** (TWh)	**39.0**	**39.0**		**39.0**	**37.4**	**37.4**		**37.4**	**35.4**	**35.4**		**35.4**

OEB Adjustment Input Sheet

Line No.	Description	Nuclear Facilities 2017 OPG Proposed 5/27/2016 (a)	2017 Update 12/19/2016 (b)	2017 OEB Adjustment (c)	2017 OEB Approved (d)	2018 OPG Proposed 5/27/2016 (e)	2018 Update 12/19/2016 (f)	2018 OEB Adjustment (g)	2018 OEB Approved (h)	2019 OPG Proposed 5/27/2016 (i)	2019 Update 12/19/2016 (j)	2019 OEB Adjustment (k)	2019 OEB Approved (l)	2020 OPG Proposed 5/27/2016 (m)	2020 Update 12/19/2016 (n)	2020 OEB Adjustment (o)	2020 OEB Approved (p)	2021 OPG Proposed 5/27/2016 (q)	2021 Update 12/19/2016 (r)	2021 OEB Adjustment (s)	2021 OEB Approved (t)
	Applicable Tax Rates																				
29	Federal Rate	15.00%	15.00%		15.00%	15.00%	15.00%		15.00%	15.00%	15.00%		15.00%	15.00%	15.00%		15.00%	15.00%	15.00%		15.00%
30	Provincial Rate	10.00%	10.00%		10.00%	10.00%	10.00%		10.00%	10.00%	10.00%		10.00%	10.00%	10.00%		10.00%	10.00%	10.00%		10.00%
31	**Total Tax Rate**	**25.00%**	**25.00%**	**-**	**25.00%**	**25.00%**	**25.00%**	**-**	**25.00%**	**25.00%**	**25.00%**	**-**	**25.00%**	**25.00%**	**25.00%**	**-**	**25.00%**	**25.00%**	**25.00%**	**-**	**25.00%**
	Tax Credits and Payment Adjustments ($M)																				
32	SR&ED Investment	(18.4)	(18.4)		(18.4)	(18.4)	(18.4)		(18.4)	(18.4)	(18.4)		(18.4)	(18.4)	(18.4)		(18.4)	(18.4)	(18.4)		(18.4)
	Taxable Income Adjustments ($M)																				
	Additions																				
33	Depreciation and Amortization	346.9	373.9		373.9	378.7	405.7		405.7	384.0	411.0		411.0	524.9	551.9		551.9	338.1	327.3		327.3
34	Pension and OPEB Accrual	272.0	291.2		291.2	280.4	298.7		298.7	289.5	343.3		343.3	271.3	352.3		352.3	279.9	359.2		359.2
35	Regulatory Liability Amortization - Income and Other Taxes Variance Acct	(2.2)	(2.2)		(2.2)	(2.2)	(2.2)		(2.2)	-	-		-	-	-		-	-	-		-
36	Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct	(24.0)	(24.0)		(24.0)	(24.0)	(24.0)		(24.0)	-	-		-	-	-		-	-	-		-
37	Taxable SR&ED Investment Tax Credits	18.4	18.4		18.4	18.4	18.4		18.4	18.4	18.4		18.4	18.4	18.4		18.4	18.4	18.4		18.4
38	Adjustment Related to Financing Cost for Nuclear Liabilities	39.6	25.9		25.9	37.1	22.1		22.1	34.5	18.3		18.3	31.9	14.5		14.5	30.2	12.4		12.4
39	Nuclear Waste Management Expenses	57.8	63.9		63.9	59.8	63.2		63.2	72.1	77.9		77.9	61.9	66.5		66.5	63.1	68.8		68.8
40	Receipts from Nuclear Segregated Funds	85.0	84.4		84.4	108.3	85.7		85.7	140.0	120.4		120.4	208.4	152.0		152.0	191.6	193.7		193.7
41	Other	63.7	63.7		63.7	49.2	49.2		49.2	38.4	38.4		38.4	38.6	38.6		38.6	40.2	40.2		40.2
42	**Total Additions**	**857.2**	**895.2**	**-**	**895.2**	**905.7**	**916.9**	**-**	**916.9**	**976.8**	**1,027.6**	**-**	**1,027.6**	**1,155.4**	**1,194.1**	**-**	**1,194.1**	**961.4**	**1,019.9**	**-**	**1,019.9**
	Deductions																				
43	CCA	394.2	394.2		394.2	504.4	504.4		504.4	571.1	571.1		571.1	594.8	594.8		594.8	597.0	597.0		597.0
44	Cash Expenditures for Nuclear Waste & Decomissioning	166.0	217.5		217.5	177.4	227.9		227.9	200.6	232.8		232.8	230.7	283.6		283.6	228.0	317.0		317.0
45	Contributions to Nuclear Segregated Funds	156.1	-		-	175.3	-		-	265.7	-		-	35.2	-		-	35.2	-		-
46	Pension Plan Contributions	171.1	200.0		200.0	175.5	202.9		202.9	180.3	243.5		243.5	157.2	247.9		247.9	162.1	250.6		250.6
47	OPEB/SPP Payments	100.9	91.1		91.1	104.9	95.7		95.7	109.2	99.9		99.9	114.1	104.3		104.3	117.8	108.5		108.5
48	Deductible SR&ED Qualifying Expenditures	27.7	27.7		27.7	27.7	27.7		27.7	27.7	27.7		27.7	27.7	27.7		27.7	27.7	27.7		27.7
49	Other	20.3	20.3		20.3	0.1	0.1		0.1	1.1	1.1		1.1	5.7	5.7		5.7	16.5	16.5		16.5
50	**Total Deductions**	**1,036.2**	**950.9**	**-**	**950.9**	**1,165.4**	**1,058.8**	**-**	**1,058.8**	**1,355.7**	**1,176.0**	**-**	**1,176.0**	**1,165.4**	**1,264.1**	**-**	**1,264.1**	**1,184.3**	**1,317.4**	**-**	**1,317.4**

