EB-2016-0152

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act 1998*, Schedule B to the *Energy Competition Act*, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act*, *1998* for an Order or Orders determining payment amounts for the output of certain generation facilities.

CROSS-EXAMINATION COMPENDIUM OF THE SCHOOL ENERGY COALITION (Panel 3B)

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Numbers may not add due to rounding.

Table 4

Comparison of In-Service Capital Additions - Nuclear Operations ($M)

Line No.	Business Unit	2013 Budget	(c)-(a) Change	2013 Actual	(g)-(c) Change	2014 OEB Approved	(g)-(e) Change	2014 Actual	(k)-(g) Change	2015 OEB Approved	(k)-(i) Change	2015 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Darlington NGS**	89.9	(18.3)	71.5	(40.5)	43.8	(12.8)	31.1	75.9	7.7	99.3	107.0
2	**Pickering NGS**	53.6	40.5	94.1	(25.4)	48.8	19.9	68.7	3.0	12.5	59.1	71.7
3	**Nuclear Support Divisions**[1]	17.4	10.4	27.8	(1.8)	6.4	19.6	26.0	(22.9)	0.7	2.4	3.1
4	**Subtotal**	160.8	32.6	193.5	(67.8)	99.1	26.7	125.7	56.0	20.9	160.9	181.8
5	**Supplemental In-Service Forecast**[2]	0.0	0.0	0.0	0.0	37.9	(37.9)	0.0	0.0	99.1	(99.1)	0.0
6	**Total Portfolio In-Service Forecast**	160.8	32.6	193.5	(67.8)	137.0	(11.3)	125.7	56.0	120.0	61.7	181.8
7	**Minor Fixed Assets**	19.9	(9.7)	10.2	12.6	21.3	1.6	22.9	(0.5)	21.7	0.6	22.3
8	**Total In-Service Capital Additions**	180.7	23.0	203.7	(55.1)	158.3	(9.7)	148.6	55.5	141.7	62.4	204.1

Line No.	Business Unit	2015 Actual	(c)-(a) Change	2016 Budget	(e)-(c) Change	2017 Plan	(g)-(e) Change	2018 Plan	(i)-(g) Change	2019 Plan	(k)-(i) Change	2020 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**Darlington NGS**	107.0	224.5	331.4	(150.1)	181.3	(29.4)	152.0	10.4	162.4	(102.4)	60.0
10	**Pickering NGS**	71.7	93.2	164.9	(78.9)	86.0	(70.2)	15.8	(13.0)	2.8	(2.8)	0.0
11	**Nuclear Support Divisions**[1]	3.1	13.9	17.1	(10.1)	6.9	(3.3)	3.6	(3.6)	0.0	0.0	0.0
12	**Subtotal**	181.8	331.6	513.4	(239.1)	274.3	(102.9)	171.4	(6.2)	165.2	(105.3)	60.0
13	**Supplemental In-Service Forecast**[2]	0.0	(47.4)	(47.4)	136.1	88.7	35.1	123.8	(68.8)	55.0	150.7	205.7
14	**Total Portfolio In-Service Forecast**	181.8	284.3	466.0	(103.0)	363.0	(67.7)	295.2	(75.0)	220.2	45.4	265.6
15	**Darlington New Fuel**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3	15.3
16	**Minor Fixed Assets**	22.3	8.7	31.0	(5.0)	26.0	(6.0)	20.0	(0.9)	19.1	0.4	19.5
17	**Total In-Service Capital Additions**	204.1	292.9	497.0	(108.0)	389.0	(73.7)	315.2	(75.9)	239.3	61.1	300.4

Line No.	Business Unit	2020 Plan	(c)-(a) Change	2021 Plan
		(a)	(b)	(c)
18	**Darlington NGS**	60.0	(21.3)	38.7
19	**Pickering NGS**	0.0	0.0	0.0
20	**Nuclear Support Divisions**[1]	0.0	0.0	0.0
21	**Subtotal**	60.0	(21.3)	38.7
22	**Supplemental In-Service Forecast**[2]	205.7	(48.0)	157.6
23	**Total Portfolio In-Service Forecast**	265.6	(69.3)	196.3
24	**Darlington New Fuel**	15.3	(15.3)	0.0
25	**Minor Fixed Assets**	19.5	(0.1)	19.3
26	**Total In-Service Capital Additions**	300.4	(84.8)	215.6

Notes:
1 Includes Engineering, Inspection and Maintenance Services, and Security & Emergency Services.
2 Supplemental forecast to reconcile BCS in-service estimates to final business plan (see Ex. D2-1-3, Section 4.0).

Table 1
Operating Costs Summary - Nuclear ($M)

Line No.	Cost Item	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	OM&A:									
	Nuclear Operations OM&A									
1	**Base OM&A**	1,127.7	1,127.1	1,159.6	1,201.8	1,210.6	1,226.0	1,248.4	1,264.7	1,276.3
2	**Project OM&A**	105.7	101.9	115.2	98.2	113.7	109.1	100.1	100.2	86.8
3	**Outage OM&A**	277.5	221.3	313.7	321.2	394.6	393.8	415.3	394.4	308.5
4	**Subtotal Nuclear Operations OM&A**	1,510.8	1,450.3	1,588.5	1,621.3	1,718.9	1,728.9	1,763.8	1,759.4	1,671.6
5	**Darlington Refurbishment OM&A**	6.3	6.3	1.6	1.3	41.5	13.8	3.5	48.4	19.7
6	**Darlington New Nuclear OM&A**[1]	25.6	1.5	1.3	1.2	1.2	1.2	1.2	1.3	1.3
7	**Allocation of Corporate Costs**	428.4	416.2	418.8	442.3	448.9	437.2	442.7	445.0	454.1
8	**Allocation of Centrally Held and Other Costs**[2]	413.5	416.9	461.0	331.9	80.2	118.2	108.3	91.1	81.3
9	**Asset Service Fee**	22.7	23.3	32.9	28.4	27.9	27.9	28.3	22.9	20.7
10	**Subtotal Other OM&A**	896.5	864.1	915.5	805.0	599.7	598.3	584.1	608.6	577.1
11	**Total OM&A**	2,407.3	2,314.5	2,504.0	2,426.3	2,318.6	2,327.1	2,347.9	2,368.0	2,248.7
12	**Nuclear Fuel Costs**	244.7	254.8	244.3	264.8	219.9	222.0	233.1	228.2	212.7
	Other Operating Cost Items:									
13	**Depreciation and Amortization**	270.1	285.3	298.0	293.6	346.9	378.7	384.0	524.9	338.1
14	**Income Tax**	(76.4)	(61.5)	(31.8)	(18.7)	(18.4)	(18.4)	(18.4)	51.2	51.7
15	**Property Tax**	13.6	14.1	13.2	13.5	14.6	14.9	15.3	15.7	17.0
16	**Total Operating Costs**	2,859.3	2,807.1	3,027.8	2,979.4	2,881.6	2,924.4	2,961.9	3,187.9	2,868.2

Notes:

1 Nuclear Operations expenditures to maintain the Nuclear New Build option. In addition there are allocated corporate costs (included in line 7) for Nuclear New Build of $0.8M in 2016, $1.1M in 2017, $0.2M in 2018, $0.5M in 2019, $0.5M in 2020 and $0.5M in 2021.

2 Comprises centrally-held costs from Ex. F4-4-1 Table 3 and amounts of approximately $1M-$6M per year for machine dynamics and performance testing services provided by Hydro Thermal Operations in support of Nuclear Operations.

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

Table 2
Base OM&A - Nuclear ($M)

Line No.	Resource Type	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	Test Period Percentage[1]
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Labour[2]**	832.4	827.1	834.0	844.7	859.0	846.9	874.3	885.0	887.9	69.9%
2	**Overtime[2]**	48.6	46.7	54.5	47.8	46.1	46.5	46.1	47.4	47.8	3.8%
3	**Augmented Staff**	3.1	3.6	4.4	3.3	4.5	3.5	3.0	2.6	1.6	0.2%
4	**Materials**	85.1	73.4	83.4	70.5	68.4	68.2	68.5	71.1	70.8	5.6%
5	**License**	34.2	32.6	34.5	36.4	37.2	38.7	39.6	40.2	40.6	3.2%
6	**Other Purchased Services**	100.0	98.7	108.4	164.1	161.1	185.1	180.8	178.3	187.3	14.3%
7	**Other**	24.3	44.9	40.3	35.0	34.2	37.0	36.2	40.2	40.3	3.0%
8	**Total Base OM&A**	1,127.7	1,127.1	1,159.6	1,201.8	1,210.6	1,226.0	1,248.4	1,264.7	1,276.3	100.0%

Notes:
1 Test Period Percentage = Sum of Test Period Resource Costs divided by Sum of Test Period Base OM&A.
2 Includes Regular and Non-Regular staff.

Board Staff Interrogatory #89

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: Exh F2-2-1 page 1 and Table 1

The evidence states that, "Base OM&A provides the main source of funding for operating and maintaining the nuclear stations in support of: the ongoing production of electricity from the operating nuclear units; ensuring the safe operation of the plants; improving the reliability of the nuclear assets, and ensuring compliance with applicable legislation and nuclear regulatory requirements."

Table 1 sets out base OM&A by stations and by support. The 2015 actual base OM&A for the Darlington station was $298.9M. The average base OM&A for Darlington for the 2017-2021 test period is $314.92M. Please explain why the base OM&A for Darlington in the test period, when there are three operational units (and only two in 2021), is higher than the 2015 actual base OM&A when there were four operational units.

Response

Darlington's base OM&A in the test period is higher than 2015 actual, despite differences in the number of operational units, for two primary reasons.

First, the majority of base OM&A costs associated with operating a four unit station remains in place during refurbishment, as discussed at Ex. L-6.1-2 AMPCO-92.

Second, base OM&A increases over this period due to labour escalation reflecting collective agreement provisions.

3.5 Gap Based Business Planning - Gap Closure and Resource Plan

The operational and financial targets established by the target setting process are the basis for site and support group business planning. As part of that process, the site and support groups establish and pursue improvement initiatives to close performance gaps to targets over the business planning period. The initiatives are either site specific or fleet-wide to improve efficiencies and reduce costs through process streamlining.

Among the most successful prior site specific or fleet wide initiatives were Fuel Handling Reliability, 3K3 Equipment Reliability, and the implementation of Days Based Maintenance. Attachment 4 to this exhibit provides details of these three prior initiatves and benefits realized.

Another key prior initiative was Business Transformation, which enables OPG nuclear to eliminate the gap associated with Goodnight staffing benchmarks in 2016. Business Transformation implemented a centre-led matrix organization design with centre-led functions supporting the Nuclear business unit. Organizational changes were also made within OPG Nuclear as part of the adoption of the matrix organization. Through Business Transformation, OPG Nuclear streamlined processes and identified efficiencies to manage regular headcount reductions through attrition while ensuring its facilities operate safely and reliably. Examples of such nuclear initiatives include Automate System and Component Health Reports; Stop In House Drawing Revisions; and Reduction of Non-Regulated Security Services.

OPG has experienced significant volatility in generation over the period 2008 to 2015 as discussed in Ex. E2-1-1, primarily as a result of forced outages/forced derates and forced extension of planned outages. This has resulted in annual production shortfalls and negative revenue impacts. OPG has identified fuel handling reliability, human performance errors, equipment reliability (both nuclear and conventional systems) and execution of planned outages as the primary contributors impacting reliability. The 2016-2018 Business Plan includes four key fleet wide initiatives to mitigate these primary contributors in order for OPG to achieve its generation and total generating cost per MWh targets in the Nuclear business unit. These four initiatives are as follows:

(i.) **Human Performance Initiative**: This initiative is focused on preventing human performance errors that propagate into events that have a consequential (unfavorable) impact on safety and reliability. A key focus is improving supervisory effectiveness and leadership oversight.

OPG Nuclear benchmarks its human performance against peers using an industry standard metric referred to as the 18-month Human Performance Error Rate ("HPER") (number per 10k Industrial Safety Accident Rate hours (# per 10k ISAR hours)) (see 2015 Benchmarking Report - Attachment 1 to this exhibit). The expected benefit of improving Human Performance will be to reduce lost generation due to human error. For the 2016-2018 Business Plan, OPG is targeting a significant improvement in human performance by achieving reductions in human errors. Improved human performance as measured by HPER will contribute to enabling OPG to achieve its 2016-2018 Business Plan targeted FLR and UCF.

(ii.) **Equipment Reliability Initiative**: This initiative is focused on improving equipment reliability, which has been a major contributor to OPG's historical FLR. The initiative is a multi-faceted Equipment Reliability Plan that focuses on People, Equipment and Processes and is measured by a new industry Equipment Reliability Index ("ERI") to drive key performance indicators. The ERI is the North American benchmark for assessing overall equipment reliability performance. The index is an effective instrument for measuring the longer term trend of improvements and uses key leading indicators projecting degradation in plant operations or reliability of key station equipment.

(iii.) **Outage Performance Initiative**: This initiative is focused on improving planned outage performance in order to achieve business plan duration targets. The major deliverables from this initiative include seeking reduced outage durations. This will be accomplished in part by the successful completion of the Machine Delivered Scrape

("MDS"), which is the deployment of new tooling with the Universal Delivery Machine ("UDM") at Pickering. Further description of the MDS project is found in the Business Case Summary included in Ex. D2-1-3. Other deliverables are focused on improved outage execution and scheduling performance, and undertaking a feasibility study on Pickering's outage cycle.

The Outage Performance improvement initiative seeks to eliminate the potential for the occurrence of Forced Extension to a Planned Outage ("FEPO") days in the test period, to eliminate loss of production and avoid additional outage OM&A costs OPG must successfully execute this initiative in order to achieve targeted production levels.

(iv.) **Parts Improvement Initiative:** Parts availability performance directly impacts OPG's ability to schedule and execute online, outage and project work in a consistent and predictable manner. The consequences of poor parts availability could be low scope completion rates, longer outages, higher assessing, planning, and maintenance backlogs, lower equipment reliability, and ultimately, reduced capacity factors. The initiative focuses on obtaining the right parts on time, reducing churn in OPG's work management system to ultimately improve equipment reliability. The initiative targets completion of 19 deliverables by cross-functional teams involving Supply Chain, Engineering, Fleet Operations & Maintenance, and Work Management over a period of three years.

Key indicators of the initiative's overall effectiveness are Work Order with Material Request Execution, which measures the percentage of work with parts that was actually executed vs. planned for online work, and Need to Use Cycle Time (Plan to Complete) for Work Orders with Material Request, which measures the overall duration it takes to complete a job that requires a part.

Through the Parts Improvement initiative, OPG is addressing many issues contributing to cycle time and expects to see improvement in the trend in the overall duration it takes to complete a job that require parts.

The 2016-2018 Business Plan also includes two fleet wide initiatives that address additional challenges, as summarized below:

- **Inventory Reduction Initiative:** Annual station materials and supply inventory targets and surplus inventory targets have been established to optimize inventory and reduce costs by targeting half the historical growth rate for 2016. An Inventory Management Organization will be established for each station with cross-functional support provided by Engineering, Supply Chain and Finance.

  A reduction in the growth of the inventory reduces the capital invested in the inventory and reduces the potential for additional obsolescence provision. This also reduces warehousing requirements and related expenses.

- **Workforce Planning and Resourcing Initiative:** The Workforce Planning and Resourcing Initiative is designed to implement a fleet-wide resourcing strategy to meet the challenge of the widening gap between labour demand and supply, leadership capability and key resource availability to ensure safe and efficient operations of OPG's nuclear facilities, while minimizing risks to the efficient execution of Pickering Extended Operations and the DRP.

OPG's 2016-2018 Business Plan (Ex. A2-2-1 Attachment 1) sets out in its Appendix 5 the resource requirements (cost, staff and investment plans) for the Nuclear operations. The plan maintains a sustainable cost structure for OPG's Nuclear operations through cost efficiencies while focusing on initiatives to ensure safe and reliable performance.

SEC Interrogatory #55

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:
[F2/1/1, p.19**]**

For each of the listened initiatives, please provide the expected OM&A savings for each year between 2017 and 2021.

Response

While the business plan is based on the successful execution of the initiatives, OPG cannot quantify specific OM&A savings attributable to individual initiatives. The initiatives have varied and, in some cases, overlapping effects on OPG's performance. Some are focused on operational matters to improve reliability to meet production targets (e.g., Forced Loss Rate and Unit Capability Factor), while others are aimed at offsetting cost pressures. Overall, the successful implementation of these initiatives is necessary to enable OPG to achieve and sustain the operational and value for money targets listed in Ex. F2-1-1.

Benchmarking Results – Plant Level Summary

Table 2 provides a summary of OPG Nuclear's performance compared to benchmark results.

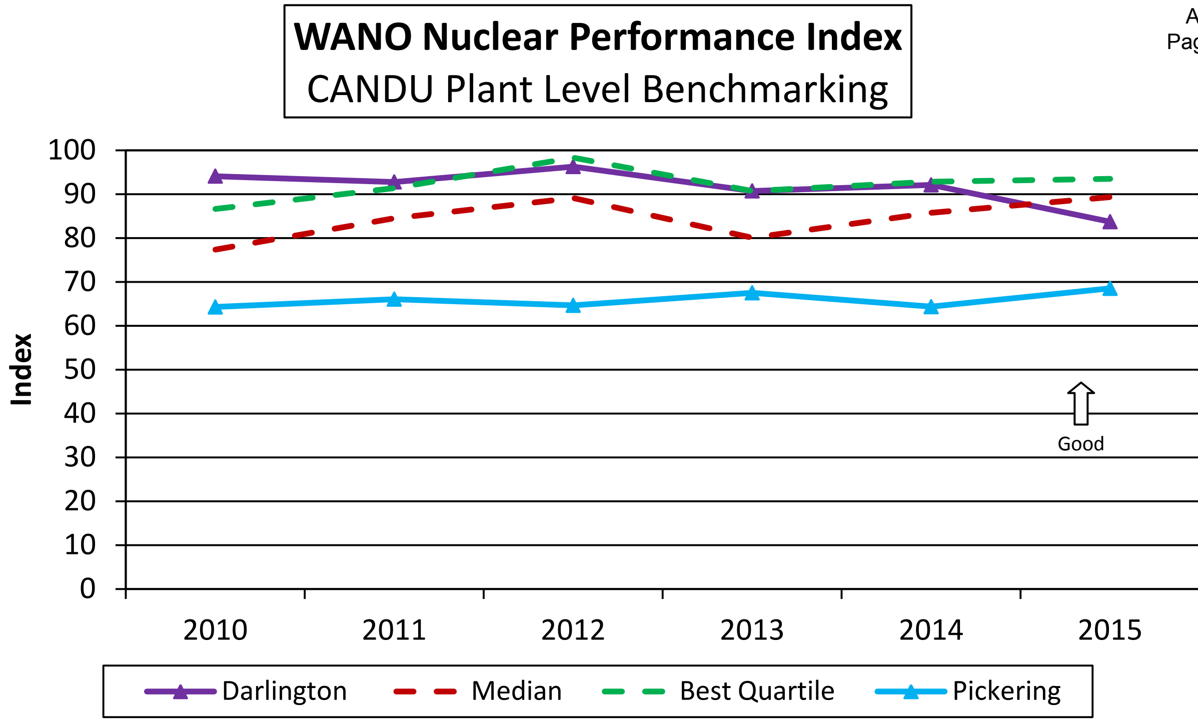
Table 2: Plant Level Performance Summary

Metric	NPI Max	2015 Actuals			
		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


WANO Nuclear Performance Index
CANDU Plant Level Benchmarking
Index
100
90
80
70
60
50
40
30
20
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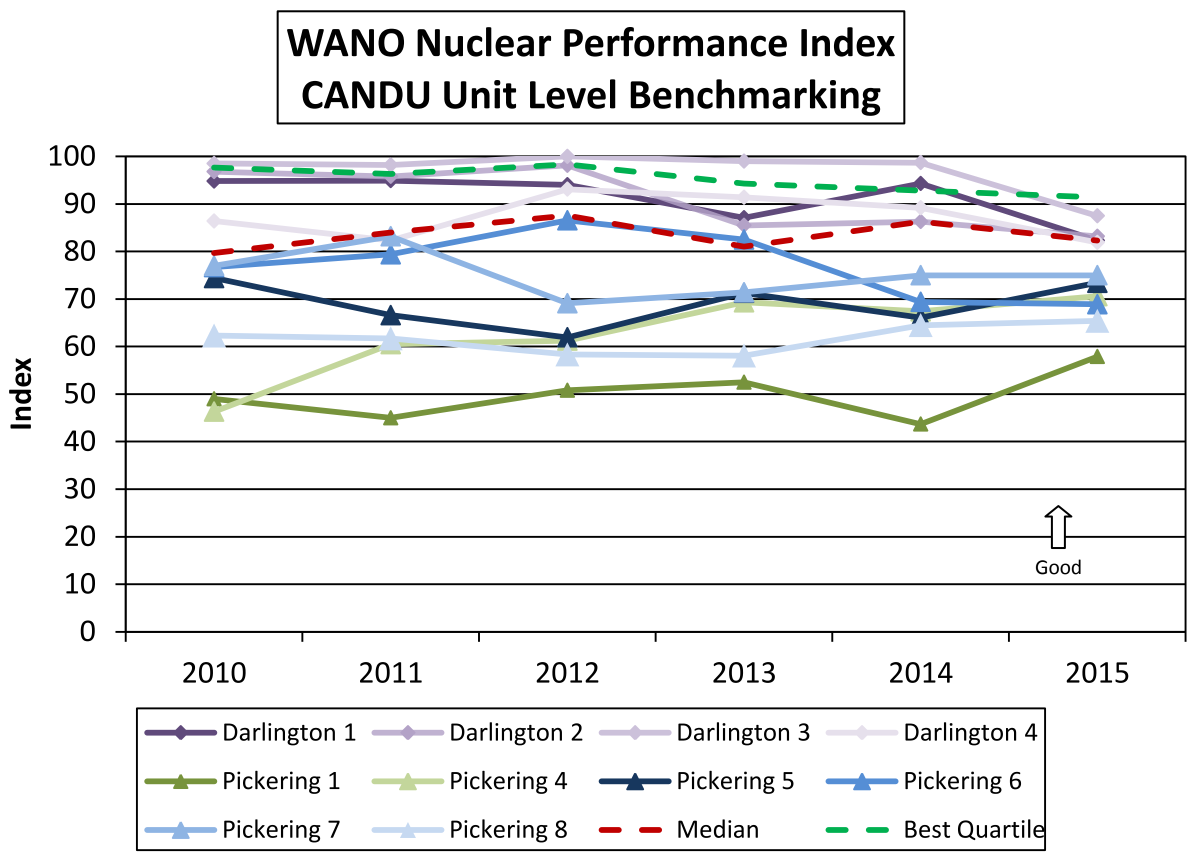
2010
2011
2012
2013
2014
2015
Good
Darlington
Median
Best Quartile
Pickering


WANO Nuclear Performance Index
CANDU Unit Level Benchmarking
Index
100
90
80
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10
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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

Filed: 2017-02-10
EB-2016-0152
Exhibit L, Tab 6.2
Schedule 15 SEC-063
Attachment 3
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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.

