November 29, 2019

VIA EMAIL

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

Dear Ms. Walli:

Re: OPG Reporting and Record Keeping Requirements

Further to the OEB's direction in EB-2010-0008 (Decision with Reasons, p. 151) and maintained in subsequent OEB decisions on OPG applications, please find attached the following information:

1) Within 60 days after calendar quarter end: unaudited balances of OPG's deferral and variance accounts; and,
2) Within 60 days for the first three quarters: OPG's MD&A and Financial Statements filed with the OSC, OPG's nuclear unit capability factors and the hydroelectric availability for its regulated facilities.

Further to the OEB's direction in EB-2016-0152 (Decision and Order, p. 151), please find attached:

3) The 2019 nuclear performance report with benchmark quartile results; and
4) The 2019 Nuclear Benchmarking Report in support of the nuclear performance report.

In its letter dated December 7, 2018, OPG filed the ScottMadden Management Consultants' report on *OPG Nuclear Cost Performance Benchmarking Methodology to Adjust for Refurbishment and Validation of Implementation* in support of its revised normalization methodology for deriving the TGC/MWh metric. OPG has subsequently made further revisions to its normalization methodology as discussed in the 2019 Nuclear Benchmarking Report. OPG is re-filing the 2018 ScottMadden Management Consultants' report and is also filing ScottMadden Management Consultants' 2019 report on *A Study of Factors Impacting TGC/MWh Performance with Normalizing Adjustments to Facilitate Closer Comparison*.

Yours truly,

[Original signed by]

Matt Kirk

Att.

cc: Cathy Nguyen, OEB
Stephanie Chan, OEB

Submitted: November 29, 2019

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 1
Summary of Variance & Deferral Account Balances

Account	Balance ($M) September 30, 2019
Regulated Hydroelectric	
Hydroelectric Water Conditions Variance Account	(220)
Ancillary Services Net Revenue Variance Account - Hydroelectric	(62)
Hydroelectric Incentive Mechanism Variance Account	0
Hydroelectric Surplus Baseload Generation Variance Account	450
Income and Other Taxes Variance Account - Hydroelectric	(2)
Capacity Refurbishment Variance Account - Hydroelectric	21
Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account	8
Pension and OPEB Cost Variance Account - Future Recovery - Hydroelectric (Dec 31, 2012 Balance)	7
Pension and OPEB Cost Variance Account - Post 2012 Additions - Hydroelectric	18
Pension & OPEB Cash Payment Variance Account - Hydroelectric	(54)
Pension & OPEB Cash Versus Accrual Differential Deferral Account - Hydroelectric	113
Pension & OPEB Cash Versus Accrual Differential Carrying Charges - Hydroelectric	0
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential - Primary Account-Hydroelectric	5
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential - Contra Account-Hydroelectric	(5)
Hydroelectric Deferral and Variance Over/Under Recovery Variance Account	18
Gross Revenue Charge Variance Account	0
Regulated Hydroelectric Subtotal	**297**
Nuclear	
Nuclear Liability Deferral Account	14
Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account	(95)
Nuclear Development Variance Account	4
Ancillary Services Net Revenue Variance Account - Nuclear	1
Capacity Refurbishment Variance Account - Nuclear - Capital Portion	63
Capacity Refurbishment Variance Account - Nuclear - Non-Capital Portion	(155)
Bruce Lease Net Revenues Variance Account - Derivative	(35)
Bruce Lease Net Revenues Variance Account - Non-Derivative	196
Income and Other Taxes Variance Account - Nuclear	(15)
Pension and OPEB Cost Variance Account - Future Recovery - Nuclear (Dec 31, 2012 Balance)	144
Pension and OPEB Cost Variance Account - Post 2012 Additions - Nuclear	367
Pension & OPEB Cash Payment Variance Account - Nuclear	(245)
Pension & OPEB Cash Versus Accrual Differential Deferral Account - Nuclear	721
Pension & OPEB Cash Versus Accrual Differential Carrying Charges - Nuclear	0
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential - Primary Account - Nuclear	33
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential - Contra Account - Nuclear	(33)
Nuclear Deferral and Variance Over/Under Recovery Variance Account	30
Fitness for Duty Deferral Account	0
SR&ED ITC Variance Account	(14)
Impact Resulting from Changes to Pickering Station End-of-Life Dates (Dec 2017) Deferral Account	(215)
Rate Smoothing Deferral Account	78
Nuclear Subtotal	**844**
Grand Total	**1,141**

Notes:
The Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential-Primary Account and related Contra account balances always nets to zero.

Submitted: November 29, 2019

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 2		
Management's Discussion & Analysis (MD&A) and Financial Statements Reporting		
Report	**Reporting Period**	**Particulars**
MD&A filed with the Ontario Securities Commission	Nine Months Ended September 30, 2019	OPG's MD&A is filed with the Ontario Securities Commission and is posted on OPG's website at the following link: https://www.opg.com/document/q3-2019-opg-pr_mda_fs/
Financial Statements filed with the Ontario Securities Commission	Nine Months Ended September 30, 2019	OPG's financial statements are filed with the Ontario Securities Commission and are posted on OPG's website at the following link: https://www.opg.com/document/q3-2019-opg-pr_mda_fs/
Nuclear Unit Capability Factors	Nine Months Ended September 30, 2019	OPG's Nuclear unit capability factors are provided on page 23 of OPG's MD&A, which is available at the following link: https://www.opg.com/document/q3-2019-opg-pr_mda_fs/
Availability for the Regulated Hydroelectric Facilities	Nine Months Ended September 30, 2019	Availability for the regulated hydroelectric facilities is provided on page 24 of OPG's MD&A, which is available at the following link: https://www.opg.com/document/q3-2019-opg-pr_mda_fs/

Pickering Performance Report

Metric	Actuals 2014	2015	2016	2017	2018	Metric	Annual Targets 2018	2019
Safety								
1-Year Total Recordable Injury Frequency (#/200k hours worked) [1]	0.22	0.44	0.49	0.06	0.16	Total Recordable Injury Frequency (#/200k hours worked)	0.22	0.20
Rolling Average[2] Industrial Safety Accident Rate (#/200k hours worked)	0.03	0.05	0.04	0.05	0.05	Industrial Safety Accident Rate (#/200k hours worked)	0.10	0.10
Rolling Average[2] Collective Radiation Exposure (Person-rem per unit)	82.24	97.72	97.23	83.96	81.65	Collective Radiation Exposure (Person-rem per unit)	110.30	92.30
1-Year Airborne Tritium Emissions (Curies) per Unit	2,390	2,409	3,067	3,103	2,772	Airborne Tritium Emissions (Curies) per Unit	2,666	2,500
Fuel Reliability Index (microcuries per gram) [4]	0.001580	0.000421	0.000261	0.000584	0.000837	Fuel Reliability Index (microcuries per gram)	0.000500	0.000500
2-Year Reactor Trip Rate (# per 7,000 hours)	0.36	0.17	0.25	0.26	0.33	Reactor Trip Rate (# per 7,000 hours)	0.50	0.50
3-Year Auxiliary Feedwater System Unavailability (#)	0.0181	0.0115	0.0070	0.0000	0.0039	Auxiliary Feedwater System Unavailability (#)	0.0200	0.0200
3-Year Emergency AC Power Unavailability (#)	0.0000	0.0030	0.0030	0.0030	0.0000	Emergency AC Power Unavailability (#)	0.0250	0.0250
3-Year High Pressure Safety Injection Unavailability (#)	0.0000	0.0000	0.0000	0.0000	0.0000	High Pressure Safety Injection Unavailability (#)	0.0200	0.0200
Reliability								
Rolling Average[2] WANO NPI (Index)	64.3	68.5	76.3	76.7	74.9	WANO NPI (Index)	75.5	74.3
Rolling Average[2] Forced Loss Rate (%)	10.08	6.85	3.76	5.01	5.20	Forced Loss Rate (%)	3.50	3.50
Rolling Average[2] Unit Capability Factor (%)	74.50	77.32	77.03	77.36	79.55	Unit Capability Factor (%)	74.60	80.56
Rolling Average[2] Chemistry Performance Indicator (Index)	1.04	1.06	1.04	1.02	1.02	Chemistry Performance Indicator (Index)	1.02	1.03
1-Year On-line Deficient Maintenance Backlog (work orders per unit)	276	251	350	383	279	On-line Deficient Maintenance Backlog (work orders per unit)	153	133
1-Year On-line Deficient Critical Maintenance Backlog (work orders per unit)				41	9	On-line Deficient Critical Maintenance Backlog (work orders per unit)	15	9
1-Year On-line Corrective Maintenance Backlog (work orders per unit)	160	125	116	25	17	On-line Corrective Maintenance Backlog (work orders per unit)	20	12
1-Year On-line Corrective Critical Maintenance Backlog (work orders per unit)				0	0	On-line Corrective Critical Maintenance Backlog (work orders per unit)	0	0
Value for Money								
3-Year Total Generating Cost per MWh ($ per Net MWh)	68.00	67.36	68.06	67.22	67.76	Total Generating Cost per MWh ($ per Net MWh)	73.17	64.89
Normalized 3-Year Total Generating Cost per MWh ($ per Net MWh)[5]				49.26	49.29	Normalized 3-Year Total Generating Cost per MWh ($ per Net MWh)		
3-Year Total Generating Cost per Unit (M $ per Unit)	228.38	228.04	231.63	233.75	234.18	Total Generating Cost per Unit (M $ per Unit)	243.03	232.93
Normalized 3-Year Total Generating Cost per Unit (M $ per Unit)[5]				184.69	183.77	Normalized 3-Year Total Generating Cost per MWh ($ per Net MWh)		
3-Year Non-Fuel Operating Cost per MWh ($ per Net MWh)	57.01	56.49	57.12	56.89	57.92	Non-Fuel Operating Cost per MWh ($ per Net MWh)	64.75	56.67
3-Year Fuel Cost per MWh ($ per Net MWh)	5.74	5.71	5.75	5.31	4.86	Fuel Cost per MWh ($ per Net MWh)	5.59	4.12
3-Year Capital Cost per MW DER (k$ per MW)	34.20	33.86	34.23	33.91	33.39	Capital Cost per MW DER (k$ per MW)	26.22	28.55
Human Performance								
18-Month Human Performance Error Rate (# per 200k ISAR and contractor hours) [3]	0.17800	0.11000	0.03840	0.11600	0.14310	18-Month Human Performance Error Rate (# per 200k ISAR and contractor hours)	0.06000	0.08000

Notes
1. In 2018, Ontario Power Generation selected Total Recordable Injury Frequency (replacing All Injury Rate) as a measure for evaluating Health and Safety performance, and reflects a change instituted by the Canadian Electrical Association. Total Recordable Injury Frequency is the average number of fatalities, lost time injuries, medical treatment injuries and restricted work injuries per 200,000 hours worked. Data prior to 2018 are All Injury Rate figures.
2. Indicates a 2-Year Rolling Average for Pickering and a 3-Year Rolling Average for Darlington.
3. 2014-2016 figures have been restated from 10k ISAR and contractor hours to 200k ISAR and contractor hours.
4. Indicates performance in the most recent quarter
5. 2017 and 2018 Normalized Actuals utilize the both ScottMadden methdologies i.e. normalizing for refurbishment as well as CANDU technology (including outage duration) and age-related impacts

For the respective year:

Green = maximum NPI results achieved or best quartile performance

White = 2nd quartile performance

Yellow = 3rd quartile performance

Red = 4th quartile performance

Darlington Performance Report

Metric	Actuals 2014	2015	2016	2017	2018	Metric	Annual Targets 2018	2019
Safety								
1-Year Total Recordable Injury Frequency (#/200k hours worked) [1]	0.31	0.22	0.23	0.40	0.32	Total Recordable Injury Frequency (#/200k hours worked)	0.22	0.20
Rolling Average[2] Industrial Safety Accident Rate (#/200k hours worked)	0.06	0.08	0.06	0.04	0.04	Industrial Safety Accident Rate (#/200k hours worked)	0.10	0.10
Rolling Average[2] Collective Radiation Exposure (Person-rem per unit)	69.06	79.55	68.77	91.80	85.43	Collective Radiation Exposure (Person-rem per unit)	79.80	80.00
1-Year Airborne Tritium Emissions (Curies) per Unit	1,831	1,313	846	875	982	Airborne Tritium Emissions (Curies) per Unit	800	900
Fuel Reliability Index (microcuries per gram) [4]	0.000158	0.000122	0.000343	0.000179	0.000187	Fuel Reliability Index (microcuries per gram)	0.000500	0.000500
2-Year Reactor Trip Rate (# per 7,000 hours)	0.00	0.13	0.24	0.29	0.15	Reactor Trip Rate (# per 7,000 hours)	0.50	0.50
3-Year Auxiliary Feedwater System Unavailability (#)	0.0000	0.0000	0.0000	0.0000	0.0000	Auxiliary Feedwater System Unavailability (#)	0.0200	0.0200
3-Year Emergency AC Power Unavailability (#)	0.0000	0.0000	0.0000	0.0000	0.0026	Emergency AC Power Unavailability (#)	0.0250	0.0250
3-Year High Pressure Safety Injection Unavailability (#)	0.0000	0.0000	0.0000	0.0000	0.0000	High Pressure Safety Injection Unavailability (#)	0.0200	0.0200
Reliability								
Rolling Average[2] WANO NPI (Index)	92.1	83.7	87.8	82.0	90.7	WANO NPI (Index)	91.3	92.1
Rolling Average[2] Forced Loss Rate (%)	2.85	3.65	3.10	3.47	1.94	Forced Loss Rate (%)	1.00	1.00
Rolling Average[2] Unit Capability Factor (%)	89.41	83.96	86.16	82.17	86.89	Unit Capability Factor (%)	86.00	89.00
Rolling Average[2] Chemistry Performance Indicator (Index)	1.00	1.00	1.00	1.01	1.03	Chemistry Performance Indicator (Index)	1.01	1.10
1-Year On-line Deficient Maintenance Backlog (work orders per unit)	176	174	170	119	124	On-line Deficient Maintenance Backlog (work orders per unit)	134	115
1-Year On-line Deficient Critical Maintenance Backlog (work orders per unit)				15	9	On-line Deficient Critical Maintenance Backlog (work orders per unit)	29	6
1-Year On-line Corrective Maintenance Backlog (work orders per unit)	20	24	14	13	6	On-line Corrective Maintenance Backlog (work orders per unit)	7	4
1-Year On-line Corrective Critical Maintenance Backlog (work orders per unit)				1	0	On-line Corrective Critical Maintenance Backlog (work orders per unit)	2	0
Value for Money								
3-Year Total Generating Cost per MWh ($ per Net MWh)	37.29	44.38	45.63	54.40	59.06	Total Generating Cost per MWh ($ per Net MWh)	70.26	65.24
Normalized 3-Year Total Generating Cost per MWh ($ per Net MWh)[6]				37.94	37.65	Normalized Total Generating Cost per MWh ($ per Net MWh)[5]	51.66	53.61
3-Year Total Generating Cost per Unit (M $ per Unit)	252.77	282.37	292.49	337.56	384.74	Total Generating Cost per Unit (M $ per Unit)	451.54	433.95
Normalized 3-Year Total Generating Cost per Unit (M $ per Unit)[6]				313.62	257.65	Normalized Total Generating Cost per Unit (M $ per Unit)[5]	347.34	356.60
3-Year Non-Fuel Operating Cost per MWh ($ per Net MWh)	28.10	33.19	33.00	39.62	42.14	Non-Fuel Operating Cost per MWh ($ per Net MWh)	49.01	45.30
Normalized 3-Year Non-Fuel Operating Cost per MWh ($ per Net MWh)[7]				36.89	36.37	Normalized Non-Fuel Operating Cost per MWh ($ per Net MWh)[5]	35.13	36.77
3-Year Fuel Cost per MWh ($ per Net MWh)	5.13	5.18	5.31	5.19	4.92	Fuel Cost per MWh ($ per Net MWh)	5.92	4.51
3-Year Capital Cost per MW DER (k$ per MW)	31.30	43.52	53.47	62.11	89.03	Capital Cost per MW DER (k$ per MW)	91.11	87.65
Normalized 3-Year Capital Cost per MW DER (k$ per MW)[7]				59.81	73.46	Normalized 3-Year Capital Cost per MW DER (k$ per MW)		
Human Performance								
18-Month Human Performance Error Rate (# per 200k ISAR and contractor hours) [3]	0.12400	0.06200	0.06940	0.05200	0.05100	18-Month Human Performance Error Rate (# per 200k ISAR and contractor hours)	0.06000	0.04000

Notes
1. In 2018, Ontario Power Generation selected Total Recordable Injury Frequency (replacing All Injury Rate) as a measure for evaluating Health and Safety performance, and reflects a change instituted by the Canadian Electrical Association. Total Recordable Injury Frequency is the average number of fatalities, lost time injuries, medical treatment injuries and restricted work injuries per 200,000 hours worked. Data prior to 2018 are All Injury Rate figures.
2. Indicates a 2-Year Rolling Average for Pickering and a 3-Year Rolling Average for Darlington.
3. 2014-2016 figures have been restated from 10k ISAR and contractor hours to 200k ISAR and contractor hours.
4. Indicates performance in the most recent quarter
5. 2018 Normalized Targets utilize the initial methodology of adding back generation and fuel costs. 2019 Normalized Targets utilize the new ScottMadden methodology for refurbishment.
6. 2017 and 2018 Normalized Actuals utilize the both ScottMadden methodologies i.e. normalizing for refurbishment as well as CANDU technology (including outage duration) and age-related impacts
7. 2017 and 2018 Normalized Actuals utilize the new ScottMadden methodology for refubishment only

For the respective year:

Green = maximum NPI results achieved or best quartile performance

White = 2nd quartile performance

Yellow = 3rd quartile performance

Red = 4th quartile performance

OPG Nuclear Performance Report

Metric	Actuals 2014	2015	2016	2017	2018
Reliability					
Rolling Average[1] WANO NPI (Index)	75.5	74.6	80.9	78.5	80.1
Rolling Average[1] Unit Capability Factor (%)	80.50	80.00	80.70	78.96	82.00
Value for Money					
3-Year Total Generating Cost per MWh ($ per Net MWh)	50.38	54.58	55.57	60.53	63.31
Normalized 3-Year Total Generating Cost per MWh ($ per Net MWh)[3]				43.44	43.41
3-Year Total Generating Cost per Unit (M $ per Unit)	238.14	249.77	255.97	273.13	287.95
Normalized 3-Year Total Generating Cost per Unit (M $ per Unit)[3]				208.24	210.16

Metric	Annual Targets 2018	2019
WANO NPI (Index)	80.8	80.2
Unit Capability Factor (%)	79.92	84.47
Total Generating Cost per MWh ($ per Net MWh)	71.74	65.06
Normalized Total Generating Cost per MWh ($ per Net MWh)[2]	60.82	59.46
Total Generating Cost per Unit (M $ per Unit)	312.54	299.94
Normalized Total Generating Cost per Unit (M $ per Unit)[2]	284.78	274.15

Notes
1. Indicates a 2-Year Rolling Average for Pickering and a 3-Year Rolling Average for Darlington.
2. 2018 Normalized Targets utilize the initial methodology of adding back generation and fuel costs. 2019 Normalized Targets utilize the new ScottMadden methodology for refurbishment.
3. 2017 and 2018 Normalized Actuals utilize the both ScottMadden methdology i.e. normalizing for refurbishment as well as CANDU technology (including outage duration) and age-related impacts

For the respective year:

Green = maximum NPI results achieved or best quartile performance

White = 2nd quartile performance

Yellow = 3rd quartile performance

Red = 4th quartile performance

ONTARIO POWER GENERATION

ONTARIO POWER GENERATION NUCLEAR

2019 NUCLEAR BENCHMARKING REPORT

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Nuclear Finance – Business Planning and Benchmarking

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1.0 EXECUTIVE SUMMARY

OPG benchmarked favourably relative to its peers in 2018 in a number of key nuclear cornerstone areas, while certain metrics were impacted by plant life extension activities (i.e., Pickering Extended Operations) and refurbishment at Darlington.

Safety

Under the Safety cornerstone, OPG's nuclear generating stations continued to achieve strong performance in a majority of the safety performance metrics. Darlington and Pickering continued to demonstrate first quartile performance in Total Recordable Injury Frequency.

OPG Nuclear Stations continue to lead in Safety

Darlington achieved maximum WANO Nuclear Performance Index (NPI) results or best quartile performance for six of the seven NPI sub-metrics under the Safety cornerstone. Pickering continued to show maximum WANO NPI results or top quartile performance for five NPI sub-metrics under the Safety cornerstone.

Pickering's Collective Radiation Exposure (CRE) improved to the second quartile and Darlington's CRE improved to the third quartile due to effectiveness of mitigation measures and initiatives being implemented to reduce identified sources of radiological hazards and human performance during execution of radiological tasks.

Airborne Tritium Emissions at Pickering remained in the third quartile and showed improvement largely due to efforts to drive tritium reduction activities, which include dedicated teams to ensure daily emissions monitoring, sustaining and improving dryer performance, heavy water leak minimization, tritium program development and innovations. Darlington tritium emissions performance moved from first quartile to median quartile mainly due to dryer performance issues in Unit 3.

Pickering's Fuel Reliability Index (FRI) remained in the fourth quartile resulting from two fuel defects. Management continues to focus on a number of corrective actions to improve FRI performance including improving the methods of surveillance and elimination of the possibility of foreign materials entrance into the Heat Transport System due to Fuel Handling and Outage practices. Darlington's FRI performance achieves maximum NPI points.

Reliability

OPG's nuclear facilities are transitioning through a refurbishment and life extension which has impacted OPG's performance under the Reliability cornerstone.

OPG Nuclear Stations have significantly improved in reducing maintenance backlogs. Corrective Critical backlogs are at 0 at Darlington and Pickering

To facilitate extended operations, OPG is experiencing a significant number of planned outage days. Despite the higher planned outage days, Pickering's performance metrics improved compared to 2017 such as the Unit Capability Factor (UCF). On-line Deficient Maintenance Backlogs, and On-line Corrective Maintenance Backlogs also improved. At Pickering, the most significant improvement was the On-line Deficient Critical Maintenance Backlogs performing better by a 78% reduction compared to 2017, which was largely attributed to a deliberate focus on scheduling deficient critical maintenance.

Pickering's NPI performance and Forced Loss Rate (FLR) have improved considerably since 2013 as the station continues to drive plant reliability improvements via the system health improvement process and recovery actions and the station has seen significant improvements in completion of critical preventive maintenance work.

Certain Darlington reliability metrics showed sustained or improved performance (e.g., WANO NPI, FLR, UCF, On-line Corrective Critical Maintenance Backlogs). Equipment reliability improvements at Darlington has been the main driver for the favourable improvement in FLR and UCF performance. Darlington improved their On-line Corrective Maintenance Backlogs by reducing the number of work orders per unit relative to 2017 as a result of continued station focus, overall maintenance efficiency and improved schedule quality. On-Line Deficient Maintenance Backlogs experienced a slight decline in performance as OPG prioritized execution of Corrective Critical Maintenance Backlogs, which has a greater effect on the safe and reliable operation of the plant than the deficient items. The fleet initiative Right Work Right Time and Right Value's implementation of Value Based Maintenance (VBM), the use of the cross-functional Fix It Now (FIN) team to tackle emergent station work, along with other initiatives to drive maintenance productivity, are expected to improve station backlog measures.

Darlington's CPI performance experienced challenges in 2018 due to chronic Unit 3 condenser tube leaks causing increased boiler conductivity, as well as increased Feed Water iron levels during startups following the unit outages. A Corrosion Product Transport (CPT) reduction plan is in place, which includes: condenser cleaning following maintenance, condenser hot well flushing prior to restart and placing condensate filtration unit in service during startup.

Value for Money

Darlington's TGC per MWh performance was in second quartile in 2018 after normalizing[1] for refurbishment as well as CANDU technology (including outage duration) and age-related impacts. Before normalization, Darlington was in the fourth quartile, driven largely by cost impacts for life post-refurbishment and reduced generation associated with refurbishment work. Darlington sustained top quartile performance in Fuel Cost per MWh.

Pickering's Total Generating Cost (TGC) per MWh performance in 2018 was comparable to 2017. Normalizing Pickering's TGC per MWh for CANDU technology (including outage duration) and age-related impacts improved its ranking by eight positions within the fourth quartile. Pickering largely managed cost pressures and TGC per MWh remained relatively flat over the 2013-2018 period with a compound growth rate of 0.17%. Pickering maintained best quartile performance in Fuel Cost per MWh and Capital Cost per MW DER.

TGC/MWh was impacted by life extension and refurbishment.

Site capacity (reflecting unit size) as well as outage durations required to extend operations continued to contribute to Pickering's TGC per MWh. Pickering units are the smallest in the peer group with total unit capacity of 540 MW compared to the peer group average of 1,026 MW. The majority of the generating units in the peer group fall within the 900 to 1,299 MW range.

Pickering's TGC per generating unit demonstrated strong performance with Pickering placing among the best in the peer group.

Human Performance

In the area of Human Performance, Darlington improved their human performance error rate and remained in the median quartile. However, Pickering declined to the fourth quartile in 2018, resulting from two station event free day resets. The Human Performance Fleet Excellence plan is targeting the following areas to address the key drivers and drive continuous improvements. The focus areas are: Nuclear Professionals/Human Performance (HU) integration, improve vendor HU proficiency, HU training improvements, innovations to improve HU trending and early identification and simplify event evaluation tools.

[1] See section 4.0 for a description of the TGC/MWh normalization methodology.

Benchmarking Results – Plant Level Summary

Table 1 provides a summary of OPG Nuclear's 2018 performance compared to benchmark results.

Table 1: Plant Level Performance Summary

Metric	NPI Max	2018 Actuals			
		Best Quartile	Median	Pickering	Darlington
Safety					
Total Recordable Injury Frequency (#/200k hours worked)		0.76	N/A[1]	0.16	0.32
Rolling Average[2] Industrial Safety Accident Rate (#/200k hours worked)	0.20	0.00	0.02	0.05	0.04
Rolling Average[2] Collective Radiation Exposure (Person-rem per unit)	80.00	38.93	81.65	81.65	85.43
Airborne Tritium Emissions (Curies) per Unit[3]		972	2,173	2,772	982
Fuel Reliability Index (microcuries per gram)	0.000500	0.000001	0.000006	0.000837	0.000187
2-Year Reactor Trip Rate (# per 7,000 hours)	0.50	0.00	0.00	0.33	0.15
3-Year Auxiliary Feedwater System Unavailability (#)	0.0200	0.0000	0.0000	0.0039	0.0000
3-Year Emergency AC Power Unavailability (#)	0.0250	0.0005	0.0024	0.0000	0.0026
3-Year High Pressure Safety Injection Unavailability (#)	0.0200	0.0000	0.0000	0.0000	0.0000
Reliability					
WANO NPI (Index)		93.0	90.7	74.9	90.7
Rolling Average[2] Forced Loss Rate (%)	1.00	1.03	1.46	5.20	1.94
Rolling Average[2] Unit Capability Factor (%)	92.00	89.42	86.93	79.55	86.89
Rolling Average[2] Chemistry Performance Indicator (Index)	1.01	1.00	1.01	1.02	1.03
1-Year On-line Deficient Maintenance Backlog (work orders per unit)		41	59	279	124
1-Year On-line Deficient Critical Maintenance Backlog (work orders per unit)		0	2	9	9
1-Year On-line Corrective Maintenance Backlog (work orders per unit)		2	4	17	6
1-Year On-line Corrective Critical Maintenance Backlog (work orders per unit)		0	0	0	0
Value for Money					
3-Year Total Generating Cost per MWh ($ per Net MWh)		35.59	43.41	67.76	59.06
Normalized 3-Year Total Generating Cost per MWh ($ per Net MWh)		33.14	37.75	49.29	37.65
3-Year Total Generating Cost per Unit (M $ per Unit)		288.06	324.52	234.18	384.74
Normalized 3-Year Total Generating Cost per Unit (M $ per Unit)		257.48	307.10	183.77	257.65
3-Year Non-Fuel Operating Cost per MWh ($ per Net MWh)		21.67	25.03	57.92	42.14
Normalized 3-Year Non-Fuel Operating Cost per MWh ($ per Net MWh)		21.67	24.84	N/A	36.37
3-Year Fuel Cost per MWh ($ per Net MWh)		6.84	7.97	4.86	4.92
3-Year Capital Cost per MW DER (k$ per MW)		41.03	58.98	33.39	89.03
Normalized 3-Year Capital Cost per MW DER (k$ per MW)		41.03	58.98	N/A	73.46
Human Performance					
18-Month Human Performance Error Rate (# per 200k ISAR and contractor hours)		0.0310	0.0595	0.1431	0.0510

Notes
1. No median benchmark available.
2. Indicates a 2-Year Rolling Average for Pickering and a 3-Year Rolling Average for Darlington.
3. 2017 Industry data is used because 2018 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

Background

This report presents a comparison of OPG Nuclear's performance to that of nuclear industry peer groups both in Canada and worldwide. The results of this report are used during business planning to drive top-down target setting with business improvement as the objective.

Performance Indicators

Good performance indicators used for benchmarking are metrics with standard definitions, reliable data sources, and utilization across a representative portion of the industry. Good indicators allow for benchmarking to be repeated year after year in order to track performance and improvement. Additionally, when selecting an appropriate and relevant set of metrics, a balanced approach covering all key areas of the business is essential. In accordance with these criteria, key performance indicators have been selected for comparison to provide a balanced view of performance and for which consistent, comparable data is available. These indicators are listed in Table 6 of Section 7.0 and are divided into four categories aligned with OPG Nuclear's four cornerstones of safety, reliability, value for money, and human performance.

Industry Peer Groups

Peer groups were selected based on performance indicators widely utilized within the nuclear industry. Overall, six different peer groups were used as illustrated in Table 6 of Section 7.0 and panel members are detailed in Tables 7 to 12 of Section 7.0.

Report Structure

Sections 2.0 to 5.0 of the report focus on the four OPG Nuclear cornerstone areas, with detailed comparisons at the plant, and where applicable, unit level.

Section 6.0 of the report provides an operator level summary across a few key metrics. The operator level analysis looks at fleet operators, primarily across North America, utilizing a simple average of the results (mean) from each of their units/plants. Operations related (WANO NPI and UCF) results were averaged at the unit level and cost related (TGC per MWh) results were averaged at the plant level. While the operator level summary can be informative, it is more appropriate to look at OPG's two nuclear facilities individually given that they are at different stages of their lifecycle, have different sized units and reflect different generations of CANDU technology. The detailed data in sections 2.0 to 5.0 of the report provide a more complete picture of plant by plant performance.

Section 7.0 provides an appendix of supporting information, including common acronyms, definitions, panel composition details and a WANO NPI plant level performance summary of OPG nuclear stations against the North American panel.