Line No.	Description	Deferral Accounts 2017 OPG Proposed 5/27/2016 (a)	2017 Update 12/19/2016 (b)	2017 OEB Adjustment (c)	2017 OEB Approved (d)	2018 OPG Proposed 5/27/2016 (e)	2018 Update 12/19/2016 (f)	2018 OEB Adjustment (g)	2018 OEB Approved (h)
	Hydroelectric Facilities ($M)								
51	Hydroelectric Water Conditions Variance	(8.7)	(8.7)		(8.7)	(8.7)	(8.7)		(8.7)
52	Ancillary Services Net Revenue Variance - Hydroelectric	(6.6)	(6.6)		(6.6)	(6.6)	(6.6)		(6.6)
53	Hydroelectric Incentive Mechanism Variance	(0.0)	(0.0)		(0.0)	(0.0)	(0.0)		(0.0)
54	Hydroelectric Surplus Baseload Generation Variance	41.2	41.2		41.2	41.2	41.2		41.2
55	Income and Other Taxes Variance - Hydroelectric	(0.0)	(0.0)		(0.0)	(0.0)	(0.0)		(0.0)
56	Capacity Refurbishment Variance - Hydroelectric	1.6	1.6		1.6	1.6	1.6		1.6
57	Pension and OPEB Cost Variance - Hydroelectric - Future	1.1	1.1		1.1	1.1	1.1		1.1
58	Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions	5.9	5.9		5.9	5.9	5.9		5.9
59	Pension & OPEB Cash Payment Variance - Hydroelectric	2.1	2.1		2.1	2.1	2.1		2.1
60	Hydroelectric Deferral and Variance Over/Under Recovery Variance	6.7	6.7		6.7	6.7	6.7		6.7
61	**Total**	**43.4**	**43.4**	**-**	**43.4**	**43.4**	**43.4**	**-**	**43.4**
	Nuclear Facilities ($M)								
62	Nuclear Development Variance	0.9	0.9		0.9	0.9	0.9		0.9
63	Ancillary Services Net Revenue Variance - Nuclear	0.5	0.5		0.5	0.5	0.5		0.5
64	Capacity Refurbishment Variance - Nuclear - Capital Portion	(18.8)	(18.8)		(18.8)	(18.8)	(18.8)		(18.8)
65	Capacity Refurbishment Variance - Nuclear - Non-Capital Portion	(15.8)	(15.8)		(15.8)	(15.8)	(15.8)		(15.8)
66	Bruce Lease Net Revenues Variance - Derivative Sub-Account	(34.3)	(34.3)		(34.3)	(34.3)	(34.3)		(34.3)
67	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions	10.3	10.3		10.3	10.3	10.3		10.3
68	Income and Other Taxes Variance - Nuclear	(2.2)	(2.2)		(2.2)	(2.2)	(2.2)		(2.2)
69	Pension and OPEB Cost Variance - Nuclear - Future	21.5	21.5		21.5	21.5	21.5		21.5
70	Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions	113.1	113.1		113.1	113.1	113.1		113.1
71	Pension & OPEB Cash Payment Variance - Nuclear	11.7	11.7		11.7	11.7	11.7		11.7
72	Nuclear Deferral and Variance Over/Under Recovery Variance	22.1	22.1		22.1	22.1	22.1		22.1
73	**Total**	**108.9**	**108.9**	**-**	**108.9**	**108.9**	**108.9**	**-**	**108.9**

OPG Rate Base and Cost of Capital

Line No.	Description	Total Generating Facilities				Nuclear Facilities															
		2017				2018				2019				2020				2021			
		OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
1	Nuclear Rate Base Financed by Capital Structure ($M)	3,344.4	3,344.4	-	3,344.4	3,513.9	3,513.9	-	3,513.9	3,449.8	3,449.8	-	3,449.8	7,494.0	7,494.0	-	7,494.0	7,959.1	7,959.1	-	7,959.1
2	Nuclear Allocation Factor	30.90%	30.90%	0.00%	30.90%	31.96%	31.96%	0.00%	31.96%	31.58%	31.58%	0.00%	31.58%	49.70%	49.70%	0.00%	49.70%	50.88%	50.88%	0.00%	50.88%