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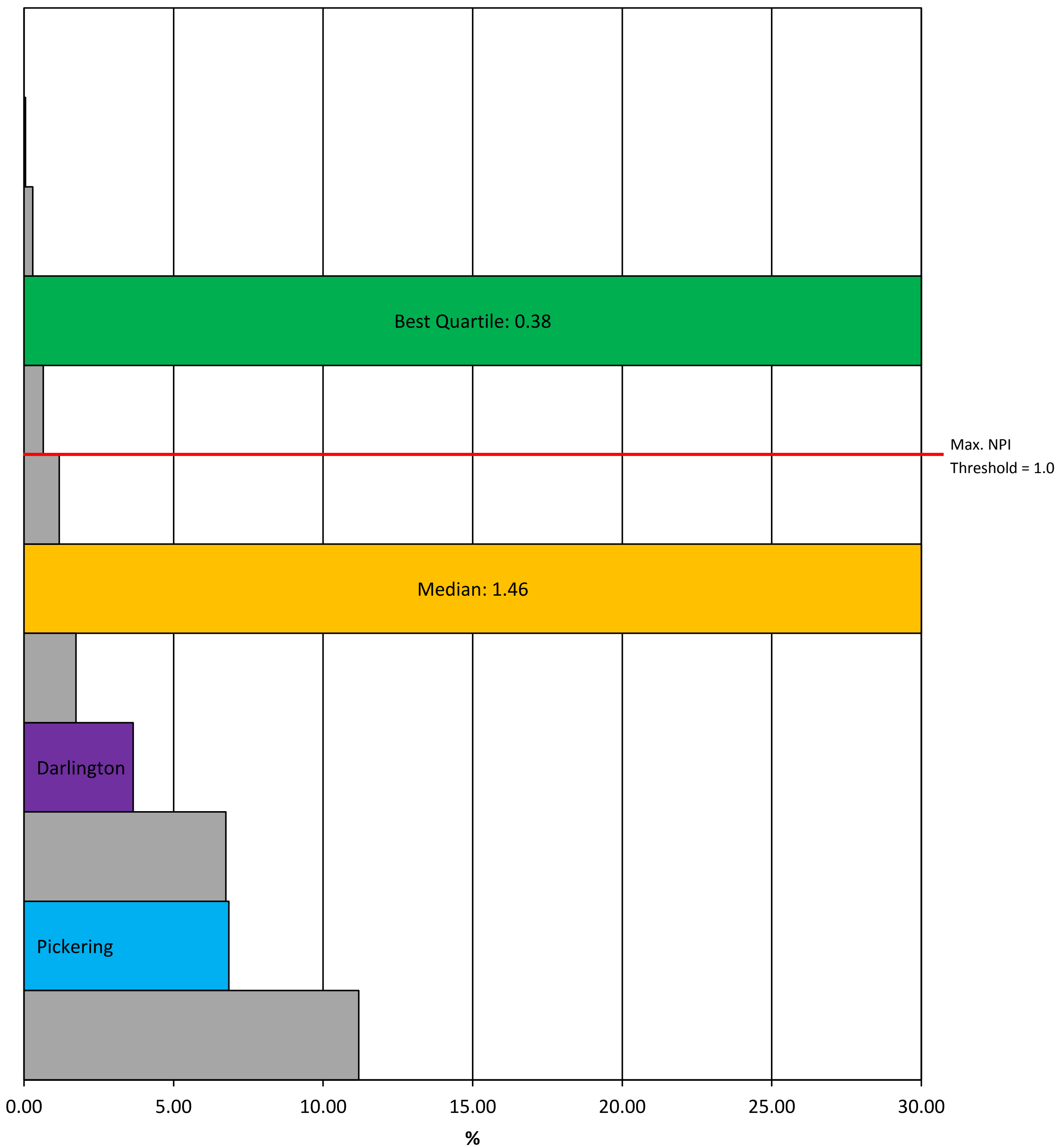
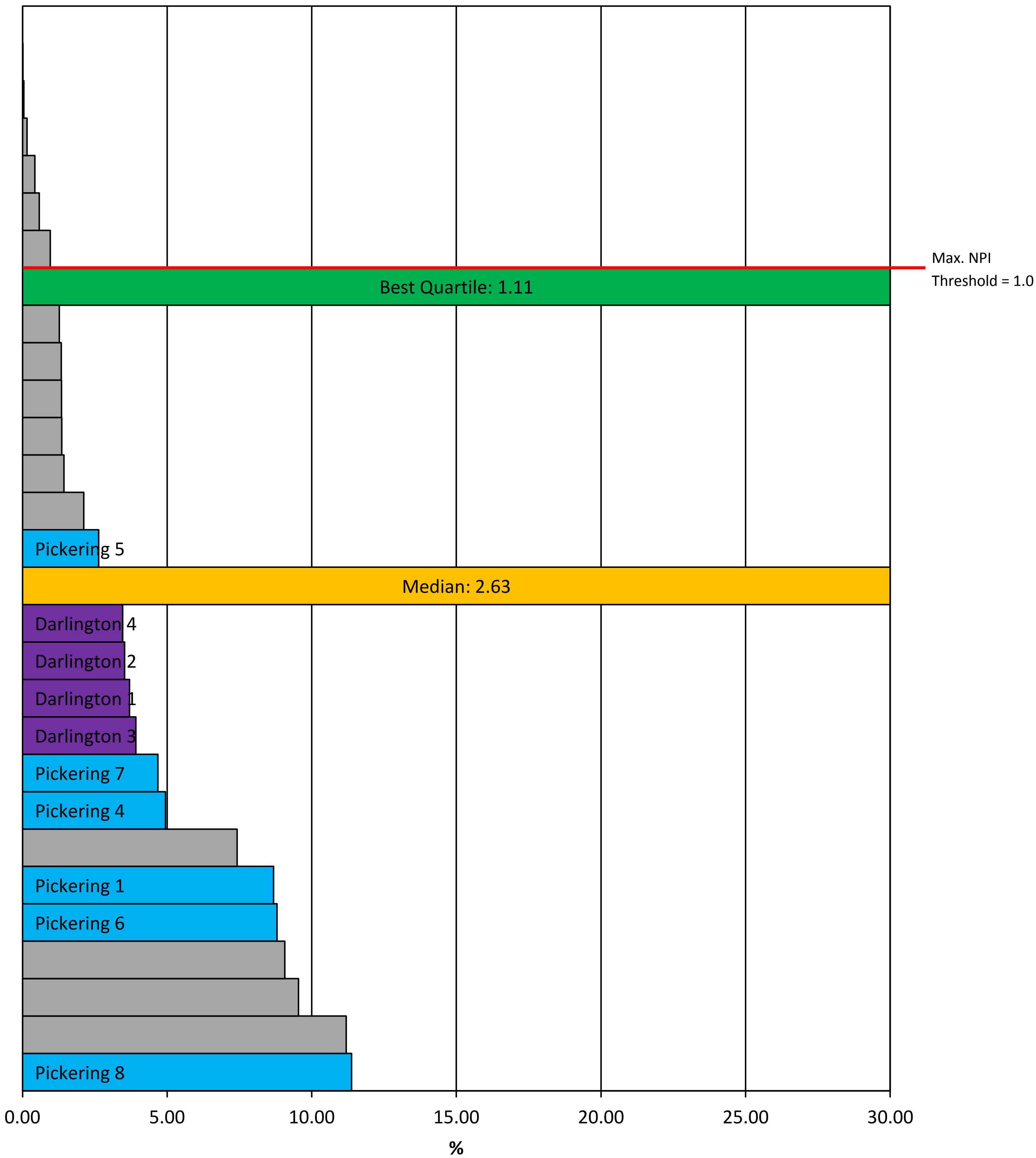
Rolling Average Forced Loss Rate

2015 Rolling Average Forced Loss Rate
CANDU Plant Level Benchmarking



2015 Rolling Average Forced Loss Rate
CANDU Unit Level Benchmarking



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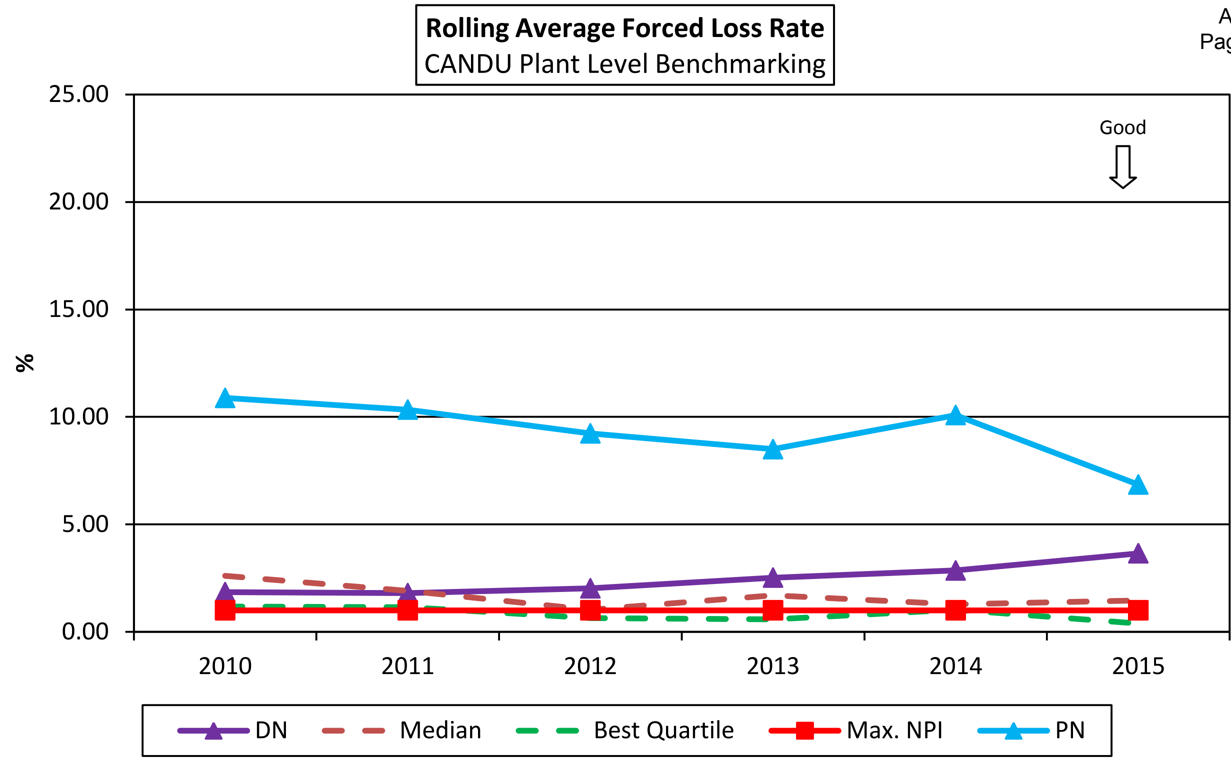

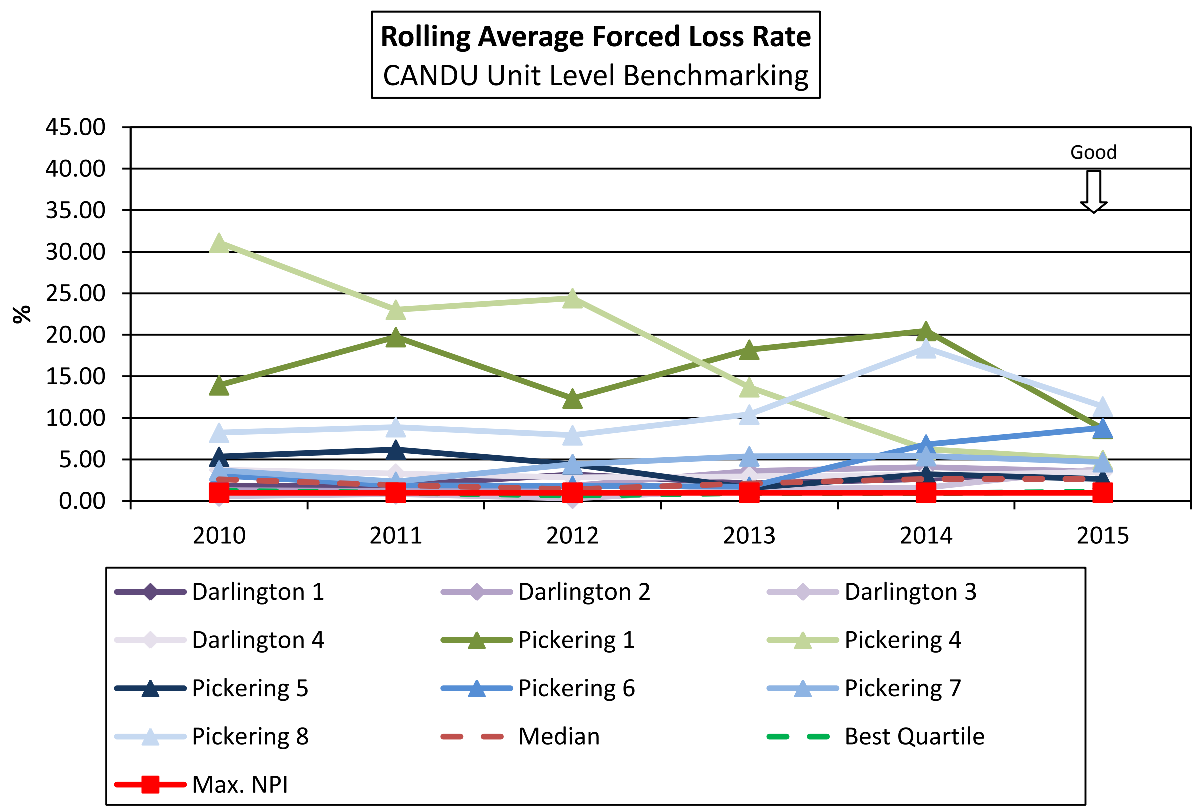

Observations – Rolling Average Forced Loss Rate (CANDU)

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.

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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.

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.

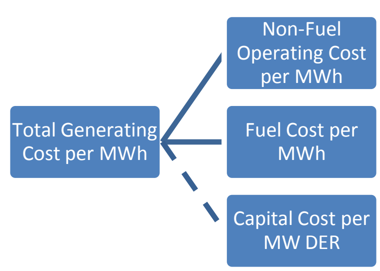
The benchmarking panel utilized for value for money metrics is made up of all North American plants reporting to EUCG. Bruce Power is the only other CANDU technology plant reporting within that panel. The remaining plants are Boiling Water Reactors or Pressurized Water Reactors. For that reason, some 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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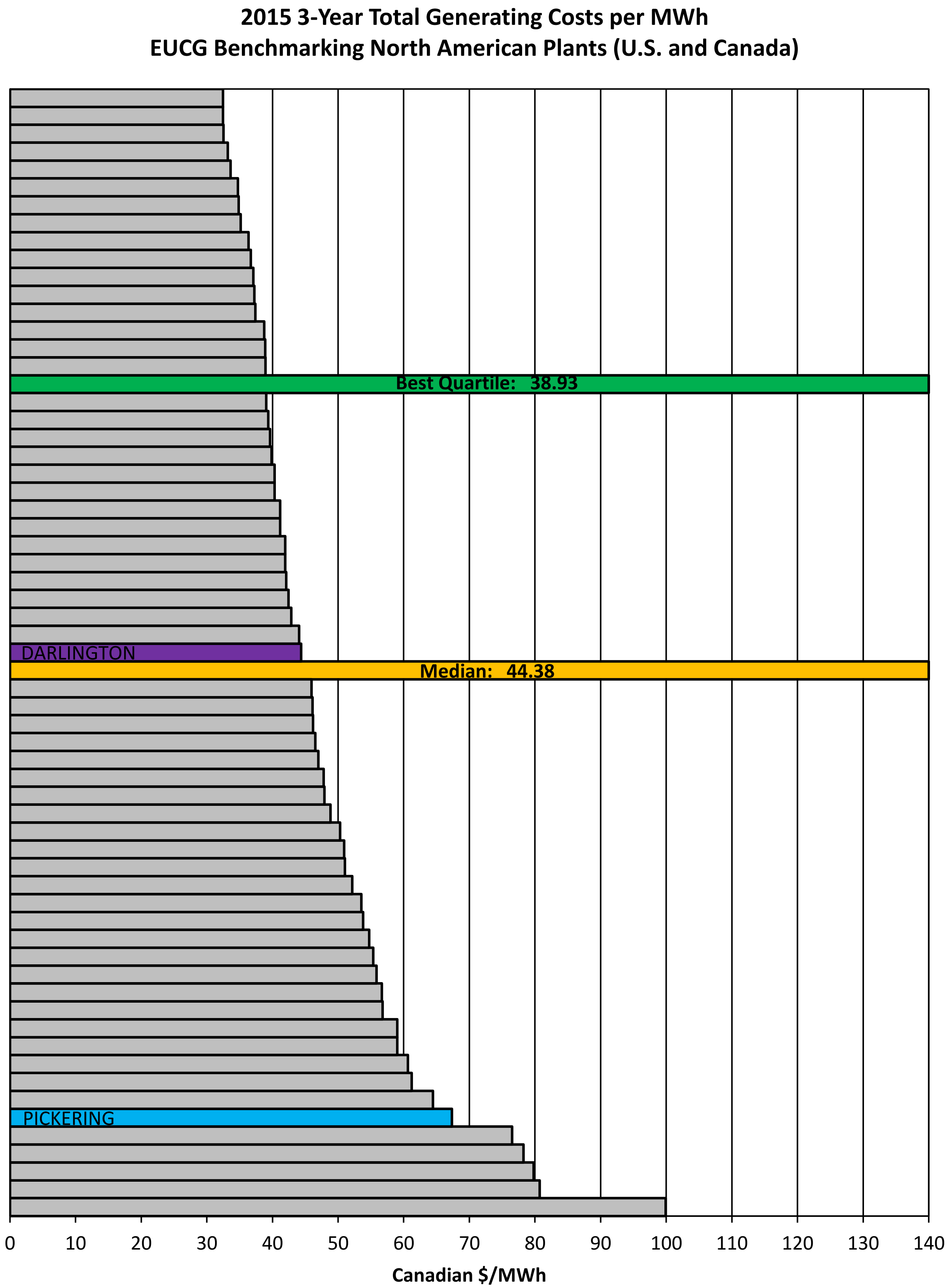
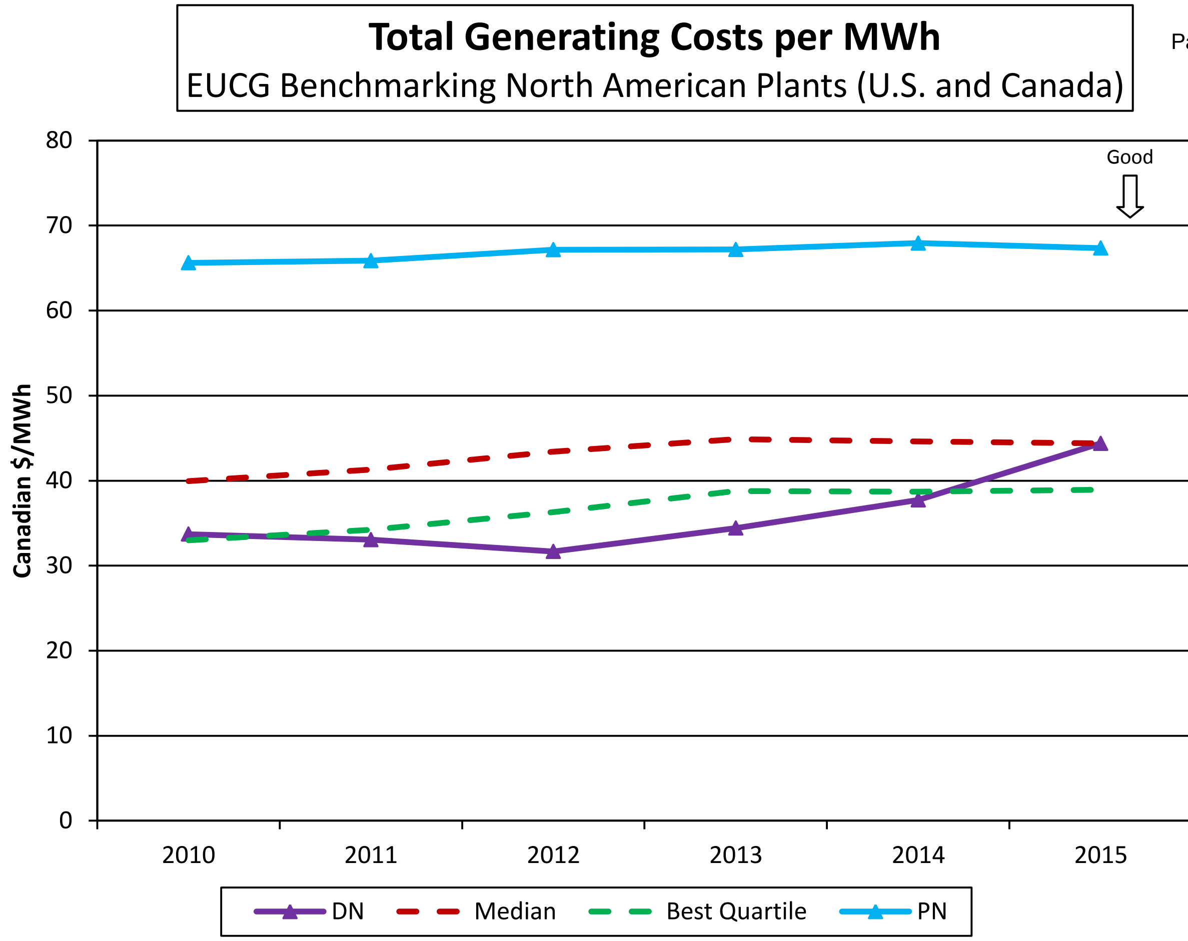
3-Year Total Generating Cost per MWh




Total Generating Costs per MWh
EUCG Benchmarking North American Plants (U.S. and Canada)
Good
Canadian $/MWh
0
10
20
30
40
50
60
70
80
2010
2011
2012
2013
2014
2015
DN
Median
Best Quartile
PN

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.

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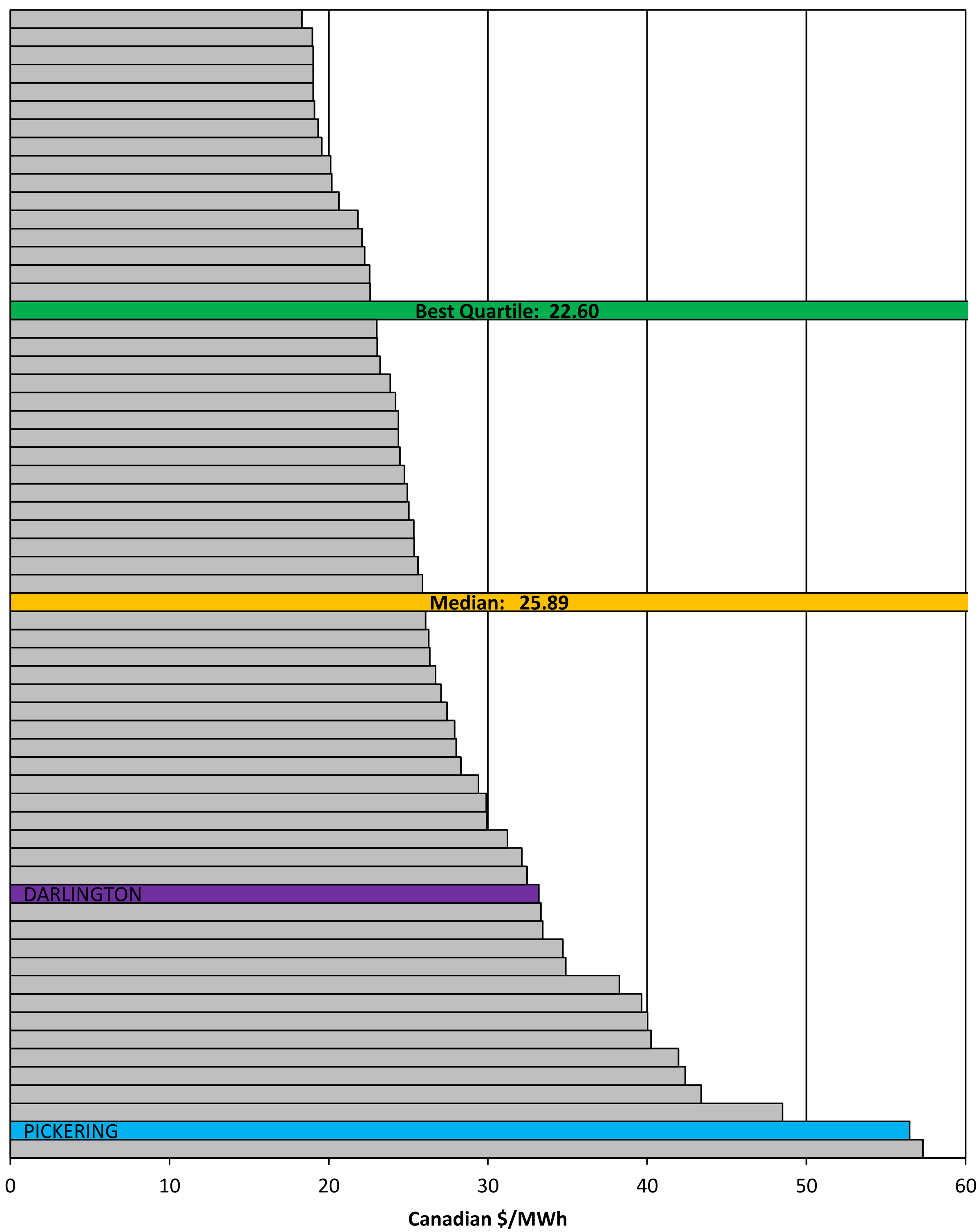
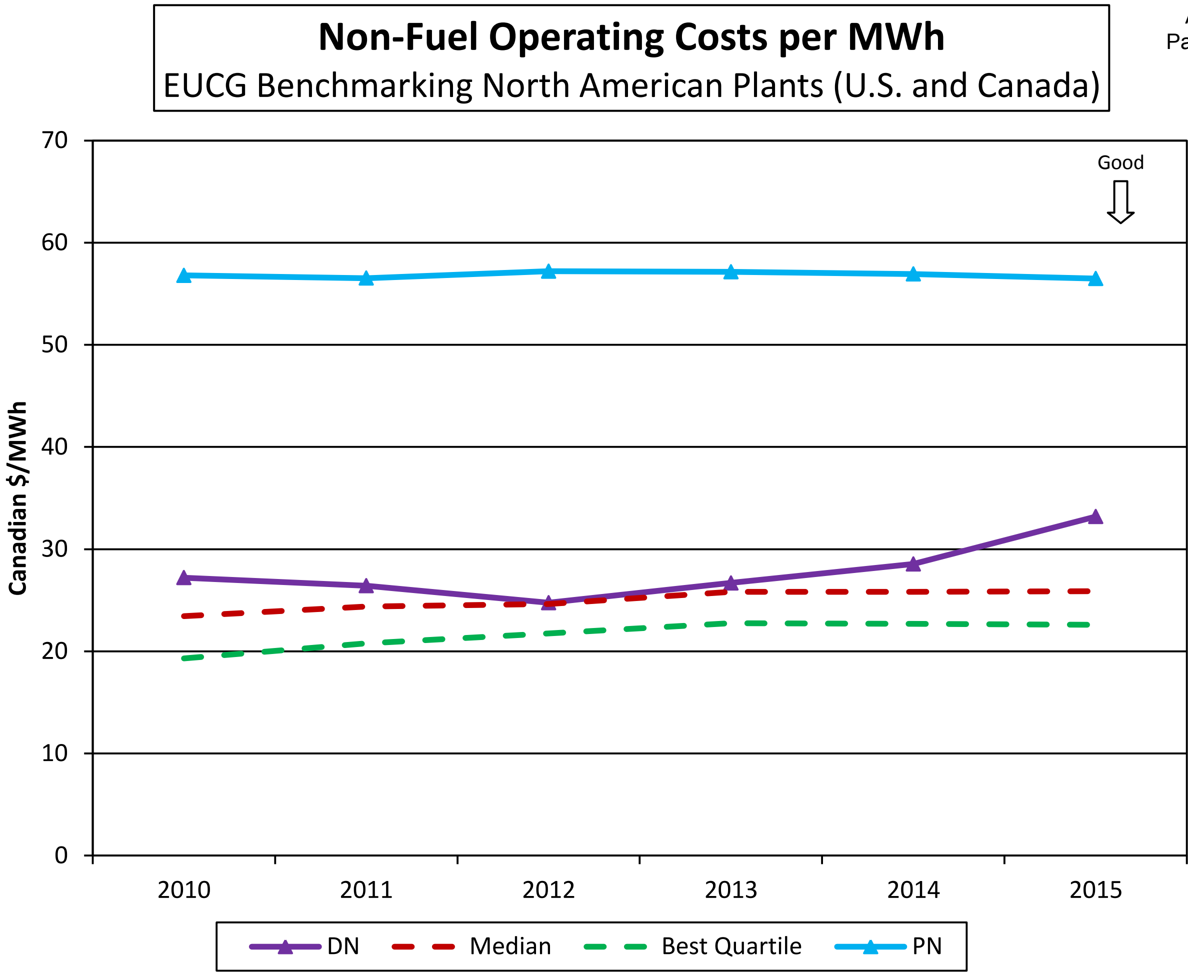
3-Year Non-Fuel Operating Cost per MWh