2.0 SAFETY

Methodology and Sources of Data

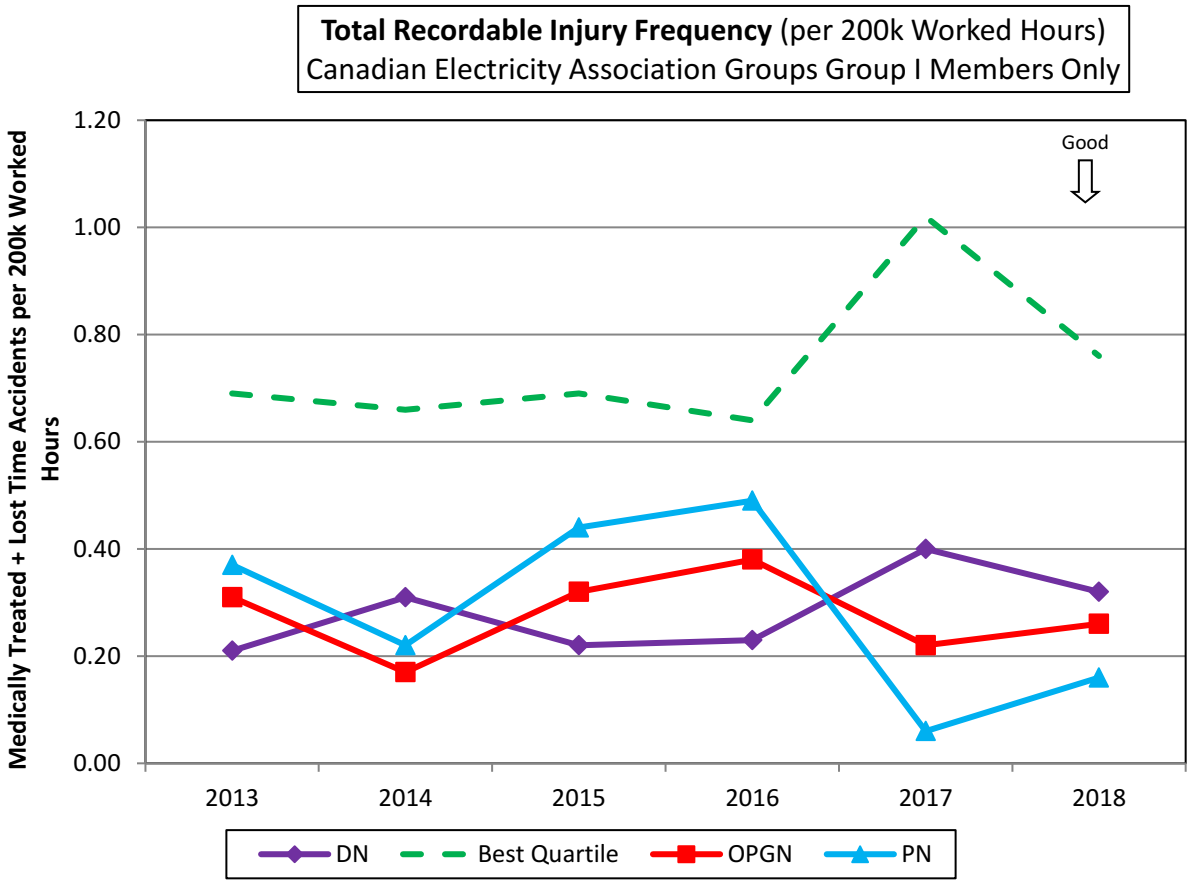
The majority of safety metrics were calculated using data from WANO. Data labelled as invalid by WANO were excluded from all calculations. Indicator values of zero are not plotted or included in calculations except in cases where zero is a valid result. Current data are obtained and consolidated with previous benchmarking data. The Embalse plant has been excluded since it was taken offline since December 31, 2015 for refurbishment.

The Total Recordable Injury Frequency (TRIF) was calculated using data from the Canadian Electricity Association (CEA). Median information and individual company information are not available for this metric. Therefore, only trend and best quartile information have been presented. The peer group for this metric is limited to Group I members of CEA (Section 7.0, Table 10).

Airborne Tritium Emissions per unit data were collected from the CANDU Owners Group (COG) as displayed in the historical trend line chart. The peer group for this metric is all CANDUs who are a member of COG.

Nine metrics are included in this benchmarking report to reflect safety performance, including seven of the ten metrics which comprise the WANO Nuclear Performance Index: Industrial Safety Accident Rate, Collective Radiation Exposure, Fuel Reliability Index, Automatic Reactor Trips, Auxiliary Feedwater Safety System Unavailability, Emergency AC Power Safety System Unavailability, and High Pressure Safety Injection Unavailability. The remaining WANO NPI metrics are included in Section 3.0 under the Reliability cornerstone. In addition to the WANO sub-indicators listed above, the CEA Total Recordable Injury Frequency and the COG Airborne Tritium Emissions per unit are included in this section of the report.

Total Recordable Injury Frequency



Observations – Total Recordable Injury Frequency (TRIF) (Canadian Electricity Association - CEA)

2018 (Annual Value)

- The Total Recordable Injury Frequency (TRIF) (All Injury Rate (AIR) was used in previous benchmarking reports) incorporates all lost time and medically treated injuries incurred by OPG employees working on site.
- Pickering, Darlington, and OPG Nuclear as a fleet all performed better than the CEA top quartile value of 0.76.
- Darlington's TRIF improved performance compared to 2017 from 0.40 to 0.32 in 2018
- Pickering's TRIF has seen an increase from 0.06 in 2017 to 0.16 in 2018.
- OPG benchmarks against CEA Group 1 (a sub-set of all CEA members), which incorporates approximately 11 organizations with more than 1500 employees, including most provincial utilities.
- In 2018, OPG was the top performer of all Group 1 members.

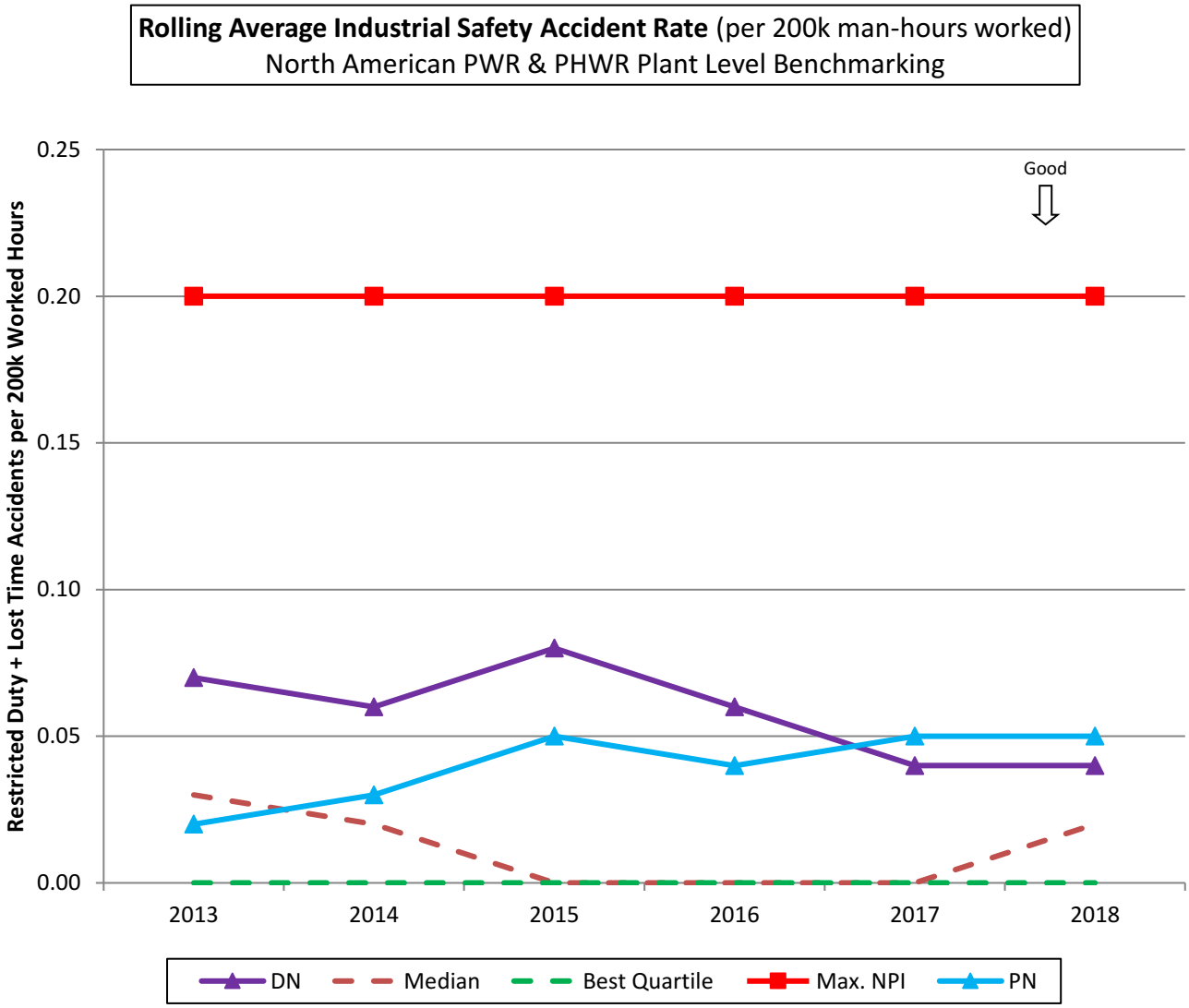
Trend

- While the industry Best Quartile has improved from last year, Darlington, Pickering and OPG Nuclear have consistently performed significantly better than the benchmark value over the past five years.
- Darlington, Pickering and OPG Nuclear TRIF performance has remained relatively stable from 2017 to 2018.
- Darlington Nuclear had a successful WANO evaluation in 2018, resulting in zero areas for improvement in Industrial Safety

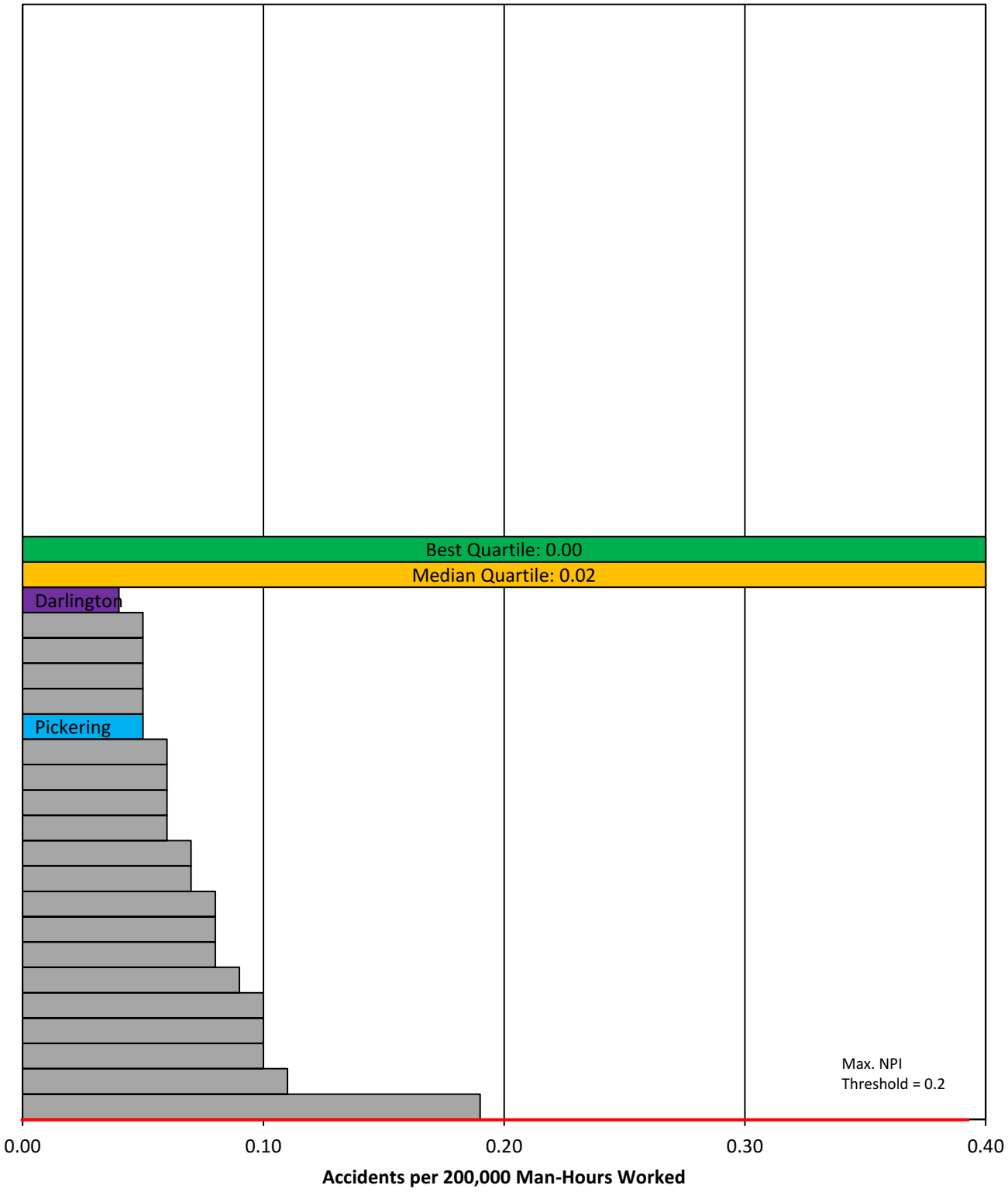
Factors Contributing to Performance

- Conventional Safety performance trends are monitored such that action plans to support continuous improvement can be implemented. These actions plans incorporate Human Performance based objectives, which are aimed at positively improving employee's risk based decision making process.
- OPG encourages a proactive reporting culture that seeks to identify and address hazards before they lead to employee injuries. Proactive reporting is tracked, trended and managed via the Station Condition Record process.
- In 2019, OPG has introduced a leading indicator safety metric called Timely Completion of Safety Corrective Actions (TCSCA). This new metric tracks the corrective actions, arising from safety events, for completion on or before the targeted due date. It aims to encourage positive behaviors and outcomes in our employees and work programs and demonstrates OPG's commitment to prioritize safety related actions.
- To further improve safety performance, OPG is making efforts to move the company beyond a 'compliance-based' mindset to a 'value-based' mindset. Multiple initiatives continue to be underway from 2018 and 2019 which include: 'iCare' branding and tone in training forums, safety communications, and in-field safety observations via an iCare Snapshot program.

Rolling Average Industrial Safety Accident Rate



2018 Rolling Average Industrial Safety Accident Rate (per 200,000 man-hours worked)
North American PWR & PHWR Plant Level Benchmarking



Observations – Rolling Average Industrial Safety Accident Rate (ISAR) (World Association of Nuclear Operators - WANO)

2018 (Rolling 2 Year Average Pickering, Rolling 3 Year Average Darlington)

- The Industrial Safety Accident Rate (ISAR) incorporates all lost time injuries and restricted work injuries incurred by OPG employees working on the site.
- For reporting the ISAR, a 2-year rolling average was used for all panel members with the exception of the Darlington station which follows a 3-year outage cycle. This is consistent with the World Association of Nuclear Operators (WANO) Nuclear Performance Index (NPI) reporting guidelines.
- WANO top quartile in 2018 remained unchanged from 2017 at 0.00 (i.e. zero ISAR events). Median performance was 0.02, which was an increase from 0.00 in 2017.
- Both Pickering and Darlington achieved maximum NPI points for the ISAR in 2018.
- Pickering ISAR performance remains steady from 2017 to 2018 (0.05 to 0.05).
- Darlington ISAR performance remains steady from 2017 to 2018 (0.04 to 0.04).

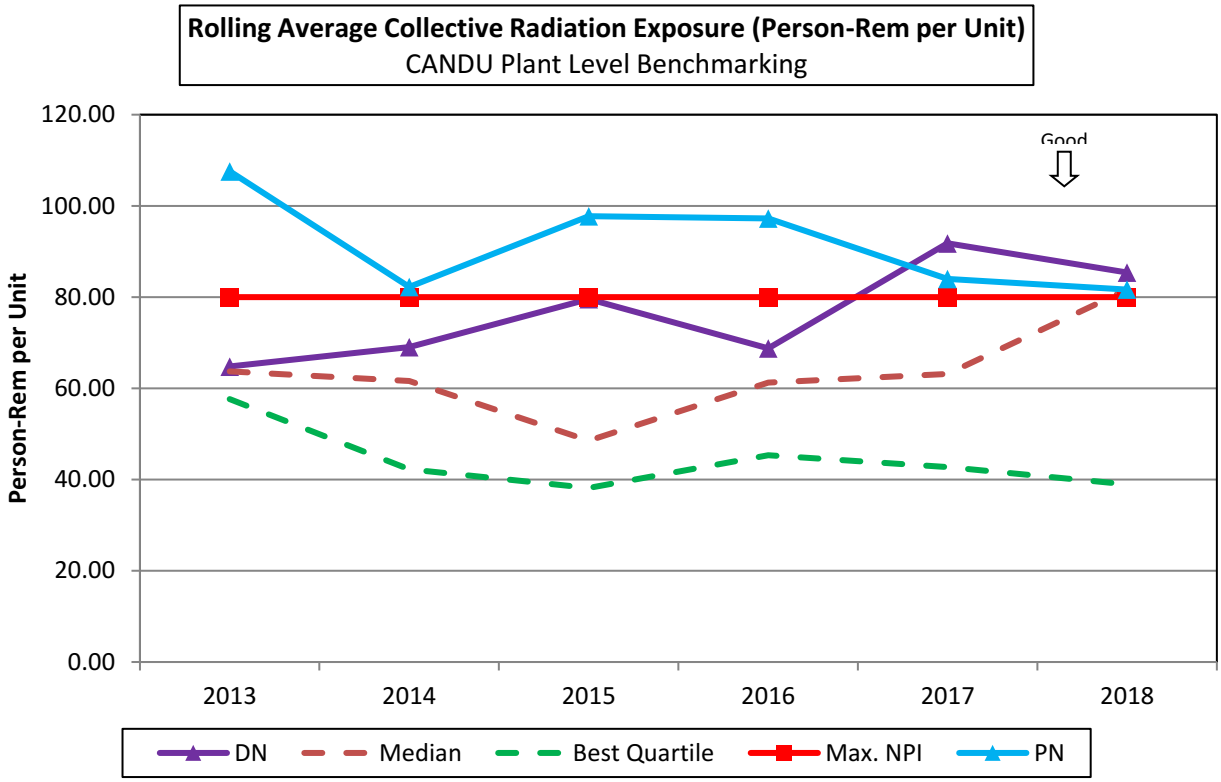
Trend

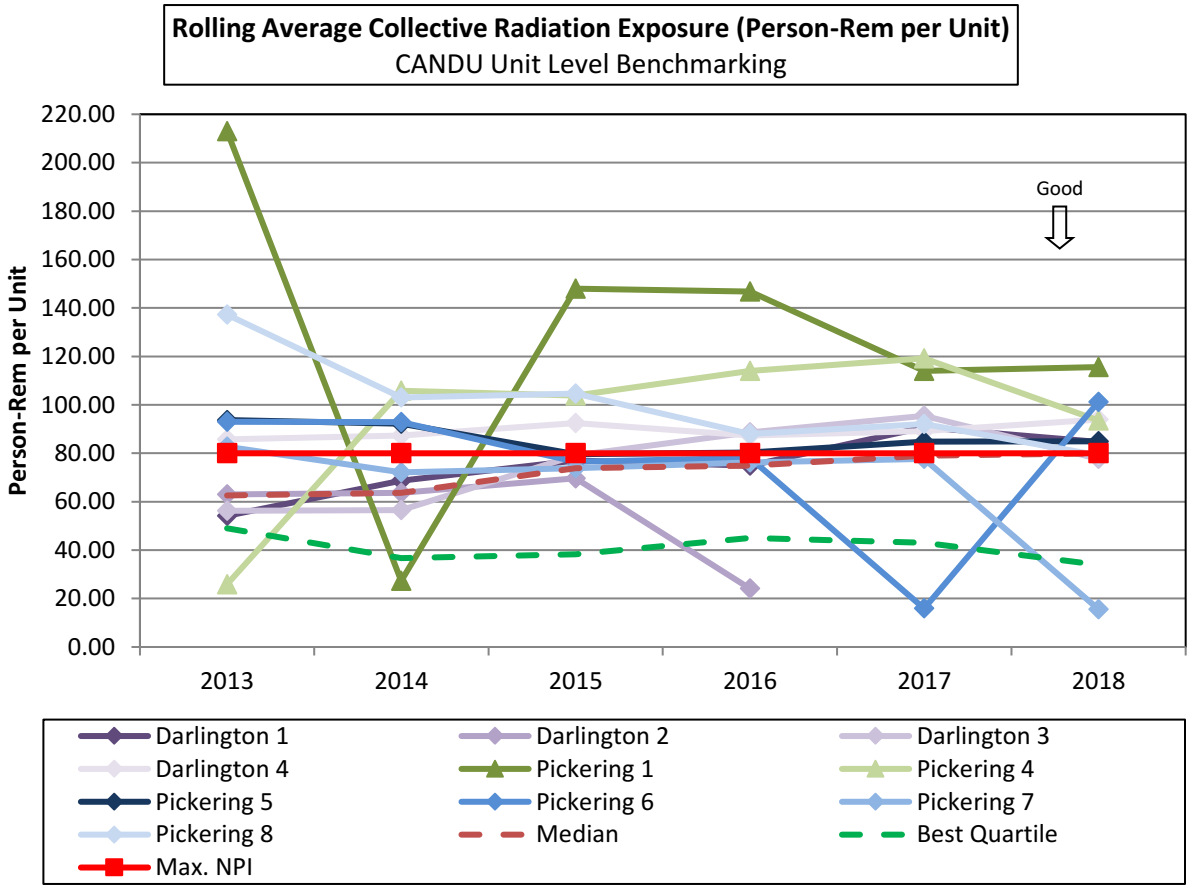
- Darlington's ISAR rolling average has maintained its performance from 2017 of 0.04 and continues to show an overall improved performance over the past five years.
- Pickering's ISAR rolling average has shown a generally stable performance over the past five years.
- The ISAR median has seen a slight increase in 2018 to 0.02 but shows a steady performance over the past five years. The industry best quartile has remained at zero for the past five years.
- While the ISAR median has increased in 2018, Pickering and Darlington ISAR have sustained at the same level

Factors Contributing to Performance

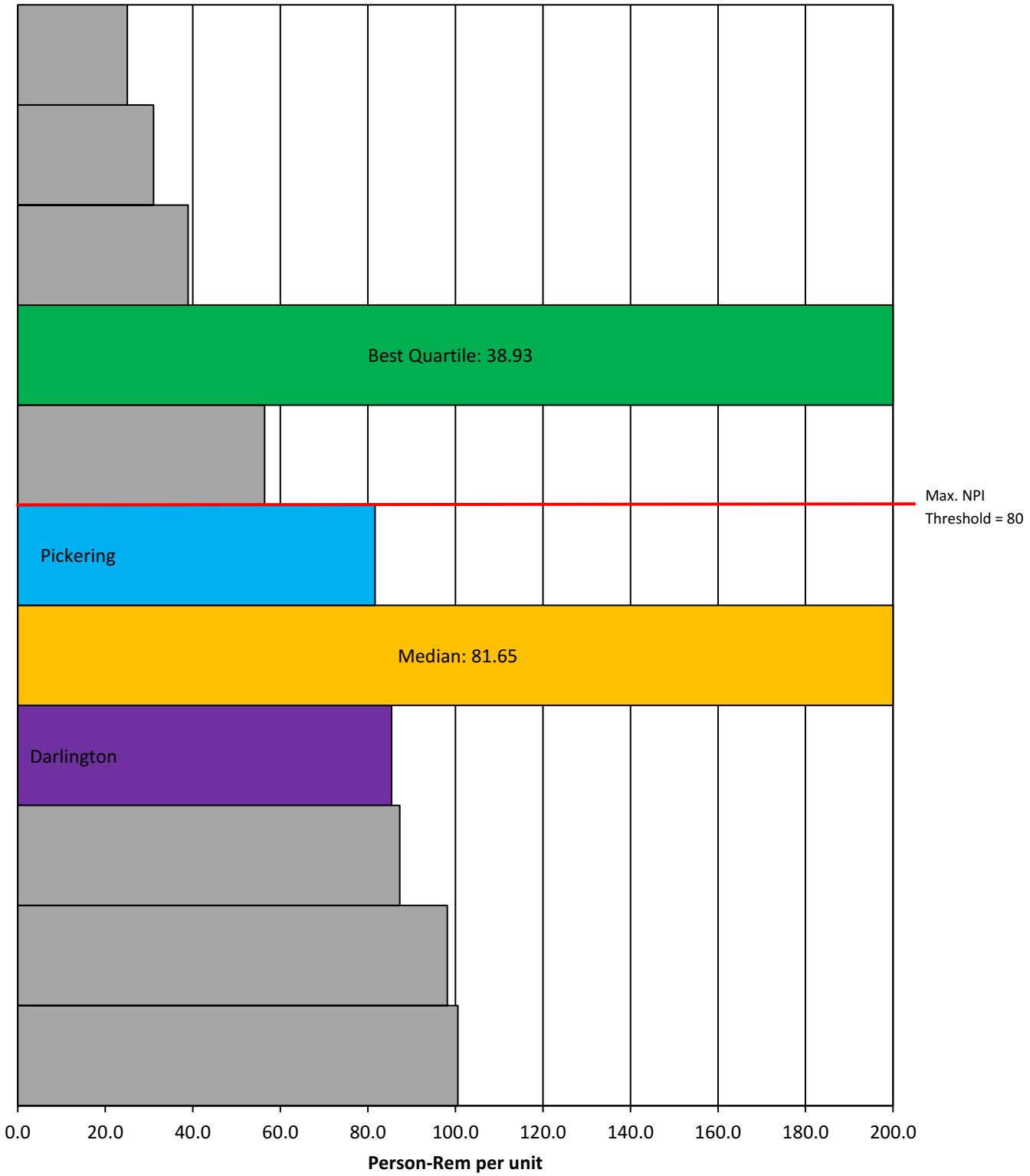
- ISAR is a measure of "permanent utility personnel" and does not include contractors. Many of the utilities in the benchmarking group utilize contractors to a greater extent than OPG Nuclear for higher risk work activities (e.g. outages). This can negatively impact OPG Nuclear's ISAR in comparison to the reported industry benchmark quartile and median.
- OPG Nuclear continues to monitor performance trends in the area of conventional safety and implements timely and specific action plans to support continuous improvement. These actions plans incorporate Human Performance based objectives, which are aimed at positively improving employees risk based decision making process.
- One major continued focus for OPG Nuclear in 2018 and 2019 is to move the company beyond a 'compliance-based' mindset to a 'value-based' mindset. OPG Nuclear is investing efforts to incorporate tactics that trigger personal reasons why everyone must choose to work safely. An 'iCare' branding and tone is being applied in multiple training forums, safety communications, and in safety observations in the field. With the 'iCare' principle, OPG aims to address safety as a value beyond compliance.

Rolling Average Collective Radiation Exposure

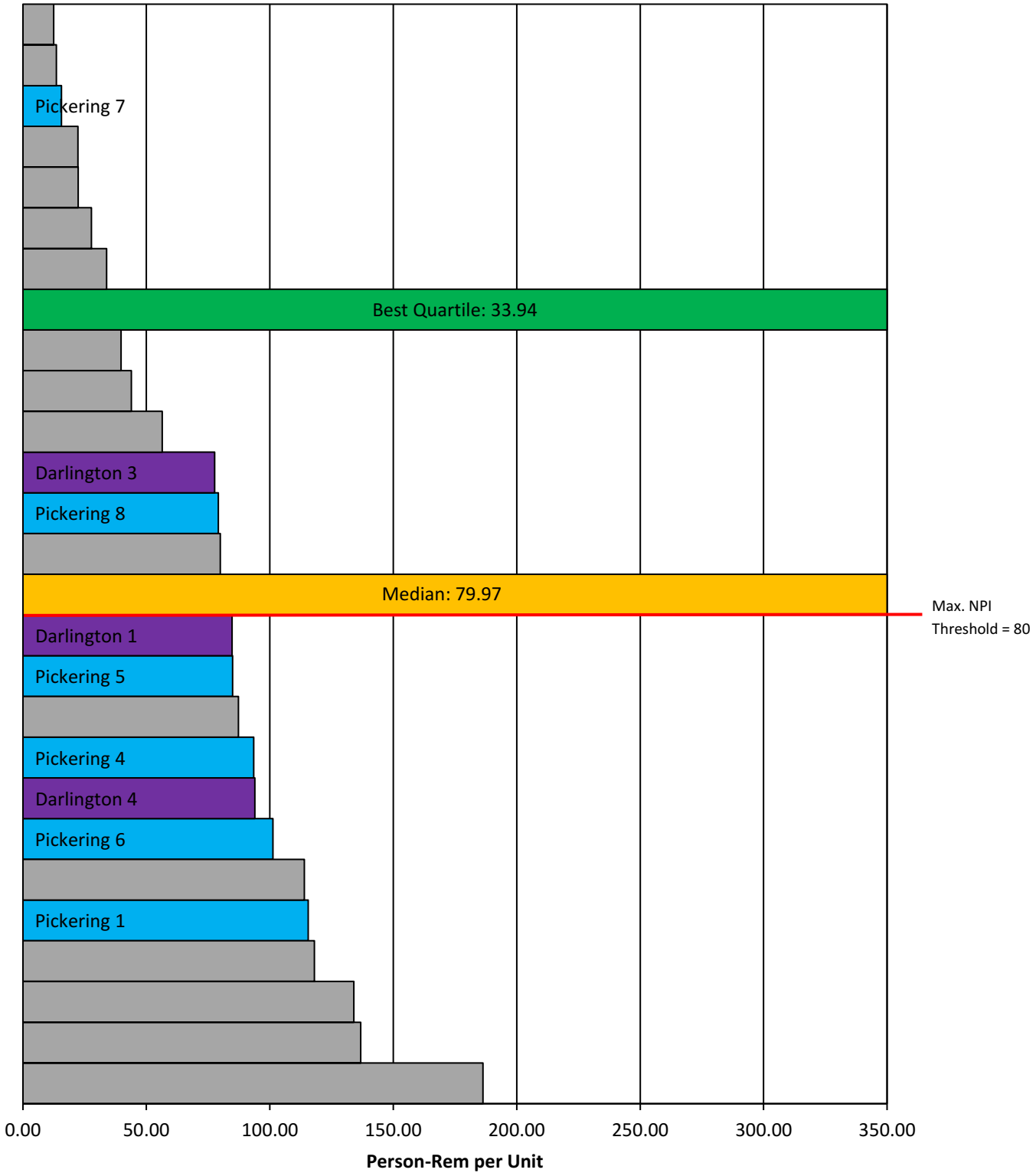




2018 Rolling Average Collective Radiation Exposure (Person-Rem per Unit) CANDU Plant Level Benchmarking



2018 Rolling Average Collective Radiation Exposure (Person-Rem per Unit) CANDU Unit Level Benchmarking



Observations – Rolling Average Collective Radiation Exposure (CANDU)

2018 (Rolling 2 Year Average Pickering, Rolling 3 Year Average Darlington)

- Collective Radiation Exposure (CRE) is an industry composite indicator encompassing external and internal collective whole body radiation dose.
- The planned outage cycles for each unit at Pickering Nuclear Generating Station (PNGS) and Darlington Nuclear Generating Station (DNGS) are two-year and three-year, respectively. Rolling average CRE for each unit at both stations is derived based on these outage cycles.
- The number of planned outages, work scope and as well as outage duration significantly contributed to plant level and unit rolling average CRE performance. Historically, Pickering has 3.0 major planned outages per year; Darlington averages 1.3 outages per year over the three year outage cycle.
- The CRE reflects total work scope performed during the year and it varies year by year. Therefore, the increase in the rolling average CRE may be attributable to larger work scope, not necessarily deficiencies in Radiation Protection program and dose reduction initiatives.
- Darlington Unit 2 began a long-term refurbishment outage on October 15, 2016. Dosage associated with Refurbishment activities has been excluded.
- The best quartile for CANDU Units in 2018 was lower than 2017, while the median value was higher than in 2017. The best quartile and median values (person-rem/unit) in 2018 vs. 2017 were 38.93 vs. 42.77 and 81.65 vs. 63.16, respectively. The benchmark value was 80 person-rem/unit. Full NPI Points were obtained at 80 person-rem/unit or less; no points were earned at 140 person-rem/unit or more.
- At the plant level, PNGS dose performance was 81.65 person-rem/unit which met the CANDU plant-level median value of 81.65 person-rem/unit.
- At the unit-level, PNGS dose performance value of 15.59 person-rem/unit for Unit 7 and of 79.14 person-rem/unit for Unit 8 were better than the maximum NPI points of 80.0 person-rem/unit, as well as the median value of 79.97 person-rem/unit. Unit 7 dose performance was also better than the best quartile value of 33.94. The performance of other four units were above the maximum NPI point value and the median value.
- In 2018 at PNGS, there were three planned outages (Unit 4, 6, 8), five forced outages (Unit 4, 6 and three on Unit 8) and two sudden outages. In addition, Unit 1 planned outage was completed January 3, 2018.
- At the plant level, DNGS dose performance was 85.43 person-rem/unit which was above the CANDU plant-level median value of 81.65 person-rem/unit.
- At the unit-level, DNGS dose performance value of 84.70 person-rem/unit for Unit 1, and of 93.93 person-rem/unit for Unit 4 was above the maximum NPI points of 80.0 person-rem/unit, as well as the median value of 79.97 person-rem/unit. Unit 3 dose performance value of 77.65 person-rem/unit was better than the maximum NPI and the median values.
- In 2018 at DNGS, there were 2 planned outages (Unit 3 and Unit 4).