Line No.	Description	Nuclear Facilities																			
		2017				2018				2019				2020				2021			
		OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Capitalization ($M)																				
3	Total Rate Base	4,119.8	3,868.4	-	3,868.4	4,239.0	3,960.6	-	3,960.6	4,124.7	3,819.3	-	3,819.3	8,118.6	7,786.2	-	7,786.2	8,549.2	8,208.6	-	8,208.6
4	Adjustment for Lesser of UNL/ARC	775.4	524.0	-	524.0	725.1	446.7	-	446.7	674.9	369.5	-	369.5	624.6	292.2	-	292.2	590.1	249.6	-	249.6
5	**Rate Base Financed by Capital Structure**	**3,344.4**	**3,344.4**	**-**	**3,344.4**	**3,513.9**	**3,513.9**	**-**	**3,513.9**	**3,449.8**	**3,449.8**	**-**	**3,449.8**	**7,494.0**	**7,494.0**	**-**	**7,494.0**	**7,959.1**	**7,959.1**	**-**	**7,959.1**
6	**Common Equity**	**1,638.7**	**1,638.7**	**-**	**1,638.7**	**1,721.8**	**1,721.8**	**-**	**1,721.8**	**1,690.4**	**1,690.4**	**-**	**1,690.4**	**3,672.1**	**3,672.1**	**-**	**3,672.1**	**3,899.9**	**3,899.9**	**-**	**3,899.9**
7	Total Debt	1,705.6	1,705.6	-	1,705.6	1,792.1	1,792.1	-	1,792.1	1,759.4	1,759.4	-	1,759.4	3,821.9	3,821.9	-	3,821.9	4,059.1	4,059.1	-	4,059.1
8	Short-Term Debt	11.5	11.5	-	11.5	11.8	11.8	-	11.8	11.7	11.7	-	11.7	18.4	18.4	-	18.4	18.9	18.9	-	18.9
9	Existing and Planned Long-Term Debt	889.5	889.5	-	889.5	1,012.6	1,012.6	-	1,012.6	1,102.1	1,102.1	-	1,102.1	1,753.1	1,753.1	-	1,753.1	1,733.0	1,733.0	-	1,733.0
10	**Other Long-Term Debt Provision**	**804.6**	**804.6**	**-**	**804.6**	**767.7**	**767.7**	**-**	**767.7**	**645.6**	**645.6**	**-**	**645.6**	**2,050.4**	**2,050.4**	**-**	**2,050.4**	**2,307.3**	**2,307.3**	**-**	**2,307.3**
	Cost of Capital ($M)																				
11	Adjustment for Lesser of UNL/ARC	39.6	25.9	-	25.9	37.1	22.1	-	22.1	34.5	18.3	-	18.3	31.9	14.5	-	14.5	30.2	12.4	-	12.4
12	**Common Equity**	**150.6**	**143.9**	**-**	**143.9**	**158.2**	**151.2**	**-**	**151.2**	**155.3**	**148.4**	**-**	**148.4**	**337.5**	**322.4**	**-**	**322.4**	**358.4**	**342.4**	**-**	**342.4**
13	Existing and Planned Long-Term Debt	43.5	43.5	-	43.5	46.6	46.6	-	46.6	49.8	49.8	-	49.8	78.8	78.8	-	78.8	77.6	77.6	-	77.6
14	Other Long-Term Debt Provision	39.3	39.3	-	39.3	35.3	35.3	-	35.3	29.2	29.2	-	29.2	92.1	92.1	-	92.1	103.4	103.4	-	103.4