2015 3-Year Non-Fuel Operating Costs per MWh
EUCG Benchmarking North American Plants (U.S. and Canada)




Non-Fuel Operating Costs per MWh
EUCG Benchmarking North American Plants (U.S. and Canada)
Canadian $/MWh
70
60
50
40
30
20
10
0
2010
2011
2012
2013
2014
2015
Good
DN
Median
Best Quartile
PN

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

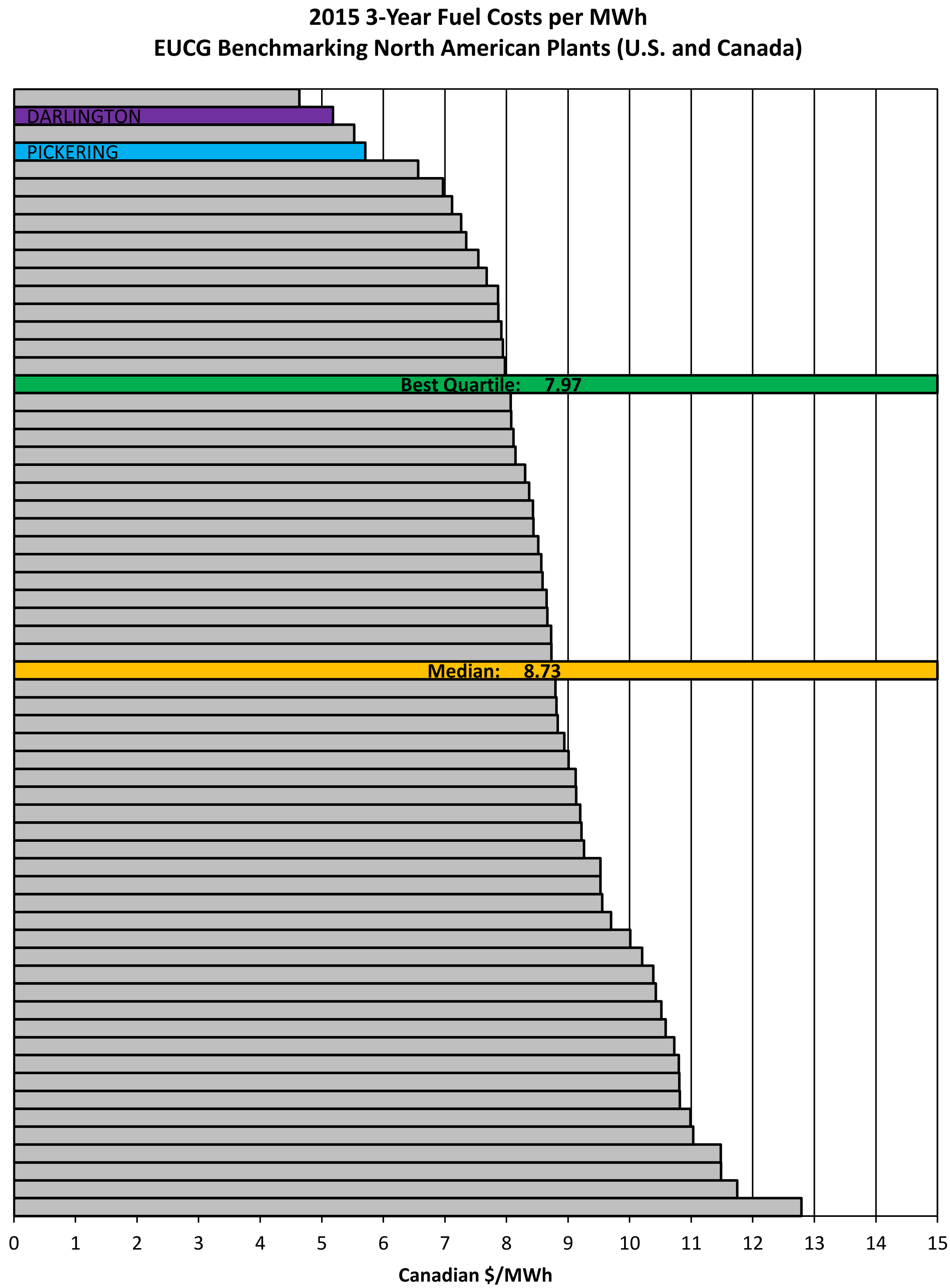
- Both best quartile and median levels increased over the 2010-2015 period with a compound annual growth rate of approximately 3.2% for the best quartile and approximately 2.0% for the median.
- Darlington annual compound growth rate was 4.1% and Pickering's effectively did not change.
- Pickering 3-yr 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.

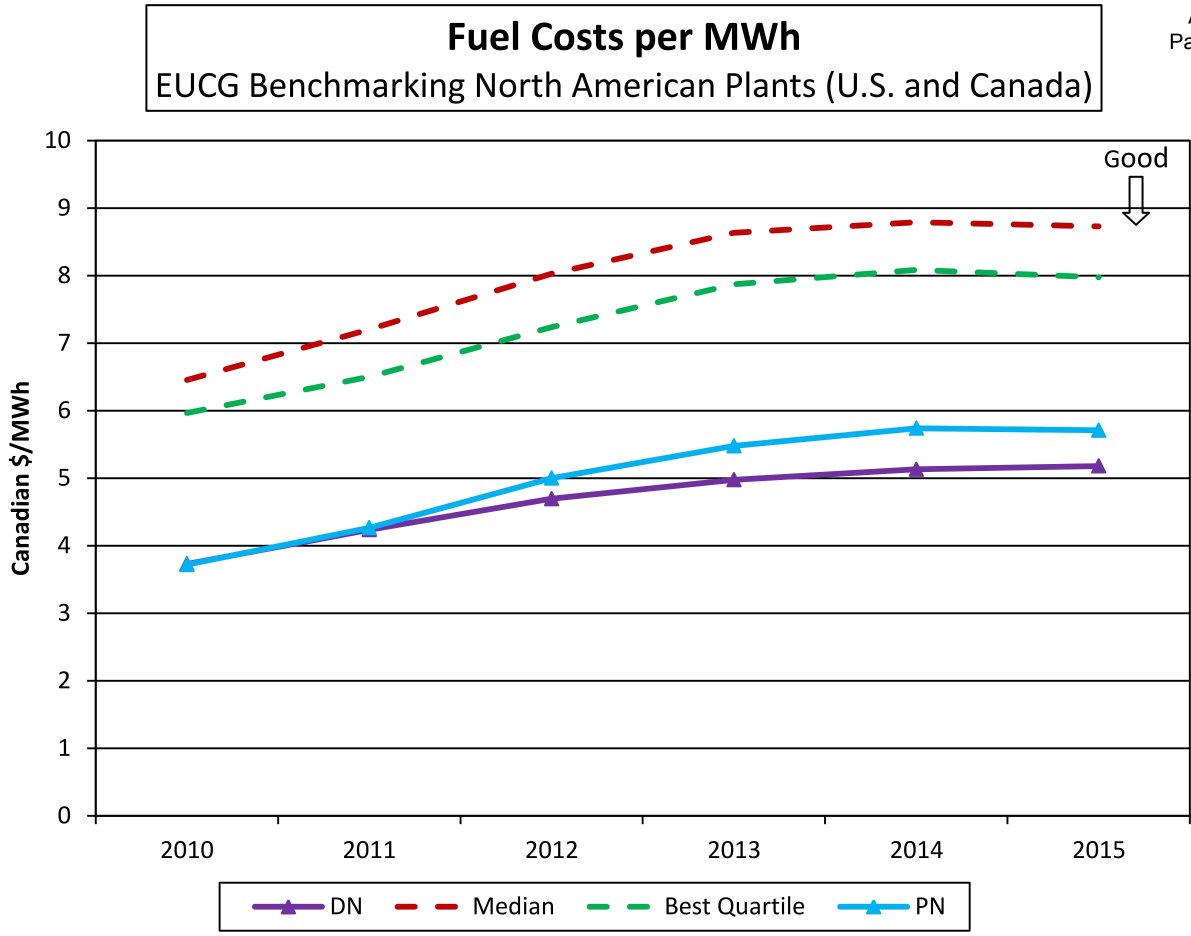
Factors Contributing to Performance – 3-Year Non-Fuel Operating Cost per MWh (CONT'D)

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




Fuel Costs per MWh
EUCG Benchmarking North American Plants (U.S. and Canada)
Good
Canadian $/MWh
10
9
8
7
6
5
4
3
2
1
0
2010
2011
2012
2013
2014
2015
DN
Median
Best Quartile
PN

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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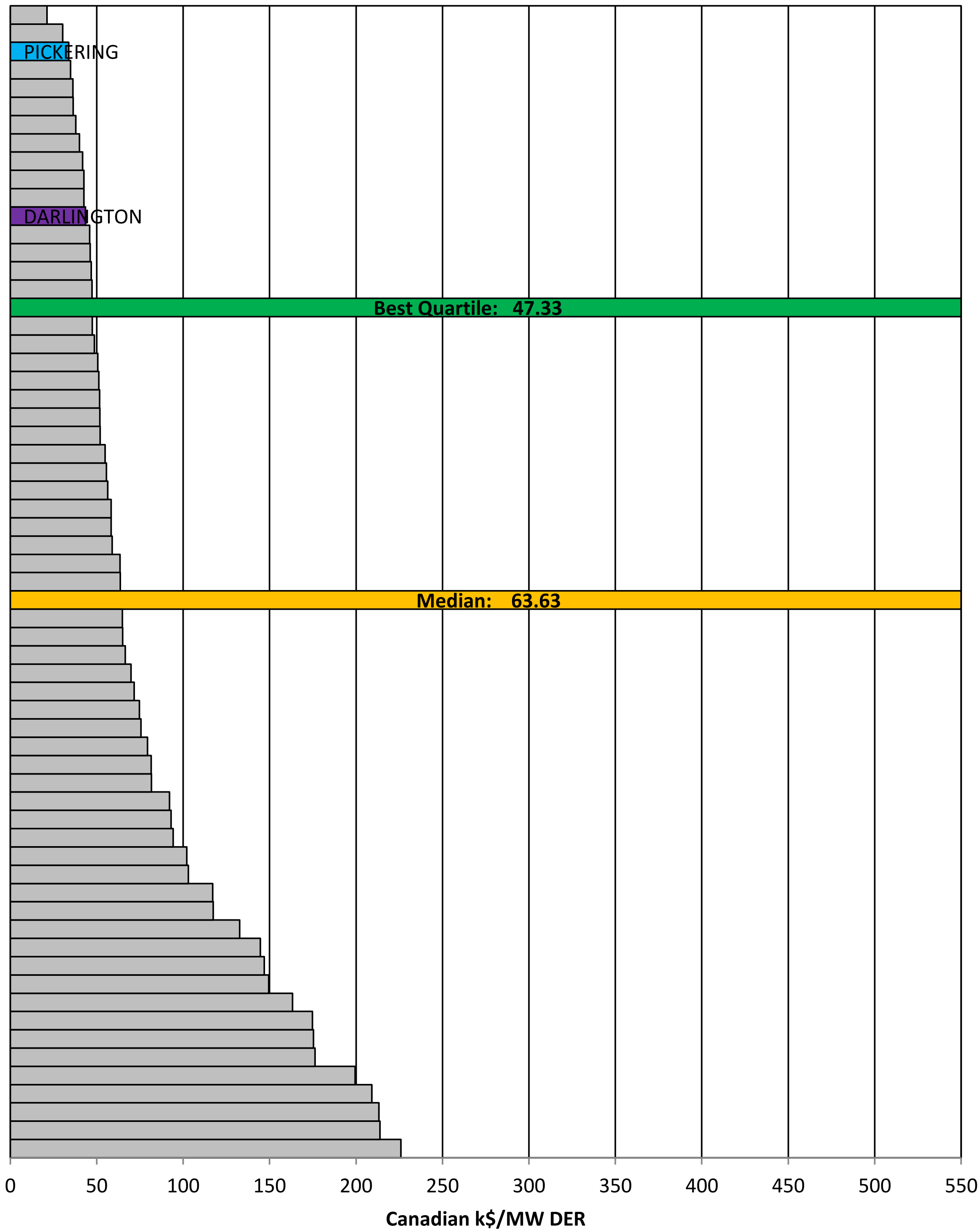
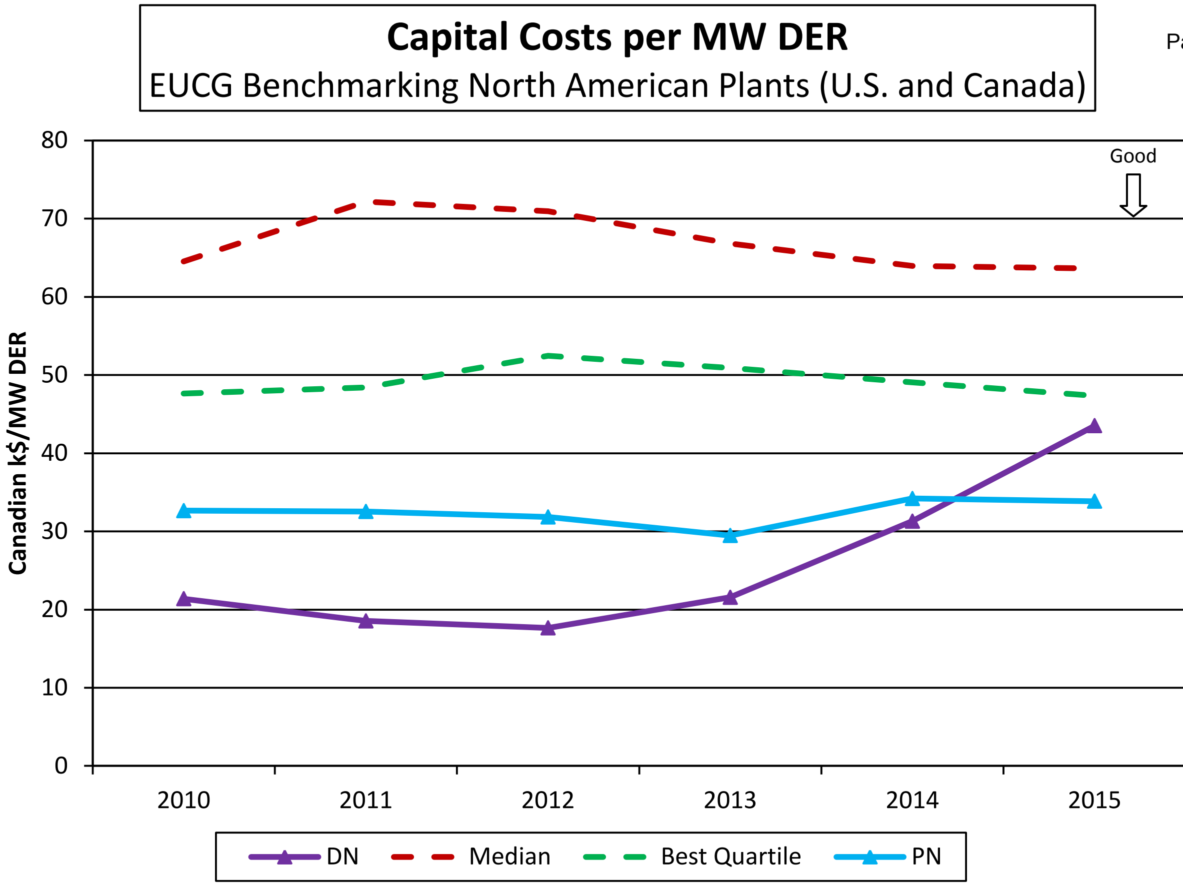
3-Year Capital Cost per MW DER (Design Electrical Rating)

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)
Canadian k$/MW DER
80
70
60
50
40
30
20
10
0
Good
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.

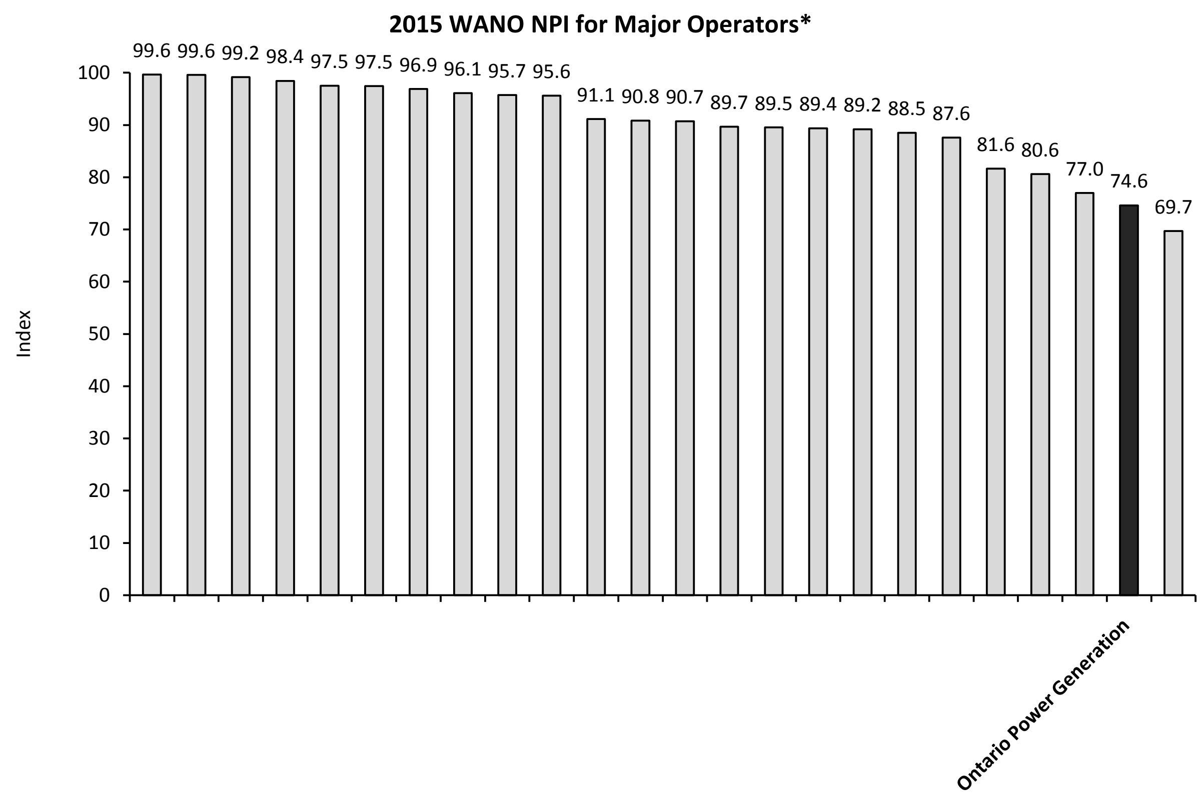
6.0 MAJOR OPERATOR SUMMARY

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.

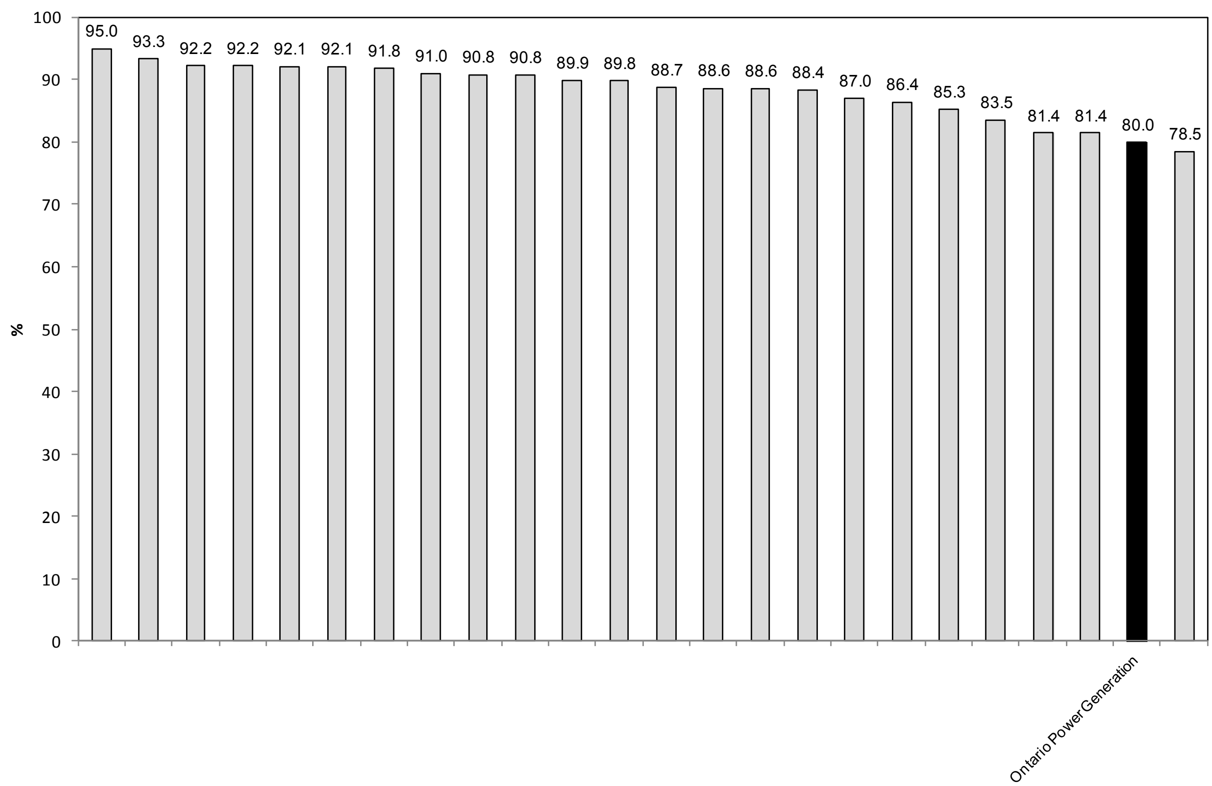
Note: Four operators are no longer ranked in 2015 (reason for 28 ranked operators in 2010 vs. 24 in 2015). These operators were removed as a result of plant acquisitions or closures. All 2010-2014 rankings and numbers are carried over from previous Benchmarking reports.

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.

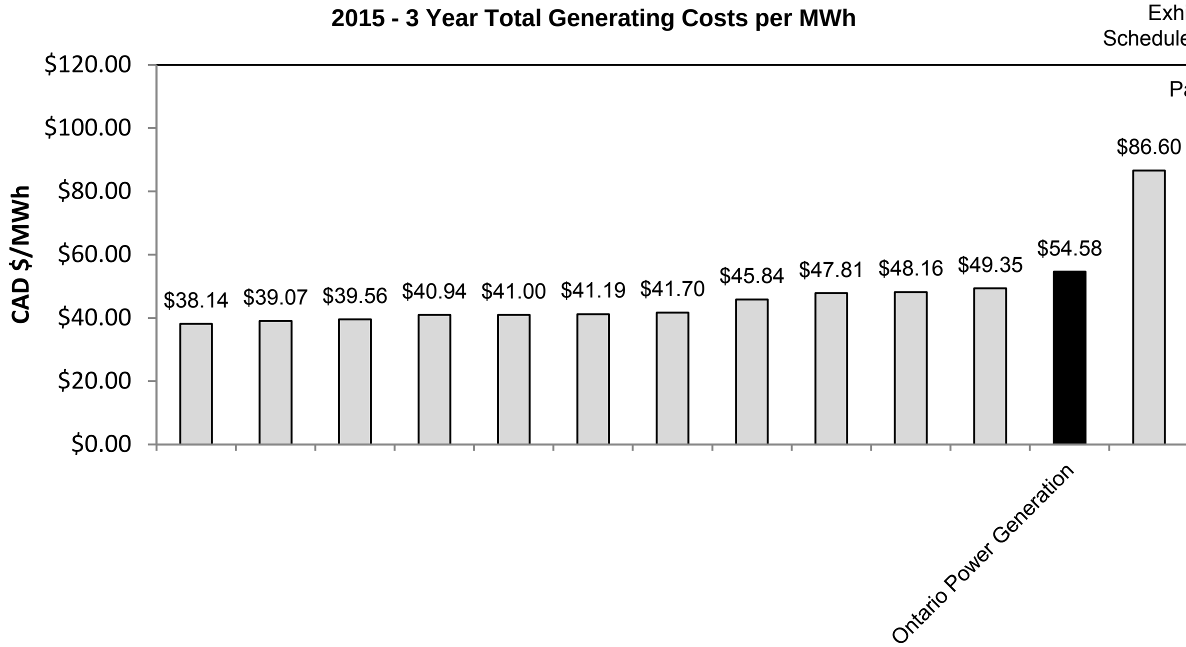
Table 4: Rolling Average Unit Capability Factor Rankings

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.