Trend

- Overall, Pickering plant-level performance has improved since 2013, approaching toward the maximum NPI value of 80 person-rem/unit. The rolling average is impacted by scope increases during outages and longer outage duration.
- Pickering unit-level performance improved from 2017 in Units 4, 7, and 8. Units 7 and 8 were better than the median value of 79.97 person-rem/unit. While Unit 4 performance improved significantly from 2017, Units 1, 4, 5, and 6 were above the median value of 79.97 person-rem/unit.
- Overall, the Darlington plant-level collective dose is above the median value since 2017, due to plant aging, increased outage scope and duration and to accommodate a single fuel channel replacement. Plant-level collective dose has decreased from 2017 and is approaching median values in 2018.
- Darlington unit-level performance has improved compared to last year, particularly Unit 3. In 2017, Unit 1, 3, and 4 were above the median value of 79.02 person-rem/unit. In 2018, the collective dose for all Darlington 3 units have decreased and Unit 3 was below the 2018 median value of 79.97 person-rem/unit.

Factors Contributing to Performance Rolling Average Collective Radiation Exposure (CANDU)

- The following factors play a significant role in the CANDU reactors' CRE performance: planned outage scope and outage duration, tritiated ambient air in accessible and access controlled areas, effectiveness of mitigation measures and initiatives being implemented to reduce identified sources of radiological hazards, and human performance during execution of radiological tasks.
- The following list represents common practices that demonstrate continuous improvement and help maintain good CRE performance for CANDU type reactors:
    - Robust Site As Low as Reasonably Achievable (ALARA) Committee, chaired by Facility Senior Vice President.
    - Reactor face shielding to reduce dose rates.
    - Use of custom vault platforms to improve workflow.
    - Teledosimetry.
    - Process fluid detritiation.
    - Use of Munters driers to enhance existing measures to minimize ambient airborne tritium levels.
    - Optimization of Fuelling Machine purification using Ion Exchange with annual resin replacement and/or sub-micron filters.
    - Sub-micron filtration in the Primary Heat Transport system.
    - Use of independent radiological oversight for higher risk work to improve human performance during execution of radiological tasks.
    - Daily accounting of dose, and work group focus on Radiation Protection Fundamentals.

- OPG establishes internal administrative dose limits to ensure that dose to each exposed individual is managed and maintained well below individual regulatory limits.
- Implementation of Dose Goal Reporting and Monitoring where individuals take ownership of their dose and strive to maintain ALARA exposure.
- OPG Nuclear fleet-wide and site specific initiatives have been implemented to incorporate the industry best practices noted above.
- Specific key initiatives are described below.

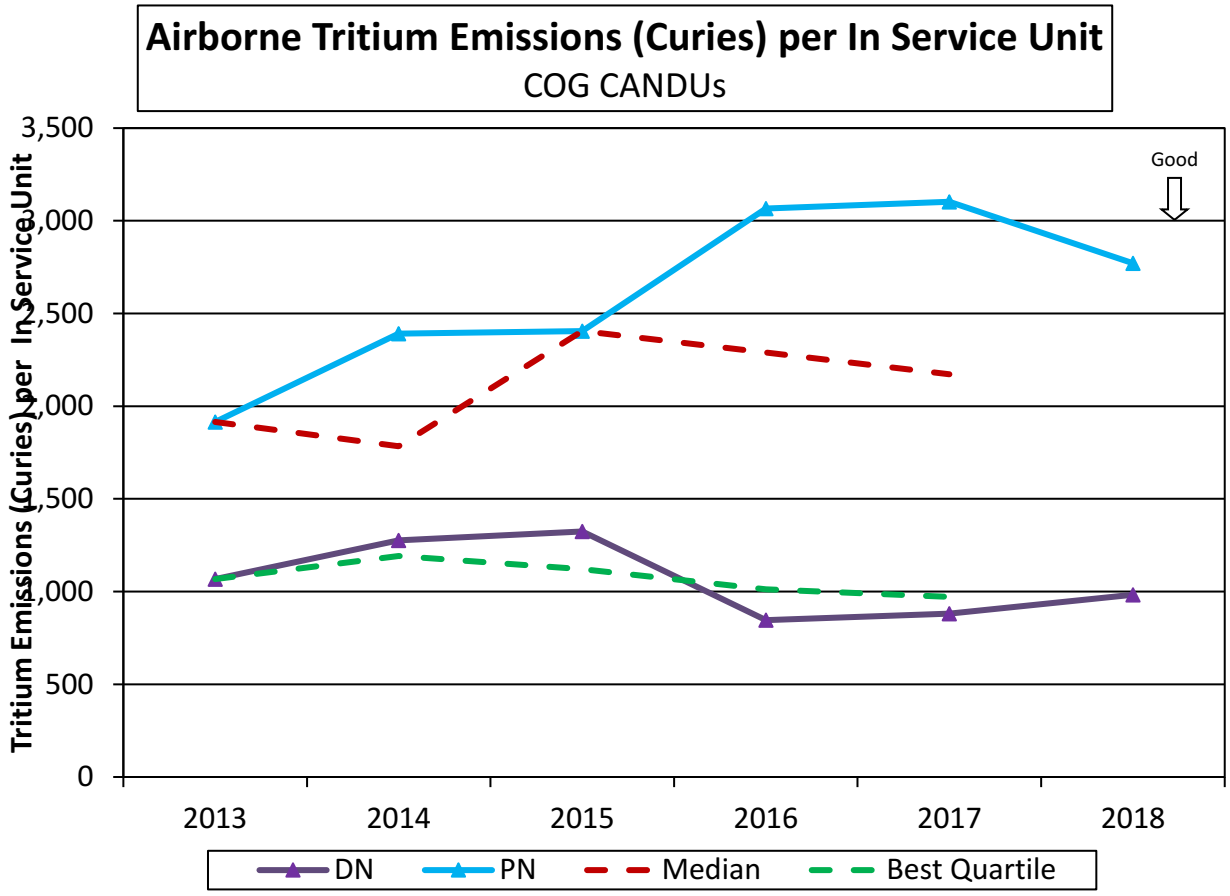
Pickering

- Implementation of Lanxess Dose Reducing Resin in Units 1 and 4, contributing to a 20% reduction in reactor face dose rates.
- Leveraging technology to avert dose using robotic equipment and remote monitoring of systems
- Deployment of CZT (Cadmium Zinc Telluride) Gamma Cameras and Gamma Spectrometers for enhanced source term monitoring.
- Source term reduction, including improvements to process fluid filtration and detritiation.
- Source term mitigation, including optimization of shielding for reactor face work, improvements to the shielding canopy for reactor face work, and dryer system health management for improved performance and reliability.
- Human performance involvement and oversight by Radiation Protection (RP) staff in respect of work with elevated radiation risk.
- Focus on dose to the individual through implementation of daily dose goals.
- Improving RP worker practices by driving individual accountability.
- Work Group specific dose reduction plans are being developed and implemented.
- Use of Dynamic Learning Activities for focused program areas to permit mentoring of ‘what excellence looks like’ in realistic work environments with simulated radiological conditions.
- Implementation of an extensive network of remote reading radiation instrumentation and other tools to provide real-time information on radiological conditions and minimize time and therefore dose in radioactive work areas.
- Use of portable gamma spectrometers to improve source term characterization.

Darlington

- Implementation of specialized magnetic shielding on Emergency Coolant Injection piping to effectively reduce hazard levels from hot spots.
- Development of performance guidelines for radiation protection oversight in order to prevent, escalate, or intervene when safety trends begin to decline.
- Optimization of breathing air management strategy with identification and tracking of defective units and use of short air hoses at breathing air headers to reduce the number of times workers need to connect and disconnect from the manifold, which causes excessive wear.
- Implementation of dose reducing resin in PHT Ion Exchange Columns to reduce dose rates due its higher retention of significant radionuclides.
- Planned contingency steps to manage jobs which involve a potential risk of wetting by tritiated heavy water.
- Initiated improvements in pre-job briefings to include discussion of expected dose (dose goals) that may be accumulated based on thorough understanding of work scope and hazard levels.
- Employed high definitions cameras to accurately identify leaking closure plugs during unit outages to minimize airborne tritium in the vault atmosphere.
- Developed and implemented a reactor face shielding strategy to reduce dose while at the same time minimize the risks of personnel injury during shielding installation.
- Implemented an improved feeder ice jacket including the application of long handled tools for jacket installation and remote data acquisition.
- Effectively utilized Teledosimetry to reduce Radiation Protection Coordinator dose. Utilized Teledosimetry as a coaching tool to improve worker radiation protection practices and reduce dose.
- Tritium mitigation strategies have been developed and implemented to reduce airborne tritium concentrations inside containment and confinement rooms.
- Developed and implemented X-ray Fluorescence (XRF) spectroscopy to identify cobalt residues in an effort to reduce cobalt deposits in the moderator system during valve overhaul activities thus reducing overall radiation dose.
- Work Group specific dose reduction initiatives have been developed and implemented.

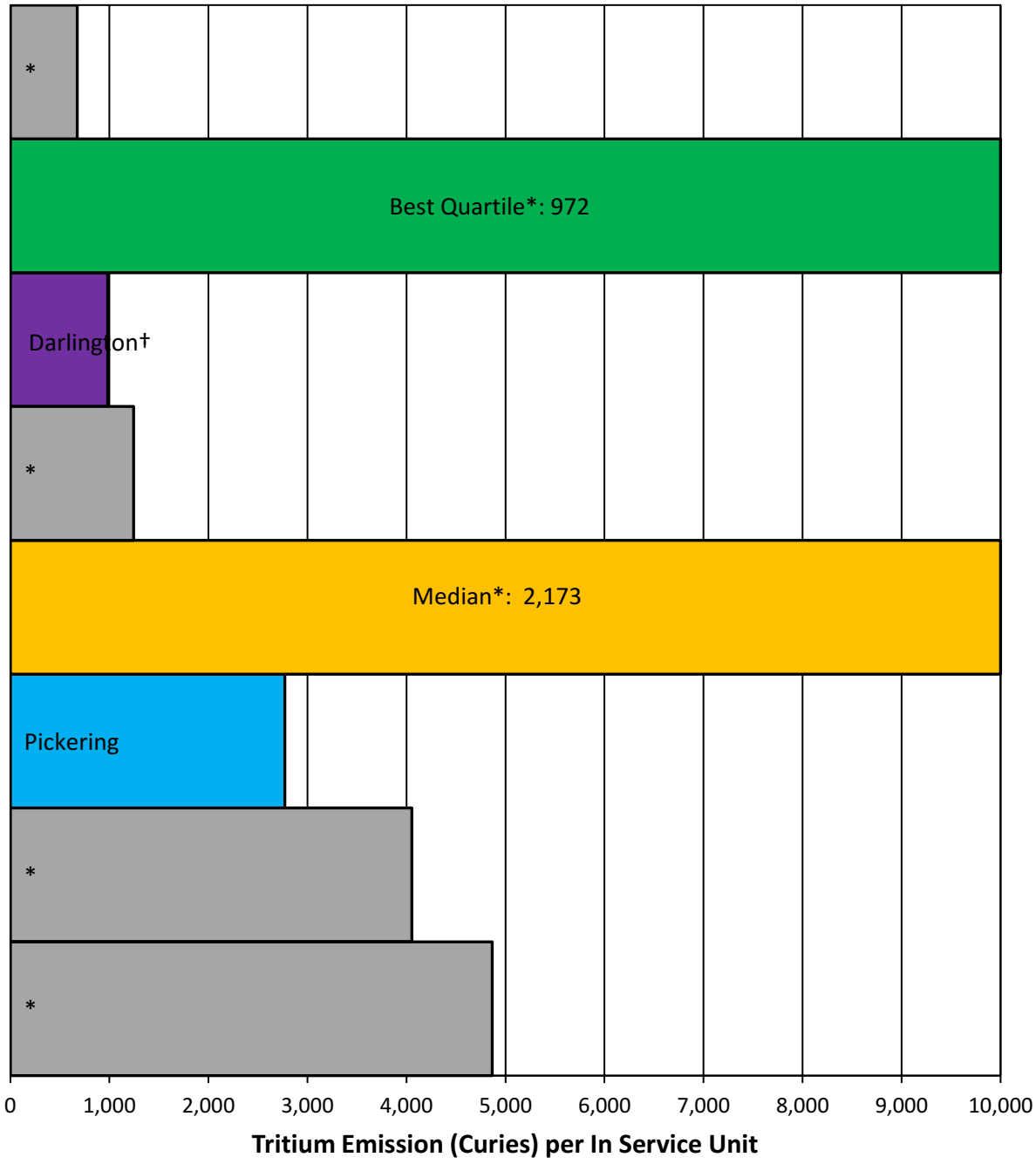
Airborne Tritium Emissions per In Service Unit



Notes:

- Median and Best Quartiles are plotted till 2017 as the 2018 results were unavailable at the time of benchmarking.
- Darlington values exclude Tritium Removal Facilities emissions consistent with COG benchmarking results.

2018 Airborne Tritium Emissions (Curies) per In Service Unit
COG CANDUs



* Industry data based on 2017 as it is the best available information at the time. Pickering and Darlington results are 2018.
†Excludes emissions from Tritium Removal Facility.
Notes:

- Two plants are excluded as one plant's 2017 data is unavailable and another plant was taken offline since December 31, 2015 for refurbishment.

Observations – Airborne Tritium Emissions (Curies) per In Service Unit

2018 (Annual Value)

- The 2017 industry results collected by the CANDU Owners Group (COG) are included in this report as the most up-to-date figures available for benchmarking performance. As of 2013, tritium emissions from the Tritium Removal Facility (TRF) are no longer included in COG benchmarking results for Darlington.
- Airborne tritium emissions from OPG facilities for 2018 are compared per in service reactor unit. As such, emissions from Darlington Unit 2 are not included in this benchmarking report due to the shutdown of Unit 2 in October 2016 for refurbishment.
- Curies per in service unit at best quartile CANDU plants was 972 or lower.
- Darlington performed at 982 curies per in service unit which is slightly above the best quartile threshold of 972 curies per in service unit, placing it in the median quartile of the in service units.
- Pickering's performance remained in the third quartile in 2018 with 2,772 curies per in service unit, higher than the industry median threshold of 2,173 curies per in service unit.

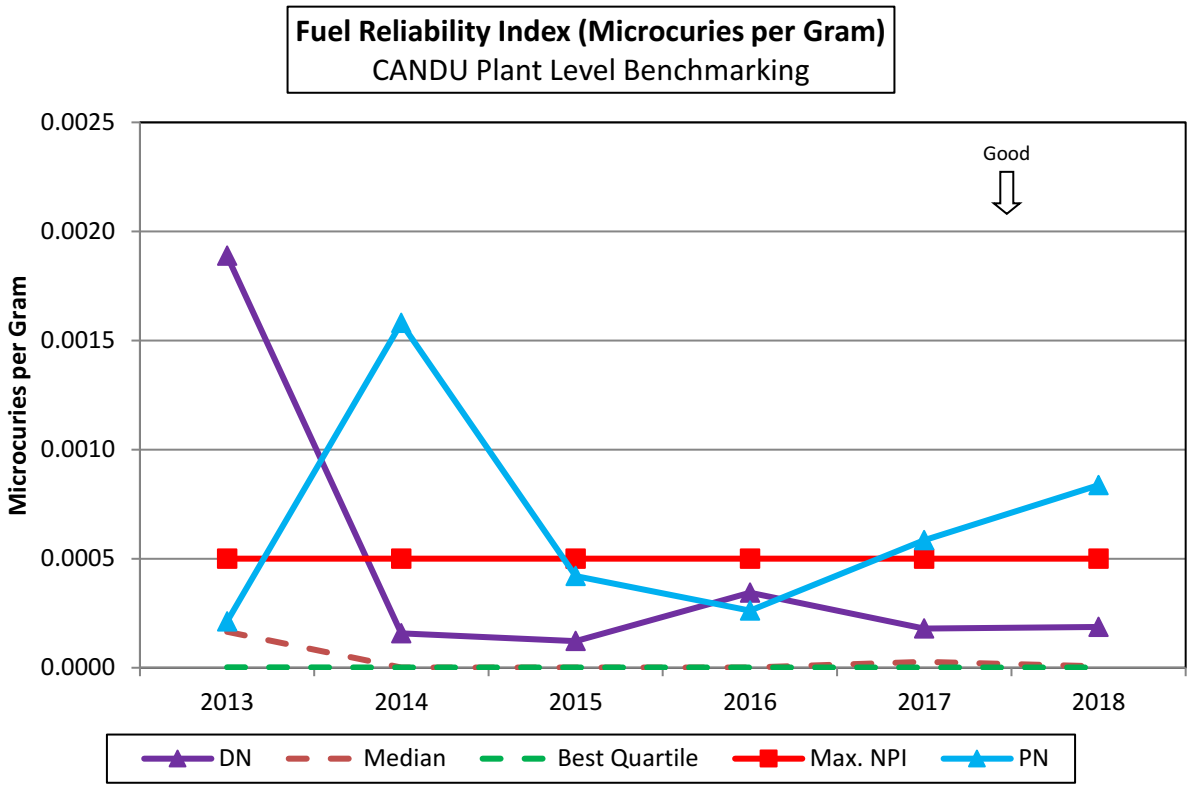
Trend

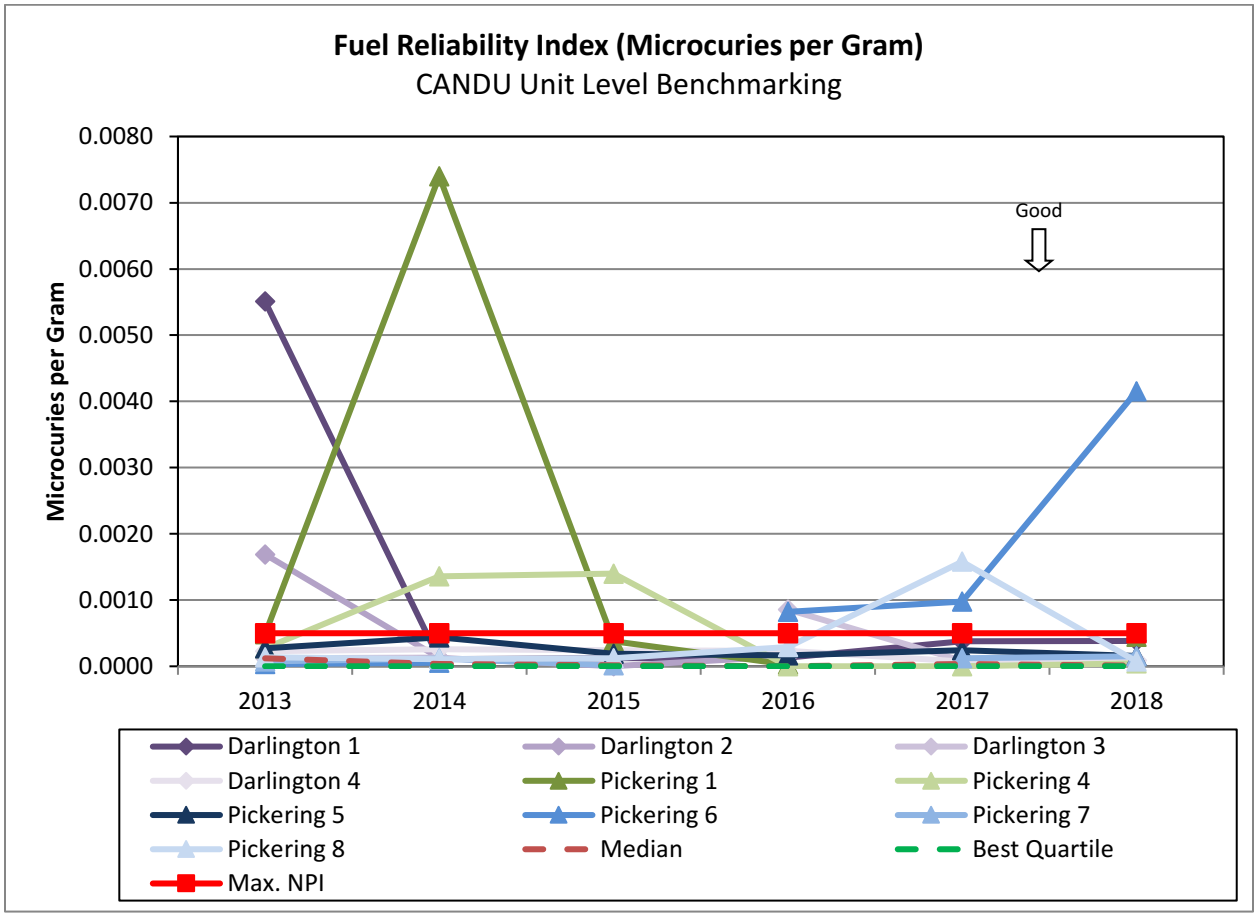
- Darlington and Pickering tritium emissions to air continue to be less than one per cent of the regulatory limits.
- Performance at Pickering improved in 2018, mainly due to effort by the High Impact Team (HIT) to drive tritium reduction activities. Increased emissions in 2016 and 2017 were primarily due to tritiated water in the Fuel Transfer Conveyor Tunnel being vented to monitored stacks, leaks and dryer performance issues.
- Performance at Darlington in 2018 is slightly higher than that in 2017, mainly due to dryer performance issues in Unit 3.
- The industry trend line graph shows that industry best quartile performance has been decreasing since 2014.

Factors Contributing to Performance

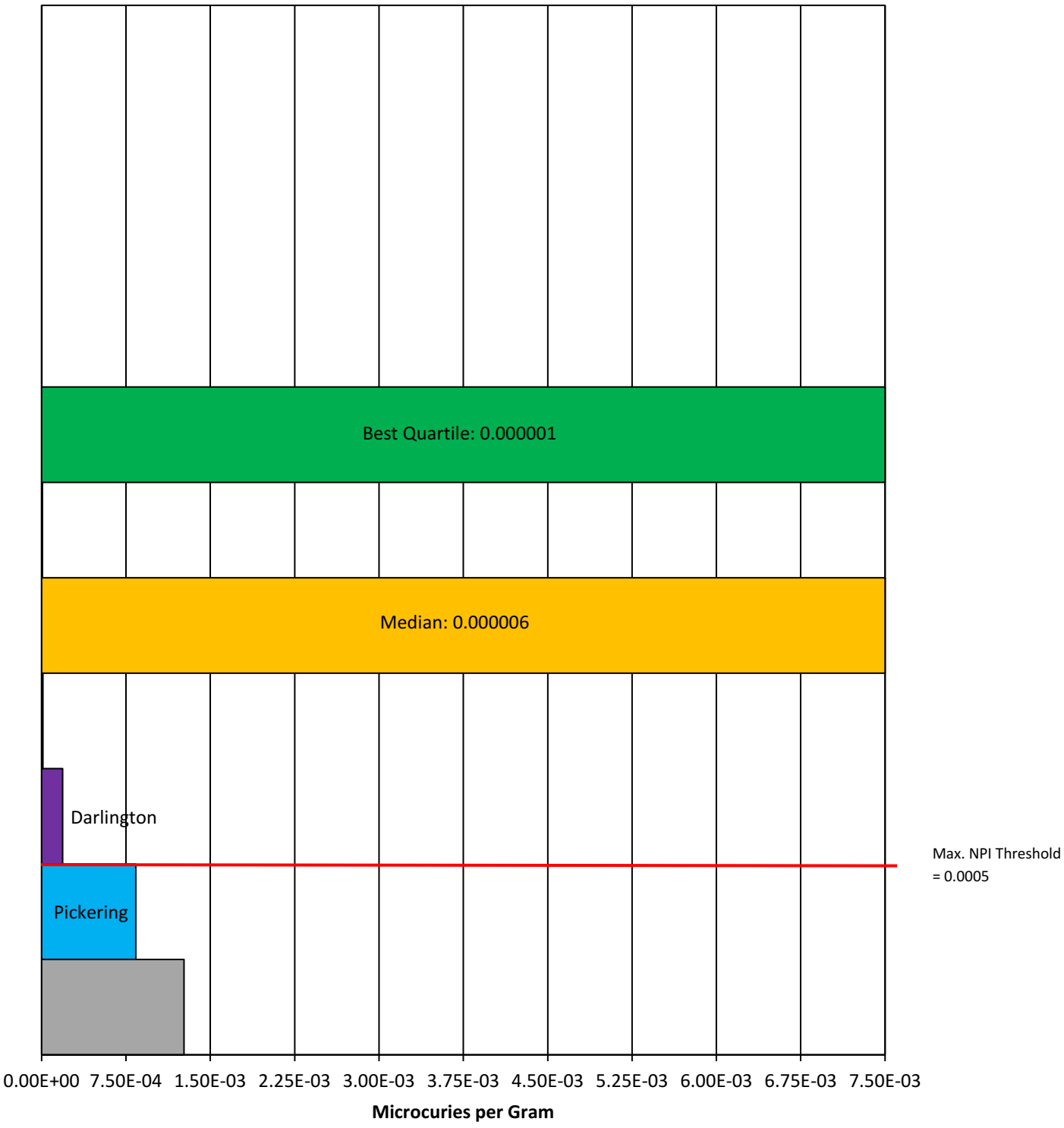
- Key factors affecting performance at Darlington and Pickering include the following:
    - Leaks from various equipment or systems,
    - Declining vapour recovery dryer performance,
    - Increased unit source term (e.g., higher moderator tritium concentrations),
    - Station focus on tritium emission reduction initiatives include dedicated teams to ensure daily emissions monitoring, sustaining and improving dryer performance, heavy water leak minimization, tritium program development and innovations
    - Other improvement initiatives include OPG's ongoing participation in COG environmental benchmarking of participating CANDU stations to determine best environmental practices.

Fuel Reliability Index





2018 Fuel Reliability Index (Microcuries per Gram)
CANDU Plant Level Benchmarking



Observations – Fuel Reliability Index (CANDU - FRI)

2018 (Most Recent Operating Quarter)

- The best quartile and median values for Fuel Reliability Index (FRI) performance for CANDU plants were 0.000001 µCi/g and the median value was 0.000006 µCi/g.
- The average Pickering plant level FRI performance at 0.000837 µCi/g in 2018 and was worse than the CANDU plant median.
- The average Darlington plant level FRI performance at 0.000187 µCi/g in 2018 was worse than the CANDU plant median.
- Post-discharge fuel inspections for Pickering indicated that the overall condition of fuel inspected was acceptable and consistent with previous years. Fuel inspections for Pickering confirmed two fuel defects in 2018. No fuel issues of significance arose at Pickering in 2018.
- Post-discharge fuel inspections for Darlington indicated that the overall condition of fuel inspected was acceptable and consistent with previous years. Fuel inspections for Darlington confirmed one fuel defect occurred in 2018. No fuel issues of significance arose at Darlington in 2018.

Trend

- The best quartile for CANDU plants remained relatively consistent at 0.000001 from 2014. The median values for CANDU plants has generally improved from 2013 and remains quite low at 0.000006 in 2018.
- The Pickering station FRI performance has generally declined since 2013 with an exception of an improved performance from 2014 to 2016.
- The Darlington station FRI performance has generally improved since 2013. FRI performance is due to the low incident rate for fuel defects in recent years.

Factors Contributing to Performance

Two defects were confirmed at the Pickering station in 2018. A team was formed to investigate the fuel defects incidents and the cause was found to be primarily due to debris fretting.