OPG Regulatory Income Taxes

Line No.	Description	Nuclear Generating Facilities																			
		2017				2018				2019				2020				2021			
		OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Applicable Tax Rates																				
1	Federal Rate	15.00%	15.00%	0.00%	15.00%	15.00%	15.00%	0.00%	15.00%	15.00%	15.00%	0.00%	15.00%	15.00%	15.00%	0.00%	15.00%	15.00%	15.00%	0.00%	15.00%
2	Provincial Rate	10.00%	10.00%	0.00%	10.00%	10.00%	10.00%	0.00%	10.00%	10.00%	10.00%	0.00%	10.00%	10.00%	10.00%	0.00%	10.00%	10.00%	10.00%	0.00%	10.00%
3	**Total Tax Rate**	**25.00%**	**25.00%**	0.00%	**25.00%**	**25.00%**	**25.00%**	0.00%	**25.00%**	**25.00%**	**25.00%**	0.00%	**25.00%**	**25.00%**	**25.00%**	0.00%	**25.00%**	**25.00%**	**25.00%**	0.00%	**25.00%**
	Taxable Income ($M)																				
4	Earnings Before Tax	198.3	171.2	-	171.2	214.2	152.5	-	152.5	222.8	160.5	-	160.5	470.8	413.7	-	413.7	503.2	383.6	-	383.6
5	Adjustments: Additions	857.2	895.2	-	895.2	905.7	916.9	-	916.9	976.8	1,027.6	-	1,027.6	1,155.4	1,194.1	-	1,194.1	961.4	1,019.9	-	1,019.9
6	Adjustments: Deductions	1,036.2	950.9	-	950.9	1,165.4	1,058.8	-	1,058.8	1,355.7	1,176.0	-	1,176.0	1,165.4	1,264.1	-	1,264.1	1,184.3	1,317.4	-	1,317.4
7	Tax Loss Carry Over	(19.3)	-		-	45.5	-		-	156.1	-		-	(182.3)	-		-	-	-		-
8	**Total Taxable Income**	**0.0**	**115.5**	**-**	**115.5**	**0.0**	**10.6**	**-**	**10.6**	**0.0**	**12.0**	**-**	**12.0**	**278.4**	**343.7**	**-**	**343.7**	**280.2**	**86.2**	**-**	**86.2**
	Income Taxes ($M)																				
9	Federal Income Taxes	0.0	17.3	-	17.3	0.0	1.6	-	1.6	0.0	1.8	-	1.8	41.8	51.6	-	51.6	42.0	12.9	-	12.9
10	Provincial Income Taxes	0.0	11.6	-	11.6	0.0	1.1	-	1.1	0.0	1.2	-	1.2	27.8	34.4	-	34.4	28.0	8.6	-	8.6
11	Tax Credits (SR&ED Investment)	(18.4)	(18.4)	-	(18.4)	(18.4)	(18.4)	-	(18.4)	(18.4)	(18.4)	-	(18.4)	(18.4)	(18.4)	-	(18.4)	(18.4)	(18.4)	-	(18.4)
12	**Total Income Taxes**	**(18.4)**	**10.5**	-	**10.5**	**(18.4)**	**(15.8)**	-	**(15.8)**	**(18.4)**	**(15.4)**	-	**(15.4)**	**51.2**	**67.5**	-	**67.5**	**51.7**	**3.2**	-	**3.2**
	Earnings Before Tax ($M)																				
13	**Requested After Tax ROE**	**150.6**	**143.9**	**-**	**143.9**	**158.2**	**151.2**	**-**	**151.2**	**155.3**	**148.4**	**-**	**148.4**	**337.5**	**322.4**	**-**	**322.4**	**358.4**	**342.4**	**-**	**342.4**
14	Bruce Lease Net Revenues	(66.1)	(16.9)	-	(16.9)	(74.3)	(17.1)	-	(17.1)	(85.9)	(27.4)	-	(27.4)	(82.1)	(23.8)	-	(23.8)	(93.1)	(38.1)	-	(38.1)
15	Total Regulatory Income Taxes After Tax Loss Carry-Over	(18.4)	10.5		10.5	(18.4)	(15.8)		(15.8)	(18.4)	(15.4)		(15.4)	51.2	67.5		67.5	51.7	3.2		3.2
16	**Total Earnings Before Tax**	**198.3**	**171.2**	**-**	**171.2**	**214.2**	**152.5**	**-**	**152.5**	**222.8**	**160.5**	**-**	**160.5**	**470.8**	**413.7**	**-**	**413.7**	**503.2**	**383.6**	**-**	**383.6**
	Adjustments ($M)																				
	Additions																				
16	Depreciation and Amortization	346.9	373.9	-	373.9	378.7	405.7	-	405.7	384.0	411.0	-	411.0	524.9	551.9	-	551.9	338.1	327.3	-	327.3
17	Pension and OPEB Accrual	272.0	291.2	-	291.2	280.4	298.7	-	298.7	289.5	343.3	-	343.3	271.3	352.3	-	352.3	279.9	359.2	-	359.2
18	Regulatory Liability Amortization - Income and Other Taxes Variance Account	(2.2)	(2.2)	-	(2.2)	(2.2)	(2.2)	-	(2.2)	-	-	-	-	-	-	-	-	-	-	-	-
19	Regulatory Asset Amortization - Bruce Regulatory Asset	(24.0)	(24.0)	-	(24.0)	(24.0)	(24.0)	-	(24.0)	-	-	-	-	-	-	-	-	-	-	-	-
20	Taxable SR&ED Investment Tax Credits	18.4	18.4	-	18.4	18.4	18.4	-	18.4	18.4	18.4	-	18.4	18.4	18.4	-	18.4	18.4	18.4	-	18.4
21	Adjustment Related to Financing Cost for Nuclear Liabilities	39.6	25.9	-	25.9	37.1	22.1	-	22.1	34.5	18.3	-	18.3	31.9	14.5	-	14.5	30.2	12.4	-	12.4
22	Nuclear Waste Management Expenses	57.8	63.9	-	63.9	59.8	63.2	-	63.2	72.1	77.9	-	77.9	61.9	66.5	-	66.5	63.1	68.8	-	68.8
23	Receipts from Nuclear Segregated Funds	85.0	84.4	-	84.4	108.3	85.7	-	85.7	140.0	120.4	-	120.4	208.4	152.0	-	152.0	191.6	193.7	-	193.7
24	Other	63.7	63.7	-	63.7	49.2	49.2	-	49.2	38.4	38.4	-	38.4	38.6	38.6	-	38.6	40.2	40.2	-	40.2
25	**Total Additions**	**857.2**	**895.2**	**-**	**895.2**	**905.7**	**916.9**	**-**	**916.9**	**976.8**	**1,027.6**	**-**	**1,027.6**	**1,155.4**	**1,194.1**	**-**	**1,194.1**	**961.4**	**1,019.9**	**-**	**1,019.9**
	Deductions																				
26	CCA	394.2	394.2	-	394.2	504.4	504.4	-	504.4	571.1	571.1	-	571.1	594.8	594.8	-	594.8	597.0	597.0	-	597.0
27	Cash Expenditures for Nuclear Waste & Decomissioning	166.0	217.5	-	217.5	177.4	227.9	-	227.9	200.6	232.8	-	232.8	230.7	283.6	-	283.6	228.0	317.0	-	317.0
28	Contributions to Nuclear Segregated Funds and Earnings	156.1	-	-	-	175.3	-	-	-	265.7	-	-	-	35.2	-	-	-	35.2	-	-	-
29	Pension Plan Contributions	171.1	200.0	-	200.0	175.5	202.9	-	202.9	180.3	243.5	-	243.5	157.2	247.9	-	247.9	162.1	250.6	-	250.6
30	OPEB Payments	100.9	91.1	-	91.1	104.9	95.7	-	95.7	109.2	99.9	-	99.9	114.1	104.3	-	104.3	117.8	108.5	-	108.5
31	SR&ED Costs Capitalized for Accounting	27.7	27.7	-	27.7	27.7	27.7	-	27.7	27.7	27.7	-	27.7	27.7	27.7	-	27.7	27.7	27.7	-	27.7
32	Other	20.3	20.3	-	20.3	0.1	0.1	-	0.1	1.1	1.1	-	1.1	5.7	5.7	-	5.7	16.5	16.5	-	16.5
33	**Total Deductions**	**1,036.2**	**950.9**	**-**	**950.9**	**1,165.4**	**1,058.8**	**-**	**1,058.8**	**1,355.7**	**1,176.0**	**-**	**1,176.0**	**1,165.4**	**1,264.1**	**-**	**1,264.1**	**1,184.3**	**1,317.4**	**-**	**1,317.4**