Table 13: NPI Plant Level Performance Summary (North American Panel)

Indicator	2015 Actuals 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

2014 Plant Level Performance Summary

Metric	NPI Max	2014 Actuals Best Quartile	Median	Pickering	Darlington
Safety					
All Injury Rate (#/200k hours worked)		0.66	N/A[1]	0.22	0.31
Rolling Average[2] Industrial Safety Accident Rate (#/200k hours worked)	0.20	0.00	0.02	0.03	0.06
Rolling Average[2] Collective Radiation Exposure (Person-rem per unit)	80.00	42.25	61.60	82.24	69.06
Airborne Tritium Emissions (Curies) per Unit[3]		1,014	2,410	2,390	1,831 ⇩
Fuel Reliability Index (microcuries per gram)	0.000500	0.000001	0.000001	0.001580 ⇩	0.000158 ⇧
2-Year Reactor Trip Rate (# per 7,000 hours)	0.50	0.00	0.05	0.36	0.00
3-Year Auxiliary Feedwater System Unavailability (#)	0.0200	0.0000	0.0015	0.0181	0.0000
3-Year Emergency AC Power Unavailability (#)	0.0250	0.0001	0.0024	0.0000	0.0000
3-Year High Pressure Safety Injection Unavailability (#)	0.0200	0.00000	0.00003	0.0000	0.0000
Reliability					
WANO NPI (Index)		92.9	85.8	64.3	92.1 ⇩
Rolling Average[2] Forced Loss Rate (%)	1.00	1.03	1.29	10.08	2.85
Rolling Average[2] Unit Capability Factor (%)	92.0	89.44	86.49	74.50	89.41
Rolling Average[2] Chemistry Performance Indicator (Index)	1.01	1.00	1.00	1.04 ⇧	1.00
1-Year On-line Deficient Maintenance Backlog (work orders per unit)		159	212	276 ⇩	176 ⇩
1-Year On-line Corrective Maintenance Backlog (work orders per unit)		11	20	160	20 ⇧
Value for Money					
3-Year Total Generating Cost per MWh ($ per Net MWh)		38.71	44.61	67.93	37.73
3-Year Non-Fuel Operating Cost per MWh ($ per Net MWh)		22.68	25.83	56.94	28.55
3-Year Fuel Cost per MWh ($ per Net MWh)		8.08	8.79	5.74	5.13
3-Year Capital Cost per MW DER (k$ per MW)		49.08	63.95	34.20	31.30
Human Performance					
18-Month Human Performance Error Rate (# per 10k ISAR and contractor hours)		0.00200	0.00400	0.00890	0.00620

Notes
1. No median benchmark available.
2. Indicates a 2-Year Rolling Average for Pickering and a 3-Year Rolling Average for Darlington.
3. 2012 data is used because 2013 and 2014 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. 2013
⇧ Improving Benchmark Quartile Performance vs. 2013

2015 Plant Level Performance Summary

Metric	NPI Max	2015 Actuals			
		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 (%)	92.0	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)		0.00100	0.00300	0.00550 ⇧	0.00310

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 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

Chart 4
Operational and FinancialTargets

Benchmarking Indicators	WANO Max NPI	Best Quartile+	Median Quartile+	Pickering – Annual Targets 2016	2017	2018	Darlington – Annual Targets 2016	2017	2018
Safety									
All Injury Rate (#/200k hours worked)		0.66	N/A	0.24	0.24	0.24	0.24	0.24	0.24
Industrial Safety Accident Rate (#/200k hours worked)	0.20	0.00	0.02	0.1	0.1	0.1	0.1	0.1	0.1
Collective Radiation Exposure (person-rem per unit)	80.00	42.25	61.60	111.5	126.9	137.3	65	87.8	72.1
Airborne Tritium Emissions (Curies) per Unit		1,014	2,410	2,333	2,333	2,333	1,014	1,014	1,014
Fuel Reliability (microcuries per gram)	0.000500	0.000001	0.000001	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Reactor Trip Rate (# per 7,000 hours)	0.50	0.00	0.05	0.5	0.5	0.5	0.5	0.5	0.5
Auxiliary Feedwater System Unavailability (#)	0.0200	0.0000	0.0015	0.02	0.02	0.02	0.02	0.02	0.02
Emergency AC Power Unavailability (#)	0.0250	0.0001	0.0024	0.025	0.025	0.025	0.025	0.025	0.025
High Pressure Safety Injection Unavailability (#)	0.020	0.00000	0.00003	0.02	0.02	0.02	0.02	0.02	0.02
Reliability									
WANO NPI (Index)		92.9	85.8	72.3	71.1	71.1	87.3	84.3	93
Forced Loss Rate (%)	1.00	1.03	1.29	5	5	5	1	1	1
Unit Capability Factor (%)	92.0	89.4	86.5	77.6	71.5	72	91.1	85.1	86
Chemistry Performance Indicator (Index)	1.01	1.00	1.00	1.03	1.03	1.03	1.01	1.01	1.01
On-line Deficient Critical and Non-Critical Mtce Backlog (work orders/unit)		159	212	196	196	196	175	159	150
On-Line Corrective Critical and Non-critical Mtce Backlog (work orders/unit)		11	20	55	28	28	20	15	10
Value for Money									
Normalized Total Generating Cost per MWh ($/Net MWh)++,^		41.78	48.15	N/A	N/A	N/A	48.09	48.16	47.68
Total Generating Cost per MWh ($/Net MWh)++,^		41.78	48.15	71.79	77.36	76.91	48.09	65.23	64.36
Normalized Non-Fuel Operating Cost per MWh ($/Net MWh)++		24.48	27.88	N/A	N/A	N/A	33.84	35.36	33.69
Non-Fuel Operating Cost per MWh ($/Net MWh)++		24.48	27.88	60.10	66.89	69.34	33.84	49.50	46.99
Fuel Cost per MWh ($/Net MWh)		8.72	9.49	5.78	6.00	6.02	5.41	5.54	5.53
Capital Cost per MW DER (k$/MW)^^		52.97	69.02	39.70	27.52	9.62	65.54	55.19	64.99
Human Performance									
Human Performance Error Rate (# per 10k ISAR hours)		0.0020	0.0040	0.003	0.003	0.003	0.003	0.002	0.002

+ Best Quartile and Median Quartile for Value for Money metrics are forecast 2018 (2014 actual 3-year rolling average escalated).

++ TGC/MWh and Non-Fuel Operating Cost per MWh exclude centrally held pension and OPEB costs and asset service fees to align with the industry standard.

^ Targets for selected metrics presented in Appendix 5 to the 2016-2018 Business Plan document (Ex. A2-2-1 Attachment 1) represent initial estimates that were subsequently finalized based on updated cost allocations, as anticipated in footnote 2 in Appendix 5.

^^ Design Electrical Rating (DER)

MWh associated with extensive additional planned outages for Pickering Extended Operations.

- For the human performance cornerstone, OPG is targeting improvement at Darlington, as indicated in the target reductions in the HPER over the 2016-2018 planning period. Pickering HPER is targeted to remain unchanged over this period.

Projected targets for the three key metrics of TGC/MWh, FLR and UCF for 2019-2021 are provided in Chart 5. These are challenging targets, which will require OPG to establish new initiatives based on future outcomes and operating conditions in order to achieve them.

Chart 5

Projected Targets for Key Metrics

Benchmarking Indicators	Pickering – Annual Targets			Darlington – Annual Targets		
	2019	2020	2021	2019	2020	2021
Safety						
Forced Loss Rate (%)	5.0	5.0	5.0	1.0	4.2	3.0
Unit Capability Factor (%)	72.6	73.4	70.6	87.8	79.4	90.9
Normalized Total Generating Cost per MWh ($/Net MWh)*	N/A	N/A	N/A	51.68	52.04	39.80
Total Generating Cost per MWh ($/Net MWh)*	78.36	74.93	81.16	64.61	73.82	64.90

* TGC/MWh and Non-Fuel Operating Cost per MWh exclude centrally held pension and OPEB costs and asset service fees to align with the industry standard.

Darlington's FLR in 2020 and 2021 is impacted by the assumed FLR for refurbished Unit 2 returning to service and is consistent with the assumptions that underpin the Darlington Refurbishment Execution Phase Business Case (Ex. D2-2-8 Attachment 1). The decline in Darlilngton's TGC/MWh in 2021 is largely explained by the expectation that two units will be subject to refurbishment in 2021. As a result there will be signficantly lower outage OM&A as there are no planned outages with the excepton of a short post refurbishment outage as described in Ex. E2-1-1.

2015 targeted staff reductions requires continuous reassessment of existing fleet and site targets and initiatives, as well as, developing new initiatives.

3.4 Gap Based Business Planning: Target Setting

Top-down targets are performance improvement targets designed to close performance gaps and significantly drive OPG nuclear operations closer to top quartile industry performance over the duration of a business plan. The CNO, in consultation with OPG's Nuclear Executive Committee ("NEC"), provided direction on top-down performance targets for each nuclear station for the planning period (i.e. 2013 - 2015). The top-down approach establishes operational, financial, generation and staff targets set by reference to historical performance, targets established in the prior years, and updated benchmarking results.

Chart 3 sets out the final OPG operational and financial targets for the 20 benchmark performance indicators for the period 2013 - 2015.

Chart 3

	Pickering Annual Targets			Darlington Annual Targets		
Benchmarking Indicators – Annual Targets	**2013**	**2014**	**2015**	**2013**	**2014**	**2015**
Safety						
All Injury Rate (#/200k hours worked)	0.89	0.89	0.89	0.89	0.89	0.89
Industrial Safety Accident Rate (#/200k hours worked)	0.15	0.15	0.15	0.15	0.15	0.15
Collective Radiation Exposure (person-rem per unit)	101.95	100.95	98.71	96.73	56.00	73.80
Airborne Tritium Emissions (Curies) per Unit	2,350	1,900	1,800	1,000	1,000	1,000
Fuel Reliability (microcuries per gram)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Reactor Trip Rate (# per 7,000 hours)	0.5	0.5	0.5	0.5	0.5	0.5
Auxiliary Feedwater System Unavailability (#)	0.02	0.02	0.02	0.02	0.02	0.02
Emergency AC Power Unavailability (#)	0.025	0.025	0.025	0.025	0.025	0.025

High Pressure Safety Injection Unavailability (#)	0.02	0.02	0.02	0.02	0.02	0.02
Reliability						
WANO NPI (Index)	66.0	72.0	74.2	97.7	97.9	96.1
Forced Loss Rate (%)	8.09	7.76	5.5	1.50	1.25	1.00
Unit Capability Factor (%)	79.2	79.9	82.1	88.8	93.5	86.3
Chemistry Performance Indicator (Index)	1.06	1.05	1.04	1.01	1.01	1.01
On-line Deficient Critical and Non-Critical Mtce Backlog (work orders/unit).	207	197	<197	200	190	180
On-Line Corrective Critical and Non-critical Mtce Backlog (work orders/unit).	104	85	78	50	29	25
Value for Money						
Total Generating Costs per MWh ($/Net MWh) [1]	65.99	66.08	60.25	40.25	36.21	42.78
Non-Fuel Operating Costs per MWh ($/Net MWh) [1]	55.83	55.71	53.34	31.76	27.21	32.82
Fuel Costs per MWh ($/Net MWh)	6.04	6.02	5.93	5.39	5.36	5.28
Capital Costs per MW DER (k$/MW) [2]	28.05	29.98	6.98	23.76	29.48	34.82
Human Performance						
Human Performance Error Rate (# per 10k ISAR hours)	.005	.004	.004	.004	.004	.004

[1] Excludes OPEB, Pension, and Asset Service Fees
[2] Design Electrical Rating (DER)

OPG is targeting improved performance by 2015 in each of its four cornerstones. Specifically:

- OPG will continue to target first quartile performance in safety for Pickering and Darlington. OPG is targeting improvements in Fuel Reliability at Darlington and Reactor Trip Rate at Pickering.

- OPG will focus on improved reliability at both Pickering and Darlington. OPG is targeting improved FLR at Darlington but its UCF will decline in 2015 due to the VBO which will take all four units off-line for more than 1 month. For Pickering, OPG is

Corporate 2014 OPG Balanced Scorecard *(Final July 2014)*

Weight	Key Performance Indicators	Threshold	Business Plan	Stretch Target
10%	**Safety, Environment, Reliability and Code of Conduct** Deliver front-line/core services			
10%	**AIR:** All Injury rate	1.69	0.89	0.36
10%	• Safety focus areas: ○ Improvement in the area of Work Protection Code ○ Continued focus on Situational Awareness ○ Nuclear and HT, public, employee, and operational safety • No significant events that impact OPG's reputation	Overall Score will be determined by CEO, incorporating assessment of AIR		
50%	**Operating Performance -** Reduce costs & improve OPG financial health			
15%	EBT, excl. nuclear waste management segment ($M)	300	500	700
10%	Operating OM&A Expenses – Total OPG ($M)	2,600	2,475	2,325
5%	Non-Electricity Generation Margin ($M)	325	350	400
15%	Production – Total OPG adjusted for Hydro SBG (TWh)	80.6	82.4	84.2
5%	Business Transformation: 2014 headcount from ongoing operations (excluding Refurbishment).	9,900		
40%	**Long Term Energy Plan and Capital Project Performance -** Support Ontario's Long Term Energy plan and deliver front-line/core services			
25%	**Nuclear Refurbishment Progress (15%)**	Deliverables 1-4 in Table A (attached)	Deliverables 1-13 in Table A (attached)	Deliverables 1-16 in Table A (attached)
	Pickering License hold point removed (210K hr) **(10%)**	Prior to unit 6 exceeding 210,000 full power hours of operation.		
10%	**Lower Mattagami** (Units in-service)	**1 Unit** Harmon G3	**2 Units** Threshold plus Smoky Falls - 1 Unit	**3 Units** BP Plus - Smoky Falls 2nd unit in-service before November 15th or Kipling G3 In service before December 15th
5%	**Atikokan – Commercial Operation**	Achieved by year-end 2014		
100%				

These measures form the basis on which our overall corporate performance will be assessed but the scores against these measures and overall Corporate score are not absolute. The Board and President reserve the right to determine the Corporate Score. In exercising their discretion, the Board and President may choose to make adjustments to the Corporate Score or individual scorecard items.

1. Refurbishment (15%)

	Threshold	Business Plan	Stretch Target	Assessment Notes
Refurbishment Progress	Table A Deliverables 1-4	Table A Deliverables 1-13	Table A Deliverables 1-16	Refer to Table A for list of deliverables. Note: All deliverables pulled ahead from 2015 to be executed within the original deliverable budget.

Table A: Darlington Refurbishment Progress		
Threshold: Deliverables 1-5	**Business Plan: Deliverables 1-13**	**Stretch Target: Deliverables 1-16**

Deliverable	Description	
1	Re-tube & Feeder Replacement Mock-up - Available for Use	
2	Fuel Handling - Dummy Fuel Bundles and Flow Reduction Orifice Bundles Mock-up Units Delivered	
3	D20 Storage Facility - Caisson Installation Complete	
4	Vehicle Screening Facility - Available for Service	
5	Holt Road Interchange - Site Preparation Complete	
6	Re-tube & Feeder Replacement - Mock-up Toolset Delivered	
7	Global Assessment Report & Integrated Implementation Plan Approved by CNSC	
8	Water & Sewer System - Available for Service	
9	Electrical Power Distribution System - 44kV Distribution Station DS5 Installation Complete	
10	3rd Emergency Power Generator - Buried Services Relocation Complete	
11	Re-tube & Feeder Replacement Island Annex - Buried Services Relocation Complete	
12	Refurb Project Office - Structural Steel Erected	
13	Operations Support Building Refurbishment - New Cladding/Windows Installed	
14	Re-tube & Feeder Replacement Unit 2 Toolset - Single Fuel Channel & Spacer Removal Tools and D2O Vacuum Drying Systems Delivered	**Current Baseline Target - September 4, 2015**
15	Auxiliary Heating System - Boilers Delivered	**Current Baseline Target- January 30, 2015**
16	D20 Storage Facility - Excavation Complete	**Current Baseline Target - February 2015**

Corporate 2015 Balanced Scorecard

Corporate 2015 Balanced Scorecard

(Revised Feb 16, 2015)

Weight	Key Performance Indicators	Threshold	Business Plan	Stretch Target
10%	**Safety, Environment, Reliability and Code of Conduct** Deliver front-line/core services			
10%	**AIR:** All Injury rate	1.20	0.69	0.25
10%	• Safety focus areas: ○ Improvement in the area of Work Protection performance with emphasis on reducing human errors ○ Fostering a stronger employee health culture with a focus on enhanced support and mental health training. • No significant events that impact OPG's reputation	Overall Score will be determined by CEO, incorporating assessment of AIR		
50%	**Operating Performance -** Reduce costs & improve OPG financial health			
15%	EBT - excl. nuclear waste management segment ($M)	400	600	800
15%	Operating OM&A Expenses – Total OPG ($M)	2,580	2,455	2,305
15%	Production – Total OPG adjusted for SBG (TWh)	78.3	80.5	82.6
5%	Headcount from ongoing operations (excluding Refurbishment).	9,491	9,264	9,084
40%	**Long Term Energy Plan and Capital Project Performance -** Support Ontario's Long Term Energy plan and deliver front-line/core services			
5%	Darlington Refurbishment - Campus Plan D_2O Storage Facility - Dyke Construction Complete	31-Dec	30-Nov	31-Oct
5%	Darlington Refurbishment - Campus Plan - 3rd Emergency Power Generator - Building complete and Generator in-place	31-Dec	30-Nov	31-Oct
10%	OPG Board Approval of Refurbishment Budget (RQE)	Before Year End		
5%	Refurbishment Project Cost ($M) - Cumulative to the end of 2015	$2,784	$2,732	$2,628
5%	Darlington Fuel Handling Reliability - Ready for on Reactor Trial	Universal Carriers Delivered Before Year End	Universal Carriers Delivered and SARF In-Service Before Year End	Universal Carrier Commissioned on SARF Before Year End
5%	Darlington Relicensing (License Term)	5 Years		13 Years
5%	Darlington VBO (Duration - Days)	47.5 Days	43.5 Days	39.5 Days
100%				

These measures form the basis on which our overall corporate performance will be assessed, but the scores against these measures and overall Corporate score are not absolute. The Board and President reserve the right to determine the Corporate Score. In exercising their discretion, the Board and President may choose to make adjustments to the Corporate Score or individual scorecard items.

Corporate 2016 Balanced Scorecard

Corporate 2016 Balanced Scorecard - Proposed Metrics (Revised Feb 17, 2016)				
Weight	**Key Performance Indicators**	**Threshold**	**Business Plan**	**Stretch Target**
10%	**Safety, Environment, Reliability and Code of Conduct -** Deliver front-line/core services			
10%	**AIR:** All Injury rate	0.50	0.38	0.31
10%	• Safety focus areas: ○ Improvement in the area of Work Protection performance with emphasis on reducing human errors ○ Continued Focus on Situational Awareness and Routine Tasks. ○ Fostering a stronger employee health culture with a focus on enhanced support and mental health training. • No significant events that impact OPG's reputation	As determined by CEO		
50%	**Financial & Operating Performance –** Deliver customer value, Reduce costs & improve OPG financial health			
20%	EBT, excl. nuclear waste management segment ($M)	510	710	910
15%	Operating OM&A Expenses – Total OPG ($M)	2,625	2,500	2,375
15%	Production – Total OPG adjusted for SBG (TWh)	79.8	82.1	84.5
40%	**Long Term Energy Plan and Capital Project Performance -** Support Ontario's Long Term Energy plan and deliver front-line/core services			
10%	Refurbishment Project Cost – 2016 Actual Expenditures ($M) as a percentage of approved 2016 budget	100%	97.5%	95%
10%	Darlington Refurbishment Execution Schedule for Unit 2 - Defueling – Number of channels defueled on December 31, 2016	212	254	311
10%	Refurbishment Campus Plan - 3rd Emergency Power Generator engine set and Containment Filtered Venting System both in-service and D2O Heavy Water Storage Facility Ready to Receive Unit 2 PHT Water.	31-Dec	30-Nov	02-Nov
5%	Peter Sutherland Sr. Generating Station - Powerhouse Phase 1 Concrete Complete	26-Nov-16	26-Sep-16	15-Aug-16
5%	Refurbishment of PGS Reservoir - Completion of liner installation	15-Jan-17	15-Nov-16	30-Sep-16
100%				
These measures form the basis on which our overall Corporate performance will be assessed, but the scores against these measures and overall Corporate Score are not absolute. The Board and President reserve the right to determine the Corporate Score. In exercising their discretion, the Board and President may choose to make adjustments to the Corporate Score or individual scorecard items.				

Corporate 2017 Balanced Scorecard

	Key Performance Indicators	Threshold	Business Plan	Stretch Target
10%	**Social Licence** - Through building and maintaining public trust, positive indigenous relations and an engaged workforce			
10%	**AIR**: All Injury rate	0.49	0.37	0.31
	Safety focus areas: o Continuing to develop and implement materials, initiatives and model behaviours that will progress and imbed the iCare Enough to Act for Safety culture o Enhance field oversight to monitor compliance to our safety initiatives and programs including contractors, with a focus on the Darlington Refurbishment Project o Continue to advance the Total Health culture in OPG through the implementation and execution of initiatives that will promote employee attendance, mental health and the adoption of healthy behaviours and lifestyles	As determined by CEO		
	No significant events that impact OPG's reputation			
35%	**Financial Strength** - Through regulated asset revenue and expansion of our core business, risk management, commercial focus and financial flexibility			
20%	**EBT**, excl. nuclear waste management segment ($M)	675	875	1075
15%	**Operating OM&A Expenses** – Total OPG ($M)	2675	2550	2425
15%	**Operational Excellence** - Through efficiencies and optimized asset management in a safe and environmentally responsible manner			
15%	**Production** – Total OPG adjusted for SBG (TWh)	70.3	72.4	74.6
40%	**Project Excellence** - Through delivering project results on time and on budget and industry leading project management			
10%	**Refurbishment Project Cost** – 2017 actual expenditures ($M) as a percentage of approved 2017 budget	100%	97.5%	95%
5%	**Refurbishment Unit 2 Critical Path Execution** – Commencement of Feeder cabinet removal (Milestone #A1012)	5-Aug-17	26-Jul-17	28-Jun-17
10%	**Refurbishment Unit 2 Critical Path Execution** - Progress of critical path on December 31, 2017	All Bellows Severed (Milestone #A1127)	50% of End Fittings Removed (Milestone #A1056)	400 Pressure Tubes Removed (Milestone #A1058)
5%	**Pump Generating Station** In-Service and within budget	1-Jun-17	1-Apr-17	1-Mar-17
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5%	**Total In-service Capital -** not including major projects otherwise on scorecard (DRP, [redacted] and PGS)	$578 +/-10% to +/-15%	$578 +/- 3% to +/-10%	$578 to +/- 3%
100%				

These measures form the basis on which our overall Corporate performance will be assessed, but the scores against these measures and overall Corporate Score are not absolute. The Board and President reserve the right to determine the Corporate Score. In exercising their discretion, the Board and President may choose to make adjustments to the Corporate Score or individual scorecard items.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	**2016**	**2015**
Revenue	**5,653**	5,476
Fuel expense	**727**	687
Gross margin	**4,926**	4,789
Operations, maintenance and administration	**2,747**	2,783
Depreciation and amortization	**1,257**	1,100
Accretion on fixed asset removal and nuclear waste management liabilities	**929**	895
Earnings on Nuclear Segregated Funds - (a reduction to expenses)	**(746)**	(704)
Income from investments subject to significant influence	**(37)**	(39)
Other net expenses	**35**	65
Income before interest and income taxes	**741**	689
Net interest expense	**120**	180
Income tax expense	**168**	92
Net income	**453**	417
Net income attributable to the Shareholder	**436**	402
Net income attributable to non-controlling interest [1]	**17**	15
Income (loss) before interest and income taxes		
Electricity generation business segments	**928**	912
Regulated – Nuclear Waste Management	**(174)**	(186)
Services, Trading, and Other Non-Generation	**(13)**	(37)
Total income before interest and income taxes	**741**	689
Cash flow		
Cash flow provided by operating activities	**1,705**	1,465
Electricity generation (TWh)		
Regulated – Nuclear Generation	**45.6**	44.5
Regulated – Hydroelectric	**29.5**	30.4
Contracted Generation Portfolio [2]	**3.1**	3.1
Total electricity generation	**78.2**	78.0
Nuclear unit capability factor (per cent) [3]		
Darlington Nuclear GS	**89.5**	76.9
Pickering Nuclear GS	**75.2**	79.4
Availability (per cent)		
Regulated – Hydroelectric	**89.0**	91.2
Contracted Generation Portfolio – hydroelectric stations	**77.3**	88.6
Equivalent forced outage rate		
Contracted Generation Portfolio – thermal stations	**1.6**	11.2
Enterprise Total Generating Cost (TGC) per MWh for the twelve months ended December 31, 2016 and 2015 ($/MWh) [4]	**48.45**	50.84
Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI) for the twelve months ended December 31, 2016 and 2015 (%) [4]	**4.2**	4.0
Funds from Operations (FFO) Adjusted Interest Coverage for the twelve months ended December 31, 2016 and 2015 (times) [4]	**5.1**	5.1

1 Relates to the 25 per cent interest of a corporation wholly owned by the Moose Cree First Nation in the Lower Mattagami Limited Partnership.

2 Includes OPG's share of generation volume from its 50 per cent ownership interests in the Portlands Energy Centre and Brighton Beach GS.

3 Nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment. Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

4 Enterprise TGC, ROE Excluding AOCI, and FFO Adjusted Interest Coverage are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about the non-GAAP measures is provided in OPG's Management's Discussion and Analysis for the year ended December 31, 2016, under the sections *Highlights – Enterprise TGC, Highlights – FFO Adjusted Interest Coverage,* and *Highlights – ROE Excluding AOCI,* as well as *Supplementary Non-GAAP Financial Measures.*

Numbers may not add due to rounding.