The steps being taken to improve FRI performance and prevent the potential of fuel defects are the following:

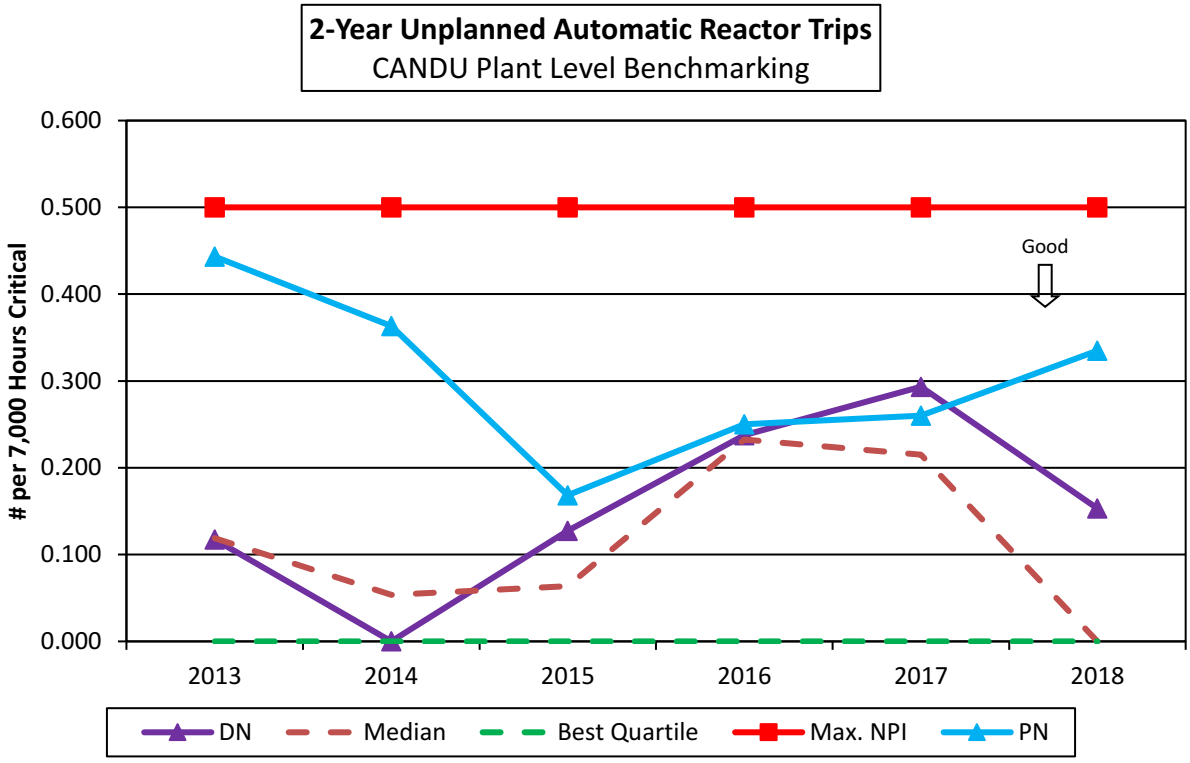
- Improving the methods of surveillance and elimination of the possibility of foreign materials entrance into the Heat Transport System (HTS) due to Fuel Handling and Outage practices,
- Developing a fuel defect guideline for Pickering,
- Increasing scope of HTS grab sampling and analysis,
- Assessing and comparing Units 1, 4 and 5 to 8 power ramps,
- Assessing impact of adjuster burn-out during operation,
- Assessing impact of pressure tube creep on fuel performance,
- Fuel bundle manufacturing assessment,

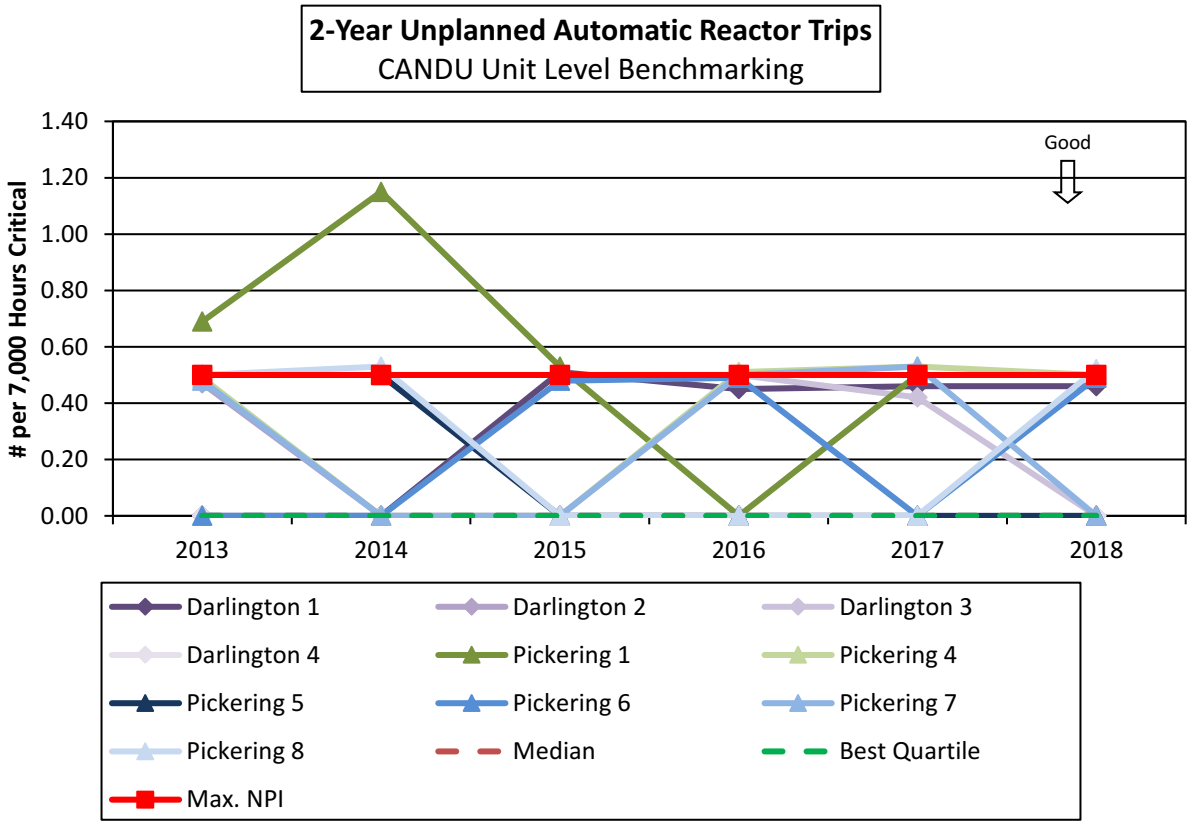
- 3rd party examinations of unirradiated Pickering fuel bundles,
- Irradiated fuel inspections and examinations,
- Improving capability of detecting the defected fuel bundles during the discharge from the fuelling machines, and
- Improving the capability of the in-bay inspection of the suspected fuel bundles to be defected.

Darlington had only one suspect fuel defect in 2018. The steps being taken to improve FRI performance and prevent the potential of fuel defects are the following:

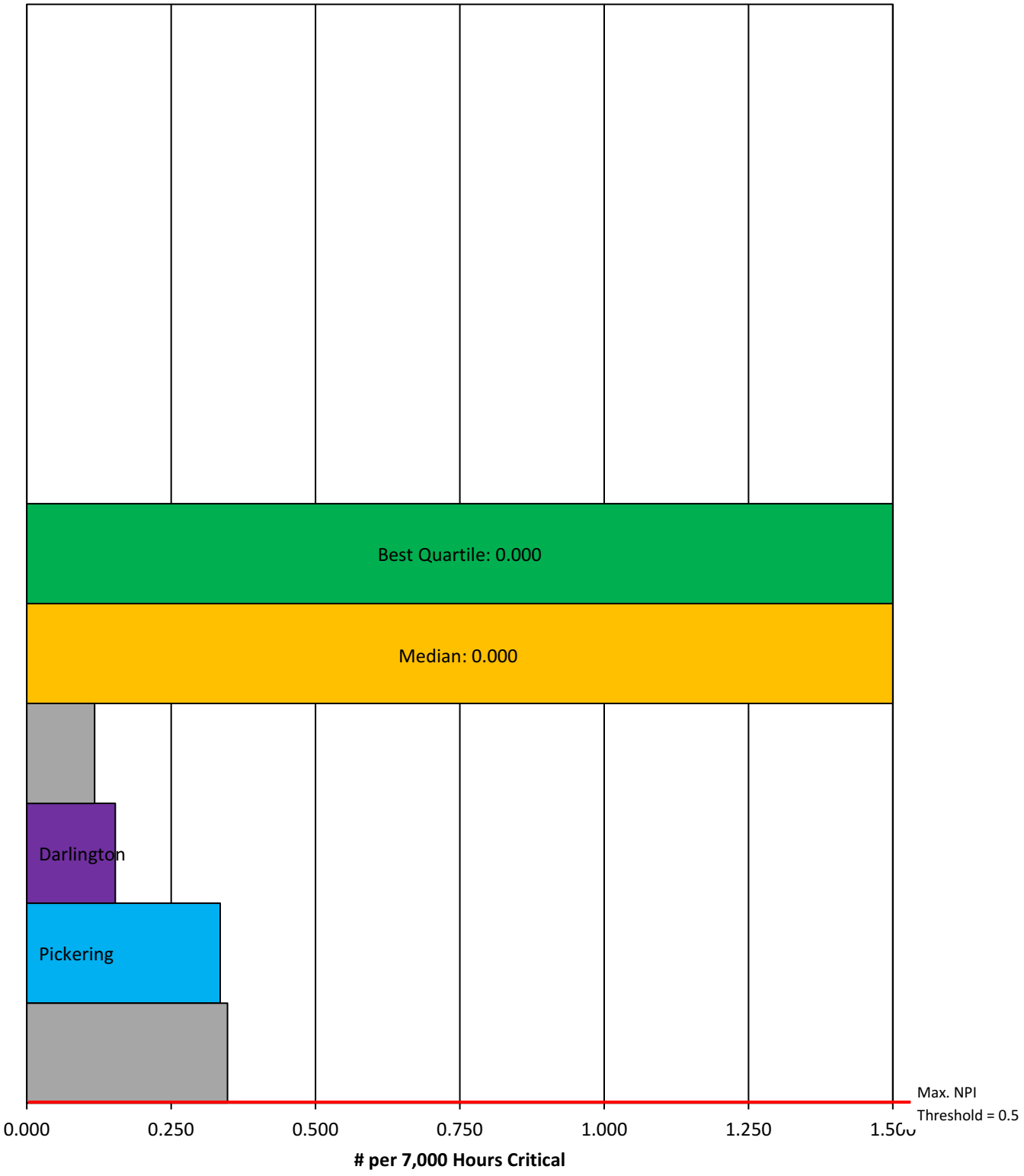
- New fuel with tighter tolerances for mass was received and is currently being used,
- Installed a new fuel inspection facility and completed inspections in East Fuelling Facility Auxiliary Area; confirmed defects in all suspect bundles and all fuel defects originated from one batch of 2786 bundles,
- OPG-supplier co-operation resulted in installation of an automatic loader of fuel pellets complete with a “go/no go” pellet diameter monitor,
- Close monitoring of existing fuel bundle inventory and core load, and
- Projects in progress on Gaseous Fission Products (GFP) and feeder scanners to improve ability to locate defects on power and during outages.

2-Year Unplanned Automatic Reactor Trips

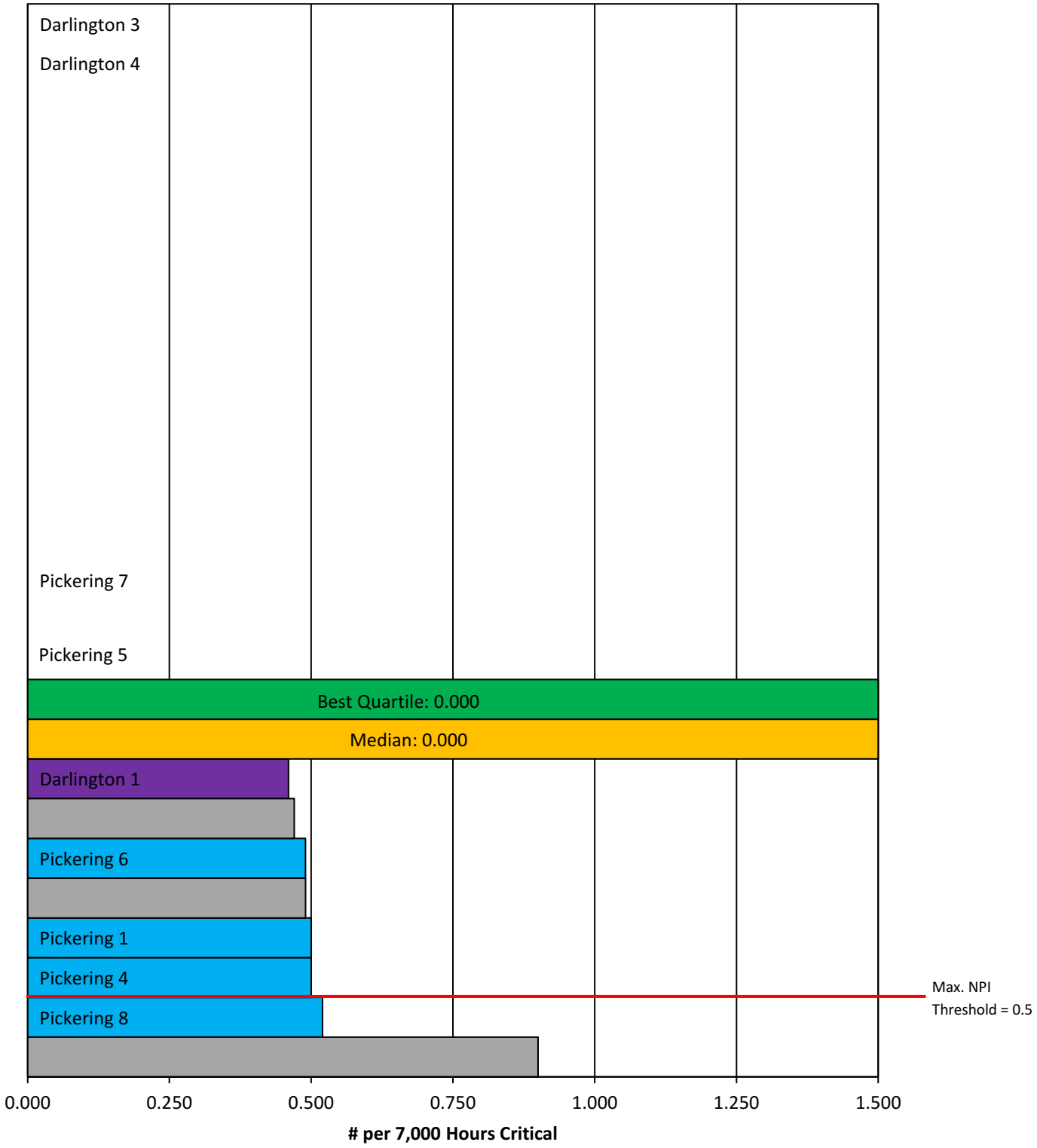




2018 2-Year Unplanned Automatic Reactor Trips
CANDU Plant Level Benchmarking



2018 2-Year Unplanned Automatic Reactor Trips
CANDU Unit Level Benchmarking



Observations – 2-Year Unplanned Automatic Reactor Trips (CANDU)

2018 (2-Year Rolling Average)

- The 2-year rolling average unplanned automatic reactor trip best quartile for CANDU plants was zero with a median of 0.00. For individual CANDU units, the best quartile and median values for unplanned reactor trip were zero.
- At the plant level, Pickering's trip rate of 0.34 was better than the maximum NPI threshold value of 0.50. On an individual unit basis, Units 5 and 7 with trip rate of zero, were at best quartile. Units 1 and 4 with the rate of 0.50, Unit 6 with the trip rate of 0.49 and Unit 8 with trip rate of 0.52, were worse than the third quartile threshold of 0.47 and better than the maximum value of 0.90.
- At the plant level Darlington's trip rate of 0.15 was below the maximum NPI threshold value of 0.50. On an individual unit basis, Unit 3 and Unit 4, with a trip rate of zero, performed at the best quartile level. Unit 1 with a trip rate of 0.46, slightly better than the third quartile threshold of 0.47, is much better than the maximum value of 0.90. Unit 2 performance is excluded due to refurbishment.

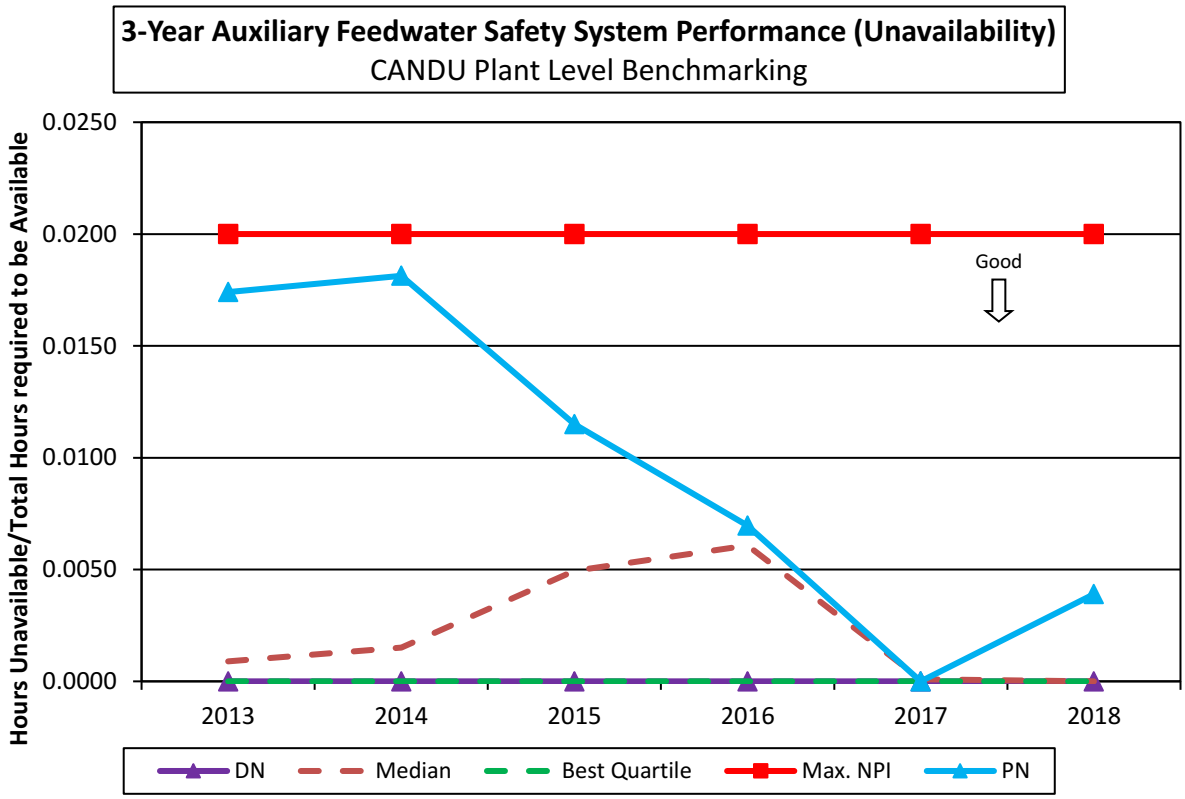
Trend

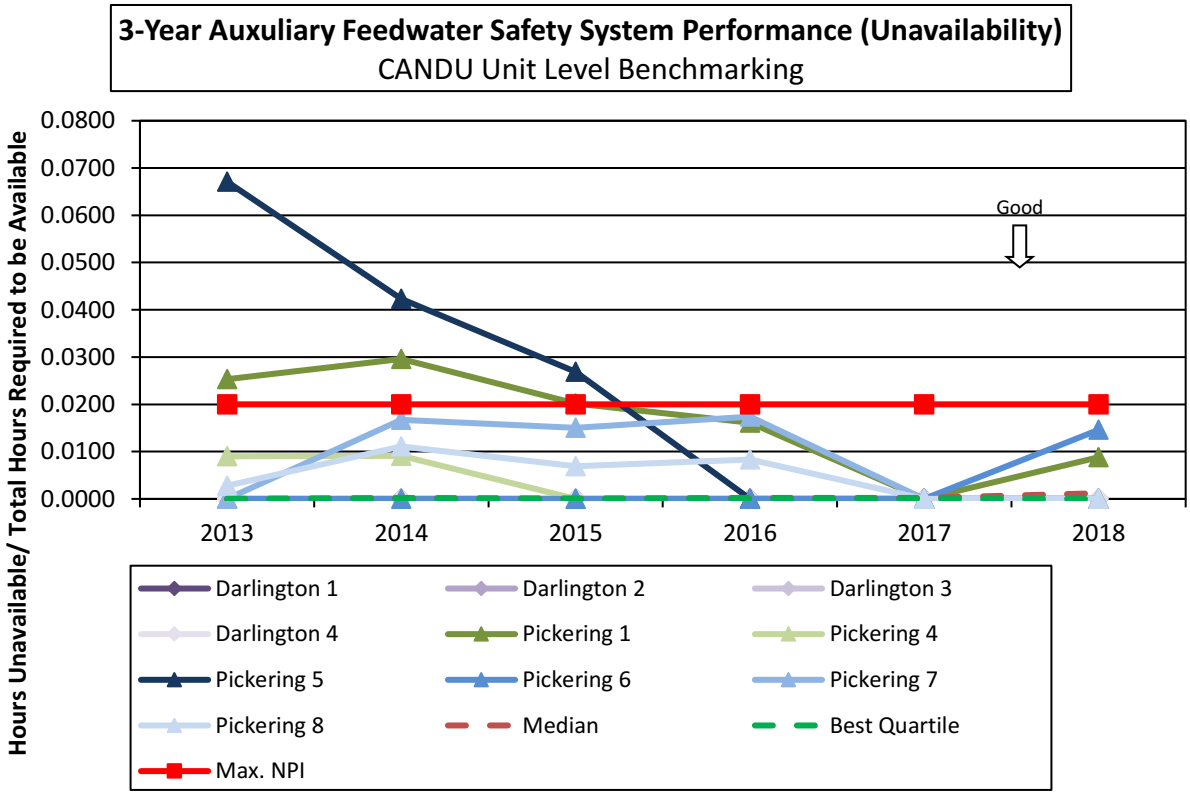
- The unplanned automatic reactor trip best quartile for CANDU plants has been zero since 2013. The median value improved in 2014 from 2013, then slightly declined in 2015, and further deteriorated in 2016 and 2017. The median value in 2018 was zero. On an individual unit basis, the industry best quartile and median has remained at zero since 2013.
- At the plant level, Pickering station performance improved each year from 2013 to 2015, but declined each year from 2016 to 2018. On an individual unit basis, Unit 1 performance declined from 2013 to 2014 and improved in 2015. After reaching a zero trip rate in 2016, performance declined in 2017 and 2018. Unit 4 performance has significantly improved from 2013 and achieved the best results in 2014 and 2015 with a zero trip rate, but decreased in 2016, 2017, and 2018. Unit 5 performance has been trending better since 2015, achieving a zero trip rate from 2015 to 2018. Unit 6 has performed at a zero trip rate in 2013 and 2014, but performance declined in 2015 and 2016. It reached a zero trip rate in 2017 again, but declined in 2018. Unit 7 performance improved from 2013, achieved the best performance in 2014 and 2015 with a zero trip rate, decreased in 2016 and 2017, but improved again in 2018 with a zero trip rate. Unit 8 performance decreased in 2014 from 2013, the best performance with a zero trip rate was achieved in 2015, 2016, and 2017, but declined in 2018 again.
- At the plant level, Darlington station performance improved from 2013, achieving the best result of a zero trip rate in 2014, but decreased each year from 2015 to 2017 and improved again in 2018. On an individual unit basis, Unit 1 has performed at a zero trip rate in 2013 and 2014, but the performance declined in 2015, improved in 2016, and slightly declined in 2017 and 2018. Unit 2 performance significantly improved in 2014, 2015, and 2016 to a zero trip rate compared to 2013 (performance of Unit 2 in 2017 and 2018 is excluded due to refurbishment). Unit 3 has consistently performed at a zero trip rate in 2013, 2014, and 2015, but declined in 2016, improved in 2017 and reached a zero trip rate in 2018 again. Unit 4 has consistently performed at a zero trip rate from 2013 to 2018.

Factors Contributing to Performance

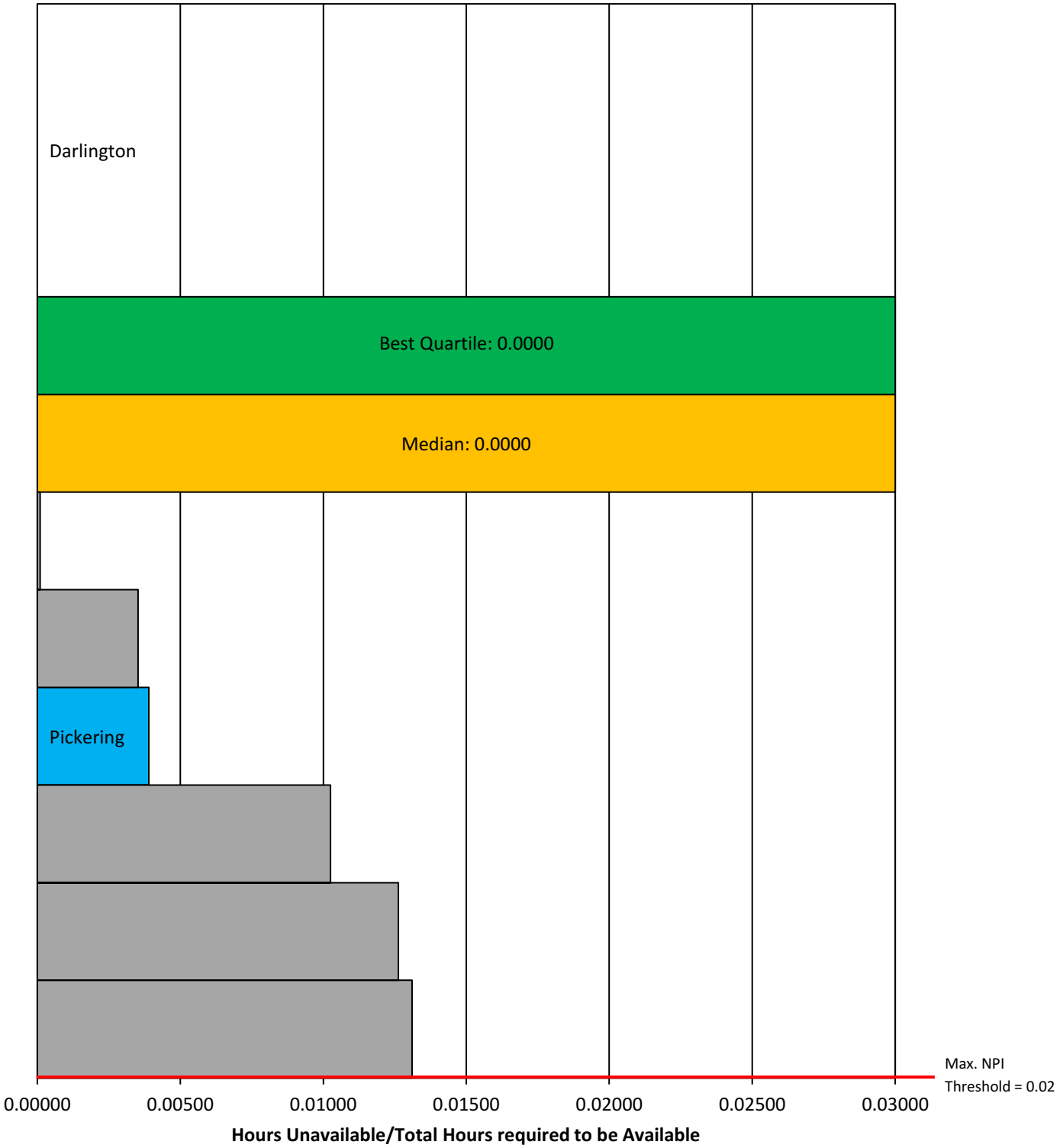
- Key performance drivers for this metric include: general equipment reliability, material condition, and human performance.
- In 2018, Pickering had 3 unplanned automatic reactor trips (1 on Unit 4, 1 on Unit 6, and 1 on Unit 8).
- In 2018, Darlington had no unplanned automatic reactor trip.
- On-going due diligence by Station Operations, Engineering, and Maintenance organizations. Operating Experience (OPEX) from each event has been shared at Pickering, Darlington and at the external summits.
- Training material and technical procedures have been revised based on OPEX.
- Like-for-like parts replacement has taken place to improve equipment reliability. System health teams are involved in obsolescence issues.