Numbers may not add due to rounding

OPG Revenue Requirement

		Nuclear Facilities																			
		2017				2018				2019				2020				2021			
Line No.	Description	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Cost of Capital ($M)																				
1	Short-term Debt	0.9	0.9	0.0	0.9	1.1	1.1	0.0	1.1	1.2	1.2	0.0	1.2	1.9	1.9	0.0	1.9	1.9	1.9	0.0	1.9
2	Long-Term Debt	82.8	82.8	0.0	82.8	81.9	81.9	0.0	81.9	79.0	79.0	0.0	79.0	170.9	170.9	0.0	170.9	181.0	181.0	0.0	181.0
3	ROE	150.6	143.9	0.0	143.9	158.2	151.2	0.0	151.2	155.3	148.4	0.0	148.4	337.5	322.4	0.0	322.4	358.4	342.4	0.0	342.4
4	Adjustment for Lesser of UNL/ARC	39.6	25.9		25.9	37.1	22.1		22.1	34.5	18.3		18.3	31.9	14.5		14.5	30.2	12.4		12.4
5	**Total**	**273.9**	**253.5**	0.0	253.5	**278.2**	**256.2**	0.0	256.2	**270.1**	**246.9**	0.0	246.9	**542.1**	**509.6**	0.0	509.6	**571.5**	**537.7**	0.0	537.7
	Expenses ($M)																				
6	OM&A	2,318.6	2,346.0	0.0	2,346.0	2,327.1	2,351.4	0.0	2,351.4	2,347.9	2,425.1	0.0	2,425.1	2,368.0	2,469.0	0.0	2,469.0	2,248.7	2,349.1	0.0	2,349.1
7	Fuel	219.9	218.2	0.0	218.2	222.0	219.9	0.0	219.9	233.1	232.1	0.0	232.1	228.2	224.4	0.0	224.4	212.7	209.1	0.0	209.1
8	Depreciation/Amortization	346.9	373.9	0.0	373.9	378.7	405.7	0.0	405.7	384.0	411.0	0.0	411.0	524.9	551.9	0.0	551.9	338.1	327.3	0.0	327.3
9	Property Taxes	14.6	14.6	0.0	14.6	14.9	14.9	0.0	14.9	15.3	15.3	0.0	15.3	15.7	15.7	0.0	15.7	17.0	17.0	0.0	17.0
10	**Total**	**2,900.0**	**2,952.6**	0.0	2,952.6	**2,942.8**	**2,991.9**	0.0	2,991.9	**2,980.3**	**3,083.5**	0.0	3,083.5	**3,136.7**	**3,261.0**	0.0	3,261.0	**2,816.5**	**2,902.5**	0.0	2,902.5
	Other Revenues ($M)																				
11	Bruce Lease Net Revenues	(66.1)	(16.9)		(16.9)	(74.3)	(17.1)		(17.1)	(85.9)	(27.4)		(27.4)	(82.1)	(23.8)		(23.8)	(93.1)	(38.1)		(38.1)
12	Ancillary and Other Revenue	31.7	31.7	0.0	31.7	22.0	22.0	0.0	22.0	22.7	22.7	0.0	22.7	22.2	22.2	0.0	22.2	22.9	22.9	0.0	22.9
13	**Total**	**(34.5)**	**14.8**	0.0	14.8	**(52.4)**	**4.9**	0.0	4.9	**(63.2)**	**(4.7)**	0.0	(4.7)	**(59.9)**	**(1.6)**	0.0	(1.6)	**(70.2)**	**(15.1)**	0.0	(15.1)
14	**Regulatory Income Tax** ($M)	**(18.4)**	**10.5**	0.0	10.5	**(18.4)**	**(15.8)**	(0.0)	(15.8)	**(18.4)**	**(15.4)**	0.0	(15.4)	**51.2**	**67.5**	0.0	67.5	**51.7**	**3.2**	0.0	3.2
15	**Revenue Requirement** ($M)	**3,189.9**	**3,201.8**	0.0	3,201.8	**3,255.0**	**3,227.5**	0.0	3,227.5	**3,295.1**	**3,319.8**	0.0	3,319.8	**3,790.0**	**3,839.8**	0.0	3,839.8	**3,509.8**	**3,458.4**	0.0	3,458.4

Numbers may not add due to rounding

OPG Revenue Requirement Deficiency / (Sufficiency)