Table 1
Comparison of Production Forecast - Nuclear

Line No.	Business Unit	2013 Budget	(c)-(a) Change	2013 Actual	(g)-(c) Change	2014 OEB Approved[1]	(g)-(e) Change	2014 Actual	(k)-(g) Change	2015 OEB Approved[2]	(k)-(i) Change	2015 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Darlington NGS											
1	**TWh**	26.9	(1.8)	25.1	2.9	27.1	0.9	28.0	(4.7)	25.0	(1.7)	23.3
2	**Unit Capability Factor (%)**	88.8	(5.9)	82.9	9.0	93.5	(1.6)	91.9	(15.0)	86.3	(9.4)	76.9
3	**PO Days**	144.4	0.1	144.5	(52.4)	77.1	15.0	92.1	174.8	188.0	78.9	266.9
4	**FEPO Days**	0.0	39.8	39.8	(39.8)	0.0	0.0	0.0	7.7	0.0	7.7	7.7
5	**FLR (%)**	1.5	3.3	4.8	(3.3)	1.3	0.3	1.5	3.4	1.0	3.9	4.9
6	**FLR Days Equivalent**	19.7	41.8	61.5	(41.0)	14.6	5.9	20.5	36.9	12.7	44.7	57.4
	Pickering NGS											
7	**TWh**	21.1	(1.5)	19.6	0.5	21.9	(1.8)	20.1	1.1	21.6	(0.4)	21.2
8	**Unit Capability Factor (%)**	79.2	(5.5)	73.7	1.6	79.9	(4.6)	75.3	4.1	82.1	(2.8)	79.4
9	**PO Days**	303.5	(82.7)	220.8	64.1	292.9	(8.0)	284.9	65.2	287.9	62.2	350.1
10	**FEPO Days**	0.0	167.6	167.6	(112.2)	0.0	55.4	55.4	(14.8)	0.0	40.6	40.6
11	**FLR (%)**	8.1	1.6	9.7	1.0	7.8	3.0	10.7	(7.8)	5.5	(2.6)	2.9
12	**FLR Days Equivalent**	152.4	21.4	173.8	24.2	147.0	51.0	198.0	(146.3)	104.5	(52.8)	51.7
	Totals											
13	**Unit Capability Factor (%)**	84.3	(5.7)	78.6	5.7	87.6	(3.3)	84.3	(6.3)	84.0	(6.0)	78.0
14	**PO Days**	447.9	(82.6)	365.3	11.7	370.0	7.0	377.0	239.9	475.9	141.0	616.9
15	**FEPO Days**	0.0	207.4	207.4	(152.0)	0.0	55.4	55.4	(7.1)	0.0	48.3	48.3
16	**FLR (%)**	4.5	2.5	7.0	(1.5)	4.1	1.5	5.6	(1.6)	3.1	0.8	3.9
17	**FLR Days Equivalent**	172.1	63.2	235.3	(16.8)	161.6	56.9	218.5	(109.4)	117.2	(8.1)	109.1
18	**Total TWh**	48.0	(3.3)	44.7	3.4	49.0	(0.9)	48.1	(3.5)	46.6	(2.1)	44.5

Line No.	Business Unit	2015 Actual	(c)-(a) Change	2016 Budget	(e)-(c) Change	2017 Plan	(g)-(e) Change	2018 Plan	(i)-(g) Change	2019 Plan	(k)-(i) Change	2020 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Darlington NGS											
19	**TWh**	23.3	2.7	26.0	(7.0)	19.0	0.2	19.3	0.4	19.7	(1.9)	17.7
20	**Unit Capability Factor (%)**	76.9	14.2	91.1	(5.9)	85.1	0.9	86.0	1.7	87.8	(8.4)	79.4
21	**PO Days[3]**	266.9	(155.9)	111.0	42.4	153.4	(10.1)	143.3	(19.2)	124.1	64.1	188.2
22	**FEPO Days**	7.7	(7.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	**FLR (%)**	4.9	(3.9)	1.0	0.0	1.0	(0.0)	1.0	0.0	1.0	3.2	4.2
24	**FLR Days Equivalent**	57.4	(44.7)	12.7	(3.3)	9.4	0.1	9.5	0.2	9.7	28.4	38.1
	Pickering NGS											
25	**TWh**	21.2	(0.4)	20.8	(1.7)	19.1	0.1	19.2	0.2	19.4	0.3	19.6
26	**Unit Capability Factor (%)**	79.4	(1.7)	77.6	(6.1)	71.5	0.5	72.0	0.6	72.6	0.8	73.4
27	**PO Days**	350.1	51.5	401.6	140.0	541.6	(10.8)	530.8	(13.7)	517.2	(18.3)	498.9
28	**FEPO Days**	40.6	(40.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	**FLR (%)**	2.9	2.1	5.0	0.0	5.0	(0.0)	5.0	0.0	5.0	0.0	5.0
30	**FLR Days Equivalent**	51.7	38.0	89.7	(7.2)	82.4	0.5	83.0	0.7	83.6	1.2	84.9
	Totals											
31	**Unit Capability Factor (%)**	78.0	6.6	84.6	(6.8)	77.8	0.7	78.5	(39.5)	39.0	37.2	76.2
32	**PO Days[3]**	616.9	(104.3)	512.6	182.4	695.0	(20.8)	674.1	(32.9)	641.3	45.8	687.1
33	**FEPO Days**	48.3	(48.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	**FLR (%)**	3.9	(1.1)	2.8	0.2	3.0	(0.0)	3.0	(0.0)	3.0	1.6	4.6
35	**FLR Days Equivalent**	109.1	(6.7)	102.4	(10.6)	91.8	0.6	92.5	0.9	93.4	29.6	122.9
36	**Total TWh**	44.5	2.3	46.8	(8.7)	38.1	0.4	38.5	0.6	39.0	(1.7)	37.4

Line No.	Business Unit	2020 Plan	(c)-(a) Change	2021 Plan
		(a)	(b)	(c)
	Darlington NGS			
37	**TWh**	17.7	(1.1)	16.6
38	**Unit Capability Factor (%)**	79.4	11.5	90.9
39	**PO Days[3]**	188.2	(131.9)	56.2
40	**FEPO Days**	0.0	0.0	0.0
41	**FLR (%)**	4.2	(1.2)	3.0
42	**FLR Days Equivalent**	38.1	(13.1)	25.0
	Pickering NGS			
43	**TWh**	19.6	(0.8)	18.8
44	**Unit Capability Factor (%)**	73.4	(2.8)	70.6
45	**PO Days**	498.9	63.9	562.8
46	**FEPO Days**	0.0	0.0	0.0
47	**FLR (%)**	5.0	(0.0)	5.0
48	**FLR Days Equivalent**	84.9	(3.5)	81.4
	Totals			
49	**Unit Capability Factor (%)**	76.2	2.8	79.0
50	**PO Days[3]**	687.1	(68.1)	619.0
51	**FEPO Days**	0.0	0.0	0.0
52	**FLR (%)**	4.6	(0.6)	4.0
53	**FLR Days Equivalent**	122.9	(16.6)	106.3
54	**Total TWh**	37.4	(2.0)	35.4

Notes:
1 OEB Approved nuclear production in 2014 is 49.0 TWh per EB-2013-0321 Decision with Reasons p. 39.
2 OEB Approved nuclear production in 2015 is 46.6 TWh per EB-2013-0321 Decision with Reasons p. 39.
3 PO days excludes planned outage days for Darlington units out of service during Darlington refurbishment.

SEC Interrogatory #64

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 2]

With respect to the Goodnight Consulting Benchmarking Report:

a. [p.14] Please explain why each of the 'CANDU-Specific Exclusions' functions are specific to CANDU reactors so that they could not be benchmarked.

b. [p.22] Please explain any changes to the raw adjustments from the report provided in EB-2013-0321.

c. [p.24] Please explain the basis for the 1.8 scaling factor.

d. [p.33] Please provide a copy of the 2014 Goodnight Consulting US Nuclear Plant Staffing Newsletter.

e. [p.29] Please provide a copy of Appendix A.

f. OPG has said that in 2016 it will be at or close to benchmark. Please confirm that OPG means that its 2016 staffing will be at or close to the 2014 benchmarking as identified in the Goodnight Consulting Benchmarking Report. If not, please provide the basis for its statement.

g. [p.31] Based on the premise of part (f), please provide a similar table to page 31 that shows which functions OPG is above or below the benchmarking.

Response

a. As indicated at Ex. F2-1-1 Attachment 2, p. 14, the CANDU-specific exclusions are unique to CANDU design with no comparable PWR activity.

b. The raw adjustments in the 2014 study are equivalent to the sum of raw adjustments and ratio adjustments in the 2013 study, with the exception of the Management function. A separate methodology was used for developing the staffing benchmark for the 2014 study for the Management function.

c. Goodnight Consulting's report, "Nuclear Staffing Benchmarking Analysis" for OPG dated February 3, 2012, Appendix D p. 61 at EB-2013-0321 Ex. F5-1-1 Part a describes factors in scaling from 2-units to 4-units, as follows:

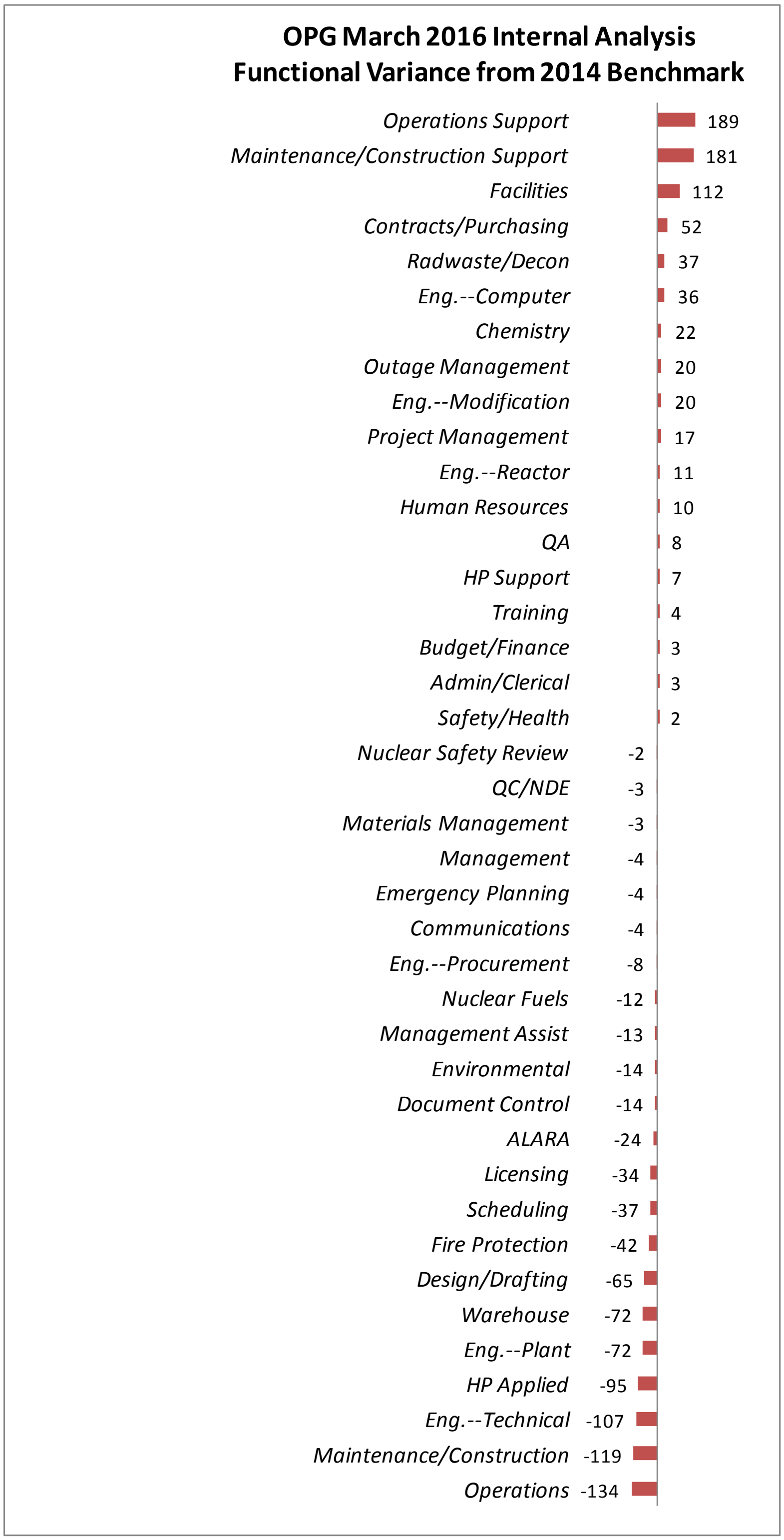
- "As a consulting team, which included experienced nuclear plant engineers and operators, we developed the scaling factors based on our experience and best estimates – for most functions, we applied a scaling factor of 1.8 times the 2-unit level for a 4-unit plant, which was based on staffing levels we have observed at several international 4-unit sites relative to our benchmark 2-unit sites
- Several exceptions from the 1.8x scaling factor were applied…"

d. Refer to Attachment 1 to this response for the 2014 Goodnight Consulting US Nuclear Plant Staffing Newsletter.

e. Appendix A "OPG Data by Staffing Function" includes details by employee name and therefore cannot be released.

f. Confirmed; the statement refers to 2016 OPG overall staffing being at or close to Goodnight's overall 2014 benchmark (see Ex. L-6.2-19 SEP-3).

g. Goodnight Consulting has not conducted a subsequent review. OPG conducted an internal analysis of functional staffing as of March 2016, which resulted in the following variances as compared to Goodnight's 2014 functional benchmarks.


OPG March 2016 Internal Analysis
Functional Variance from 2014 Benchmark
Operations Support 189
Maintenance/Construction Support 181
Facilities 112
Contracts/Purchasing 52
Radwaste/Decon 37
Eng.--Computer 36
Chemistry 22
Outage Management 20
Eng.--Modification 20
Project Management 17
Eng.--Reactor 11
Human Resources 10
QA 8
HP Support 7
Training 4
Budget/Finance 3
Admin/Clerical 3
Safety/Health 2
Nuclear Safety Review -2
QC/NDE -3
Materials Management -3
Management -4
Emergency Planning -4
Communications -4
Eng.--Procurement -8
Nuclear Fuels -12
Management Assist -13
Environmental -14
Document Control -14
ALARA -24
Licensing -34
Scheduling -37
Fire Protection -42
Design/Drafting -65
Warehouse -72
Eng.--Plant -72
HP Applied -95
Eng.--Technical -107
Maintenance/Construction -119
Operations -134

SEP Interrogatory #3

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, p 11 "OPG continues to examine staffing levels as part of its benchmarking studies and anticipates that it will eliminate the Goodnight staffing benchmark gap to industry peers in 2016. "

a) Using 2014 actuals as the starting point please provide a table which shows the staffing changes in 2015 and 2016 which result in the "benchmark gap" being eliminated in 2016. Use the staffing categories provided in F2-1-1, Attachment 2, p9 for this table [either the data organized by OPG Business Group or the data as organized by Goodnight].

b) Will the 2016 year end staffing profile by categories provided in answer to a) be substantially maintained through 2017 until 2021 or will there be material changes made? In either case, please explain why.

Response

a) Goodnight Consulting has not conducted a subsequent review. OPG conducted an internal analysis of functional staffing as of March 2016, which resulted in the following FTEs by process area, indicating that the overall benchmark gap has been more than eliminated as shown in Chart 1.

Chart 1

Process Area	**March 2014 Actual**	**March 2016 Actual**	**Change 2016 vs. 2014**
	(a)	(b)	(b) - (a)
Configuration Control	345	364	19
Equipment Reliability	442	407	(35)
Loss Prevention	303	302	(1)
Materials & Services	208	169	(39)
Operate The Plant	1,072	1,059	(13)
Support Services & Training	1,149	1,073	(76)
Work Management	1,902	1,686	(216)
OPG Benchmarked FTEs	**5,421**	**5,060**	**(361)**
2014 Goodnight Benchmark	5,208	5,208	
Benchmark Gap	**213**	**(148)**	

By year end 2016, OPG benchmarked FTEs are projected to increase based upon hiring of regular staff, partially offset by a corresponding reduction in non-regular and augmented staff. OPG anticipates that the resulting benchmarked FTEs at year end 2016 will continue to remain at or below the 2014 Goodnight benchmark.

b) The Goodnight benchmarks are based upon ten steady-state running units at Darlington and Pickering. As Darlington Refurbishment commences in October 2016 and preparations begin for Pickering End of Commercial Operations, staffing will change for reasons beyond the benchmarked scope, particularly in operations and maintenance. However, after taking the anticipated operating changes into consideration, the resulting benchmarked OPG FTEs during 2017-2021 are expected to continue to remain at or below the 2014 Goodnight benchmark.

2014 Nuclear Staffing Benchmarking Analysis

A Report For:

ONTARIO POWER GENERATION

December 22nd 2014

GOODNIGHT CONSULTING

Executive Summary: OPG Has Reduced The Variance From The Staffing Benchmarks Since 2011

- OPG asked Goodnight Consulting to compare OPG Nuclear staffing to other North American nuclear operators through an approach consistent with the one we used in 2011 and 2013.
- We benchmarked 5,421 OPG Nuclear staff and long-term contractors; 2,036 OPG Nuclear personnel could not be benchmarked.
- Our current analysis shows that OPG, as of March 2014, is 213 FTEs (4.1%) above the total benchmark of 5,208 FTEs.
- OPG is above benchmark staffing in 17 job functions, and at or below benchmark staffing in 23 functions.
- OPG's variance above the benchmark has narrowed from 17% in 2011 due to attrition, increases in the benchmarks, OPG actions including the centre-led initiative and the Pickering Station amalgamation.

GOODNIGHT CONSULTING

Goodnight Consulting's Staffing Functions Allow For "Apples-To-Apples" Comparisons

- Job descriptions, titles, and organizational structures vary from company to company
- Goodnight Consulting maintains our own job functions and definitions to establish commonality between companies
- Functions allow benchmark comparisons between different companies by aligning common activities, independent of job position titles or organizational/group labels
- Descriptions for specific functions capture the majority of activities performed by individuals performing work in that activity

GOODNIGHT CONSULTING

5,421 OPG Employees & Contractors Were Functionalized For Benchmarking

	Employees	Contractor FTEs	Grand Total
Assurance	36	0	36
Business & Admin Services	570	71	641
Commercial Operations & Environment	33	0	33
Corporate Relations & Communications	16	0	16
Finance	66	1	67
Nuclear	3606	305	3911
Nuclear Projects	199	114	313
People and Culture	364	41	405
Grand Total	**4890**	**531**	**5421**

This data is organized by OPG Business Group; employees supporting various job functions are found within each Business Group, for example the "People & Culture" Business Group includes Training, HR, and Support staff

	Regular	Contractor	Grand Total
Configuration Control	310	35	345
Equipment Reliability	406	36	442
Loss Prevention	268	35	303
Materials & Services	187	21	208
Operate The Plant	1055	17	1072
Support Services & Training	1013	136	1149
Work Management	1651	251	1902
Grand Total	**4890**	**531**	**5421**

This data is organized by Goodnight Consulting Process Area.

A line-by-line accounting of where each employee was functionalized is provided in the Appendix

GOODNIGHT CONSULTING

OPG Contractor Support Data Was Reviewed To Identify Headcounts For Baseline Contractors

Staff augmentation contractor data	• *Professional staff providing specialized skills, including authorized training contractors and/or variable work support*
Other purchased service data	• *Specialized contractors, such as nuclear safety analysis, and maintenance/construction trades*
Exclusions	• *Consistent with our standard nuclear benchmarking methodology, outage execution contractors and outage overtime were both excluded*

GOODNIGHT CONSULTING

OPG Contractor Data Was Converted From Hours Or Costs, Into Full Time Equivalents (FTEs)

Data Provided

OPG provided contractor data via contractor billed annual costs, or cumulative contractor annual hours

Spend Converted to FTEs

Cumulative contractor billed annual dollar values were first divided by an average hourly cost that include wages plus benefits, and then by estimated annual hours* to prorate the data into annual FTEs

Hours Converted to FTEs

Cumulative contractor annual hours were also divided by the same value to prorate the data into annual FTEs

*1890 hours/year = 1 FTE, consistent with previous studies

Applicable OPG Baseline Contractors Equates To 531 FTEs In 32 Job Functions

32 job functions where OPG contractor FTEs were identified

	Contractor FTEs
Admin/Clerical	14
Budget/Finance	1
Chemistry	12
Contracts/Purchasing	3
Emergency Planning	11
Eng.--Computer	2
Eng.--Modification	11
Eng.--Plant	17
Eng.--Procurement	1
Eng.--Reactor	17
Eng.--Technical	12
Environmental	2
Facilities	77
HP Applied	4
HP Support	2
Human Resources	1
Licensing	1
Maintenance/Construction	133
Maintenance/Construction Support	53
Management	3
Management Assist	1
Nuclear Fuels	6
Nuclear Safety Review	17
Operations Support	3
Project Management	32
QA	2
QC/NDE	5
Radwaste/Decon	26
Safety/Health	4
Scheduling	1
Training	39
Warehouse	18
Grand Total	**531**

Number of OPG contractor FTEs identified in each function (531 total)

A line-by-line accounting of where each Contractor was functionalized is provided in the Appendix

GOODNIGHT CONSULTING

2,036 OPG Nuclear Personnel Could Not Be Benchmarked

CANDU-Specific Exclusions*

- *Fuel Handling*: Comparable function in PWRs only occurs during outages
- *Heavy Water Handling*
- *Tritium Removal Facility*
- *Feeder and Fuel Channel Support*
- *Other CANDU-Specific support to excluded functions e.g. Refueling Ops*

*Unique to CANDU design with no comparable PWR activity

OPG-Specific Exclusions

- *Pickering Units 2 & 3 Safe Store Support:* However, cross-tied operations for Units 2 & 3 ***were counted***
- *Major Projects/ One time initiatives:* e.g., Darlington Refurbishment, New Build, etc.

Generic Exclusions**

- *Nuclear waste and used fuel*: Functions not performed by plants in the benchmark
- *Outage execution activities:* Less than 10% were applied as "on-line" support to various functions
- *Water treatment:* Functions not performed by plants in the benchmark

**Both CANDU & PWR activities but excluded as non-baseline/non-steady state

Other Exclusions

- *Security:* Excluded consistent with OPG Security policy
- *Information Management:* Benchmarked via a different method external to this study
- *Long Term Leave Personnel*: Excluded consistent with Goodnight Consulting benchmarking methodology
- *Corporate Support Not Directly Supporting The Nuclear Program:* Excluded consistent with Goodnight Consulting benchmarking methodology

GOODNIGHT CONSULTING

To Identify Staffing Benchmarks, We Used A Methodology Similar To Prior OPG Engagements

Identify Plants	Identify Benchmarks	Adjust For Technology	Adjust For Work Rules	Finalize Benchmarks
Identify applicable nuclear plants/nuclear organizations as the benchmarking sources	Identify staffing benchmarks reflecting steady-state operations from functional staffing data using selected nuclear plants	Adjust for technical/design differences (i.e., PWR vs. CANDU)	Adjust for regulatory and/or work rule differences (i.e., 35 vs. 40 hour work week)	Apply adjustments and identify final functional staffing benchmarks

GOODNIGHT CONSULTING

We Apply Several Key Assumptions In Our Staffing Benchmarking Methodology

Benchmarks Are From Steady State, On-Power Activities

Plants are considered to be in steady state operation:

- Short-term & outage contractors *excluded*
- Baseline contractors are *included*
- Major initiatives (i.e., Darlington Refurbishment, PWR Steam Generator Replacement, PWR Vessel Head replacements, etc.) are *excluded*

Average Productivity Is Assumed

No productivity adjustments are applied to the benchmarks or OPG staffing; *however, the benchmarks were adjusted for 35 vs. 40 hour work weeks where applicable*

Current Vacancies Excluded

Benchmark staffing levels do not include permanent vacancies, i.e., vacancies not planned to be filled in the next 30 days are not counted. Regular staff absences (e.g., maternity leave or long term disability leave) are not counted as "regular staff", but may be captured as non-regular staff i.e., temporary backfills

2-Unit CANDU Staffing Benchmark Is 1,024* (Includes Corporate & Contractor FTEs)

Staffing Function	2014 2-Unit U.S. PWR Bmk	Raw Adjustments 2014	Total Bmk (2014)
Admin/Clerical	36	3	39
ALARA	5	2	7
Budget/Finance	13	1	14
Chemistry	27	0	27
Communications	3	0	3
Contracts/Purchasing	8	0	8
Design/Drafting	16	1	17
Document Control	15	2	17
Emergency Planning	6	0	6
Engineering - Computer	4	0	4
Engineering - Mods	31	3	34
Engineering - Plant	47	8	55
Engineering - Procurement	8	2	10
Engineering - Reactor	6	5	11
Engineering - Technical	29	5	34
Environmental	5	2	7
Facilities	28	0	28
Fire Protection	31	0	31
HP Applied	29	3	32
HP Support	11	1	12
Human Resources	6	1	7
Licensing	9	1	10
Maintenance/Construction	177	22	199
Maintenance/Construction Support	39	4	43
Management Assist	4	0	4
Materials Management	9	0	9
Nuclear Fuels	8	-1	7
Nuclear Safety Review	11	0	11
Operations	126	0	126
Operations Support	40	0	40
Outage Management	11	3	14
Project Management	19	1	20
QA	12	0	12
QC/NDE	11	1	12
Radwaste/Decon	9	3	12
Safety/Health	5	0	5
Scheduling	22	2	24
Training	50	3	53
Warehouse	18	2	20
Total	**944**	**80**	**1024**

The ***Raw Adjustments*** account for technical differences between PWR and CANDU plants and are detailed on the next page

*Does not include Management. A Separate Management Benchmark was developed and is discussed later in this section

Client Confidential Information

GOODNIGHT CONSULTING

Technical Adjustments Were Utilized To Derive The 2-Unit CANDU Staffing Benchmark From PWRs*