3-Year Auxiliary Feedwater Safety System Unavailability

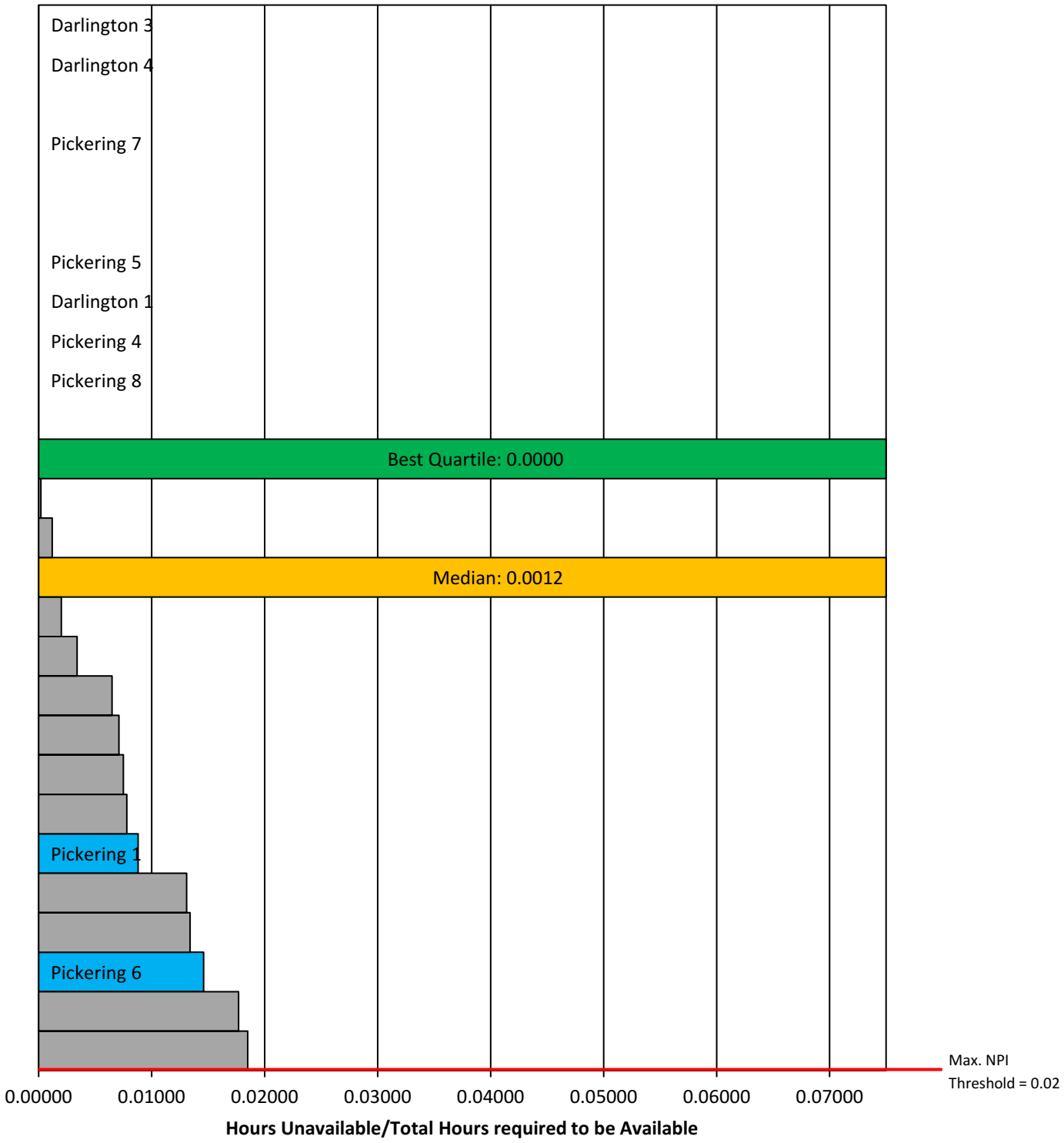




2018 3-Year Auxiliary Feedwater Safety System Performance (Unavailability) CANDU PlantLevel Benchmarking



2018 3-Year Auxiliary Feedwater Safety System Performance (Unavailability) CANDU Unit Level Benchmarking



Observations – 3-Year Auxiliary Feedwater System (CANDU)

2018 (3-Year Rolling Average)

- Auxiliary feedwater (AFW) safety system performance at best quartile for CANDU plants was zero with a median value of 0.0000. For individual CANDU units, the best quartile was zero with the median value of 0.0012.
- At the plant level, Pickering station, with an unavailability of 0.0039, is below the maximum NPI threshold value of 0.02. On an individual unit basis, all units achieved maximum NPI points for AFW unavailability.
- Darlington station achieved best quartile performance of zero unavailability at both the station and unit levels in 2018. Performance of Unit 2 at Darlington is excluded due to refurbishment.

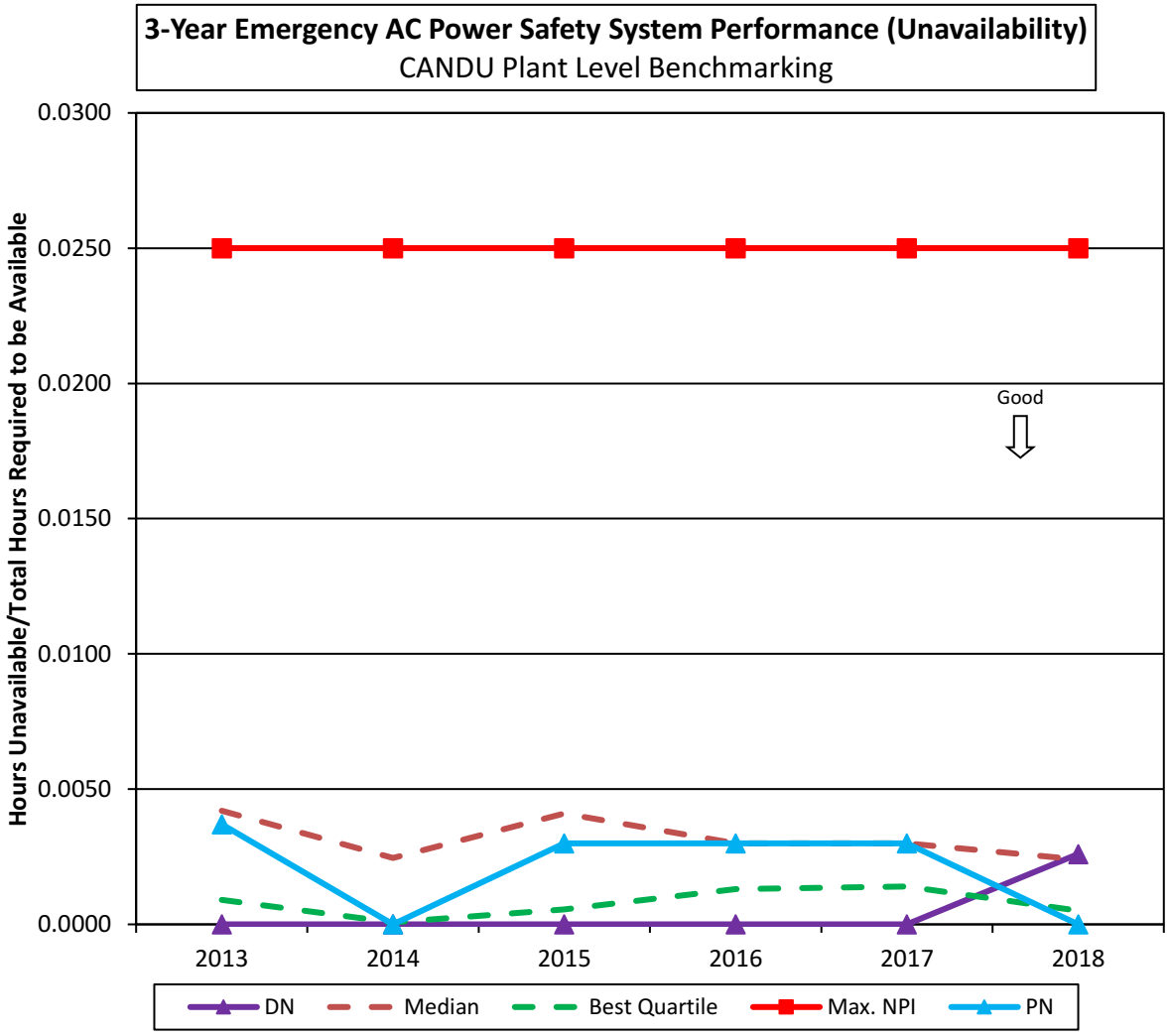
Trend

- The 3-Year Auxiliary Feedwater unavailability best quartile performance of CANDU plants maintained zero unavailability from 2013 to 2018. The plant level industry median value has fluctuated slightly over the review period but has remained below the NPI maximum threshold. At the unit level, the industry best quartile has remained at zero over the review period and the median value is at or close to zero over the review period except in 2018 when it increased but has remained below the NPI maximum threshold.
- At the plant level, Pickering station performance approached the NPI maximum threshold in 2013 and 2014, but improved thereafter and achieved zero unavailability in 2017, but declined in 2018. On an individual unit basis, Unit 6 has consistently performed at zero unavailability over the review period except in 2018. Unit 1 performance declined in 2014, improved thereafter and achieved an unavailability of zero in 2017, but declined in 2018. Unit 4 performance was at an unavailability of 0.0090 and 0.0091 in 2013 and 2014, respectively and improved to zero unavailability from 2015 to 2018. Unit 5 performance improved from 2013 and reached zero unavailability in the period of 2016 to 2018. Unit 7 performed at zero unavailability in 2013, declined in 2014, improved in 2015, deteriorated in 2016. In 2017 and 2018, performance improved to zero unavailability. Unit 8 performance declined in 2014 from 2013. The performance in 2015 and 2016 is better than 2014 and reached zero unavailability in 2017 and 2018.
- Darlington station and unit performance have been at zero unavailability since 2013.

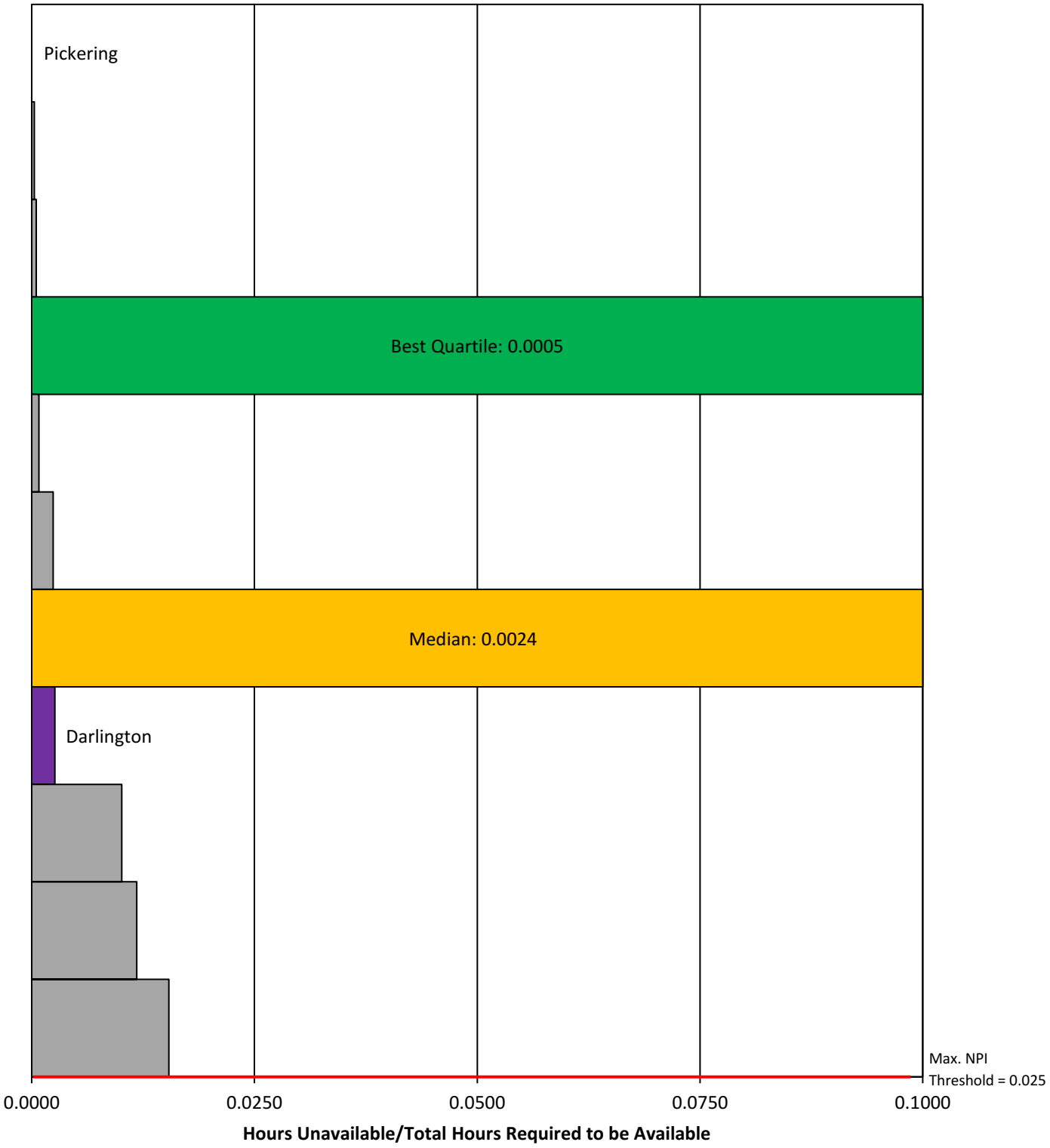
Factors Contributing to Performance

- Key performance drivers for this metric include: general equipment reliability, material condition, and human performance.
- Quarter 1 – 2018, Pickering Unit 1 event: During execution of the routine test NA44-SRS-P-007, Unit 1 Auxiliary Condensate Extraction Pump 1-43210-P4 tripped when selected back to 'Auto'. A field inspection found the power supply breaker for the pump tripped causing it to be declared unavailable to start from Main Control Room (MCR). This resulted in 'System Does Not Meet Design Intent' Impairment of Auxiliary Boiler Feedwater System. Following pump motor megger and breaker inspection the cause of the pump trip was traced to a defective MCR panel hand switch. The hand switch was replaced, P-007 testing was successfully completed and the impairment was lifted. The routine test NA44-SRS-P-007 is performed every 4 weeks and it is designed to identify and correct hidden failures form affecting unit operation.
- Quarter 2 – 2018, Pickering Unit 6 event - During the performance of the routine test NK30-SRS-P-023, it was discovered that Auxiliary Boiler Feedwater pump 6-43230-P5 was not providing the required flow of 23 kg/s. "System Does Not Meet Design Intent" impairment was declared. The setpoint adjustment on pump pressure controller 6-64323-PC206 was performed. Pump test was repeated and passed, impairment removed Extent of condition review analysis of routine tests NA44-SRS-P-001 / NK30-SRS-P-023 were performed, and no adverse flow rate trends related to Auxiliary Boiler Feedwater system were identified.

3-Year Emergency AC Power Safety Unavailability



2018 3-Year Emergency AC Power Safety System Performance (Unavailability)
CANDU Plant Level Benchmarking



Observations – 3-Year Emergency AC Power Safety System (CANDU)

2018 (3-Year Rolling Average)

- 3-Year Emergency AC Power Safety System performance at best quartile for CANDU plants was 0.0005. The industry median value was 0.0024.
- At the plant level, Pickering station is one of the best performing stations in the CANDU peer group, achieving an unavailability of 0.000.
- Darlington station had an unavailability of 0.0026, below the maximum NPI threshold of 0.025.

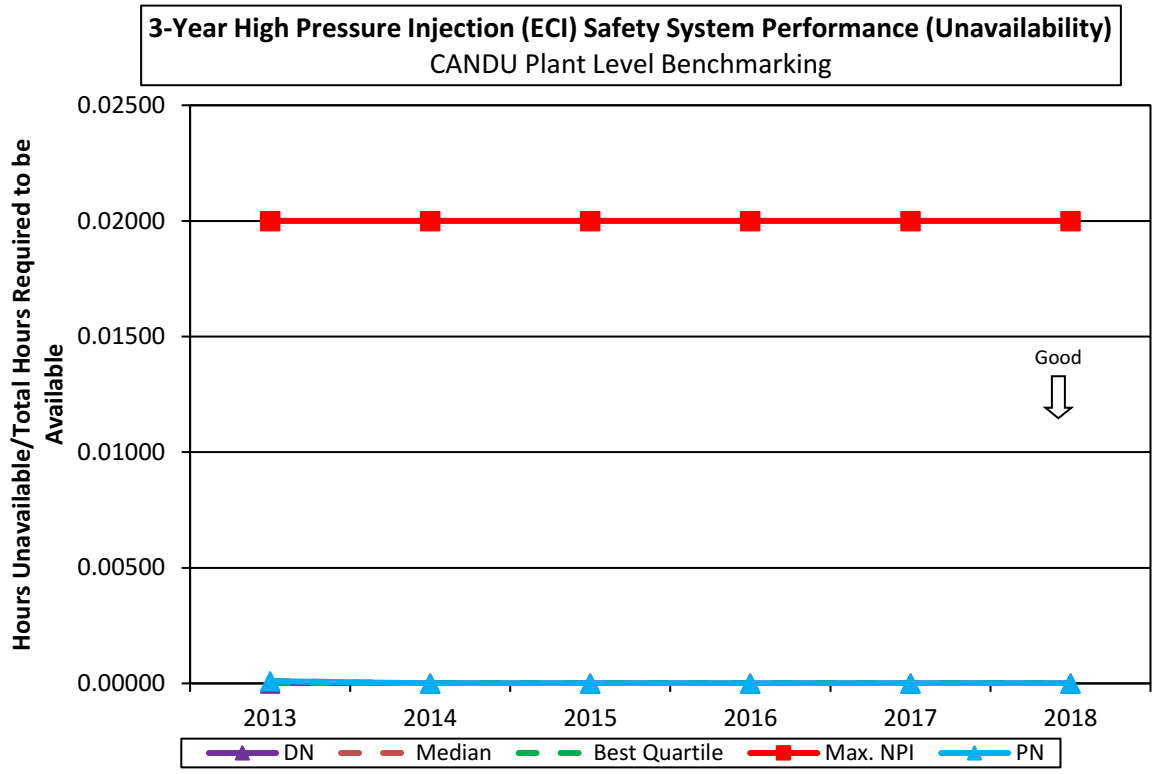
Trend

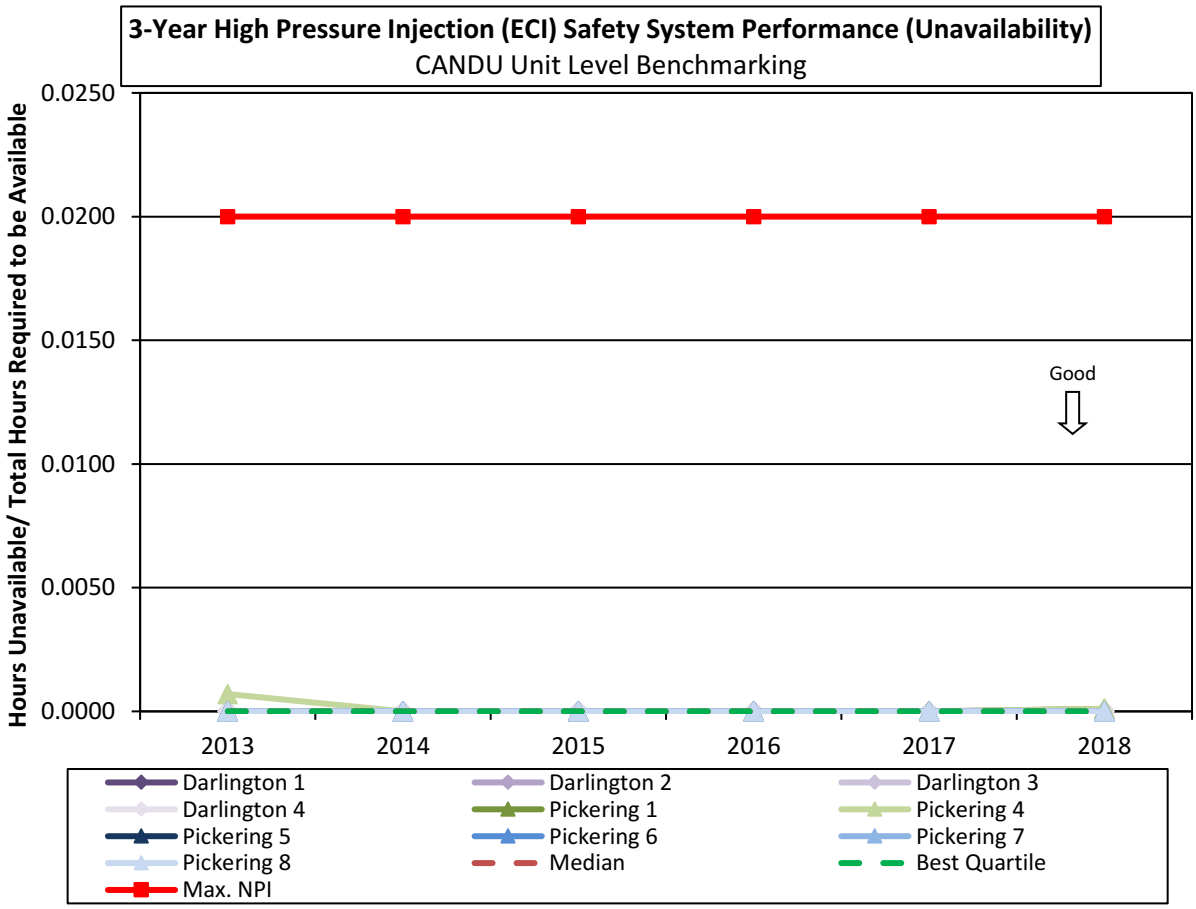
- The 3-year Emergency AC Power Safety System unavailability industry best quartile for CANDU plants improved in 2014 from 2013, declined each year from 2015 to 2017 and improved in 2018. The industry median value improved in 2014 from 2013, followed by a decline in 2015. Performance improved in 2016 and remained unchanged in 2017 with further improvement in 2018.
- Pickering station performance has improved over the review period, reaching its best performance in 2014 and 2018, achieving zero unavailability, but station performance declined in 2015 and then remained unchanged in 2016 and 2017.
- Darlington station performance achieved zero unavailability over the review period of 2013 to 2017 and declined in 2018.

Factors Contributing to Performance

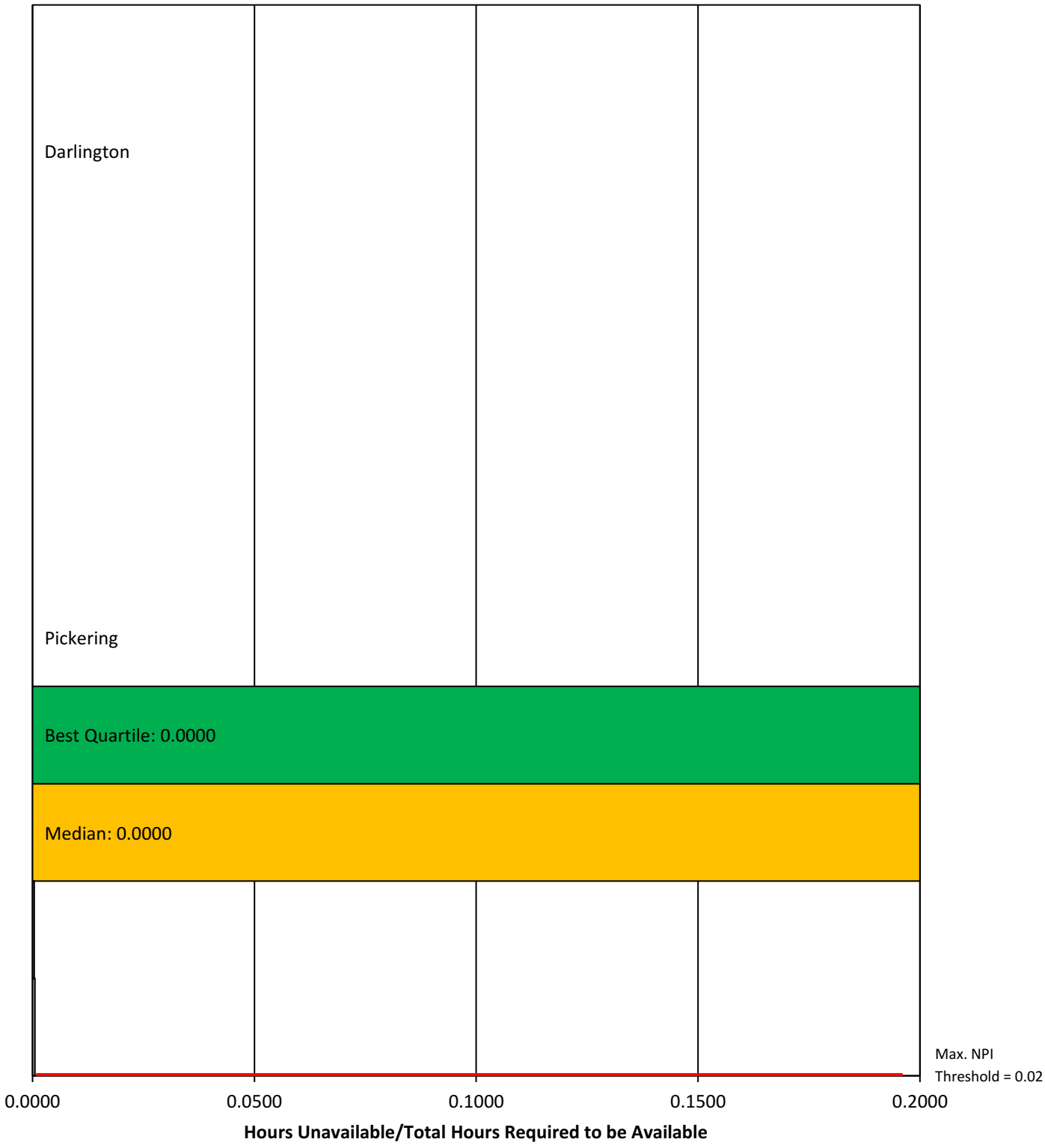
- Key performance drivers for this metric include: general equipment reliability, material condition, and human performance.
- Quarter 2 – 2018, Darlington 0-49100-SG3 event - During the execution of Section 14.2 "ECI Injection Valve Logic Initiated" of Abnormal Incident Manual NK38-OM-09013G, a spurious Loss of Coolant Accident (LOCA) injection signal was received from Unit 2. This caused the Standby Generators (SGs) 0-49100-SG2, SG3, and SG4 to receive a start signal. 0- 49100-SG1 was on maintenance outage. Standby Generator 0-49100-SG3 tripped on start up when the starter motor supply breaker tripped. This was due to a failure of the SG3 starter motor contactor that had contacts stuck closed. When SG3 tripped, while SG1 was on planned outage, this resulted in reduction of SG redundancy for Class III power supply. Mitigating actions included creation of an operating memo for actions to perform after each SG shutdown including SG starter motor contactor checks and installing original arc suppressors for SG1 to SG3.

3-Year High Pressure Safety Injection

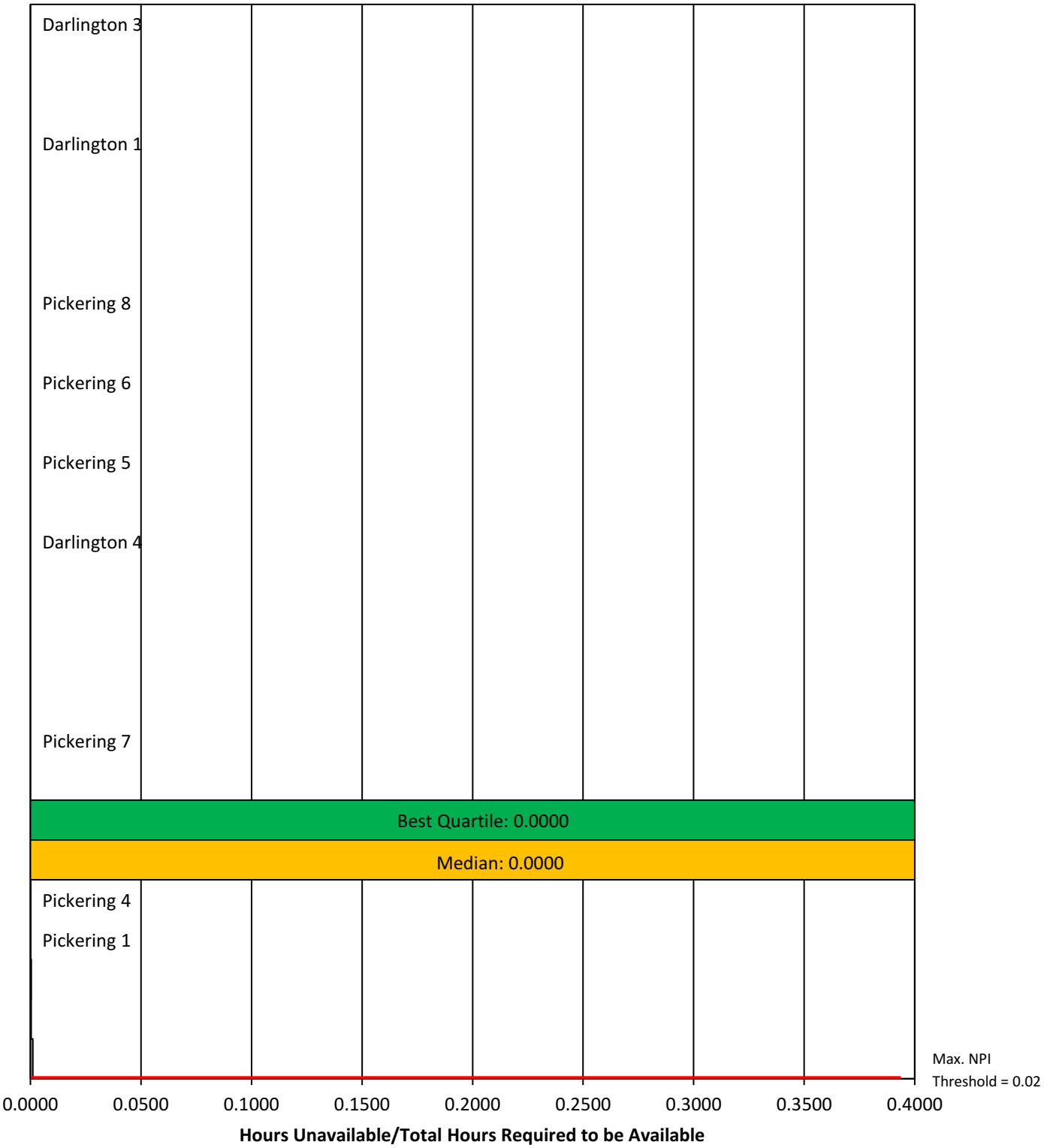




2018 3-Year High Pressure Injection (ECI) Safety System Performance (Unavailability)
CANDU Plant Level Benchmarking



2018 3-Year High Pressure Injection (ECI) Safety System Performance (Unavailability)
CANDU Unit Level Benchmarking



Observations – 3-Year High Pressure Safety Injection Unavailability (CANDU)

2018 (3-Year Rolling Average)

- The best quartile and median values for the 3-Year High Pressure Safety Injection Unavailability performance for CANDU plants were zero. For individual CANDU units, both the best quartile and median value were zero.
- Pickering achieved best quartile performance of zero unavailability at the station level in 2018.
- Darlington achieved best quartile performance of zero unavailability at both the station and unit levels in 2018. Performance of Unit 2 is excluded due to refurbishment.

Trend

- The 3-Year High Pressure Safety Injection unavailability best quartile performance of CANDU plants has been zero since 2013. The plant level industry median performance improved from 2013 and achieved zero unavailability from 2014 to 2018. At the unit level, the industry best quartile and median value have remained at zero over the review period.
- At the plant level, Pickering station performance has consistently improved over the review period, achieving zero unavailability from 2014 to 2018. On an individual unit basis, Units 5, 6, 7, and 8 have been at the best quartile value of zero since 2013. Units 1 and 4 performance improved from 2013 achieving zero unavailability from 2014 to 2017, but slightly declined in 2018.
- At the plant level, Darlington station performance has maintained a best quartile value of zero from 2013 to 2018. On an individual unit basis, Units 1, 3, and 4 have been at the best quartile value of zero since 2013. Performance of Unit 2 at Darlington is excluded due to refurbishment.