Nuclear Facilities

Line No.	Description	2017 OPG Proposed 5/27/2016 (a)	2017 Update 12/19/2016 (b)	2017 OEB Adjustment (c)	2017 OEB Approved (d)	2018 OPG Proposed 5/27/2016 (e)	2018 Update 12/19/2016 (f)	2018 OEB Adjustment (g)	2018 OEB Approved (h)
	Production & Revenue								
1	Forecast Production (TWh)	38.1	38.1	0.0	38.1	38.5	38.5	0.0	38.5
2	Current Payment Rate ($/MWh)	59.29	59.29	0.00	59.29	59.29	59.29	0.00	59.29
3	**Revenue From Current Payment Rate ($M)**	**2,258.9**	**2,258.9**	**0.0**	**2,258.9**	**2,280.9**	**2,280.9**	**0.0**	**2,280.9**
	Revenue Requirement								
4	Revenue Requirement ($M)	3,189.9	3,201.8	0.0	3,201.8	3,255.0	3,227.5	0.0	3,227.5
5	**Revenue Requirement Deficiency (Sufficiency)** ($M)	**931.1**	**943.0**	0.0	**943.0**	**974.0**	**946.6**	0.0	**946.6**

Line No.	Description	2019 OPG Proposed 5/27/2016 (i)	2019 Update 12/19/2016 (j)	2019 OEB Adjustment (k)	2019 OEB Approved (l)	2020 OPG Proposed 5/27/2016 (m)	2020 Update 12/19/2016 (n)	2020 OEB Adjustment (o)	2020 OEB Approved (p)	2021 OPG Proposed 5/27/2016 (q)	2021 Update 12/19/2016 (r)	2021 OEB Adjustment (s)	2021 OEB Approved (t)
	Production & Revenue												
1	Forecast Production (TWh)	39.0	39.0	0.0	39.0	37.4	37.4	0.0	37.4	35.4	35.4	0.0	35.4
2	Current Payment Rate ($/MWh)	59.29	59.29	0.00	59.29	59.29	59.29	0.00	59.29	59.29	59.29	0.00	59.29
3	**Revenue From Current Payment Rate ($M)**	**2,313.9**	**2,313.9**	**0.0**	**2,313.9**	**2,214.8**	**2,214.8**	**0.0**	**2,214.8**	**2,097.9**	**2,097.9**	**0.0**	**2,097.9**
	Revenue Requirement												
4	Revenue Requirement ($M)	3,295.1	3,319.8	0.0	3,319.8	3,790.0	3,839.8	0.0	3,839.8	3,509.8	3,458.4	0.0	3,458.4
5	**Revenue Requirement Deficiency (Sufficiency)** ($M)	**981.2**	**1,005.9**	0.0	**1,005.9**	**1,575.2**	**1,625.0**	0.0	**1,625.0**	**1,411.9**	**1,360.6**	0.0	**1,360.6**

Numbers may not add due to rounding

OPG Requested Payment Amounts

		Hydroelectric Facilities																			
		2017				2018				2019				2020				2021			
Line No.	Description	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
1	**Requested Payment Amount ($/MWh)**	41.71	41.71		41.71	42.33	42.33		42.33	42.97	42.97		42.97	43.61	43.61		43.61	44.27	44.27		44.27

		Nuclear Facilities																			
		2017				2018				2019				2020				2021			
Line No.	Description	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
2	Revenue Requirement ($M)	3,189.9	3,201.8	0.0	3,201.8	3,255.0	3,227.5	0.0	3,227.5	3,295.1	3,319.8	0.0	3,319.8	3,790.0	3,839.8	0.0	3,839.8	3,509.8	3,458.4	0.0	3,458.4
3	Stretch Adjustment ($M)	N/A	N/A	N/A	N/A	5.0	5.0	0.0	5.0	10.1	10.2	0.0	10.2	15.2	15.3	0.0	15.3	20.4	20.6	0.0	20.6
4	Forecast Production (TWh)	38.1	38.1	0.0	38.1	38.5	38.5	0.0	38.5	39.0	39.0	0.0	39.0	37.4	37.4	0.0	37.4	35.4	35.4	0.0	35.4
5	**Unsmoothed Payment Amount ($/MWh)**	83.73	84.04	-	84.04	84.48	83.77	-	83.77	84.17	84.81	-	84.81	101.05	102.38	-	102.38	98.62	97.16	-	97.16
6	**Smoothed Payment Amount (11%)**	65.81	65.81	-	65.81	73.05	73.05	-	73.05	81.09	81.09	-	81.09	90.01	90.01	-	90.01	99.91	99.91	-	99.91