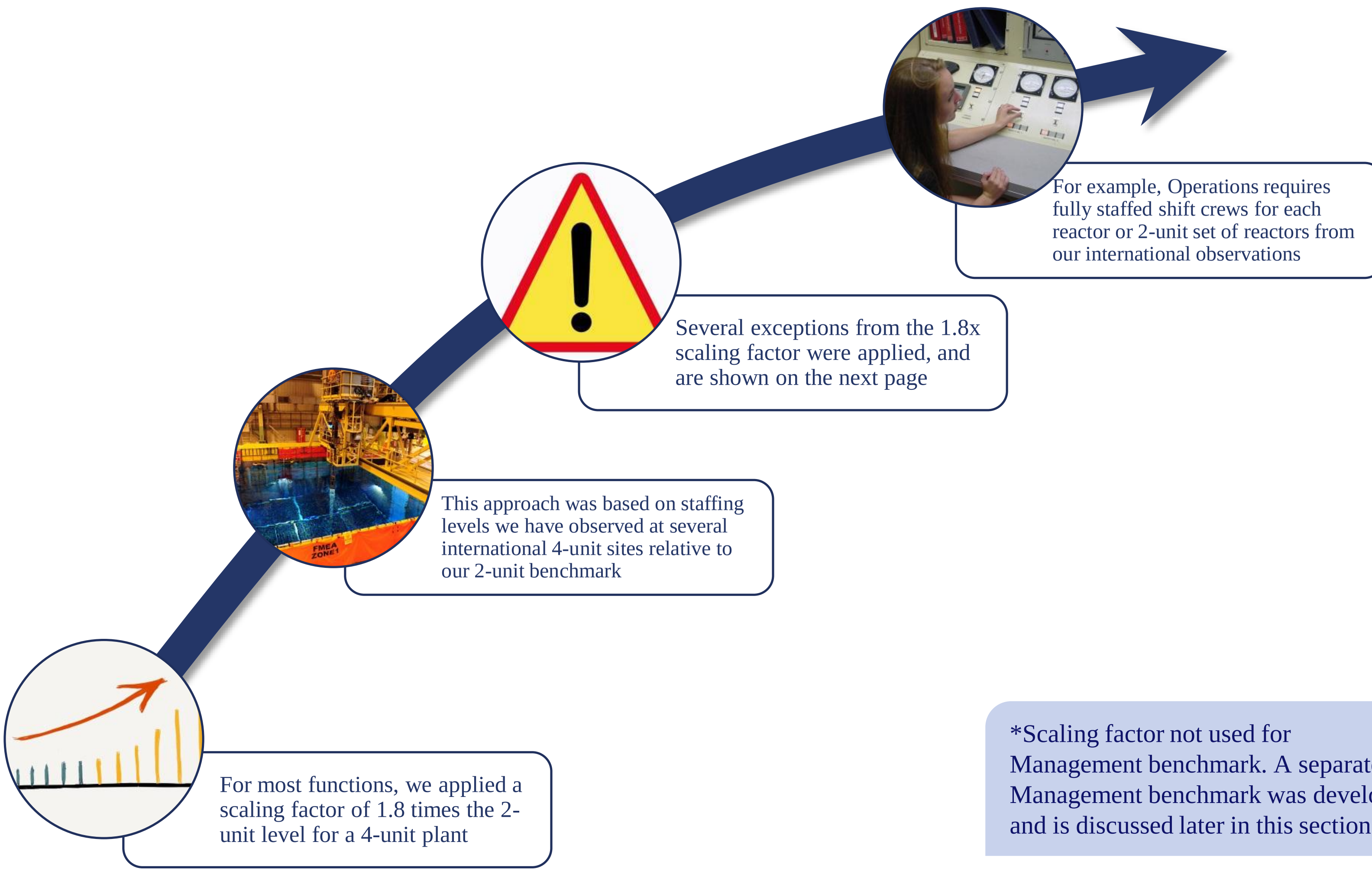
Staffing Function	Raw Adjustments 2014	Total Bmk (2014)	Rationale
Admin/Clerical	3	39	Approximately 1 additional admin/clerical person is needed for each additional 25 staff
ALARA	2	7	"Hotter shop" tritium, alpha radiation pervasive, more opportunities for ALARA-more equipment, bigger source of radiation and more space.
Budget/Finance	1	14	1 FTE additional functional staff needed to support the added personnel due to CANDU technology differences
Chemistry	0	27	No basis for adjustment
Communications	0	3	No basis for adjustment
Contracts/Purchasing	0	8	No basis for adjustment
Design/Drafting	1	17	Higher number of systems
Document Control	2	17	Higher number of systems, more control documents to manage
Emergency Planning	0	6	No basis for adjustment
Engineering - Computer	0	4	No basis for adjustment
Engineering - Mods	3	34	Higher number of systems
Engineering - Plant	8	55	Higher number of systems
Engineering - Procurement	2	10	Higher number of commercial parts dedications due to a smaller vendor market, lower availability of conforming parts
Engineering - Reactor	5	11	Adjusted to 2-unit equivalent of OPG CANDU stated requirements
Engineering - Technical	5	34	Higher number of systems, diversity instead of redundancy design philosophy
Environmental	2	7	Tritium monitoring, Canadian regulatory requirements
Facilities	0	28	No basis for adjustment
Fire Protection	0	31	No basis for adjustment
HP Applied	3	32	Additional radiation sources, differences in staffing are due to choices in program structures
HP Support	1	12	Additional radiation sources, differences in staffing are due to choices in program structures
Human Resources	1	7	1 FTE additional functional staff needed to support the added personnel due to CANDU technology differences
Licensing	1	10	Different regulatory scheme, greater number of safety systems, design philosophy of diversity over redundancy
Maintenance/Construction	22	199	Higher number of systems, diversity instead of redundancy design philosophy-track IMS impacts on numbers
Maintenance/Construction Support	4	43	Higher number of systems, diversity instead of redundancy design philosophy
Management Assist	0	4	No basis for adjustment
Materials Management	0	9	No basis for adjustment
Nuclear Fuels	-1	7	Adjusted to 2-unit equivalent of OPG CANDU stated requirements
Nuclear Safety Review	0	11	No basis for adjustment
Operations	0	126	Additional systems to monitor= increases, common systems = decreases
Operations Support	0	40	Additional systems to monitor= increases, common systems = decreases
Outage Management	3	14	Non fueling outages=decreases, more systems to deal with during an outage=increase
Project Management	1	20	Higher number of systems, diversity instead of redundancy design philosophy
QA	0	12	No basis for adjustment
QC/NDE	1	12	Due to additional maintenance work, additional QC/NDE work is required, "Innate" IMS counted here,
Radwaste/Decon	3	12	Larger volumes of I&LLW generated and packaged.
Safety/Health	0	5	No basis for adjustment
Scheduling	2	24	Greater number of systems resulting in more scheduling work
Training	3	53	Additional trainers required to handle additional maintenance training requirements
Warehouse	2	20	Additional parts and components needed for more systems and to overcome more materials kept on hand due to a smaller vendor base
Total	**80**	**1024**	

*Does not include Management. A Separate Management Benchmark was developed and is discussed later in this section

GOODNIGHT CONSULTING

We Developed Functional Scaling Factors* Based On Our Experience & Best Estimates

This is similar to the approach that was applied in 2011 and 2013



*Scaling factor not used for Management benchmark. A separate Management benchmark was developed and is discussed later in this section

GOODNIGHT CONSULTING

2-Unit *OPG* CANDU Benchmark Is 1,024*
Adjusted 4-Unit *OPG* CANDU Benchmark Is 1,976*

- Where applicable, adjustments were made for OPG's 35 Hour Work work week vs. 40 hours at U.S. plants
- The net increase in the 2-Unit benchmarks from the work week adjustment is 55 FTEs
- CANDU 2-Unit then scaled up to a 4-Unit model

2-unit to 4-unit Scaling Factors, by Functional Area

Staffing Function	2-Unit CANDU Benchmark	35 hour week?	Adjustment for 35 hour week	Scaling Factor From 2 to 4-Units	Initial 4-Unit CANDU Benchmark
Admin/Clerical	39	1	45	1.8	81
ALARA	7		7	1.8	13
Budget/Finance	14	1	16	1.8	29
Chemistry	27		27	1.8	49
Communications	3		3	1.8	5
Contracts/Purchasing	8	1	9	1.8	16
Design/Drafting	17	1	19	1.8	34
Document Control	17	1	19	1.9	36
Emergency Planning	6	1	7	1.5	11
Engineering - Computer	4	1	5	2	10
Engineering - Mods	34	1	39	1.8	70
Engineering - Plant	55	1	63	1.8	113
Engineering - Procurement	10	1	11	1.8	20
Engineering - Reactor	11	1	13	2	26
Engineering - Technical	34	1	39	1.8	70
Environmental	7	1	8	1.8	14
Facilities	28		28	1.8	50
Fire Protection	31		31	1.8	56
HP Applied	32		32	1.8	58
HP Support	12	1	14	1.8	25
Human Resources	7	1	8	1.8	14
Licensing	10	1	11	1.8	20
Maintenance/Construction	199		199	1.8	358
Maintenance/Construction Support	43		43	1.8	77
Management Assist	4	1	5	1.8	9
Materials Management	9	1	10	1.8	18
Nuclear Fuels	7	1	8	1.8	14
Nuclear Safety Review	11	1	13	1.8	23
Operations	126		126	2	252
Operations Support	40		40	2	80
Outage Management	14		14	1.8	25
Project Management	20	1	23	1.8	41
QA	12	1	14	1.8	25
QC/NDE	12		12	1.8	22
Radwaste/Decon	12		12	1.8	22
Safety/Health	5	1	6	1.8	11
Scheduling	24		24	1.8	43
Training	53		53	1.8	95
Warehouse	20	1	23	1.8	41
Total	**1024**		**1079**		**1976**

*Scaling factor not used for Management benchmark. A Separate Management Benchmark was developed and is discussed later in this section

GOODNIGHT CONSULTING

Adjustments For Pickering Units 1-4 Increase The OPG 2-Unit CANDU Benchmark To 1,095*

- Some cross-tied systems remain active at Pickering Units 2 & 3: We adjusted the benchmark to include personnel required to support those systems (16)
- FTEs assigned to SAFESTORE activities at Pickering Units 2 & 3 were **not** included in the benchmark

Adjustments to 2-Unit OPG CANDU for Pickering Units 1-4						
Staffing Function	2-Unit CANDU Benchmark	35 hour week	Adjustment for 35 hour week	Adjustments for Units 2 & 3	Pickering 1-4 Benchmark	Rationale
Admin/Clerical	39	1	45		45	
ALARA	7		7		7	
Budget/Finance	14	1	16		16	
Chemistry	27		27		27	
Communications	3		3		3	
Contracts/Purchasing	8	1	9		9	
Design/Drafting	17	1	19		19	
Document Control	17	1	19		19	
Emergency Planning	6	1	7		7	
Engineering - Computer	4	1	5		5	
Engineering - Mods	34	1	39		39	
Engineering - Plant	55	1	63	4	67	One additional System Engineer per discipine (M, E, I&C, Civil)
Engineering - Procurement	10	1	11		11	
Engineering - Reactor	11	1	13		13	
Engineering - Technical	34	1	39		39	
Environmental	7	1	8		8	
Facilities	28		28		28	
Fire Protection	31		31		31	
HP Applied	32		32	1	33	One additional Rad Pro technican to conduct surveillances
HP Support	12	1	14		14	
Human Resources	7	1	8		8	
Licensing	10	1	11		11	
Maintenance/Construction	199		199	5	204	Estimated Additional staff (FIN-like)
Maintenance/Construction Support	43		43	1	44	Ratio of support to additional Maintenance/Construction
Management Assist	4	1	5		5	
Materials Management	9	1	10		10	
Nuclear Fuels	7	1	8		8	
Nuclear Safety Review	11	1	13		13	
Operations	126		126	5	131	1 Additional Ops person per shift crew for rounds
Operations Support	40		40		40	
Outage Management	14		14		14	
Project Management	20	1	23		23	
QA	12	1	14		14	
QC/NDE	12		12		12	
Radwaste/Decon	12		12		12	
Safety/Health	5	1	6		6	
Scheduling	24		24		24	
Training	53		53		53	
Warehouse	20	1	23		23	
Total	**1024**		**1079**		**1095**	

*Scaling factor not used for Management benchmark. A Separate Management Benchmark was developed and is discussed later in this section

GOODNIGHT CONSULTING

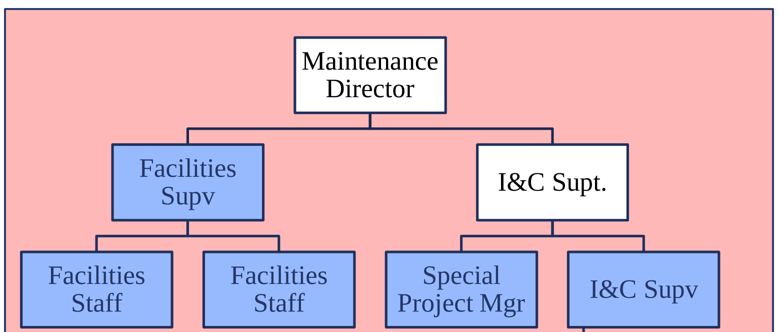
Management Is A Function, Not A Title, In Our Model; It Includes All Personnel Above 1st Line Supervisors

Management Function

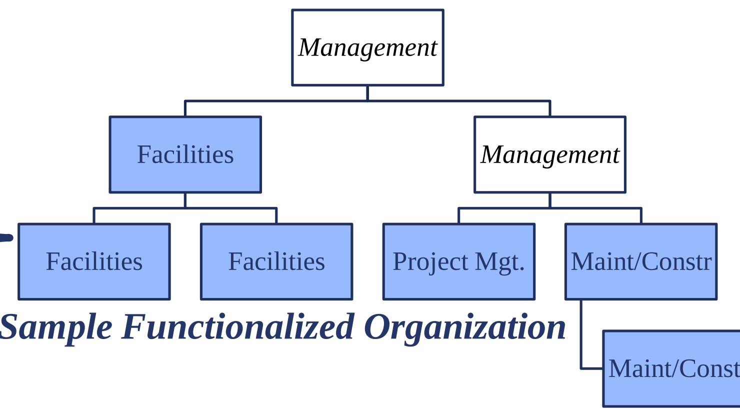
- All those above first line supervisor
- Job title not a factor
- At least one of their direct reports must also have a direct report

All Other Functions

- First Line Supervisors
- Individual Contributors



Sample Actual Organization



Sample Functionalized Organization

A Separate Methodology Was Used For Developing The Staffing Benchmark For The *Management* Function

OPG *Management* Function Benchmark = 161

- 97 for Pickering
- 64 for Darlington
- These include distributed Management Function staff from OPG Corporate Nuclear
- These 161 FTEs are 3.1% of total benchmarked staffing which is close to the expected ratio of Management/Total for smaller fleets like OPG

Applying the aforementioned scaling to the Management function produced an output not reflective of a reasonable organizational structure

The benchmark for this function is based on a reasonable organizational structure for OPG

We accounted for OPG's fleet environment, which provides opportunities for efficiency

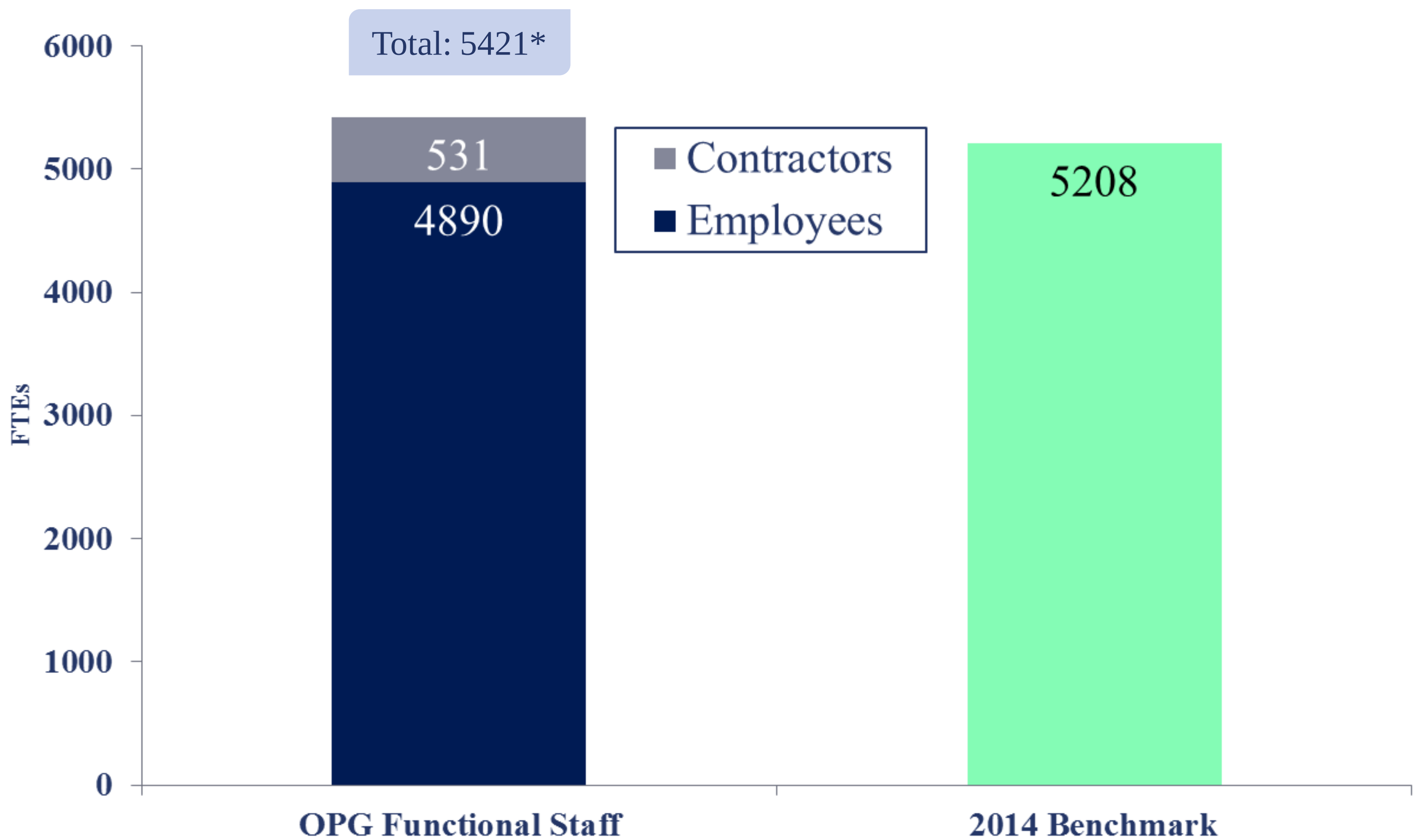
Final Benchmark Nuclear Organizational Chart has 161 Managers (excluding managers for not-benchmarked activities such as Info Management, Security, Refueling Ops, Etc.

Benchmarking *Summary:*
Total 2014 OPG Nuclear Benchmark Is 5,208

	Pickering 1-4	Pickering 5-8	Darlington	Total
Large 2-Unit PWR Benchmark	944	944	944	2832
CANDU Technology Adjustment	80	80	80	240
35 Hour Work Week Adjustment	55	55	55	165
Scale From 2 to 4 Units	0	897	897	1794
Adjust For Pickering Units 2 & 3	16	0	0	16
Add Management Benchmarks	37	60	64	161
Total	**1132**	**2036**	**2040**	**5208**

GOODNIGHT CONSULTING

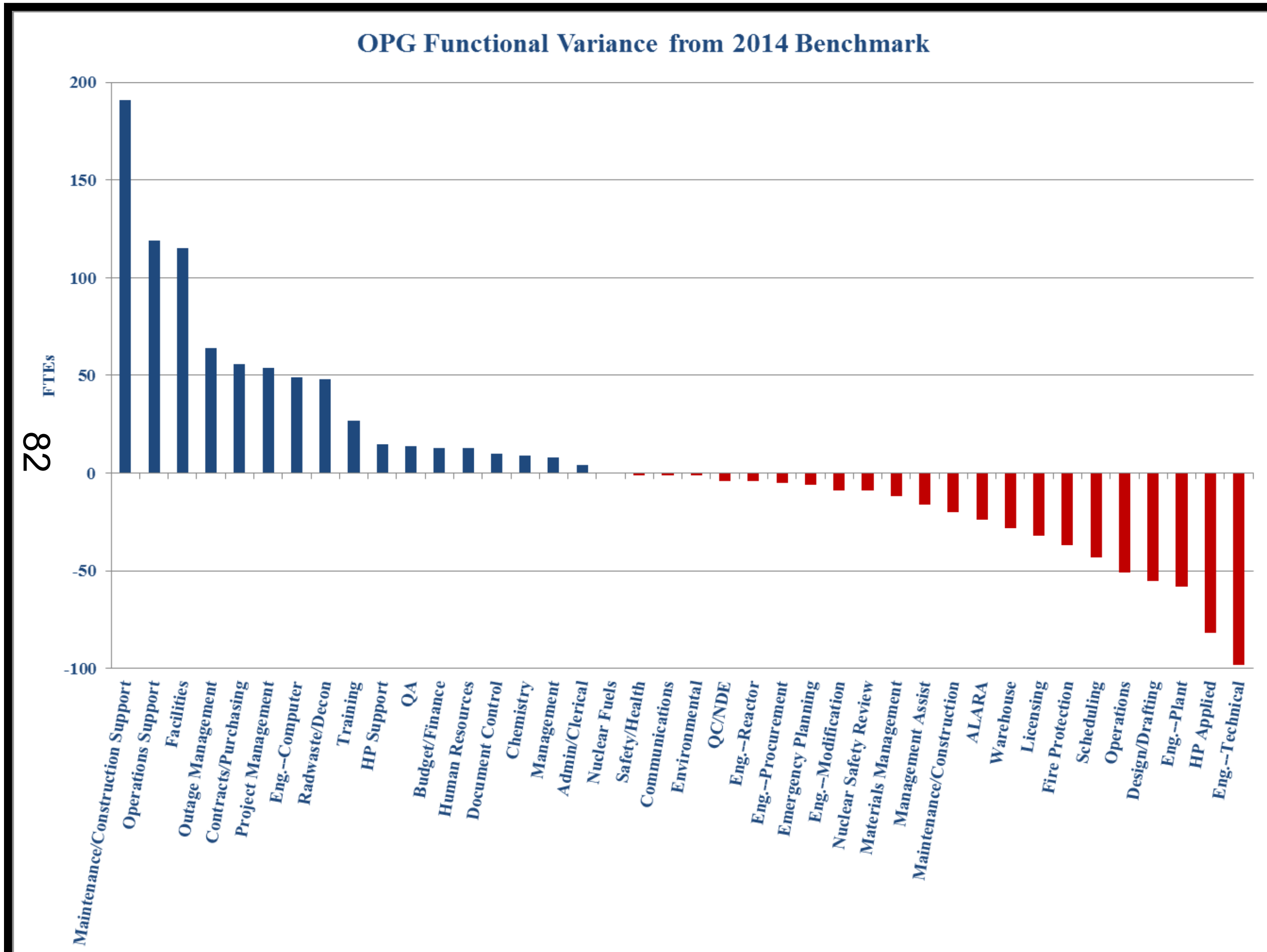
OPG Is 213 FTEs (4.1%) Above The Current Benchmark



*Data from March 2014

GOODNIGHT CONSULTING

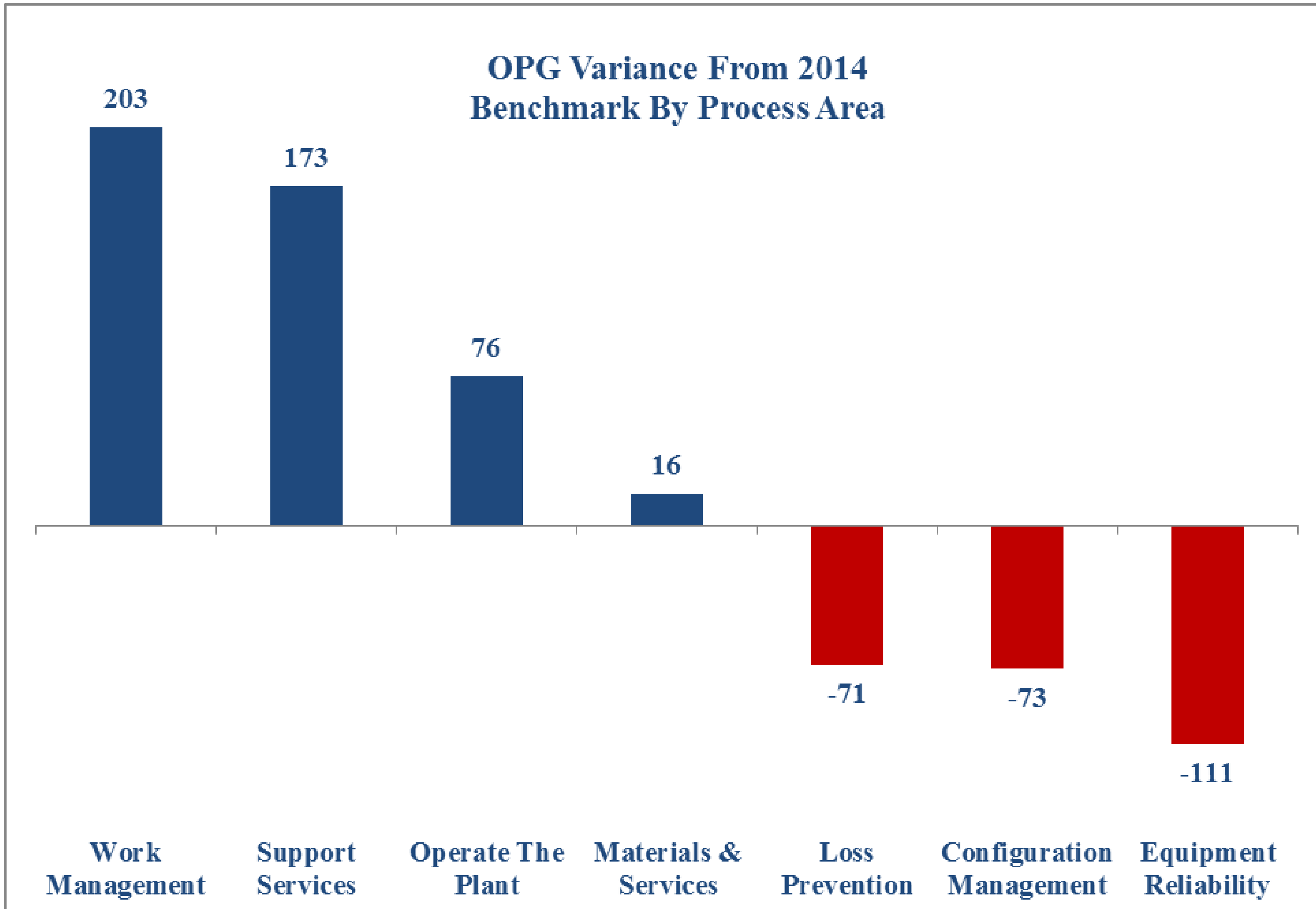
17 Functions Are Above The 2014 Benchmark; 23 Functions Are At Or Below The 2014 Benchmark



Maintenance/Construction Support	191
Operations Support	119
Facilities	115
Outage Management	64
Contracts/Purchasing	56
Project Management	54
Eng.--Computer	49
Radwaste/Decon	48
Training	27
HP Support	15
QA	14
Budget/Finance	13
Human Resources	13
Document Control	10
Chemistry	9
Management	8
Admin/Clerical	4
Nuclear Fuels	0
Safety/Health	-1
Communications	-1
Environmental	-1
QC/NDE	-4
Eng.--Reactor	-4
Eng.--Procurement	-5
Emergency Planning	-6
Eng.--Modification	-9
Nuclear Safety Review	-9
Materials Management	-12
Management Assist	-16
Maintenance/Construction	-20
ALARA	-24
Warehouse	-28
Licensing	-32
Fire Protection	-37
Scheduling	-43
Operations	-51
Design/Drafting	-55
Eng.--Plant	-58
HP Applied	-82
Eng.--Technical	-98

GOODNIGHT CONSULTING

Work Management & *Equipment Reliability* Are The Process Areas With The Largest Variances



GOODNIGHT CONSULTING

Qualitative Analysis Of Key Functions Can Help OPG Identify Functions Warranting Change

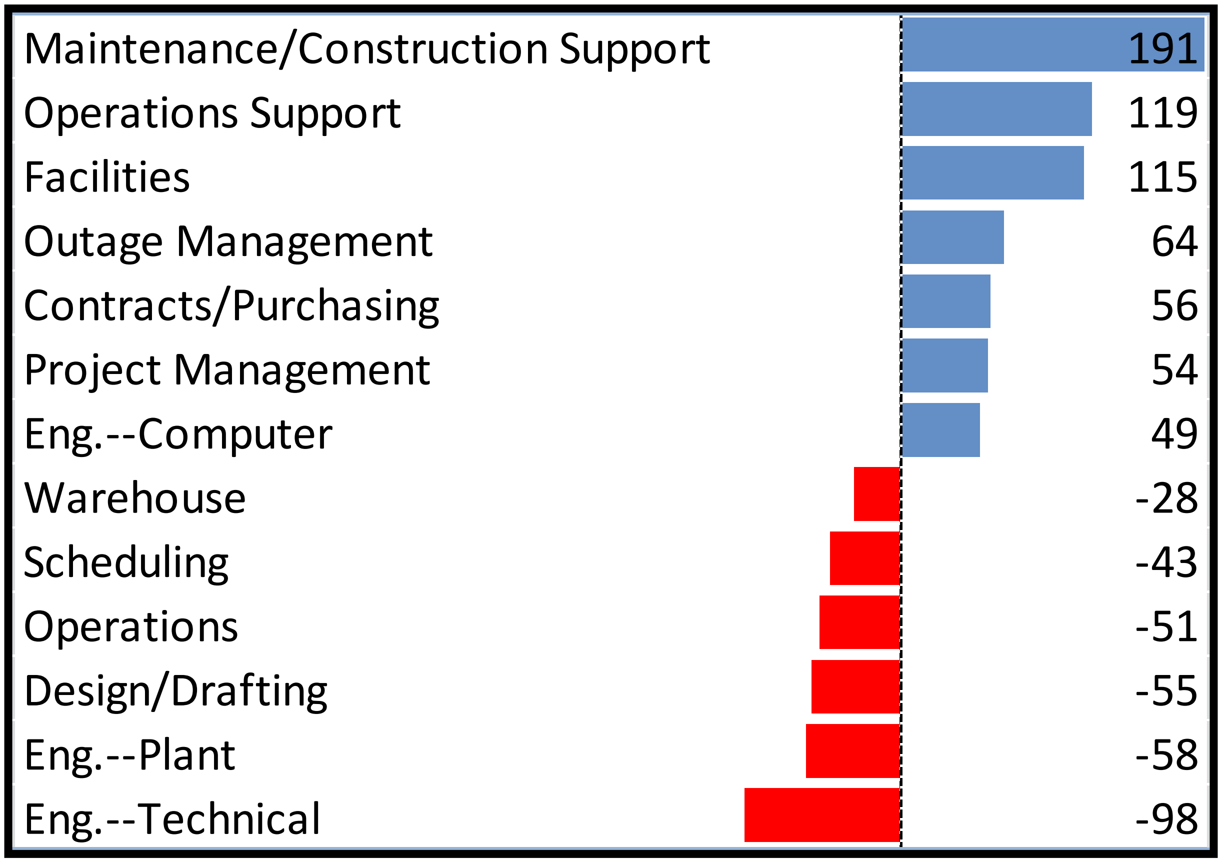
- Benchmarking provides a quantitative snapshot of *"what"* staffing looks like.
- A qualitative evaluation of the "why" behind the numbers can highlight differences from the benchmarks to help OPG determine whether changes are warranted.
- However, for certain functions, a qualitative analysis is inefficient, costly, and provides OPG with no useful information in identifying the functions warranting change:
    - For example, functions with smaller variances seldom provide clear opportunities for effective change as they are rarely driven by major inefficiencies or significant differences from benchmark plants.