Factors Contributing to Performance

- Key performance drivers for this metric include: general equipment reliability, material condition, and human performance.
- Quarter 1 – 2018, Pickering 058-33350-HTR16-3-TS3, HTR26-3-TS1, and HTR40-3-TS2 - During routine panel monitoring, ECI heat trace alarm ("B" alarm for piping < 6°C) was received. Per operating procedure NK30-OM-5-33350-05.13.04.01, HPECI pump 058-33350-P5 was placed in service in recirculation mode to mitigate the low piping temperature and prevent the freezing in the pipeline. As a result of warm water circulating in the HPECI piping, the low temperature alarm cleared. The impairment was removed and the HPECI pump P5 was shutdown. This leads to Level 2 impairment of ECI as per operating procedure NK30-AIM-058-09013-3.2, applicable to Units 1, 4, and 5 to 8 given that the water temperature in the HPECI piping was detected to be less than 6°C.

- Quarter 3 – 2018, Pickering Units 1 and 4 Emergency Cooling Injection (ECI) system - A lake debris run resulted in multiple Unit shutdowns for Pickering B. As a result of this Pickering Unit 1 and 4 experienced ECI Level 1 impairment due to normal Site Electrical System (SES) unavailable to 2-54120-BUB MCC18/MCC19 and 3-54120-BUA MCC18/MCC19, which was reduced to Level 3 impairment by running standby generators 012-SG3 and 034-SG3, respectively. This leads to Unit 1 and 4 ECI system unavailability.

To improve the system performance at Pickering station the following actions were taken:

1) Investigated failure of primary heater to alarm and calibrate ECI heaters temperature switches.
2) A memo documenting the probabilistic and deterministic safety assessment on running 014-SGs to supply Interstation Transfer Power Supply Buses (ISTB) once Pickering 058 supply to ISTB becomes unavailable was prepared.
3) Document Change Request (DCR) against Operating Policy and Principle (OP&P) 54.4 regarding standard configuration of ISTB submitted.
4) DCR against ISTB Operating Safety Requirements (OSR) to align with OP&P submitted.

3.0 RELIABILITY

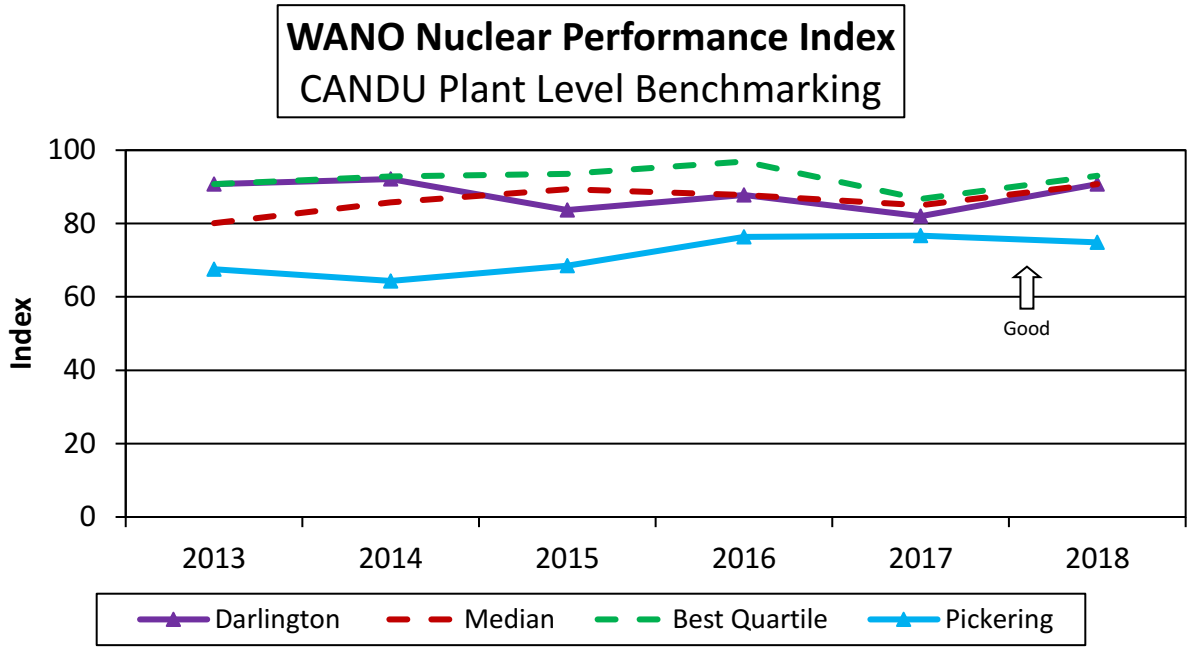
Methodology and Sources of Data

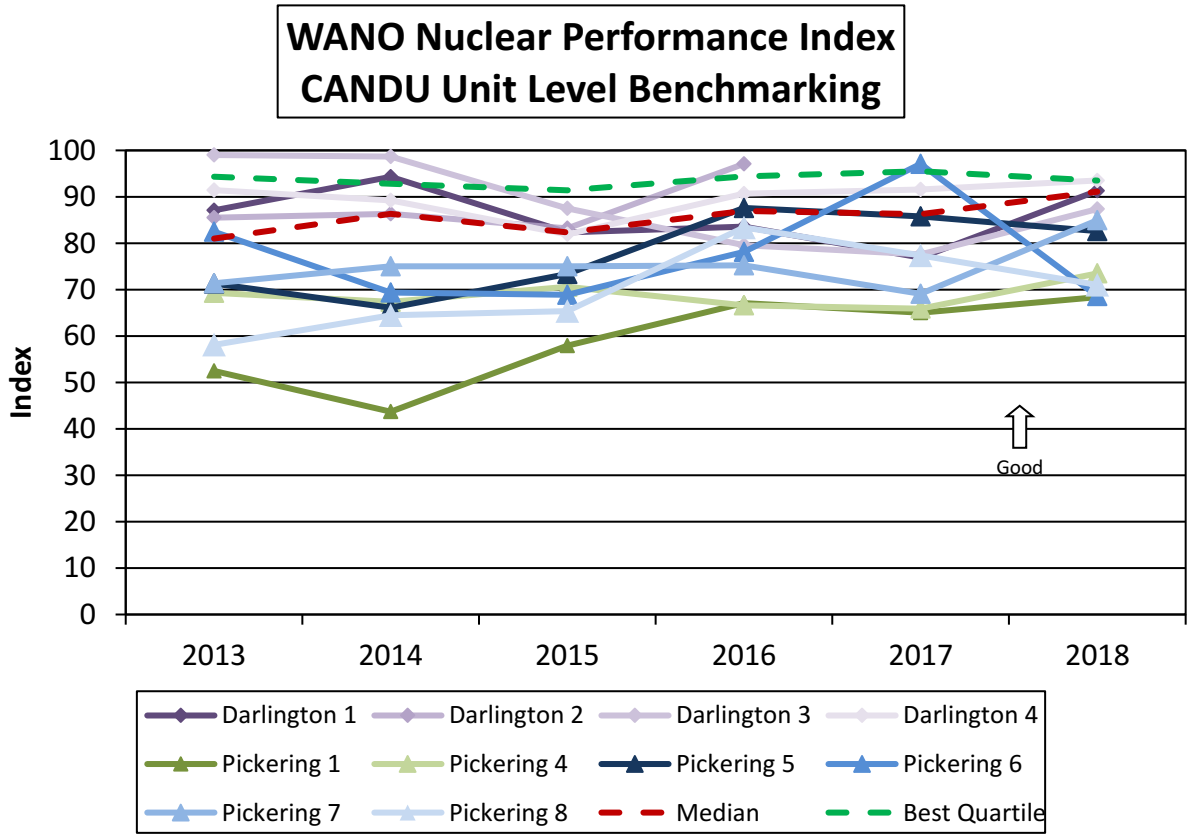
The majority of reliability metrics were calculated using data from WANO. Any data labelled as invalid by WANO was excluded from all calculations. Indicator values of zero are not plotted or included in calculations except in cases where zero is a valid result. Complete data for the review period was obtained and averages are as provided by WANO. The Embalse plant is excluded since it was taken offline since December 31, 2015 for refurbishment.

Two backlog metrics, On-line Deficient and Corrective maintenance, are also included within this section and the data comes from an industry sponsored INPO AP-928 subcommittee. The On-line Deficient and Corrective maintenance backlog industry data was collected from INPO for 2018. Data points benchmarked on backlogs are a single point in time, not a rolling average. All of the data is self-reported.

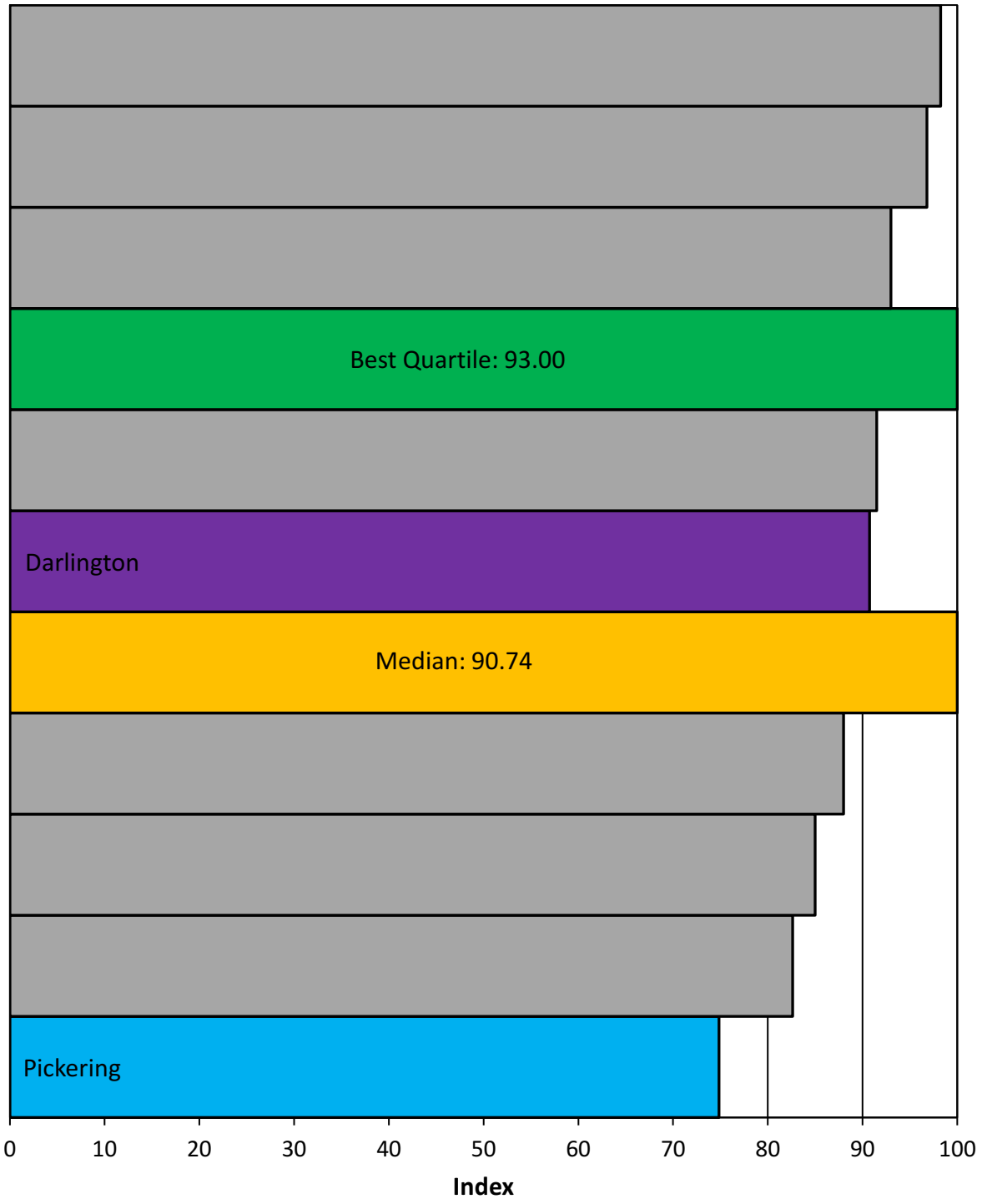
The primary metric within the reliability section is the WANO Nuclear Performance Index (NPI). A maximum score of 100 is possible. The WANO NPI is an operational performance indicator comprised of 10 metrics, three of which are analyzed in this section: Forced Loss Rate, Unit Capability Factor, and Chemistry Performance Indicator. The remainder of the WANO NPI components are analyzed in the safety section (Section 2.0).

WANO Nuclear Performance Index

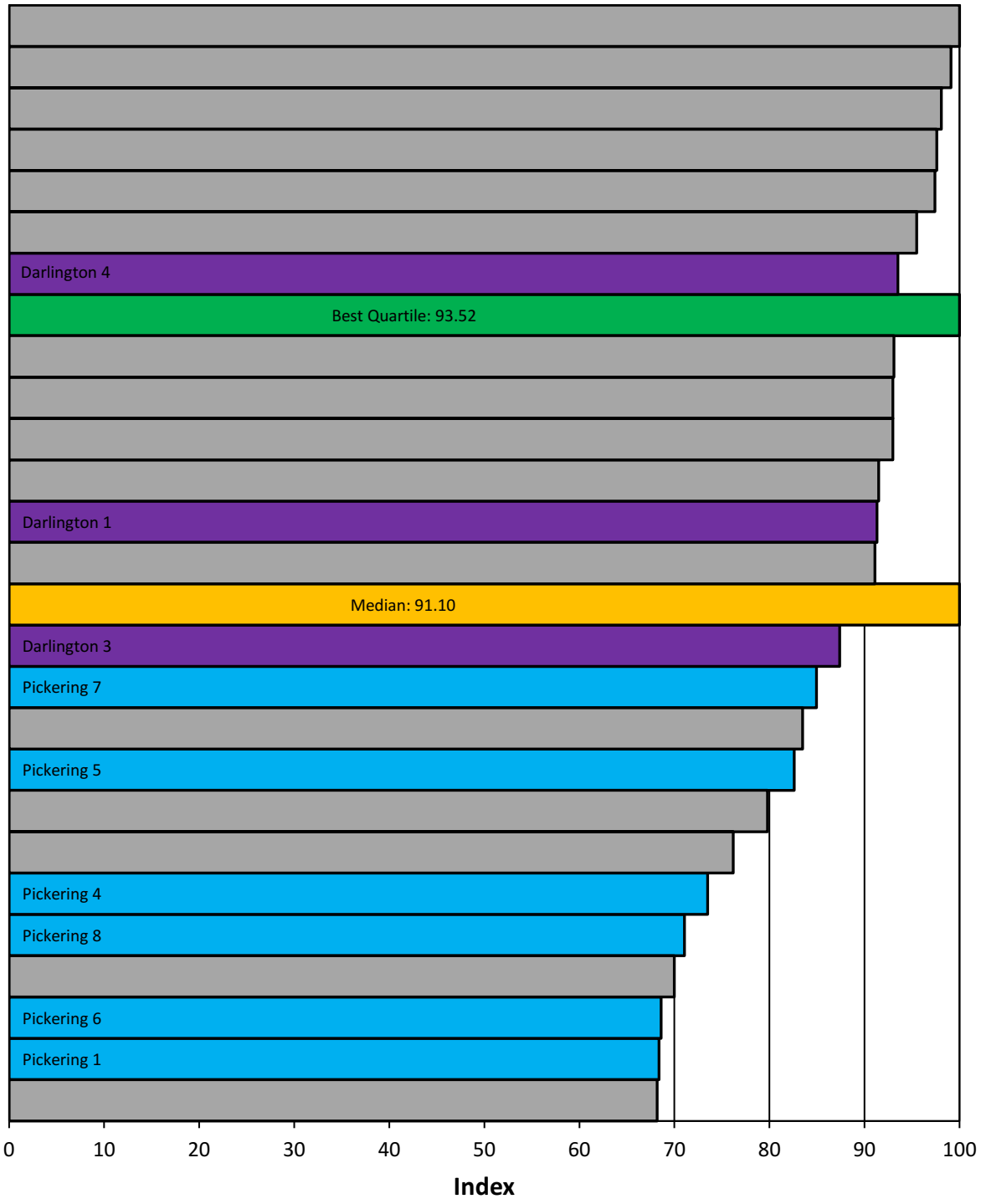




2018 WANO Nuclear Performance Index
CANDU Plant Level Benchmarking



2018 WANO Nuclear Performance Index
CANDU Unit Level Benchmarking



Observations – WANO Nuclear Performance Index (NPI) (CANDU)

2018

- The 2018 best quartile of the CANDU plant comparison panel for WANO NPI is 93.00. This represents a 6.3 points increase when compared with the 2017 best quartile.
- The median of the CANDU plant comparison panel increased 5.74 points, compared to last year, to 90.74 in 2018.
- At the plant level, Darlington scored at the median NPI while Pickering scored below median NPI performance in 2018.
- In 2018, Darlington had one unit in the best quartile one in the second quartile and one 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 trended positive in the low 90's from 2013 to 2016. In 2017 the best quartile performance trended down and recovered in 2018.
- The median value of the CANDU plant comparison panel trended positive from 2013 to 2015. It declined slightly in 2016 and 2017. This performance recovered in 2018.
- A positive trend at Pickering began in 2014 and continued in 2015, 2016, and 2017 with a slight decline in 2018. This trend was due in part to improvements in the Forced Loss Rate (FLR) results in 2016, 2017, and 2018.
- Darlington achieved best quartile performance over the majority of the review period, ranking at or just below top quartile until 2014. Performance declined in 2015 due to the station vacuum building containment outage for planned regulatory maintenance and higher FLR. The declining trend continued in 2016 due to Primary Heat Transport pump motor replacements affecting FLR and higher radiation dose from nuclear safety improvements projects. In October 2016, Darlington Unit 2 entered refurbishment. The same trend continued in 2017 due to unbudgeted outages affecting unit capability factor and FLR. In 2018, the trend improved due to lower number of unbudgeted and forced outages.

Factors Contributing to Performance

- The WANO NPI is a composite index reflecting the weighted sum of 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.

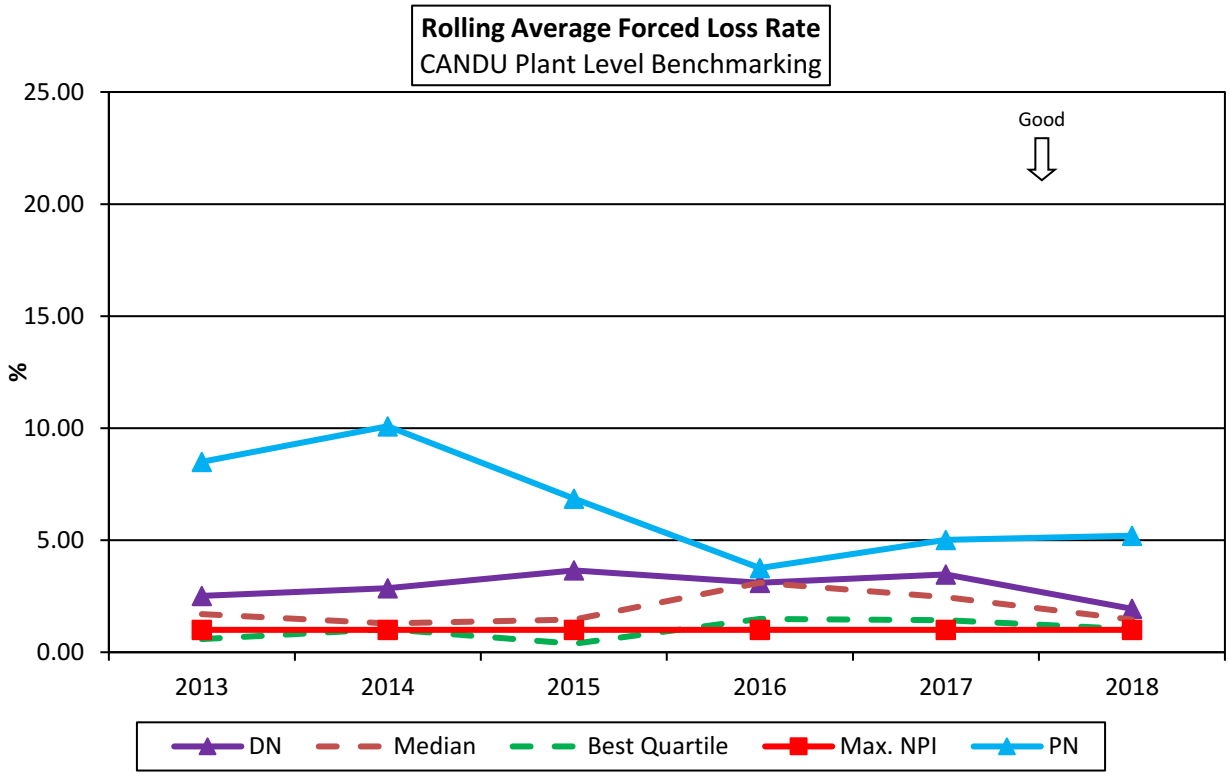
Pickering

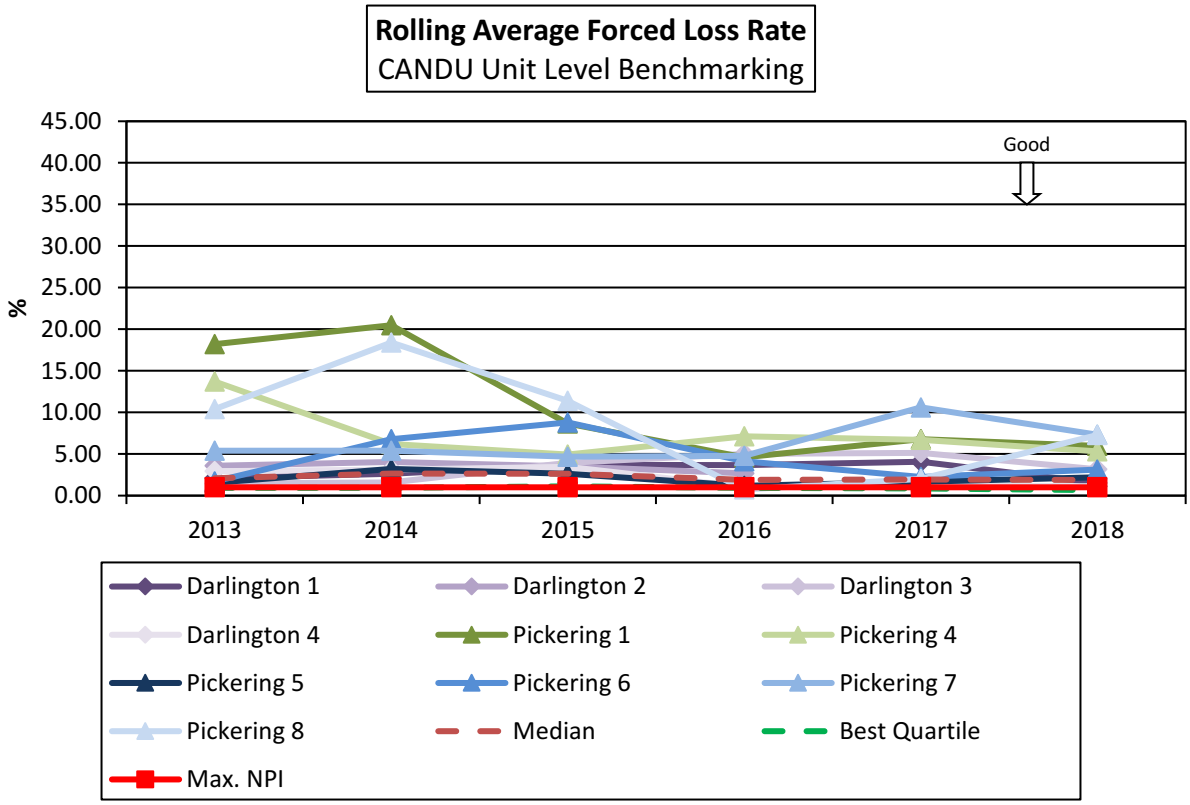
- For 2018, Pickering achieved maximum scores or majority points for 8 out of 10 NPI sub-indicators.
- For the key safety system related metrics of Reactor trip rate, High pressure injection, Auxiliary feedwater and Emergency alternating current (AC) power, the station received 10 out of 10 points.
- Pickering has also achieved a perfect score for Industrial safety accident rate (5 out of 5).
- Pickering earned 8.7 points for Fuel reliability.
- Pickering achieved 4.8 points out of 5 for Chemistry performance and 7.9 out of 10 for Collective radiation exposure.
- Pickering's NPI performance is impacted by the need for long outages to accommodate fuel channel inspection programs, planned outages extension and forced outages that are affecting the unit capability factor, forced loss rate and collective radiation exposure metrics
- Pickering received 2.5 out of 15 points for unit capability factor and 6.0 out of 15 for forced loss rate.

Darlington

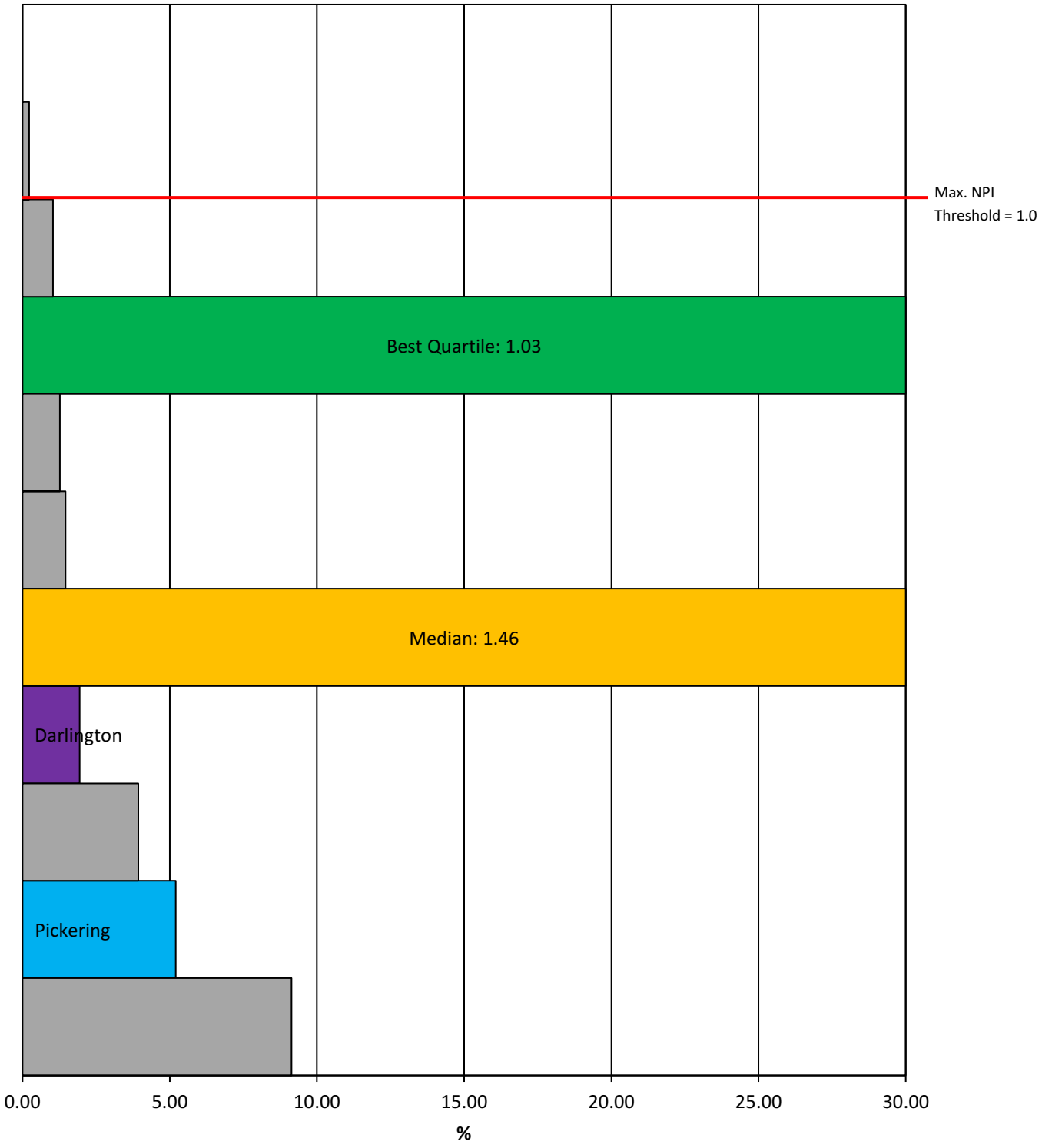
- Darlington's NPI performance has been impacted by higher forced loss rate and by a lower unit capability factor due to forced outages, planned outages and unbudgeted planned outages.
- For 2018, Darlington has achieved maximum points for 6 out of 10 NPI sub-indicators.
- For the key safety system related metrics of Reactor trip rate, High pressure injection, Auxiliary feedwater and Emergency alternating current (AC) power, the station received 10 out of 10 points.
- Darlington has also achieved a perfect score for Industrial safety accident rate (5 out of 5) and Fuel reliability (10 out of 10).
- Darlington earned 4.4 out of 5 points for Chemistry performance and 9 out of 10 points for Collective radiation exposure.
- Darlington achieved 8.9 out of 15 points for unit capability factor and 13.5 out of 15 points for forced loss rate.