Numbers may not add due to rounding

OPG Recovery of Deferral and Variance Accounts and Riders

Line No.	Description	Previously Regulated Hydroelectric Facilities — Amortization 2017/2018: OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)
	Variance Accounts ($M)				
1	Hydroelectric Water Conditions Variance	(17.3)	(17.3)	0.0	(17.3)
2	Ancillary Services Net Revenue Variance - Hydroelectric	(13.2)	(13.2)	0.0	(13.2)
3	Hydroelectric Incentive Mechanism Variance	(0.1)	(0.1)	0.0	(0.1)
4	Hydroelectric Surplus Baseload Generation Variance	82.5	82.5	0.0	82.5
5	Income and Other Taxes Variance - Hydroelectric	(0.0)	(0.0)	0.0	(0.0)
6	Capacity Refurbishment Variance - Hydroelectric	3.3	3.3	0.0	3.3
7	Pension and OPEB Cost Variance - Hydroelectric - Future	2.1	2.1	0.0	2.1
8	Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions	11.8	11.8	0.0	11.8
9	Pension & OPEB Cash Payment Variance - Hydroelectric	4.3	4.3	0.0	4.3
10	Hydroelectric Deferral and Variance Over/Under Recovery Variance	13.5	13.5	0.0	13.5
11	**Total**	**86.8**	**86.8**	0.0	**86.8**
12	**2015 Actual Production (divided by 12, multiplied by 24)** (TWh)	**60.5**	**60.5**	0.0	**60.5**
13	**Rider** ($/MWh) (Line 12 / Line 13)	**1.44**	**1.44**	0.0	**1.44**

Line No.	Description	Nuclear Facilities — Amortization 2017/2018: OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)
	Variance Accounts ($M)				
14	Nuclear Development Variance	1.7	1.7	0.0	1.7
15	Ancillary Services Net Revenue Variance - Nuclear	1.0	1.0	0.0	1.0
16	Capacity Refurbishment Variance - Nuclear - Capital Portion	(37.6)	(37.6)	0.0	(37.6)
17	Capacity Refurbishment Variance - Nuclear - Non-Capital Portion	(31.6)	(31.6)	0.0	(31.6)
18	Bruce Lease Net Revenues Variance - Derivative Sub-Account	(68.6)	(68.6)	0.0	(68.6)
19	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions	20.6	20.6	0.0	20.6
20	Income and Other Taxes Variance - Nuclear	(4.3)	(4.3)	0.0	(4.3)
21	Pension and OPEB Cost Variance - Nuclear - Future	42.9	42.9	0.0	42.9
22	Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions	226.2	226.2	0.0	226.2
23	Pension & OPEB Cash Payment Variance - Nuclear	23.4	23.4	0.0	23.4
24	Nuclear Deferral and Variance Over/Under Recovery Variance	44.1	44.1	0.0	44.1
25	**Total**	**217.9**	**217.9**	0.0	**217.9**
26	**Forecast Production** (TWh)	**76.6**	**76.6**	0.0	**76.6**
27	**Rider** ($/MWh) (Line 28 / Line 29)	**2.85**	**2.85**	0.0	**2.85**

Numbers may not add due to rounding

OPG Customer Bill Impacts

Line No.	Description	Residential Consumers																			
		2013-0321/2014-0370 >> EB-2016-0152				EB-2016-0152				EB-2016-0152				EB-2016-0152				EB-2016-0152			
		2017				2018				2019				2020				2021			
		OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Production and Demand																				
1	Typical Usage, including Line Losses[1] (kWh/Month)	789.4	789.4	n/a	789.4	789.4	789.4	n/a	789.4	789.4	789.4	n/a	789.4	789.4	789.4	n/a	789.4	789.4	789.4	n/a	789.4
2	Forecast Production (TWh)	68.3	68.3	-	68.3	68.7	68.7	-	68.7	69.3	69.3	-	69.3	67.6	67.6	-	67.6	65.6	65.6	-	65.6
3	IESO Forecast Provincial Demand[2] (TWh)	137.6	137.6	n/a	137.6	137.6	137.6	n/a	137.6	137.6	137.6	n/a	137.6	137.6	137.6	n/a	137.6	137.6	137.6	n/a	137.6
4	OPG Proportion of Consumer Usage (line 2 / line 3)	49.7%	49.7%	0.0%	49.7%	49.9%	49.9%	0.0%	49.9%	50.3%	50.3%	0.0%	50.3%	49.1%	49.1%	0.0%	49.1%	47.7%	47.7%	0.0%	47.7%
5	Typical Usage of OPG Generation (kWh/Month) (line 1 x line 4)	392	392	-	392	394	394	-	394	397	397	-	397	388	388	-	388	376	376	-	376
6	**Typical Bill[1] ($/Month)**	**150.58**	**150.58**	n/a	**150.58**	**150.58**	**150.58**	n/a	**150.58**	**150.58**	**150.58**	n/a	**150.58**	**150.58**	**150.58**	n/a	**150.58**	**150.58**	**150.58**	n/a	**150.58**
	Production-Weighted Average Rates																				
7	Prior Year weighted average rate with proposed payment amounts and riders ($/MWh)	60.66	60.66	-	60.66	57.37	57.37	-	57.37	61.76	61.76	-	61.76	64.45	64.45	-	64.45	69.26	69.26	-	69.26
8	Current Year weighted average rate with proposed payment amounts and riders ($/MWh)	57.37	57.37	-	57.37	61.76	61.76	-	61.76	64.45	64.45	-	64.45	69.26	69.26	-	69.26	74.27	74.27	-	74.27
	Impact																				
9	**Typical Bill Impact** ($/Month)	**(1.29)**	**(1.29)**	**-**	**(1.29)**	**1.73**	**1.73**	**-**	**1.73**	**1.07**	**1.07**	**-**	**1.07**	**1.86**	**1.86**	**-**	**1.86**	**1.89**	**1.89**	**-**	**1.89**
10	**Percentage Change of Typical Bill** (line 9 / line 6)	**-0.9%**	**-0.9%**	**0.0%**	**-0.9%**	**1.1%**	**1.1%**	**0.0%**	**1.1%**	**0.7%**	**0.7%**	**0.0%**	**0.7%**	**1.2%**	**1.2%**	**0.0%**	**1.2%**	**1.3%**	**1.3%**	**0.0%**	**1.3%**