We Conducted A Heuristic Analysis To Identify Functions Best Suited For Qualitative Analysis

- To identify functions meriting qualitative analysis, we conducted a heuristic analysis based on our expertise, which included these factors within each function (as applicable):
  - Functional Importance / Mission Criticality
  - Feasibility/cost of potential change
  - Pareto optimality/ROI of potential change
  - Magnitude of variance from benchmark
  - Staffing benchmark variance on a per reactor basis
  - Degree of specialization
  - OPG's application of industry best practices
  - Unique variables per function
  - Etc.
- By applying this approach we identified 13 functions for qualitative analysis.

The 13 Functions We Identified Represent The Majority Of OPG's Total Variance From The Benchmark

We identified these 13 functions for qualitative analysis by applying the methodology discussed on pages 35-36



GOODNIGHT CONSULTING

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

Numbers may not add due to rounding

Line No.	NUCLEAR FACILITIES	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Staff** (Regular and Non-Regular)	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**	**FTEs**
2										
3	**Nuclear - Direct**									
4	Management	578.6	553.1	521.7	573.3	605.8	602.9	606.2	596.0	583.2
5	Society	2,008.5	1,922.2	1,893.7	2,089.7	2,119.0	2,117.1	2,065.9	1,994.4	1,955.1
6	PWU	4,026.9	4,002.4	3,975.2	4,164.9	4,162.8	4,165.6	4,173.2	4,015.4	3,885.7
7	EPSCA	60.2	69.6	94.2	119.6	170.7	172.1	139.6	165.1	213.1
8	Subtotal	6,674.2	6,547.3	6,484.8	6,947.4	7,058.4	7,057.7	6,984.9	6,770.9	6,637.0
9										
10	**Nuclear - Allocated**									
11	Management	382.2	376.0	368.6	353.6	352.7	347.3	339.6	337.6	337.4
12	Society	607.1	625.6	590.3	664.2	665.5	652.8	642.2	638.9	636.9
13	PWU	930.2	882.8	658.0	739.5	708.7	687.6	682.0	666.6	665.9
14	EPSCA	0.0	0.0	12.0	16.0	16.0	16.0	16.0	16.0	16.0
15	Subtotal	1,919.5	1,884.4	1,628.9	1,773.3	1,742.8	1,703.7	1,679.8	1,659.0	1,656.2
16										
17	**NUCLEAR FACILITIES**									
18	Management	960.8	929.1	890.3	926.9	958.5	950.2	945.7	933.6	920.6
19	Society	2,615.5	2,547.8	2,484.0	2,753.9	2,784.5	2,769.9	2,708.1	2,633.3	2,592.0
20	PWU	4,957.1	4,885.2	4,633.2	4,904.3	4,871.4	4,853.2	4,855.3	4,681.9	4,551.5
21	EPSCA	60.2	69.6	106.2	135.6	186.7	188.1	155.6	181.1	229.1
22	Total	8,593.7	8,431.8	8,113.7	8,720.7	8,801.2	8,761.4	8,664.7	8,429.9	8,293.2
23										
24	**Salary & Incentive Pay** (including Fiscal Adjustment)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
25	Management	145.8	147.8	144.1	147.2	152.9	153.5	155.0	154.8	153.7
26	Society	318.9	312.9	310.8	348.9	361.0	367.3	363.0	362.1	363.5
27	PWU	502.1	507.0	487.3	535.8	549.1	555.2	565.2	560.4	553.9
28	EPSCA	8.9	10.6	14.3	13.6	19.1	19.3	16.3	19.3	25.0
29	Total	975.7	978.4	956.5	1,045.6	1,082.1	1,095.3	1,099.5	1,096.7	1,096.1
30	**Overtime**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
31	Management	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	Society	46.8	32.2	36.8	33.1	36.0	35.7	36.8	30.4	24.0
33	PWU	110.5	83.4	89.4	77.5	79.6	78.4	80.3	69.9	54.6
34	EPSCA	1.8	1.9	5.7	1.3	1.8	1.7	1.5	1.6	2.5
35	Total	159.2	117.6	132.0	111.9	117.5	115.7	118.6	101.9	81.1
36	**Benefits** (Current Benefits and Pension & OPEB)	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
37	Management	57.8	48.7	51.3	50.2	52.6	51.4	51.8	51.6	51.0
38	Society	147.1	117.7	136.3	141.0	145.0	141.7	142.8	142.5	143.1
39	PWU	194.0	174.8	228.6	200.2	201.8	200.0	204.6	203.1	201.4
40	EPSCA	0.5	0.6	1.0	5.1	7.2	7.2	6.1	7.2	9.4
41	Total	399.5	341.9	417.2	396.5	406.5	400.3	405.2	404.4	404.9
42										
43	Current Benefits (Statutory)	56.5	55.6	58.7	56.1	58.2	57.2	57.4	57.5	57.7
44	Current Benefits (Non-Statutory)	48.3	47.5	47.2	63.2	65.1	64.5	64.2	64.0	65.1
45	Pension & OPEB (Current Service)*	294.7	238.8	311.3	277.2	283.2	278.7	283.6	283.0	282.1
46	**TOTAL COMPENSATION**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
47	Management	203.6	196.6	195.4	197.5	205.5	204.8	206.8	206.4	204.8
48	Society	512.8	462.9	483.9	523.0	542.0	544.7	542.6	535.0	530.7
49	PWU	806.6	765.3	805.4	813.5	830.5	833.7	850.0	833.5	809.9
50	EPSCA	11.3	13.1	21.0	20.0	28.2	28.2	23.8	28.2	36.9
51	Total	1,534.4	1,437.8	1,505.7	1,554.0	1,606.1	1,611.4	1,623.3	1,603.0	1,582.2
52										
53	*presented on an accrual basis									

EXECUTIVE SUMMARY:

RECOMMENDATIONS:

1. Extended Operations of all six Pickering Units beyond the end of 2020 shows economic value and qualitative benefits to OPG and the Ontario electricity system. Based on this assessment, operation of two units to nominally 2022 and the remaining 4 units to nominally 2024 is recommended.
2. OPG should continue working to provide improved certainty associated with implementation of the Preferred Extended Operations Alternative by refining the extended operations targeted ends-of-life for each unit as greater certainty becomes available regarding the technical fitness-for service of the fuel channels in each of the units.
3. The incremental costs to enable Extended Operations are estimated at approximately $310M. It is recommended that $52M (including $5M contingency) be released in order to complete the Periodic Safety Review, the Fuel Channel Life Assurance Project and to execute incremental outages and inspections in 2016 and 2017. Management will seek a full release following confirmation of the fuel channel life of the units and completion of the Periodic Safety Review.

OPG's planning assumption for the 2015-2017 Business Plan had all six of the Pickering units shutting down at the end of 2020. OPG has been working with the IESO and the Ministry of Energy to explore options to extend operations beyond 2020. Preliminary technical and economic assessments have been undertaken that demonstrate that extending operations would be safe, is technically feasible and would have economic and qualitative benefits. Extending the life of Pickering would also optimize the value of OPG's existing assets, improve OPG's financial position and mitigate Ontario electricity system capacity uncertainties during Darlington and Bruce Refurbishment outages in the early 2020s. This business case summarizes the status of the technical and economic feasibility assessment of continuing to operate the Pickering Units for 2-4 years after 2020.

In the fall of 2014 and early 2015, OPG assessed a number of alternatives for extending the operation of Pickering beyond the end of 2020. Data was provided to the IESO in December 2014 and again in October 2015 to facilitate the completion of an independent system economic value analysis. The Ministry of Energy was periodically briefed on the status of the assessments.

Based on the assessments completed by OPG and independently by the IESO, the preferred alternative of operating six units to 2022 and four units to 2024 was selected in the spring of 2015. This alternative, herein called the **Preferred Alternative** is summarized in Table E1 below:

Table E1: Preferred Alternative Selected

Preferred Alternative			
P1 & 4 (End of)	**P5-8 (End of)**	**Assumed VBO (*)**	**Comments**
2022	2024	2021	High Confidence in Fuel Channel life assumed to be achieved to the end of 2024 for P5-8. Preferred alternative from a system value perspective.

OPG has assessed the incremental generation associated with the Preferred Alternative. Incremental generation is the amount of generation over and above that which would have been achieved in the Base Case of operation to 2020. OPG's economic assessment shows that the value to the Ontario electricity system ranges from $0.5 Billion to $0.6 Billion.

SEC Interrogatory #46

Issue Number: 4.4

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

Interrogatory

Reference:
[D2/1/2]
Please provide a table showing for each capital nuclear capital project (tier 1, 2 and 3) that will go in-service between 2014 and 2016, its forecasted cost and its actual cost. Please provide an explanation for all variances +/- 5% and why it is prudent. Please provide a copy of all Project Over-Variance Approval documents for those projects not already included in the pre-filed evidence.

Response

Following is a table showing all Tier 1, 2 and 3 projects that have or are scheduled to go in-service between 2014 and 2016 as of October 15, 2016.

There are no projects with actual or forecasted costs that exceed approved costs (i.e. total project cost including contingency in the most recent BCS). Projects obtain approval for increased costs through over-variance approvals or superseding business cases before their approved amount is exceeded. No explanations are provided where the in-service amount is less than the approved cost of the project. An outcome where the final in-service amount will be less than the approved amount is not unexpected since the approved amount includes contingency, which may not be fully used in some projects.

Projects	OEB Tier	Actual or Forecast In-Service Date	Actual or Forecast In-Service (M$)	Approved Cost (M$)	Variance (M$)
(a)	(b)	(c)	(d)	(e)	(f)
25619 - DN OSB Refurbishment	1	Oct-15	60.6	62.7	(2.1)
33955 - Shutdown System Computer Aging Management	1	Nov-16	20.4	20.4	0.0
34000 - DN Auxiliary Heating System	1	Oct-17	98.7	107.1	(8.4)
41023 - Unit 1 & 4 Fuel Channel East Pressure Tube Shift Tooling (Capital)	1	Mar-16	27.8	29.7	(1.9)
73706 - DN Holt Road Interchange Upgrade	1	Aug-16	24.6	31.0	(4.0)

UNDERTAKING JT2.16

Undertaking

BESIDE COLUMN D, ON 4.4 SEC 46, PROVIDE THE VALUE OF THE FIRST EXECUTION BUSINESS CASE AND PUT AN EXTRA COLUMN IN WITH THE VALUE OF THE FIRST EXECUTION BUSINESS CASE FOR THE PROJECT AND THE CORRESPONDING VARIANCE ATTACHED TO THAT.

Response

Values may not add due to rounding.

Projects	**OEB Tier**	**Actual or Forecast In-Service Date**	**Actual or Forecast In-Service (M$)**	**Total Cost - First Execution BCS(M$)**	**Variance to First Execution BCS (M$)**	**Approved Cost (M$)**	**Variance (M$)**
(a)	**(b)**	**(c)**	**(d)**			**(e)**	**(f)**
25619 - DN OSB Refurbishment	1	Oct-15	60.6	47.8	12.8	62.7	(2.1)
33955 - Shutdown System Computer Aging Management	1	Nov-16	20.4	17.2	3.2	20.4	0.0
34000 - DN Auxiliary Heating System	1	Oct-17	98.7	45.6	53.1	107.1	(8.4)
41023 - Unit 1 & 4 Fuel Channel East Pressure Tube Shift Tooling (Capital)	1	Mar-16	27.8	22.0	5.8	29.7	(1.9)
73706 - DN Holt Road Interchange Upgrade	1	Aug-16	24.6	31.0	(6.4)	31.0	(6.4)
31306 - DN Passive Auto-Catalytic Recombiners	2	Jun-16	5.1	6.5	(1.4)	5.8	(0.7)
33623 - DN Installation of partial discharge monitors	2	Feb-14	5.6	3.3	2.3	7.1	(1.5)
36002 - DN MOT Capital Spares	2	Sep-16	8.1	8.3	(0.2)	8.3	(0.2)
40680 - PB Main Generator AVR and Protective Relay Upgrade	2	Jul-15	18.7	16.1	2.6	18.8	(0.1)
46605 - PA Passive Auto-Catalytic Recombiners	2	May-14	12.1	5.0	7.1	14.4	(2.3)
49116 - PB SG/EPG Fire Detection Upgrade and CO2 Suppression Removal	2	Jul-16	6.9	5.7	1.2	10.7	(3.8)
49126 - PB Powerhouse Office Facilities (Capital)	2	Dec-14	4.2	9.0	(4.8)	6.7	(2.5)

Projects	OEB Tier	Actual or Forecast In-Service Date	Actual or Forecast In-Service (M$)	Total Cost - First Execution BCS(M$)	Variance to First Execution BCS (M$)	Approved Cost (M$)	Variance (M$)
(a)	(b)	(c)	(d)			(e)	(f)
49132 - PB RBSW Dechlorination & MISA Cleanup	2	Dec-16	14.1	11.8	2.3	14.1	(0.0)
49134 - PB Replacement of Containment Box-up Monitors	2	Jul-15	6.9	7.9	(1.0)	8.8	(1.9)
49140 - PB Screenhouse Trash Bar Screen Replacement	2	Jul-15	6.8	3.1	3.7	7.7	(0.9)
49146 - PN Fire Code Compliance for Relocatable Structures in Un-Zoned Area for Pickering Station	2	Jul-16	17.1	9.6	7.5	18.8	(1.7)
49247 - Unit 1 & 4 Fuel Channel East Pressure Tube Shift Tooling (CMFA)	2	Mar-16	8.7	10.1	(1.4)	8.9	(0.2)
49267 - PN Standby Boiler Capacity Improvement	2	Nov-15	5.1	6.1	(1.0)	6.4	(1.3)
49284 - PN Administration Building Rehab	2	Dec-14	16.4	13.5	2.9	19.4	(3.0)
49296 - PA Class II Emergency Lighting	2	Aug-15	4.0	6.1	(2.1)	6.1	(2.1)
66255 - OPGN Pressure Tube to Calandria Tube Gap	2	Aug-15	16.8	26.3	(9.5)	17.5	(0.7)
66533 - Multiple Simultaneous Inspections for Feeders	2	Sep-14	0.4	8.3	(7.9)	0.5	(0.0)
73397 - DN ESW Pipe and Component Replacement	2	Jan-16	5.2	6.7	(1.5)	6.7	(1.5)
80027 - SES Station Personnel Emergency Accounting	2	Dec-16	0.2	3.3	(3.2)	3.3	(3.2)
25918 - Security Project A	2	Dec-16	9.9	4.7	5.2	9.9	0.0
31406 - DN SG Battery Rectifier upgrade (Capital)	3	Mar-14	3.8	4.6	(0.8)	4.0	(0.2)
31410 - DN TRF CRS Hydrogen Compressors Condition Monitoring System	3	May-16	6.6	6.6	0.0	6.6	(0.0)
31437 - DN F/H Service Area Bridge Mtce Platform	3	Dec-14	0.6	0.6	(0.0)	0.6	(0.0)
31530 - DN MOT/LIST/SST/10MVA Spare Transformer Storage Facility	3	Sep-16	5.1	5.6	(0.5)	5.6	(0.5)
31538 - DN RIH Instrumentation	3	Dec-16	1.4	2.3	(0.9)	1.7	(0.3)

Projects	OEB Tier	Actual or Forecast In-Service Date	Actual or Forecast In-Service (M$)	Total Cost - First Execution BCS(M$)	Variance to First Execution BCS (M$)	Approved Cost (M$)	Variance (M$)
(a)	(b)	(c)	(d)			(e)	(f)
Upgrade							
33214 - DN Building Heating Condensate Return Header Pipe Movement	3	Jan-16	2.8	2.5	0.3	2.8	0.0
33218 - DN Bleed Condenser Isolating Valve - Unit 1	3	Jul-14	1.2	1.5	(0.3)	1.5	(0.3)
33220 - DN End Shield Cooling Button-up Valve Access Platform	3	Dec-14	0.8	0.8	(0.0)	0.8	(0.0)
33222 - DN FH IFB ESW Top-up Valve Access Platform	3	Apr-15	0.7	0.6	0.1	0.7	(0.0)
33904 - Plant Information System Addt'n in the MCR	3	Apr-14	4.6	4.4	0.2	4.8	(0.2)
36005 - DN Class IV 4kV 10MVA Transformer Capital Spare	3	Oct-16	0.5	0.5	0.0	0.5	0.0
36007 - DN UST Capital Spare	3	Oct-16	2.7	1.8	0.9	3.0	(0.3)
38946 - DN Domestic Waterline Replacement	3	Dec-15	3.4	3.0	0.4	3.9	(0.5)
40658 - PB Boiler Level Control Obsolescence	3	Feb-15	1.9	2.9	(1.1)	2.9	(1.1)
40692 - PB Turbine Supervisory Equipment (TSE) Obsolescence (Capital)	3	Dec-16	3.9	5.5	(1.6)	5.0	(1.1)
40708 - PB Bleed Condenser Bundle Replacement	3	Jan-16	3.9	5.9	(2.0)	4.4	(0.5)
40975 - PN N293-07 Fire Code Compliance Modifications	3	May-15	4.3	3.0	1.3	4.3	0.0
40978 - PN Fueling Machine Vault Camera Replacement	3	Dec-16	4.0	2.5	1.5	4.2	(0.2)
40982 - PA Enhancement of Pickering A Chlorination System (Capital)	3	Sep-15	3.1	3.4	(0.3)	3.4	(0.3)
40987 - PA Replacement of AIFB Supertool	3	Dec-16	3.1	0.7	2.4	3.4	(0.3)
40992 - PN Replacement of Auto Transfer Switch ATS1 & ATS2	3	Aug-14	0.4	0.4	(0.0)	0.4	(0.0)
40993 - PA Bulk CO2 Tank Replacement	3	Aug-14	1.2	0.7	0.5	1.5	(0.3)

Projects	OEB Tier	Actual or Forecast In-Service Date	Actual or Forecast In-Service (M$)	Total Cost - First Execution BCS(M$)	Variance to First Execution BCS (M$)	Approved Cost (M$)	Variance (M$)
(a)	(b)	(c)	(d)			(e)	(f)
40994 - PA Fire Water Chlorination Skid	3	Sep-16	1.6	0.6	1.0	1.7	(0.2)
40998 - PA Generator Field Breaker Replacement	3	May-14	0.8	0.7	0.1	1.0	(0.2)
40999 - PA Generator Turbine Temperature Monitor Replacement	3	Apr-15	0.3	0.4	(0.1)	0.4	(0.1)
41005 - PA Reheat Drain Pumps Reliability Improvement	3	Dec-16	2.3	1.1	2.2	2.3	0.0
41006 - PN Comfo Washer Replacement	3	Nov-16	0.5	0.6	(0.1)	0.6	(0.1)
41008 - PN South Decontamination Shop Facility Upgrade	3	Feb-14	0.2	0.4	(0.2)	0.4	(0.2)
41009 - PA SRV Enclosure Ventilation Improvement	3	May-15	1.3	0.7	0.6	1.5	(0.1)
41011 - PN Upper Chamber Vacuum Pumps Replacement	3	Mar-14	0.3	1.0	(0.7)	1.0	(0.7)
41012 - PA 230 kV Disconnect Switches Replacement (DS138/DS142/DS154)	3	Apr-14	1.0	1.9	(0.9)	1.9	(0.9)
41033 - PN Whole Body Monitor Seismic Qualification	3	Feb-14	0.4	1.2	(0.9)	1.2	(0.9)
41034 - PA Fire Code Compliance (FSA Followup)	3	Jun-15	2.8	3.0	(0.2)	3.0	(0.2)
41040 - PN Permanent Power Supplies For Ontario Electrical Safety Code Compliance	3	Apr-14	0.8	0.9	(0.1)	0.9	(0.1)
41047 - PA Critical Pump and Motor Spares	3	Dec-15	0.5	3.9	(3.4)	2.9	(2.4)
49124 - PB Permanent Data Logger for Screenhouse	3	Sep-15	3.3	4.5	(1.2)	3.5	(0.2)
49142 - Pickering Site Engineering Services Bldg - 1 (ESB1) HVAC System Upgrades	3	Sep-14	4.2	4.4	(0.2)	4.4	(0.2)
49143 - PB Purchase of CEP Motor Capital Spares	3	Mar-16	0.3	0.3	0.0	0.3	(0.0)
49144 - PB Purchase of HPSW Motor Capital Spares	3	Mar-16	0.2	0.2	0.0	0.2	0.0

Projects	**OEB Tier**	**Actual or Forecast In-Service Date**	**Actual or Forecast In-Service (M$)**	**Total Cost - First Execution BCS(M$)**	**Variance to First Execution BCS (M$)**	**Approved Cost (M$)**	**Variance (M$)**
(a)	**(b)**	**(c)**	**(d)**			**(e)**	**(f)**
49163 - PA Fire Code Compliance for Relocatable Structures in Powerhouse	3	Dec-16	2.0	4.6	(2.6)	4.8	(2.8)
49289 - Pickering A - AVR Replacement for Standby Generators	3	Jul-16	4.8	5.2	(0.4)	4.8	0.0
49302 - PB Fire Code Compliance for Relocatable Structures in Powerhouse	3	Jan-16	2.9	4.6	(1.6)	4.6	(1.6)
62552 - Inspection Qualification	3	Dec-16	3.4	4.2	(0.8)	3.4	(0.0)
66599 - IMS Steam Generator Inspection Improvements	3	Dec-14	1.5	2.5	(0.9	2.5	(0.9)
80020 - DN TRF Cold Box Vacuum System Obsolescence	3	May-16	3.7	4.9	(1.3)	4.9	(1.3)
80119 - PA Switchyard Air Blast Circuit Breaker Replacement	3	Apr-14	3.5	3.5	0.0	3.5	0.0
80149 - DN Sewage Lift Station Replacement	3	Feb-16	1.2	4.8	(3.5)	4.8	(3.5)

Table 7
Capital Projects - Nuclear Operations
Status of Projects $5M and Greater with 2014 and 2015 In-Service Dates in EB-2013-0321

Line No.	Project Number	Project Name	In-Service Date at Time of EB-2013-0321 Application	Project Stage at Time of EB-2013-0321 Application	Current Project Status	
					Project Status	Projected/Actual In-Service Date
	(a)	(b)	(c)	(d)	(e)	(f)
1	25619	Operations Support Building Refurbishment	Sep-15	Defintion	Close-out	Oct-15
2	31306	Passive Auto-Catalytic Recombiners	Sep-15	Execution	Execution	Jun-16
3	31403	Active Liquid Waste System Upgrade	Jan-14	Execution	Execution	Dec-17
4	31422	Pressurizer Heaters & Controllers Replacement	Jun-15	Execution	Execution	Aug-19
5	31508	Fukushima Phase 1 Beyond Design Basis Event Emergency Mitigation Equipment	Dec-15	Execution	Execution	Dec-17
6	31717	Improve Maintenance Facilities	Oct-14	Execution	Close-out	Dec-13
7	33509	Replacement of Obsolete Computer Components	Jul-14	Execution	Execution	Feb-17
8	33621	Secondary Control Area Air Conditioning Unit Replacement	Oct-14	Execution	Execution	Apr-17
9	33623	Installation of Partial Discharge Monitors	Feb-14	Execution	Complete	Jan-14
10	33955	Shutdown System Computer Aging Management	Jun-14	Execution	Execution	May-16
11	33977	Digital Control Computer Replacement / Refurbishment / Upgrades	Sep-14	Execution	Execution	Dec-18
12	34000	Auxiliary Heating System	Apr-15	Execution	Execution	Apr-16
13	40680	Main Generator Automatic Voltage Regulator and Protective Relay Upgrade	Dec-14	Execution	Execution	Jun-15
14	40691	Emergency Power Generator Protective Relays	Dec-15	Execution	Execution	Dec-17
15	40984	PA ECI Strainer Capacity Margin (Capital)	Jan-14	Execution	Complete	May-13
16	46605	Passive Auto-Catalytic Recombiners	May-14	Execution	Close-out	May-14
17	49116	Standby and Emergency Power Generator Fire Detection Upgrade and CO2 Suppression Removal	Apr-14	Execution	Execution	Jul-16
18	49134	Pickering B Containment Box-up Monitors Replacement	Aug-14	Execution	Execution	May-15
19	49247	Unit 1 & 4 Fuel Channel East Pressure Tube Shift	Jan-14	Execution	Execution	Mar-16
20	49267	Standby Boiler Capacity Improvement	Oct-14	Execution	Execution	Nov-15
21	49296	Pickering A Class II Emergency Lighting	Dec-14	Execution	Execution	Jul-15
22	66255	Pressure Tube to Calandria Tube Gap	Apr-14	Execution	Close-out	Sep-14
23	66533	Multiple Simultaneous Inspections for Feeders	Apr-14	Execution	Cancelled	Aug-14
24	66594	Channel Inspection and Gauging Apparatus (CIGAR) Gap System and Drive Reliability	Dec-15	Execution	Execution	Jun-17
25	49158 49299	Fukushima Phase 1 Beyond Design Basis Event Emergency Mitigation Equipment	Dec-15	Execution	Execution	Dec-17

ONTARIO POWER GENERATION

Internal Audit

Project Controls Audit - Project & Modifications Group

March 9, 2016

Report Rating: **Requires Improvement**

Distribution:

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1.0 EXECUTIVE SUMMARY

1.1 Summary of Internal Audit Findings

Report Rating: **Requires Improvement**

No.	Finding	Risk Type	Risk Rating[1]		
			High	Moderate	Low
1	Project estimates are not at a sufficient level of accuracy prior to the execution phase.	Financial	x		
2	Cost and Schedule Control Baselines ("CSCB's") are not keeping pace with approved project changes.	Operational		x	
3	A Gating Process for AISC Portfolio Projects has not been formally implemented.	Operational		x	
4	Governance and Procedures specific to AISC projects require improvement.	Operational			x
Total			**1**	**2**	**1**

1.2 Background

The Projects and Modifications ("P&M") Group, part of the Nuclear Projects Organization, is responsible for the management and execution of Operations, Maintenance and Administration ("OM&A") and Capital Projects supporting the Darlington and Pickering Nuclear Generating Stations and Western Waste Facility. The P&M Group has a total project portfolio of $1.1B over the three year period from 2015 through to 2017. The projects that the Asset Investment Steering Committee ("AISC") manages total $833M, with the remaining portfolio related to projects supporting the Darlington Nuclear Refurbishment ("DNR") Project. DNR Projects are executed using the Nuclear Project's Project Management framework which has different requirements than is currently used on the AISC projects, which follows Finance governance. To address these differences, a "Project Excellence" initiative is now in place and includes the development of a common set of standards for all projects across Nuclear. This initiative had just started at the time of the audit.