Rolling Average Forced Loss Rate

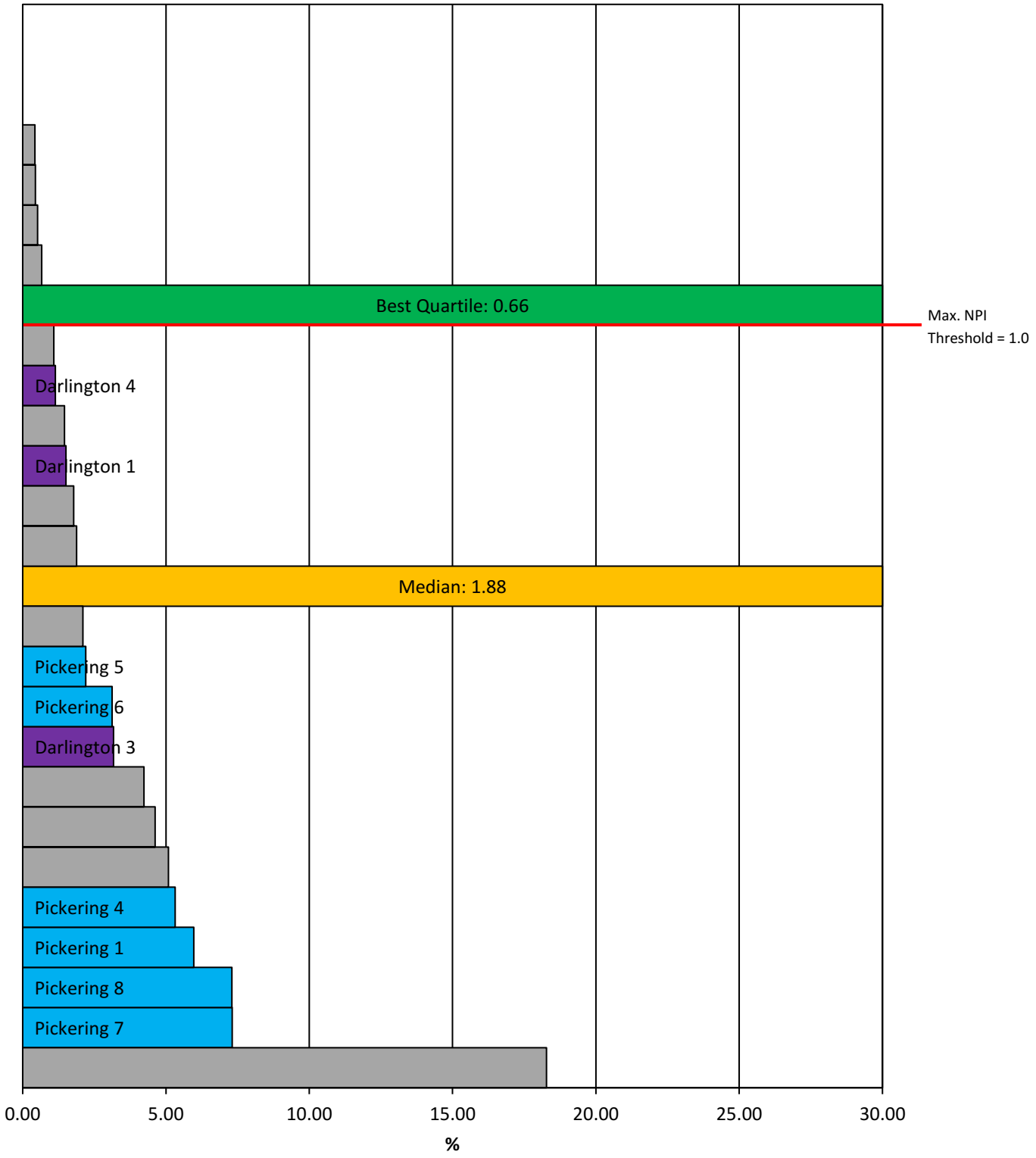




2018 Rolling Average Forced Loss Rate
CANDU Plant Level Benchmarking



2018 Rolling Average Forced Loss Rate
CANDU Plant Level Benchmarking



Observations – Rolling Average Forced Loss Rate (CANDU)

2018 (Rolling 2 Year Average, Pickering %; Rolling 3 Year Average, Darlington %)

- The industry plant level best quartile was 1.03 and the industry median was 1.46.
- Pickering Forced Loss Rate (FLR) had a slight decline in performance, increasing from 5.01 in 2017 to 5.20 in 2018.
- Darlington FLR performance improved from 3.47 in 2017 to 1.94 in 2018. Unit 2 was excluded in both of these years due to refurbishment.

Trend

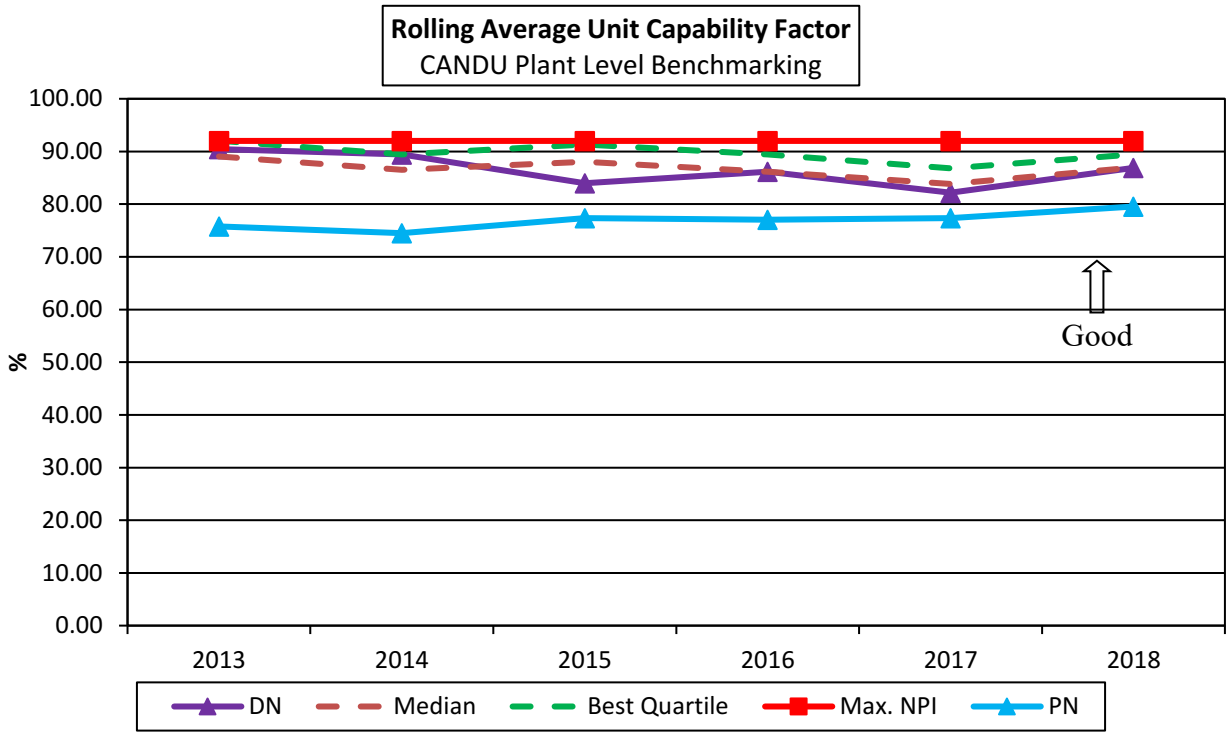
- Industry plant median FLR trend improved from 2.46 in 2017 to 1.46 in 2018.
- Pickering's overall trend over the review period, has shown considerable improvement, having been as high as 10.08 in 2014. Although there was a slight decline in performance from 2017 to 2018, the 2018 FLR still remains well below the average of 6.57 over the review period.
- Over the review period, there has also been an improvement in FLR performance at Darlington. The 2018 FLR was well below the average FLR over the trending period of 2.92.
- Equipment reliability improvements at both Pickering and Darlington have been the main drivers for the favourable improvement in FLR performance.

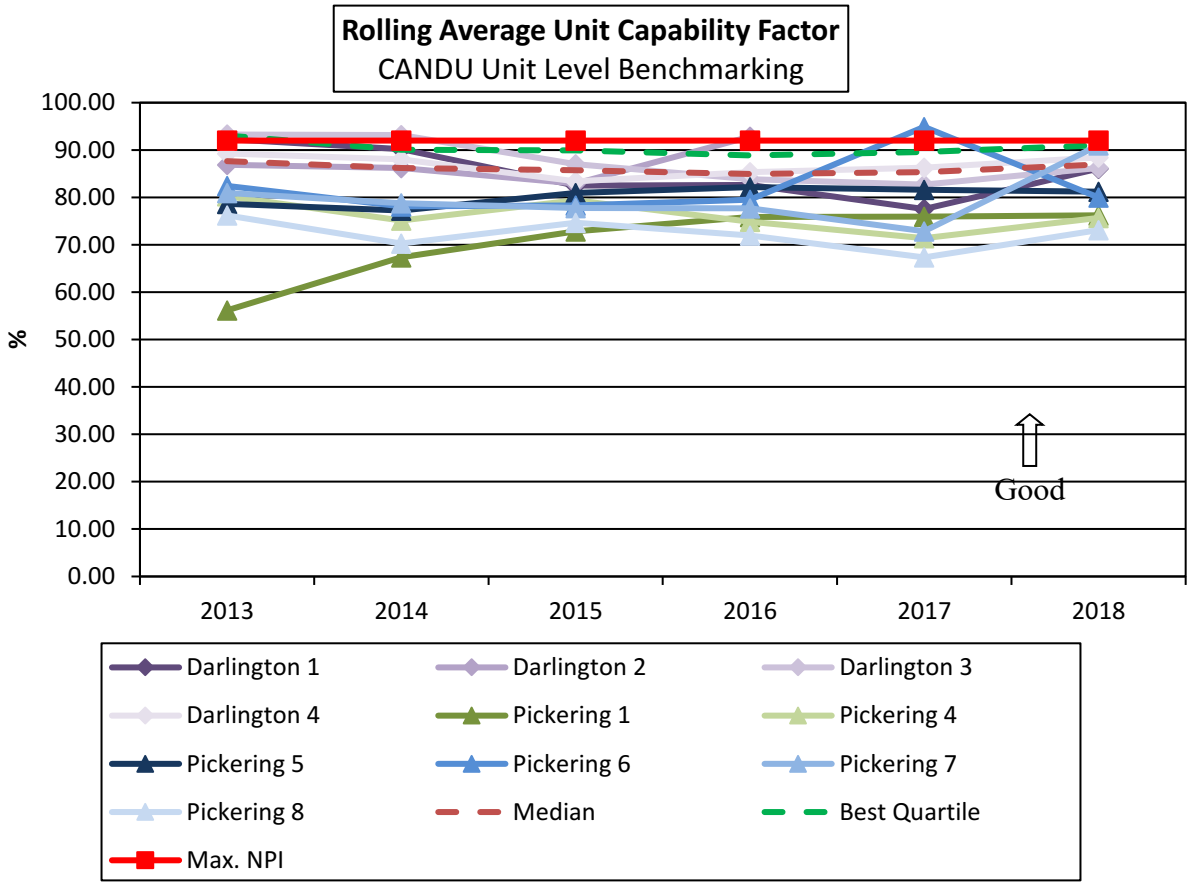
Factors Contributing to Performance

- At Pickering, the causes for 2018 forced losses were varied, including:
  - Unit 8 inspection and refurbishment of fuelling machine D20 supply control valves
  - Unit 1 turbine trip due to low stator cooling flow
  - Unit 4 high condenser back pressure
  - Unit 6 loss of power to class III bus during emergency transfer scheme testing (P-006) following loss of Class IV
- At Darlington, the causes for 2018 forced losses were also varied, including:
  - Unit 1 turbine trip circuit pressure switch failure
  - Unit 4 failed power supply for DCC
  - Unit 3 temporary loss of Class II bus
- Both Pickering and Darlington 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 and 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.
- Both Pickering and Darlington have seen significant improvements in completion of critical preventive maintenance work.

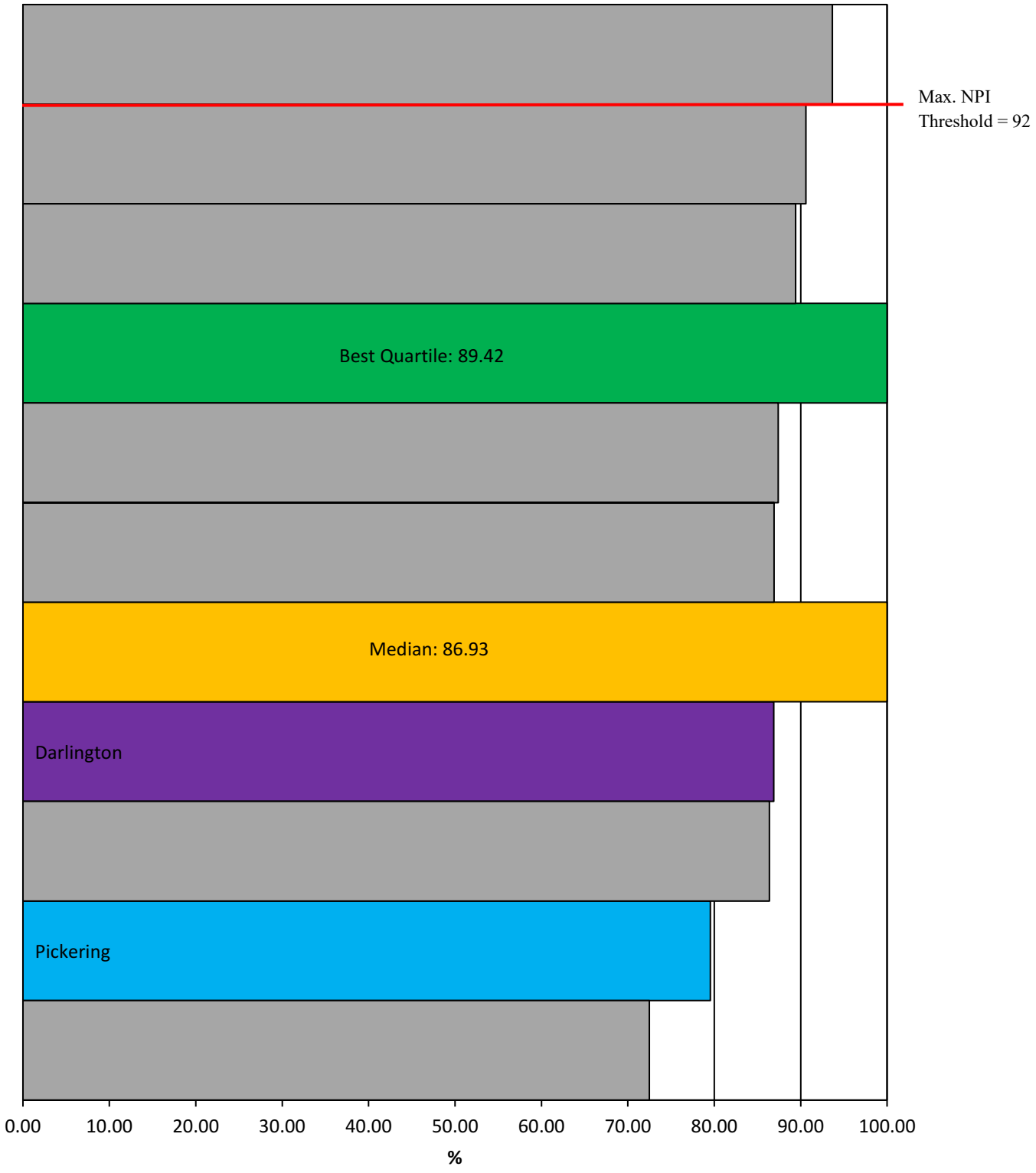
- There is currently a fleet initiative to implement Value Based Maintenance (VBM). Although it is still early in the process, the intent of this initiative is to ensure that the sites complete the right work at the right time.
- The definition of critical components was aligned with industry standards which has allowed the organization to better focus the station equipment reliability processes and resources on the most critical components to improve overall equipment reliability and safety.

Rolling Average Unit Capability Factor

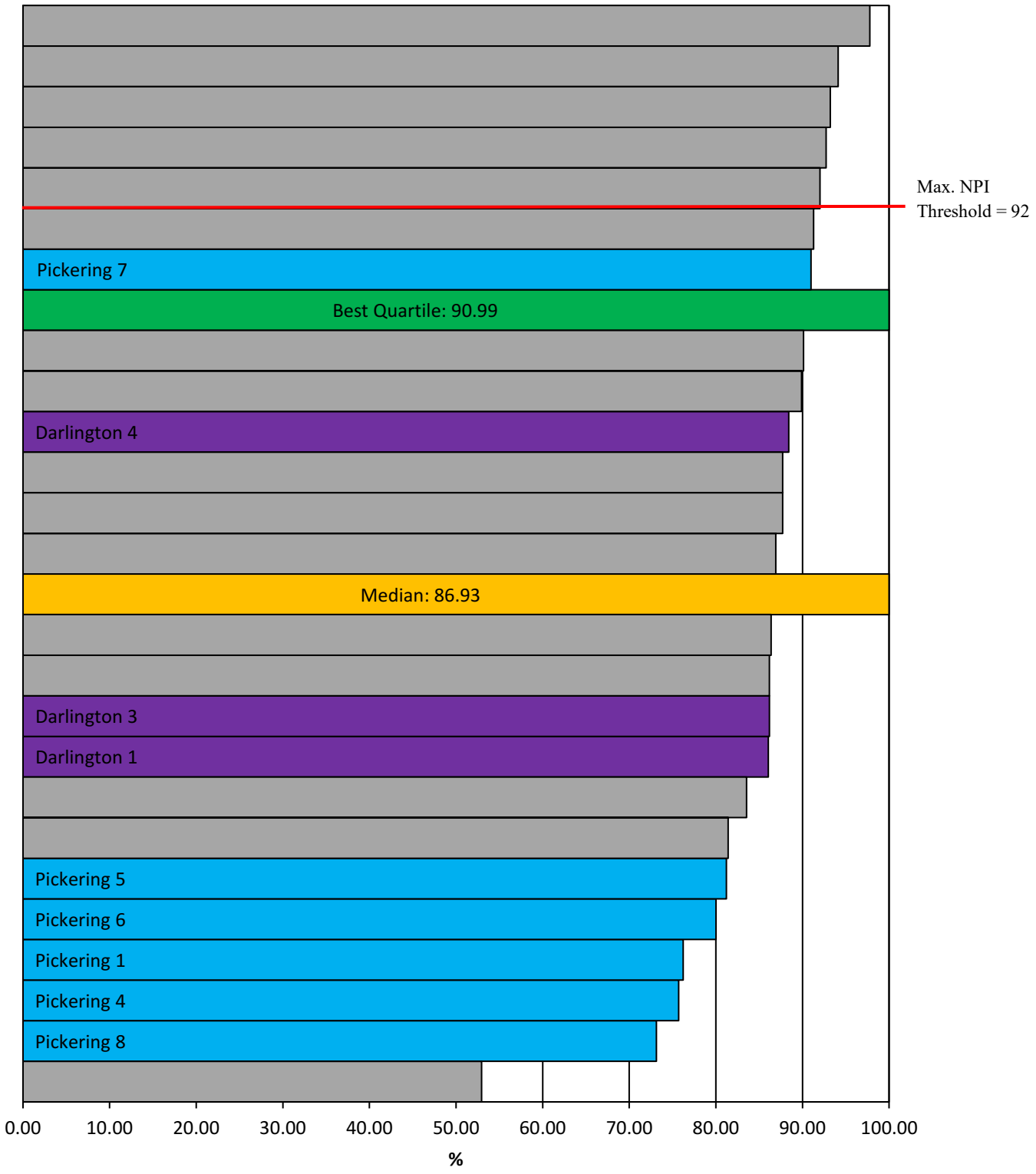




2018 Rolling Average Unit Capability Factor
CANDU Plant Level Benchmarking



2018 Rolling Average Unit Capability Factor
CANDU Unit Level Benchmarking



Observations – Rolling Average Unit Capability Factor-UCF (CANDU)

2018 (Rolling 2 Year Average, Pickering %; Rolling 3 Year Average, Darlington %)

- The industry best quartile was 89.42 and the industry median was 86.93.
- Pickering UCF performance improved from 77.36 in 2017 to 79.55 in 2018.
- Darlington UCF performance also improved from 82.17 in 2017 to 86.89 in 2018. It should be noted that Darlington Unit 2 began a long-term refurbishment outage on October 15, 2016 and data points associated with Refurbishment have been excluded with respect to UCF.

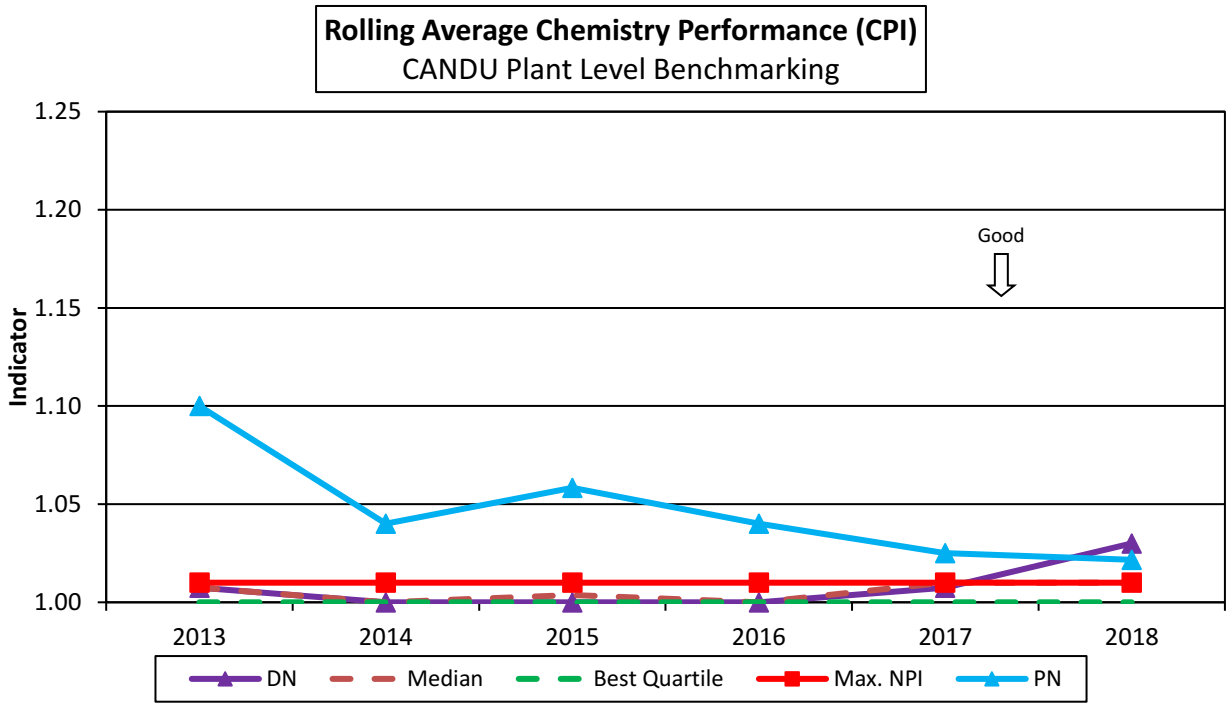
Trend

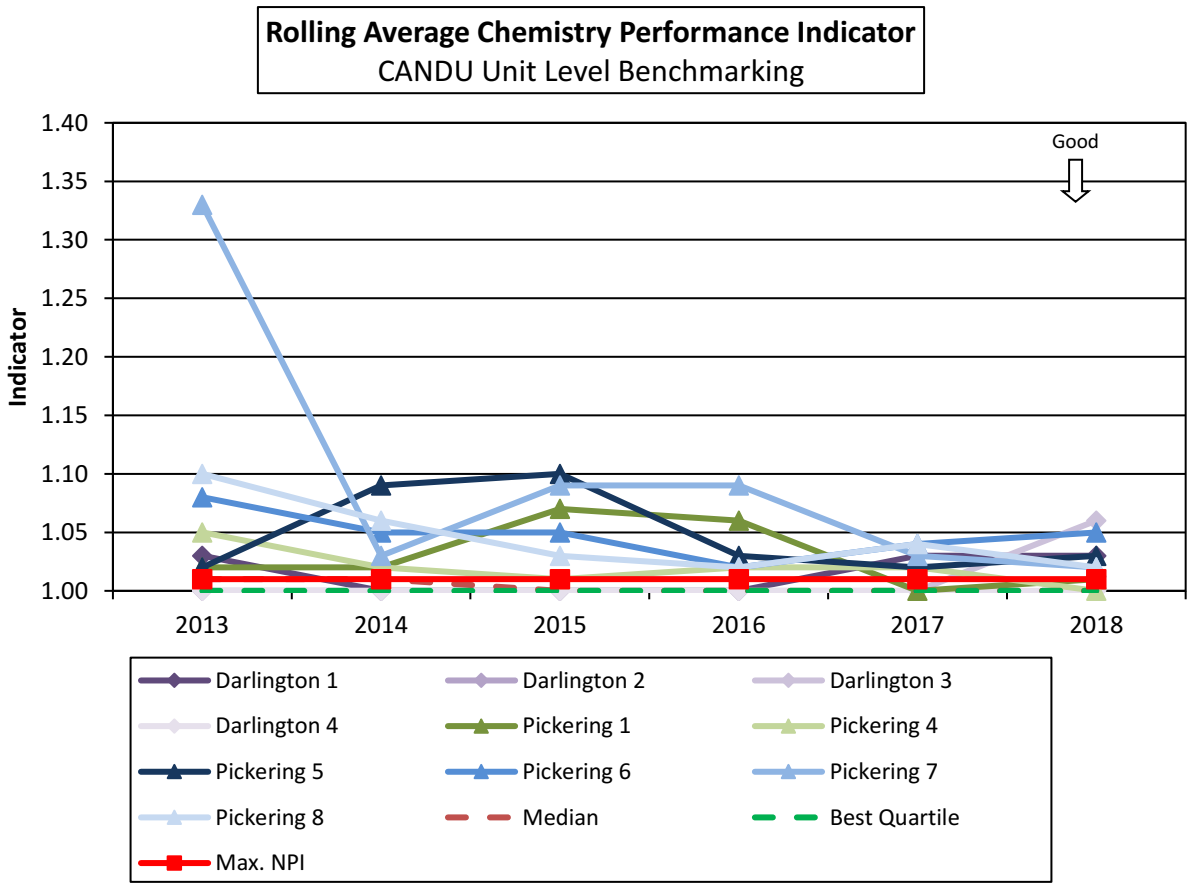
- Pickering's UCF has been relatively stable over the past 3 years and improved in 2018. The overall trend of Pickering's UCF demonstrates continuous improvement.
- Darlington's UCF has shown an overall downward trend over the past 4 years as units approach refurbishment but has seen significant improvement in 2018.
- Equipment reliability improvements at both Pickering and Darlington have been the main drivers for the favourable improvement in UCF performance over the past year.
- Industry plant median and best quartile UCF benchmarks both increased in 2018.

Factors Contributing to Performance

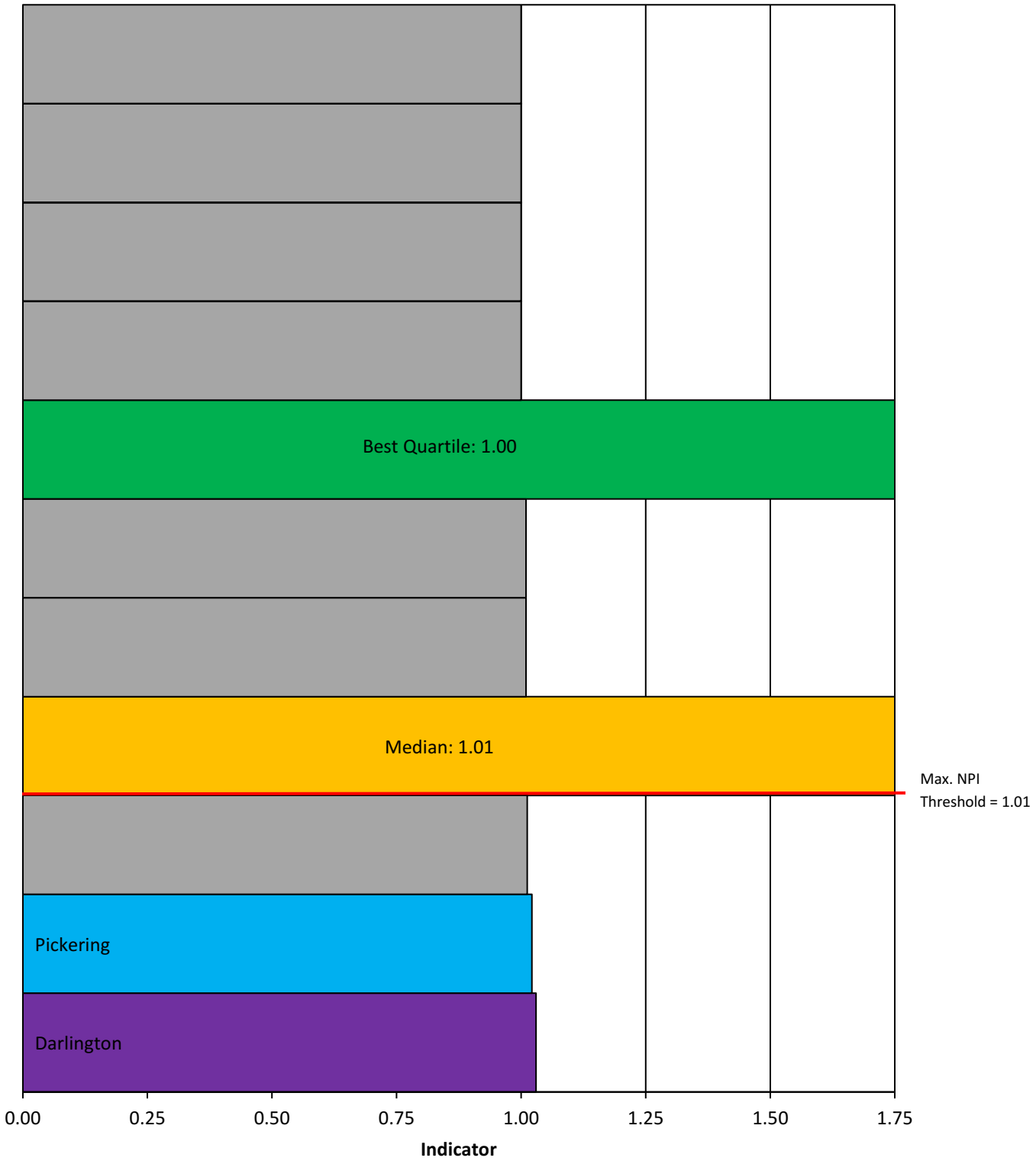
- Higher number of planned outage days contributes to lower UCF when compared to CANDU peers.
- FLR performance challenges also negatively impact UCF. Significant improvements in equipment reliability have correlated with improved FLR and UCF performance and are expected to continue to do so going forward.
- Pickering and 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.
- Both Pickering and Darlington have seen significant improvements in completion of critical preventive maintenance work.