Line No.	Description	2013-0321/2014-0370			
		Current Rates			
		OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)
	Payment Amounts ($MWh)				
11	Regulated Hydroelectric	40.72	40.72	n/a	40.72
12	Nuclear	59.29	59.29	n/a	59.29
	Riders ($MWh)				
13	Regulated Hydroelectric	3.83	3.83	n/a	3.83
14	Nuclear	13.01	13.01	n/a	13.01
	Total Annual Rates ($MWh)				
15	Regulated Hydroelectric	44.55	44.55	n/a	44.55
16	Nuclear	72.30	72.30	n/a	72.30
	Forecast Production EB-2016-0152 (TWh)				
17	Regulated Hydroelectric	33.8	33.8	n/a	33.83
18	Nuclear	46.8	46.8	-	46.8
19	**Total**	**80.6**	**80.6**	**-**	**80.6**
	Production-Weighted Average Rates ($MWh)				
20	Regulated Hydroelectric	18.69	18.69	n/a	18.69
21	Nuclear	41.97	41.97	-	41.97
22	**Total** (line 20 + line 21)	**60.66**	**60.66**	**-**	**60.66**
23	**Total Production-Weighted Average Rate** ($MWh)	**60.66**	**60.66**	**-**	**60.66**

Line No.	Description	EB-2016-0152				EB-2016-0152				EB-2016-0152				EB-2016-0152				EB-2016-0152			
		Proposed Rates				Proposed Rates				Proposed Rates				Proposed Rates				Proposed Rates			
		2017				2018				2019				2020				2021			
		OPG Proposed 5/27/2016	N1 Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 7/9/1905	N1 Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 7/9/1905	N1 Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 7/9/1905	N1 Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 7/9/1905	N1 Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Payment Amounts ($MWh)																				
24	Regulated Hydroelectric	41.71	41.71	-	41.71	42.33	42.33	-	42.33	42.97	42.97	-	42.97	43.61	43.61	-	43.61	44.27	44.27	-	44.27
25	Nuclear	65.81	65.81	-	65.81	73.05	73.05	-	73.05	81.09	81.09	-	81.09	90.01	90.01	-	90.01	99.91	99.91	-	99.91
	Riders ($MWh)																				
26	Regulated Hydroelectric	1.44	1.44	-	1.44	1.44	1.44	-	1.44												
27	Nuclear	2.85	2.85	-	2.85	2.85	2.85	-	2.85												
	Total Annual Rates ($MWh)																				
28	Regulated Hydroelectric	43.14	43.14	-	43.14	43.77	43.77	-	43.77	42.97	42.97	-	42.97	43.61	43.61	-	43.61	44.27	44.27	-	44.27
29	Nuclear	68.66	68.66	-	68.66	75.90	75.90	-	75.90	81.09	81.09	-	81.09	90.01	90.01	-	90.01	99.91	99.91	-	99.91
	Forecast Production EB-2016-0152 (TWh)																				
30	Regulated Hydroelectric	30.2	30.2	n/a	30.23	30.2	30.2	n/a	30.23	30.2	30.2	n/a	30.23	30.2	30.2	n/a	30.23	30.2	30.2	n/a	30.23
31	Nuclear	38.1	38.1	-	38.1	38.5	38.5	-	38.5	39.0	39.0	-	39.0	37.4	37.4	-	37.4	35.4	35.4	-	35.4
32	**Total**	**68.3**	**68.3**	**-**	**68.3**	**68.7**	**68.7**	**-**	**68.7**	**69.3**	**69.3**	**-**	**69.3**	**67.6**	**67.6**	**-**	**67.6**	**65.6**	**65.6**	**-**	**65.6**
	Production-Weighted Average Rates ($MWh)																				
33	Regulated Hydroelectric	19.09	19.09	n/a	19.09	19.26	19.26	n/a	19.26	18.75	18.75	n/a	18.75	19.51	19.51	n/a	19.51	20.39	20.39	n/a	20.39
34	Nuclear	38.28	38.28	-	38.28	42.50	42.50	-	42.50	45.70	45.70	-	45.70	49.75	49.75	-	49.75	53.88	53.88	-	53.88
35	**Total** (line 20 + line 21)	**57.37**	**57.37**	**-**	**57.37**	**61.76**	**61.76**	**-**	**61.76**	**64.45**	**64.45**	**-**	**64.45**	**69.26**	**69.26**	**-**	**69.26**	**74.27**	**74.27**	**-**	**74.27**
36	**Total Production-Weighted Average Rate** ($MWh)	**57.37**	**57.37**	**-**	**57.37**	**61.76**	**61.76**	**-**	**61.76**	**64.45**	**64.45**	**-**	**64.45**	**69.26**	**69.26**	**-**	**69.26**	**74.27**	**74.27**	**-**	**74.27**

Numbers may not add due to rounding

Notes:

1 Typical monthly consumption (750 kWh) and typical monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at: http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+UtilityTypical Consumption includes line losses (Assumed loss factor of 1.0525)

2 Based on forecast demand for 2017 (137.6 TWh) from Table 3.1 of IESO 18-Month Outlook Update for April 2016 to September 2017, published March 22, 2016.