The AISC is a committee that meets to review, prioritize and provide budgets for sustaining projects for OPG's Nuclear Generating Stations. The committee works in conjunction with business line sponsors to prioritize and recommend projects for approval in accordance with business objectives.

Given the high value of P&M's AISC project portfolio and the critical role these projects play in OPG's on-going nuclear operations, this audit was performed as part of Internal Audit's ("IA's") cyclical audit program.

[1] Please refer to Appendix D for risk rating definitions

1.3 Audit Objective & Scope

The objective of this audit was to assess the design and operational effectiveness of project management controls implemented by the P&M Group to support timely completion of the current portfolio of AISC projects in a manner that achieves project goals.

The scope of the audit included a review of processes and testing, on a sample basis, to determine whether:

A. Governance & Procedures

1. Policies and procedures for project control processes have been established and reflect current practices;
2. Roles and responsibilities for project control processes have been clearly defined.

B. Planning

1. Each project has a valid Business Case Summary (“BCS”) which has been approved by the ASIC;
2. A Project Charter and Project Management Plan (“PMP”) has been developed, approved, and communicated;
3. The project scope has been clearly defined, with the input of key stakeholders and approved;
4. An appropriate Work Breakdown Structure (“WBS”) has been developed which identifies all work to be performed by the project and its deliverables;
5. A schedule has been created that considers resource requirements;
6. The schedule is structured in accordance with the project’s WBS, built upon the logical division of work by cost accounts, work packages;
7. The schedule integrates and identifies interdependencies between activities, including critical path as appropriate;
8. Costs are planned, structured, controlled and reported based on the project’s WBS, Cost Accounts, and Work Packages;
9. Risks are formally identified with mitigation plans and managed with periodic reviews and updates throughout the project; and
10. Contingency amounts are assigned, formally tracked and appropriately approved when released.

C. Execution

1. Schedule monitoring and control has been established on the project;
2. Schedules are updated on a timely basis and accurately reflect the current status of all deliverables, activities, interdependences and timelines across the project;
3. Performance Metrics have been adopted on the project and are reported to management (e.g. Schedule Performance Index, Cost Performance Index, etc.);
4. The project has a material procurement schedule or tracking sheet representing the receipt of materials, equipment and prefabricated items;
5. Scope, cost, schedule, and contingency changes are managed and approved through a change management process;
6. Forecasts are generated and reviewed for expected variances to plan;
7. Completion of work packages is validated including quality requirements;
8. Projects are executed in accordance with OPG’s quality requirements; and
9. Projects are assessed for completeness of scope, cost, schedule and quality objectives, and approved by project sponsors prior to close-out.

D. Reporting

1. Costs are accurately coded to projects to allow for proper tracking;
2. Cost, quality and schedule performance is accurately measured and reported to management on a timely basis. Variances and mitigation efforts to recover on these variances are explained and reported in a complete fashion;
3. Post-implementation reviews are performed to validate that completed projects have met their objectives and to gather lessons learned for future projects; and
4. System access to reporting systems are controlled and monitored.

The scope of the audit included an evaluation of thirteen projects (see Appendix A) from P&M's AISC Portfolio up to the end of September, 2015. Projects were selected based on size, facility, and phase to ensure a cross-section of the population.

1.4 Conclusion

Positive Observations

- The P&M Group is in the process of implementing several changes to their project management framework to align with the revised Nuclear Projects governance, including adopting more up-front planning activities prior to execution; and

- The P&M group's project management team were found to be highly knowledgeable concerning project management principles and how to deploy them on their projects.

Key Findings and Recommendations

The audit has noted the following key findings:

- Project scope definition and estimate accuracy is sometimes insufficient for the start of a project's execution phase. This has caused significant variances to project estimates on several AISC projects. The P&M group should ensure, through implementation of its new gating process, that an AACE[2] Class 3 or better estimate for the project is developed, approved and established as a baseline prior to the start of execution phases. The amount of contingency should reflect risks, including the confidence in and the class of estimate;

- Cost and Schedule Control Baselines ("CSCB's") are not keeping pace with approved changes in Business Case Summaries ("BCS's") and Project Change Request Authorization Forms ("PCRAF's"). The P&M Group should evaluate resource requirements and work with its vendors to ensure proper CSCB's are deployed prior to starting work. In addition, a review of the project change management processes should be undertaken as considerable amount of time is required to get approval for changes;

- The plan to change to the Gated Process for AISC Portfolio Projects to facilitate oversight, phased approval and release of project funds has not been fully implemented. The Nuclear Projects group should work with the AISC Chair in the implementation of a gating process for AISC projects, clearly defining the requirements for each gate; and

[2] Association for the Advancement of Cost Engineering ("AACE").

- There are gaps in governance and procedures. For example a Terms of Reference ("TOR") document for AISC should be finalized and reporting for cost and schedule performance should be standardized.

The findings noted in the report have been reviewed with management who has committed to specific action plans to address them. Please refer to Section 2.0 for details of the above findings along with the potential causes, impacts, recommendations and management action plans.

<u>Opportunities for improvement</u>

The P&M group should look at:

- Expanding its use of Earned Value ("EV") techniques such that cost and schedule variances are explained formally by work package, and Cost Performance Index ("CPI") values take on a greater role in cost and forecast management. At present, use of EV techniques have not been fully implemented for AISC projects, although the plan is to implement EV techniques going forward on all new 2016 projects;

- Improving the Contingency Management process utilized in AISC projects such that specific contingency is established and tracked on a per-risk basis. Contingency Tracking Logs should be used to monitor the allocation of contingency on an on-going basis. The confidence level associated with the class of estimate at the various release phases should be considered in contingency development. Management should also review the assignment and ownership of contingency for monitoring and releases; and

- Improving housekeeping efforts on Risk Registers such that risks and risk action items are closed in a timely manner.

2.0 DETAILED AUDIT FINDINGS

1. Project estimates are not at a sufficient level of accuracy prior to the execution phase.	High

As per OPG's BCS requirements and the Association for the Advancement of Cost Engineering ("AACE") standards, cost estimates should be developed to at least a Class 3 estimate prior to execution (see Appendix B). For certain projects, a Class 2 estimate may be used as a "check estimate" once construction work packages are complete and just prior to the start of field execution to confirm accuracy of the Class 3 estimate submitted as part of the Execution Phase BCS. In order to come to a more precise estimate, detailed engineering must be substantially complete to determine material and labour requirements.

It was noted that of the six projects sampled in the execution phase, all six projects did not have an Estimate at Completion ("EAC") for the project established at either a Class 3 or Class 2 level and they were still performing detail engineering work while in their execution phase. In some cases, the true EAC value for the entire project is not identified until the project is in the advanced stages of execution when a significant portion of the execution costs have already been incurred. (Refer to Appendix A for sample projects reviewed in the execution phase).

Potential Causes & Impact

Potential Cause:

- The current AISC process, which utilizes Finance Governance, does not mandate the establishment of at least an AACE Class 3 estimate prior to the start of execution governance allows for execution to be released with different class of estimates;
- Business Case Summary documents and governance does not require clearly identifying the class of estimate and the range for the potential costs for the current release and the total project;
- Contingency assigned does not always fully address potential variances associated with the class of estimate;
- Lack of a formal gating process and clear definition of gate requirements; and
- Station requirements for "fast tracking" of projects to address emergent issues.

Impacts:

- Growth in project estimate-at-completion values through the execution phase of the project;
- Insufficient budget assignments when entire cost of project is not defined prior to execution, potentially resulting in deferrals or cancellations of other downstream projects; and
- The decision process to proceed with projects may be based on inaccurate cost/benefit analysis when releases are sought with incomplete cost information.

Recommendations	**Management Action Plan**	**Owner & Target Completion Date**
Management should ensure sufficient detailed engineering is completed in the definition phase to yield at least an AACE 3 estimate prior to start of execution and factor in potential variability associated with the class of estimate when establishing contingency in the various phases of the project. The BCS's and reporting of EAC for Definition Phase should provide the approving authorities with the understanding of the ranges of estimate for the release and the total project.	As part of the Nuclear Projects "Project Excellence" initiative, an estimating Centre of Excellence ("COE") is now in place within the Planning and Project Controls group; all 2016 AISC Project New Starts greater than $5 Million will require estimate review by the COE, consistent with the Gated process (See Finding 3). Gated process will also provide increased oversight in the release phase of projects and cost and estimate accuracy and contingency management.	Gary Rose VP Planning and Controls April 30, 2016

2. Cost and Schedule Control Baselines ("CSCB's") are not keeping pace with approved project changes.	**Moderate**

Cost and Schedule Control Baselines ("CSCB's") are the primary control for measuring cost and schedule performance on a project. When setup correctly (i.e. Built upon reliable project estimates and front-end planning), they provide an indication of which work packages on a project are ahead or behind on cost and schedule performance, the magnitude of these variances and their net impact on the overall project.

CSCB's on three out of 13 projects sampled were found not to be keeping pace with cost and schedule baseline changes being requested and approved in Business Case Summaries ("BCS's") and Project Change Request Authorization Forms ("PCRAF's"). The reliability of contractor data has contributed to this issue. This lack of accurate and timely data has contributed to Cost Performance Index ("CPI") measurements being skewed at work package levels.

In addition to the above, two of the projects were found to be without CSCB's entirely. The P&M group has indicated that they are in the process of implementing project planning and control protocols with their Engineer-Procure-Construct ("EPC") vendors to ensure vendor schedules are received at the start of projects and that CSCB's are created, beginning with new project starts for 2016.

Potential Causes & Impact

Potential Causes:

- Less than adequate front-end planning due to a substantially larger work program executed in short time frame;
- Contractors are not providing accurate cost and schedule information as required by the contract. Therefore, cost and schedule are being updated through PCRAFs and BCS' by OPG Cost and Schedule Analysts ("CSA's") who are challenged to keep up with increasing changes;
    - CSA resources are constrained due to competing priorities associated with processing numerous BCS and contingency releases;
- Some station priority projects are fast-tracked with reduced front-end planning that may result in increased changes later in the project; and
- Difficulty incorporating vendor schedules within CSCB's due to the significant volume of scope changes.

Impact:

A CSCB is the primary control mechanism used to manage and control cost and schedule performance on a project. The absence of a current and realistic CSCB may result in potential cost increases and schedule delays.

Recommendations	**Management Action Plan**	**Owner & Target Completion Date**
Management should: • Review workloads of CSAs and evaluate resource requirements; • Work with contractors to ensure proper CSCB's are deployed prior to starting work; and • Review the current BCSs and PCRAF approval processes to reduce time for approvals.	P&M is reviewing the Project Controls work processes executed by CSAs in planning and controlling projects and the amount of project work which will be executed by P&M through the Business Plan period. This information will help in determining the resource gap with CSAs. Once the gap has been determined, an appropriate resourcing strategy will be implemented. This review will include the review of BCSs and PCRAF approval processes to determine opportunities to reduce time of approval.	Jamie Lawrie Director, Project Controls September 30, 2016

3. A Gating Process for AISC Portfolio Projects has not been formally implemented.	**Moderate**

A gating process is meant to define a clear list of requirements, deliverables, and expectations a project should follow in order to be granted approval to proceed to its next phase within the typical five phases of a project's life cycle.[3] In addition to the above, a robust gating process also requires that a project be defined and associated work scope be estimated to specified levels of accuracy.

Although the AISC acts as a de facto Gate Review Board for AISC projects, the gating process outlined in the Nuclear Projects governance (N-STD-AS-0028) and Project Management Manual (N-MAN-00120-10001-GRB) has not been fully implemented for AISC projects. At present, the primary control used for gate approval between phases in the AISC project life cycle is the BCS process. While this is an important requirement, the BCS process does not constitute a complete list of all the deliverables required at each gate approval, nor formalize the challenge process that should take place regarding the approval of each deliverable. Management has indicated that they are in the process of formalizing a gating process for AISC projects in Q1 2016.

Potential Causes & Impacts

Potential Cause:
The new Nuclear Projects governance and procedures are high-level principle-based documents which do not specifically address AISC requirements.

Impact:
Potential for cost increases and schedule delays due to insufficient independent oversight and control of project activities and objectives.

Recommendations	**Management Action Plan**	**Owner & Target Completion Date**
Management should: • Complete its plans to develop and deploy a formal gating process for P&M use on AISC projects; • Ensure gate review documentation packages are created and maintained as a key part of the gate-approval process; and • Ensure that formal gate reviews and approvals are performed and that required stakeholders such as Finance are involved in the gate review and challenge process.	The Nuclear Projects Gated process will become the standard approach for P&M AISC projects beginning with 2016 Project New Starts. This change has been approved by the SVP/CNE and VP, P&M and an initiative is underway to align and implement the Gated process. Finance will be involved in the gate review process. Implementation requires the following actions: 1. Establish a common Gated process for all Nuclear Projects. 2. Through a Change Management Plan, prepare and issue desktop guides for Project Life Cycle to AISC Members and Project Managers. 3. Preparation and Issuance of AISC Terms of Reference to AISC Members and Project Managers.	Actions #1 and #2: Gary Rose VP Planning and Controls April 30, 2016 Action #3: Steve Woods SVP & CNE April 30, 2016

[3] The five standard phases in a project life-cycle are Identification, Initiation, Definition, Execution and Closeout.

4. Governance and Procedures specific to AISC projects require improvement.	**Low**

There are three key gaps identified in governance and procedures that should be addressed:

1. A formal Terms of Reference ("TOR") document does not exist to govern the role, accountabilities, and operation of the AISC;

2. Although Nuclear Projects Governance should apply to AISC funded projects, this principal is not adequately documented as AISC projects follow existing Finance governance. To reduce this confusion, some AISC specific processes should be defined including:
   - The scope and change management process involving PCRAF's should be substituted with the current process in Nuclear projects called CCF;
   - The gating process, including the requirements and deliverables for each gate; and
   - The process for establishing and integrating vendor schedules, establishing forecast inputs, work breakdown structure requirements, etc.

3. Requirements for month-end performance reports and record keeping are undefined. Each project manager runs their project using a different set of month-end reports and reports are not formally stored by project in a central directory for future reference.

Potential Causes & Impact

Potential Cause:
The new Nuclear Projects governance and procedures are high-level principle-based documents which do not specifically address AISC requirements.

Impacts:
- Potential for confusion amongst project team members on how to handle AISC specific requirements versus other DNR requirements; and
- Potential for cost increases and schedule delays due to ineffective planning and control of project activities and objectives.

Recommendations	**Management Action Plan**	**Owner & Target Completion Date**
Management should: 1. Formalize a Terms of Reference document for the AISC; 2. Formalize requirements specific to AISC Project Management; leveraging Nuclear Project's governance where possible; and 3. Standardize the reporting for AISC projects and store these in a centralized repository for future reference. i.e. Book of Record.	Recommendations 1 and 2: Action plan for Finding 3 will include issuance of AISC Terms of Reference and a desktop guide to assist projects under AISC authority in the use of Nuclear Projects Governance, specifically the gated process. Recommendations 3 and 4: Nuclear Projects is in the process of developing standardized reports using Ecosys. Phase 1 implementation will be in Nuclear Refurbishment and Phase 2 will be in P&M.	Recommendations 3 and 4: Gary Rose VP Planning and Controls December 31, 2016

APPENDIX A – LIST OF PROJECTS REVIEWED

Item	Project No.	Project Description	Project Area	Current Project Phase	Current EAC (CDN$M)
1	31412	DN Class II UPS Replacement	Darlington	Execution	55.099
2	31422	DN Pressurizer Heaters & Controllers Replacement Project	Darlington	Execution	14.511
3	31426	DN F/H Inverter Replacement	Darlington	Execution	14.386
4	31508	DN Fukushima Phase 1 Beyond Design Basis Event (BDBE) Emergency Mitigation Equipment (EME)	Darlington	Execution	58.391
5	31710	DN Shutdown Cooling Heat Exchanger Replacement	Darlington	Execution	56.085
6	80058	NWM Western Waste Management Facility Groundwater Monitoring Network	NWM	Execution	4.710
7	33623	DN Installation of partial discharge monitors	Darlington	Close-out	7.147
8	40682	PB MOT8 Foundation Settlement	Pickering	Close-out	3.844
9	60144	IC-18's/IC-HX's	NWM	Close-out	9.730
10	40990	PN Bay Module Loader PLC Replacement	Pickering	Definition	1.200
11	41027	PN Fukushima Phase 2 Beyond Design Basis Event (BDBE) Emergency Mitigation Equipment (EME)	Pickering	Definition	46.302
12	38419	DN Capping of D2O Collection Lines	Darlington	Definition	8.398
13	31516	DN Station Lighting Retrofit	Darlington	Deferred	11.379

Legend:
EAC= Estimate-At-Complete based upon latest Business Case Summary ("BCS").

APPENDIX B – AACE AND BCS CLASSIFICATIONS FOR ESTIMATES

Estimate Class

Estimate Class is a cost estimate classification system developed by the Association for the Advancement of Cost Engineering International (AACE) which defines the estimate "quality" based on the input information used and the project's stage of development. AACE uses five estimate classes with Class 5 being the least accurate, and Class 1 being the most accurate. Below is a table that is included in the instructions for Cost Estimates in the BCS template.

Estimate Class	Class 5	Class 4	Class 3	Class 2	Class 1
Project Phase	**Identification**	**Initiation**	**Definition**	**Execution**	**Execution**
Level of Project Definition (%)	0% to 2	1 to 15	10 to 40	30 to 75	65 to 100
Expected Accuracy Range (%)	-50 to +100	-30 to +50	-20 to +30	-15 to +20	-10 to +15

APPENDIX C – PROJECTS WITH BASELINE DISCREPANCIES

Item	Project No.	Project Description	Latest EAC (CDN$M)	Latest Target In-Service Date	CSCB Out-of-Date	CSCB Does Not Exist	Summary of Discrepancy
1	31412	DN Class II UPS Replacement	55.099M	2023-Q4	x		Vendor Schedule has not been integrated into Baseline Schedule.
2	31422	DN Pressurizer Heaters & Controllers Replacement Project	14.511M	2020-03-20	x		The current Performance Measurement Baseline (PMB) does not yet include baseline changes required by PCRAF No.'s 3 and 4 dated 15Apr2015 and 22Oct2015, respectively.
3	31508	DN Fukushima Phase 1 Beyond Design Basis Event (BDBE) Emergency Mitigation Equipment (EME)	58.391	2017-12-23	x		No Vendor Schedule. Vendor Schedule has not been integrated into Baseline Schedule.
4	40990	PN Bay Module Loader PLC Replacement	1.2M	TBD BCS under Revision		x	Integrated Cost & Schedule Control Baseline not yet established in P6 and Proliance.
5	80058	NWM Western Waste Management Facility Groundwater Monitoring Network	4.710M	2016-09-30		x	Integrated Cost & Schedule Control Baseline not yet established in P6 and Proliance.
				Totals:	**3**	**2**	

Legend:

BCS= Business Case Summary
CSCB= Cost and Schedule Control Baseline
EAC= Estimate-At-Complete
P6= OPG's Scheduling Software System.
Proliance= OPG's Cost Management Software
TBD= To be Determined

Notes:
Latest EAC and Target In-Service Date based upon latest Business Case Summary inputs.

APPENDIX D – RISK RATING DEFINITIONS FOR AUDIT FINDINGS

Ratings are derived through professional judgement by the audit team and discussion with management. The ratings for individual control findings are outlined below.

Rating	Definition
High Risk	The finding presents a risk that could potentially have severe/major impact on financial sustainability (≥$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations.
Moderate Risk	The finding presents a risk that could potentially have a moderate impact on financial sustainability ($500K to <$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. If not remediated, this risk could escalate to high risk.
Low Risk	The finding could potentially have a minor impact on financial sustainability (<$500K), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. Recurring "low risk" findings may be elevated to medium risk status.

OVERALL REPORT RATING SCALE

An overall report rating has been assigned as an indication of the overall design, existence and effectiveness of the components of the internal control structure that was subject to the internal audit. The internal audit rating should be considered in conjunction with the definitions noted above.

- *Effective:* control and risk management practices provide reasonable assurance that business process objectives will be achieved and may include minor improvements and/or opportunities for improvement.
- *Generally Effective*: control and risk management practices require more than minor but less than significant improvements to provide reasonable assurance that business process objectives will be achieved.
- *Requires Improvement*: control and risk management practices require significant improvements in high risk and/or core areas to provide reasonable assurance that business process objectives will be achieved.
- *Not Effective:* control and risk management practices are not designed and/or are not operating effectively.

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News Release

Canadian Nuclear Safety Commission Commission canadienne de sûreté nucléaire

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Canadian Nuclear Safety Commission invites comments on draft REGDOC-2.2.4, Fitness for Duty

November 9, 2015, Ottawa ON

The Canadian Nuclear Safety Commission (CNSC) is asking the public to provide their comments on draft REGDOC-2.2.4, *Fitness for Duty*.

This document provides fitness-for-duty requirements and guidance for workers at high-security sites, including drug and alcohol testing. A high-security site refers to a nuclear power plant or a nuclear facility where Category I or II nuclear material is processed, used or stored.

REGDOC-2.2.4, *Fitness for Duty*, is part of the CNSC's regulatory framework series on human performance management.

New to consultation is an impact statement specific to this document, which outlines the regulatory objectives and approach, as well as the estimated impacts on stakeholders. The public is asked to provide clear and specific feedback to help CNSC staff refine, or revisit, initial assumptions and objectives.

To review and comment on the document and impact statement, visit the REGDOC-2.2.4, *Fitness for Duty* Web page. Please submit your feedback by January 22, 2016*. Comments submitted, including names and affiliations, are intended to be made public.

The CNSC regulates the use of nuclear energy and materials to protect the health, safety and security of Canadians and the environment; to implement Canada's international commitments on the peaceful use of nuclear energy; and to disseminate objective scientific, technical and regulatory information to the public.

Quick facts

- REGDOC-2.2.4, *Fitness for Duty*, incorporates feedback received in response to discussion paper DIS-12-03, *Fitness for Duty: Proposals for Strengthening Alcohol and Drug Policy, Programs and Testing*, which was published for public consultation from April to August 2012.
- REGDOC-2.2.4 also updates the information found in RD-363, *Nuclear Security Officer Medical, Physical, and Psychological Fitness*.
- REGDOC-2.2.4, *Fitness for Duty: Managing Worker Fatigue*, is being consulted upon separately and its subject matter is not addressed in this broader document.

Relevant links

- *General Nuclear Safety and Control Regulations*
- *Nuclear Security Regulations*
- *Class I Nuclear Facilities Regulations*
- *Fitness for Duty: Proposals for Strengthening Alcohol and Drug Policy, Programs and Testing*
- Regulatory framework overview
- Regulatory documents

***NOTE: The consultation period has been extended to March 7, 2016**

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