Rolling Average Chemistry Performance Indicator

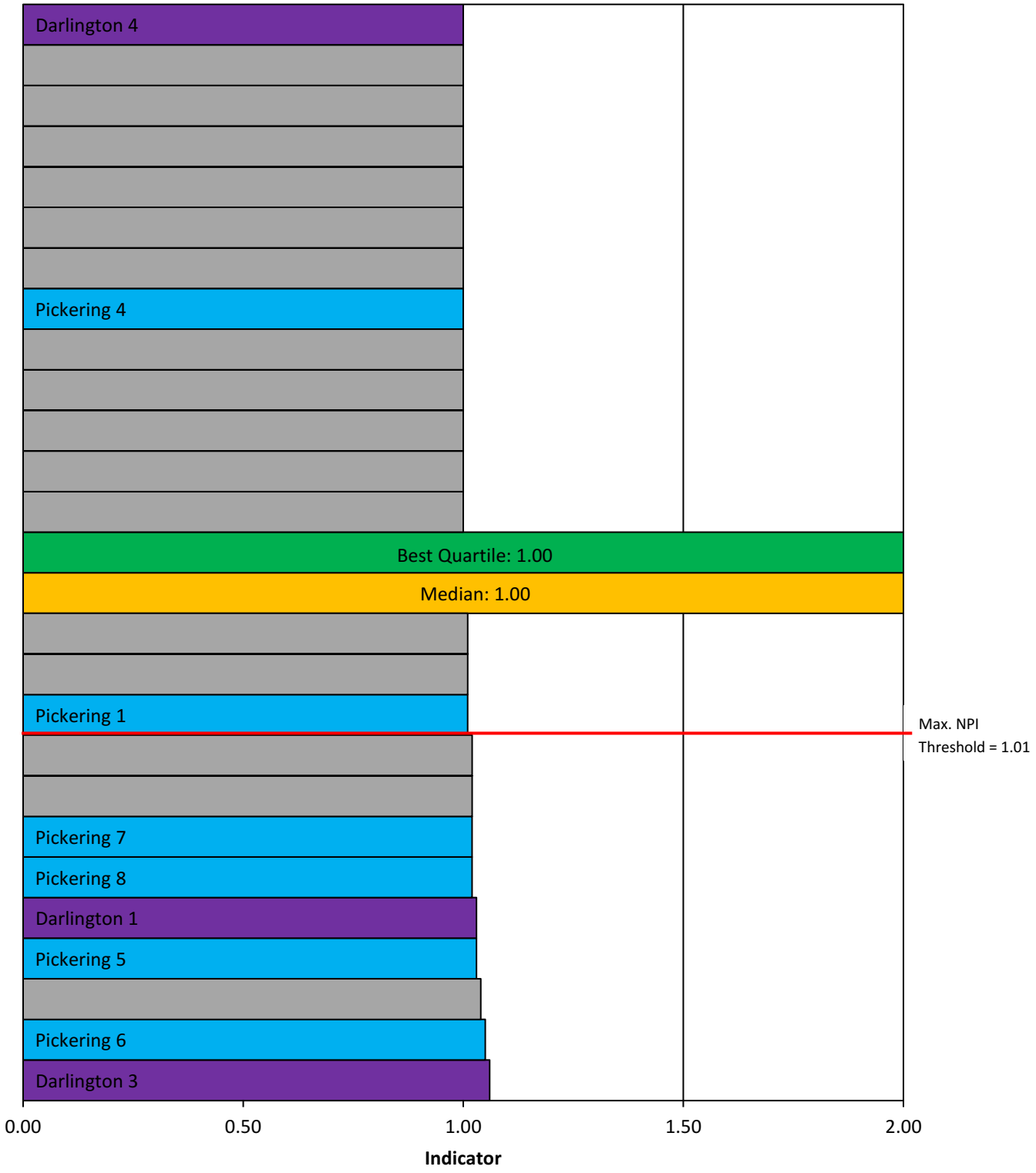




2018 Rolling Average Chemistry Performance Indicator
CANDU Plant Level Benchmarking



2018 Rolling Average Chemistry Performance Indicator
CANDU Unit Level Benchmarking



Observations – Rolling Average Chemistry Performance Indicator (CANDU)

2018 (Rolling 2 Year Average Pickering, Rolling 3 Year Average Darlington)

- CANDU plant median and best quartile values are 1.01 and 1.00, respectively.
- CANDU unit median and best quartile values are both 1.00.
- Pickering station CPI performance has maintained the same 1.02 in 2018 compared to 2017.
- Darlington station CPI performance has declined to 1.03 in 2018 from 1.01 in 2017.

Trend

- Overall Pickering station CPI performance has trended the same 1.02 per target in 2018 compared to 2017.
- Darlington station CPI overall performance has declined to 1.03 in 2018 from 1.01 in 2017.

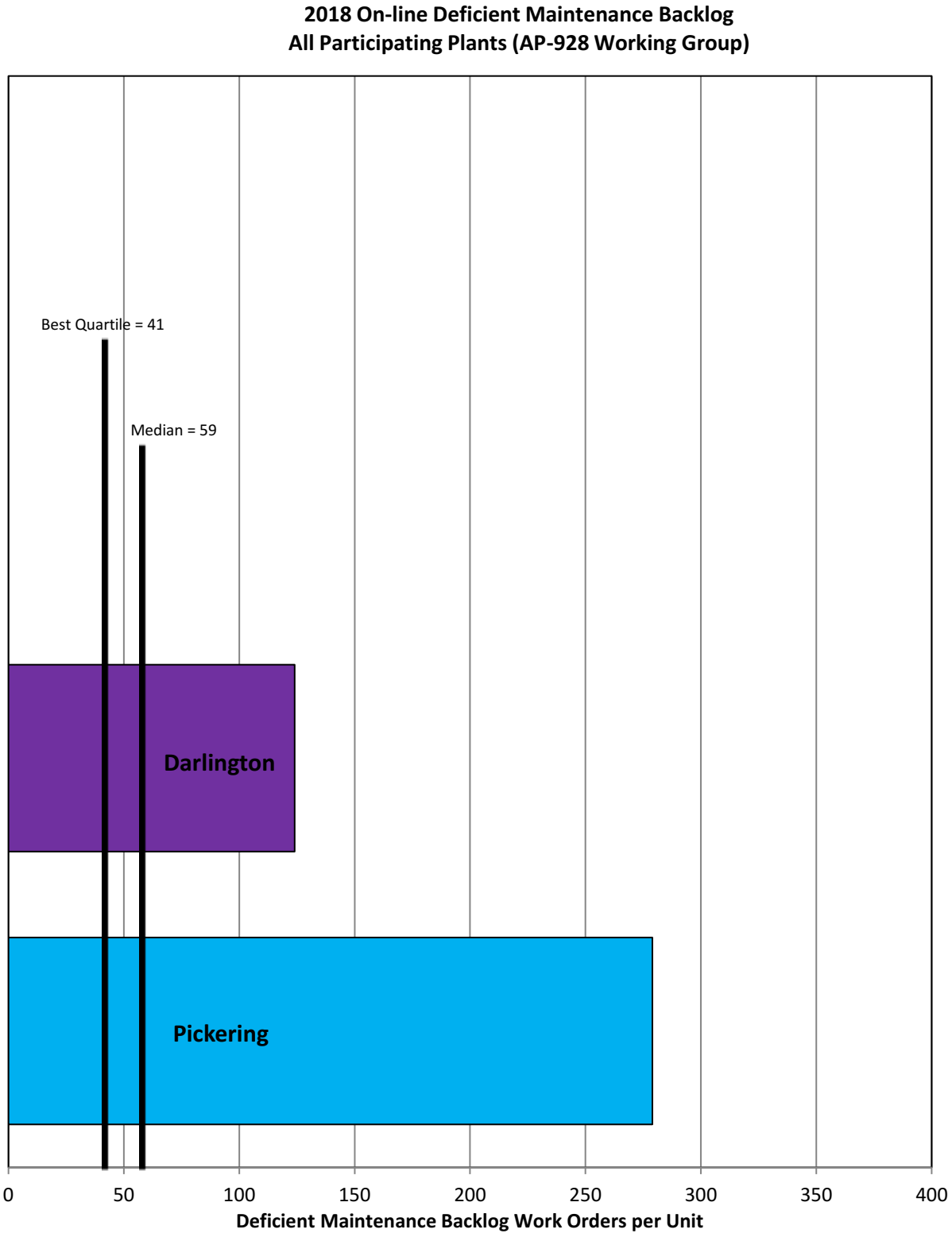
Factors Contributing to Performance

- Contributing factors for continuous chemistry performance improvement at Pickering include: improved outage Foreign Materials Exclusion (FME) practices, improved Water Treatment Plant (WTP) output quality controls, adherence to blowdown frequency, timely support from the Operations and Maintenance departments and improved advocacy at all levels.
- Darlington performance declined in 2018 due to chronic Unit 3 condenser tube leaks causing increased boiler conductivity, as well as increased Feed Water iron levels during startups following the unit outages. A Corrosion Product Transport (CPT) reduction plan is in place, which includes: condenser cleaning following maintenance, condenser hot well flushing prior to restart and placing condensate filtration unit in service during startup. All condenser tube leaks on Unit 3 have been isolated. Tube plugging is in progress.
- Best practices among top performing plants include:
  - Improved boiler layup practices during the planned outages;
  - Hot/cold soaks being performed to drive out impurities from the boilers. Boiler secondary side deposit minimization strategy (i.e. minimize impurity hideout and returns prior to start-up to normal operation in the boilers).
  - Timely condenser inspections and hot well cleaning to remove source of corrosion product transport (CPT) to boilers during start-up.
  - Timely reporting and clearing the action levels to stay within the specifications.
  - Organizational support to protect nuclear assets; elevate and escalate issues to bring back chemistry in the specification as soon as possible.
  - Condensate filtration to minimize CPT to boilers during the startup after the planned outage
  - Increased boiler blow downs to bring back/maintain boiler ions in the specification.

Chemistry initiatives in place to further improve CPI to best quartile:

- Boiler blowdown piping (buried section) improvement project at Pickering to support system reliability and availability to Station end-of-life.
- Condenser hot well cleaning during planned outages.
- EPRI Smart Chemistry online analyser demonstration at Darlington, which allows for early identification of degrading conditions.
- Implementation of post welding cleanliness instructions.
- Ongoing use of local portable feedwater dissolved oxygen analyzer carts at Pickering to ensure representative feed water dissolved oxygen monitoring.
- Ongoing oversight of Water Treatment Plant (WTP) product water quality to meet boiler make-up water specifications.
- Condensate Filtration for the control of corrosion product transport at Darlington during startup after planned outages.
- Qualification of Film Forming Amine (FFA) at Darlington for application as a planned outage pre-requisite to minimize corrosion and limit corrosion product to the boilers on startup.
- Procurement of a new WTP at Darlington for improved makeup water quality.
- Leveraging emergent work processes, utilizing cross-functional resolution teams, and advocacy forums to ensure a coordinated effort is timely to mitigate chemistry excursions.

1-Year On-line Deficient Maintenance Backlog



Observations – On-Line Deficient Maintenance Backlog (AP-928 Working Group)

2018 (Annual Value)

- The industry Best Quartile and Median Thresholds were 41 and 59 work orders per unit respectively for On-Line Deficient Maintenance (DM) backlog.
- Darlington DM backlogs were at 124 Work Orders per unit and deficient critical (DC) backlogs were at 9 work orders per unit
- Pickering DM backlogs were at 279 Work Orders per unit and deficient critical backlogs were at 9 work orders per unit

Trend

- In comparison to the 2017 data:
    - Darlington DM performance in 2018 has declined from 119 to 124 work orders per unit
        - Darlington DC performance improved from 15 to 9 work orders per unit
    - Pickering performance in 2018 improved from 383 to 279 work orders per unit
        - Pickering DC performance improved significantly from 41 to 9 work orders per unit
    - Median backlog has improved from 89 to 59 work orders per unit.

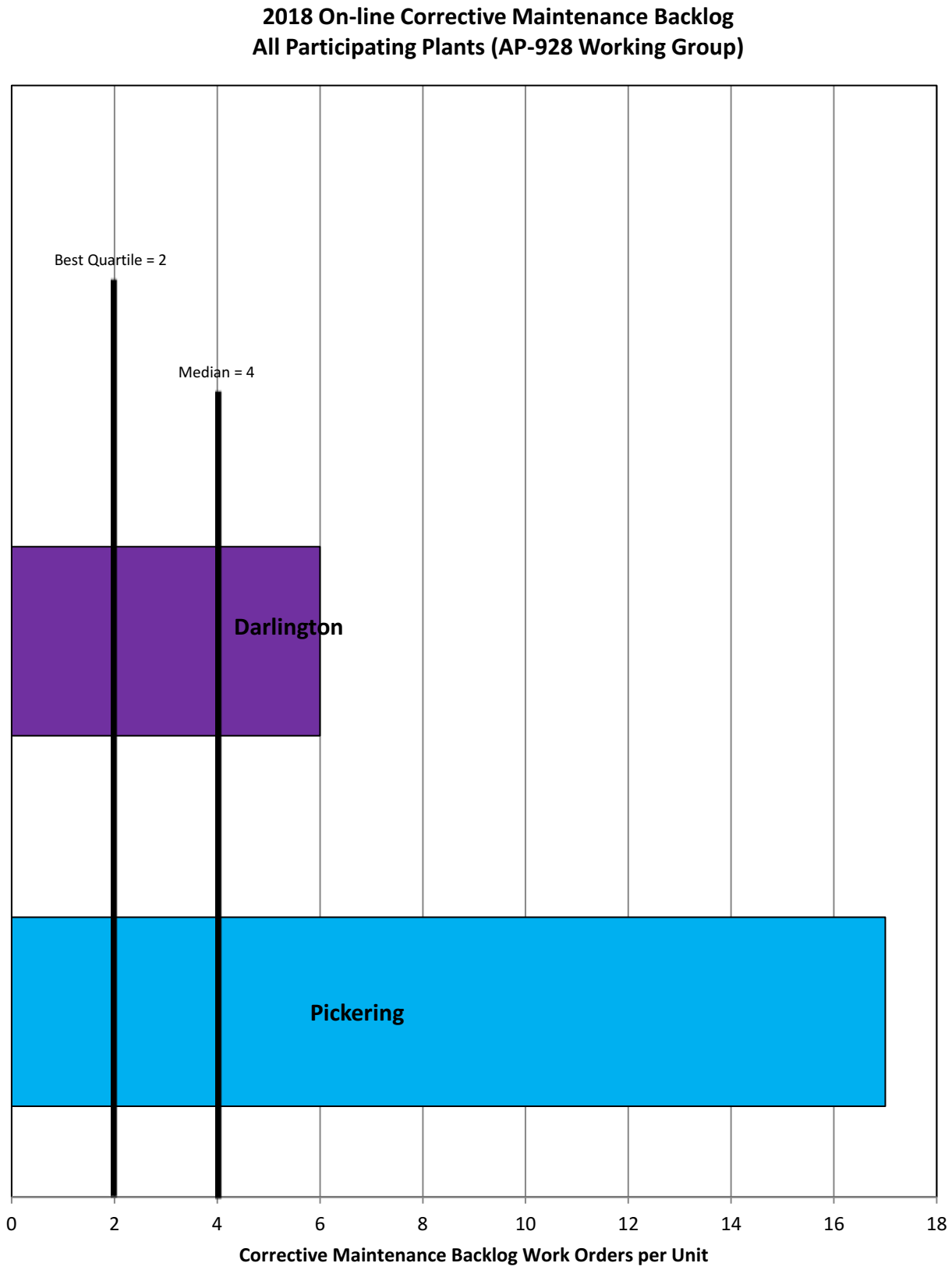
Factors Contributing to Performance

- At Darlington, the increase in deficient maintenance backlog is due, in part, to a deliberate focus on planning and scheduling corrective maintenance. Reducing the corrective backlog has a greater effect on the safe and reliable operation of the plant than the deficient items.
- At both stations, the focus has been to reduce on-line deficient critical and corrective critical backlogs, which has resulted in the corrective critical backlogs being at zero for Pickering and one for Darlington.
- To improve performance there are two fleet wide plans under Right Work, Right Time, Right Value initiative:
    - 1. Station Productivity:
        - Working Efficiently – to do more work without increasing resources
        - Assessing Optimization – to reduce resources required to plan work
        - Enhancing Fix It Now Teams – to complete more work without detailed planning
        - Resourcing Strategy – to optimize the focus of specialty crews; use of purchased services agreement to get non-core work done through contracting
        - Management & Leadership – to develop business acumen; foster an innovation culture; improve performance oversight and reporting

Factors Contributing to Performance (continued)

- 2. Value Based Maintenance:
  - Preventative Maintenance Program Reduction – to match the program to available resources and support condition based maintenance
  - Work Management & Resource Strategy – to align with supporting processes and maintenance strategy
  - Monitoring & Diagnostic Centre – to leverage technology to support value based and condition based maintenance strategies
  - Data Analytics and Reporting – to identify opportunities for improvement
  - Culture Shift – to adopt value based and condition based maintenance

1-Year On-line Corrective Maintenance Backlog



Observations – On-Line Corrective Maintenance Backlog (AP-928 Working Group)

2018 (Annual Value)

- The industry Best Quartile and Median Thresholds were 2 and 4 work orders per unit respectively for On-Line Corrective Maintenance (CM) backlog.
    - Darlington CM backlogs were at 6 Work Orders per unit and corrective critical backlogs were at 0 work order per unit
    - Pickering CM backlogs were at 17 Work Orders per unit and corrective critical backlogs were at 0 work orders per unit

Trend

- In comparison to the 2017 data:
    - Darlington performance in 2018 has improved from 13 to 6 work orders per unit
    - Pickering performance in 2018 has improved from 25 to 17 work orders per unit
    - Median backlog has improved from 6 to 4 work orders per unit.
- Darlington has shown backlog improvement from 2013 through 2018.
- Pickering has shown significant backlog improvement in each of the last four years.

Factors Contributing to Performance

- Refer to the Factors Contributing to Performance discussed above in the 1 Year On-Line Deficient Maintenance Backlog, as the same factors affect both backlog measures.

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 period from 2013-2018. 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. As a result, beginning in 2018, Pickering and Darlington's TGC per MWh performance has been normalized for CANDU technology (including outage duration) and age-related impacts.

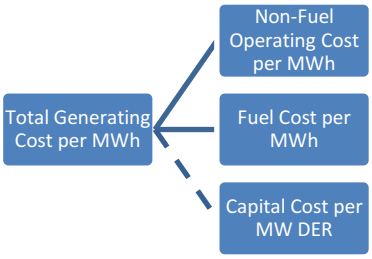
Darlington's TGC per MWh, NFOC per MWh and Capital Cost per MW DER performance have also been normalized for refurbishment. The refurbishment normalization methodology allows OPG to adjust the distribution of actual operating and capital costs to reflect Darlington as a three-unit site rather than a four-unit site. OPG is performing a mid-life refurbishment at Darlington, which involves the replacement of certain life-limiting components. It is necessary to normalize these metrics during refurbishment to allow for comparisons to prior site performance and industry peers, given reduced generation and no corresponding decline in fixed costs.

OPG engaged ScottMadden Management Consultants (ScottMadden) to develop the normalization methodologies[2]. The combined normalization allows for a more comparable assessment of performance between peers.

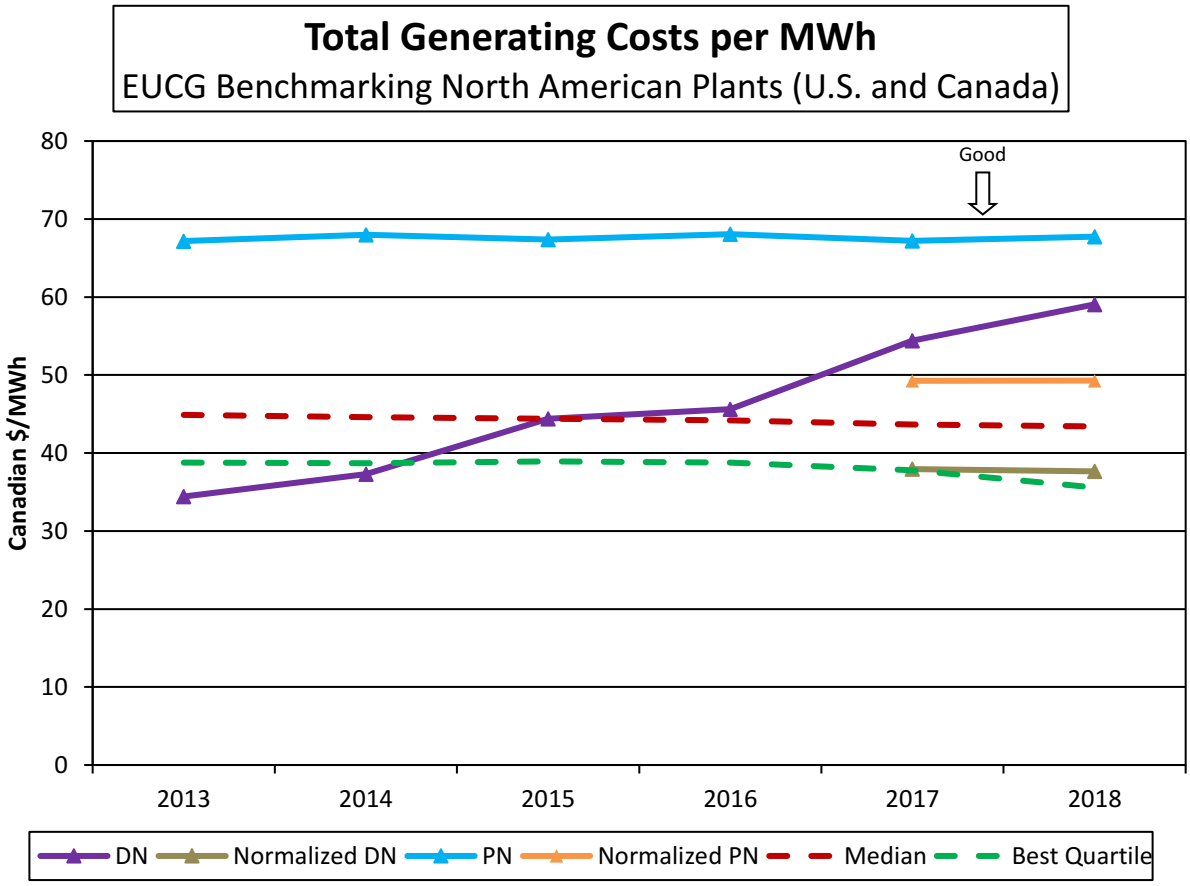
[2] Two ScottMadden normalization reports provide details on the normalization methodologies: 1) *A Study of Factors Impacting TGC/MWh Performance with Normalizing Adjustments to Facilitate Closer Comparison* and 2) *OPG Nuclear Cost Performance Benchmarking Methodology to Adjust for Refurbishment and Validation of Implementation*

The relationship underlying certain value for money metrics is shown in the illustration below. Total Generating Cost per MWh is the sum of Non-Fuel Operating Cost (NFOC), 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, it is difficult to compare plants by using non-fuel operating cost, fuel cost or capital cost metrics separately.

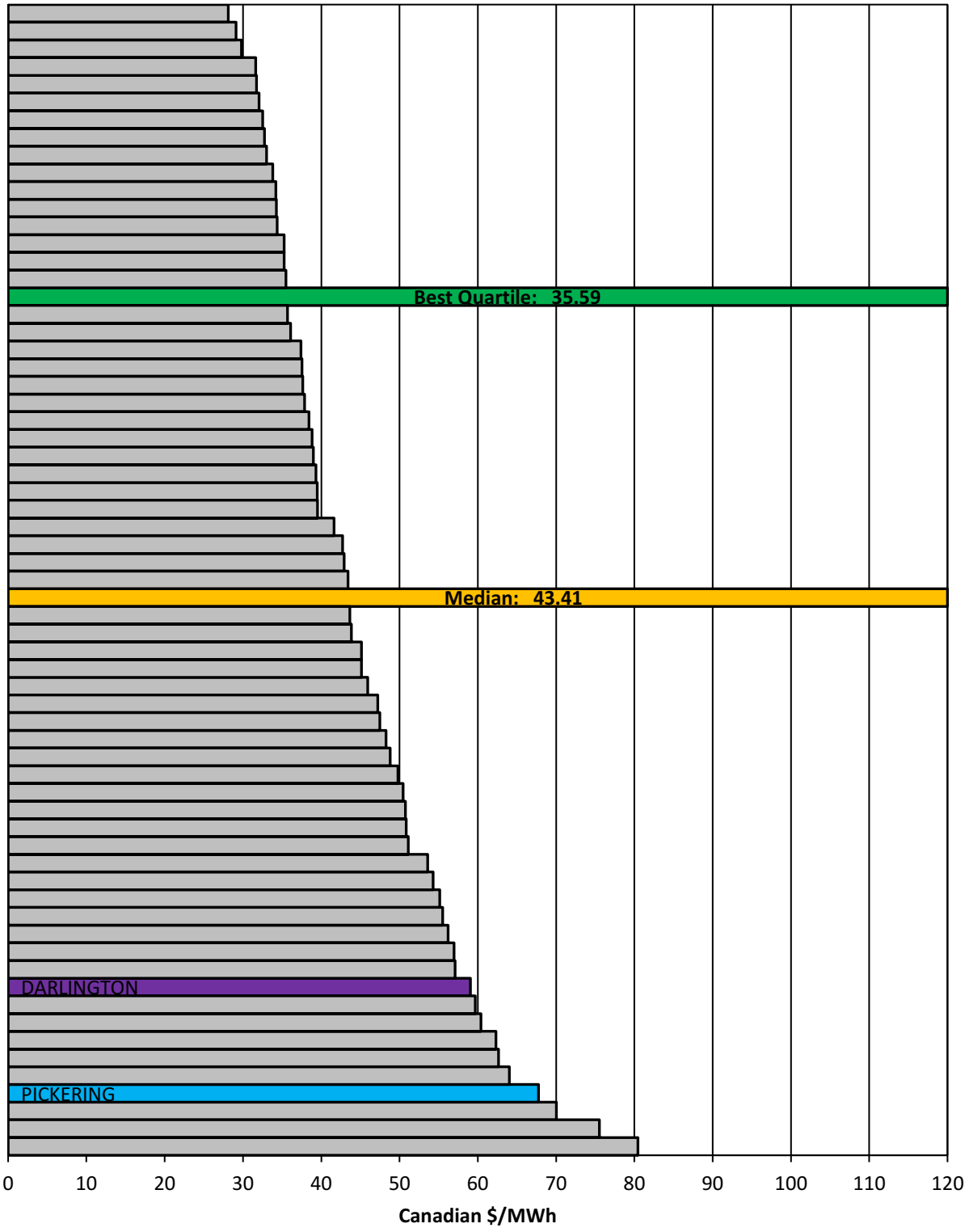
Diagram of Summary Relationship of Value for Money Metrics:



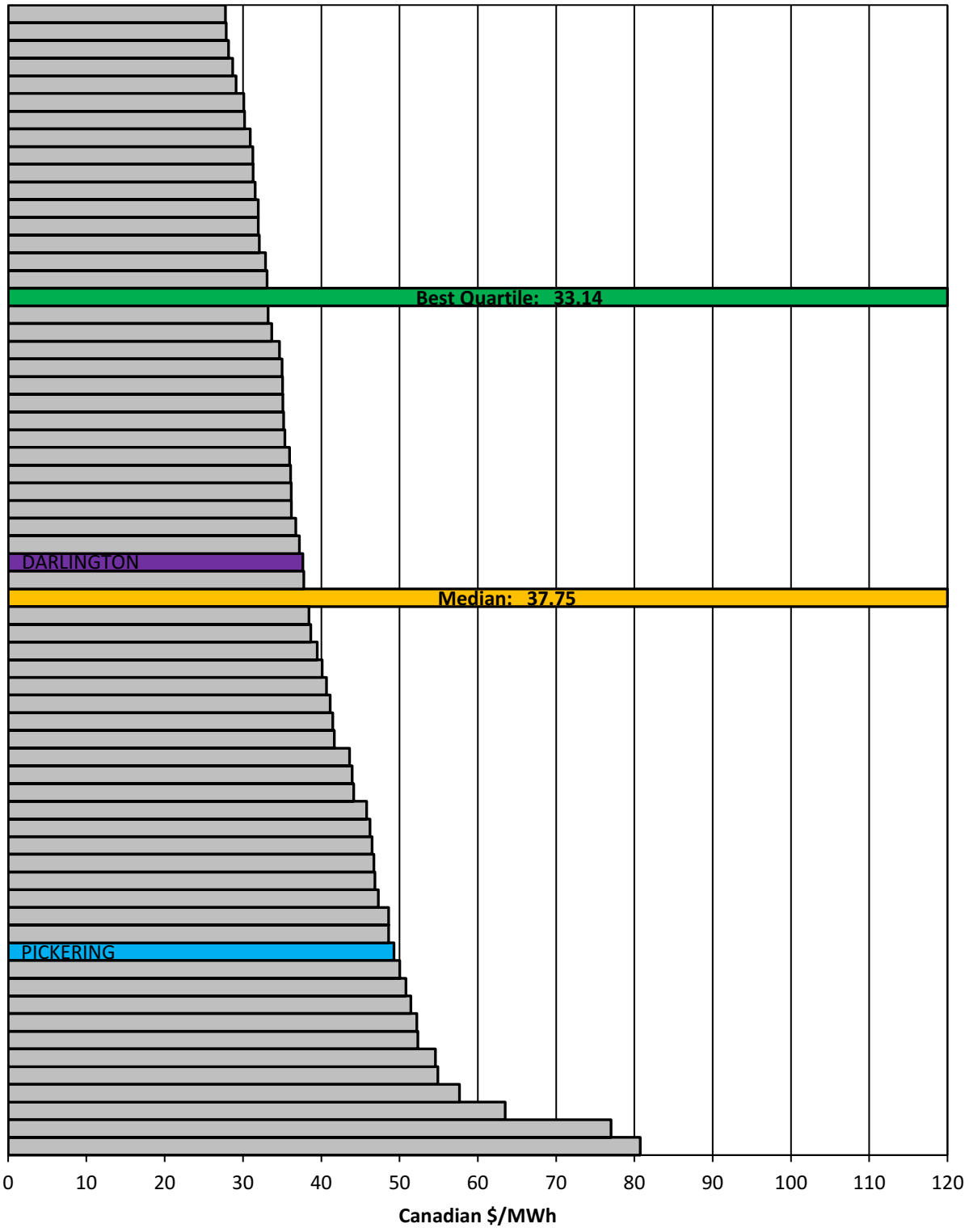
3-Year Total Generating Cost per MWh



2018 3-Year Total Generating Costs per MWh
EUCG Benchmarking North American Plants (U.S. and Canada)



2018 Normalized 3-Year Total Generating Costs per MWh
EUCG Benchmarking North American Plants (U.S. and Canada)



Observations – 3-Year Total Generating Cost per MWh (All North American Plants)

2018 (3-Year Rolling Average)

- The best quartile level for Total Generating Cost per MWh (TGC/MWh) among North American EUCG participants was $35.59/MWh while the median level was $43.41/MWh.
- Darlington normalized TGC/MWh was $37.65 and non-normalized was $59.06/MWh.
- Pickering normalized TGC/MWh was $49.29 and non-normalized was $67.76/MWh.

Trend

- Over the 2013 to the 2018 period the best quartile cost has improved by $3.20/MWh while the median cost improved by $1.48/MWh. Darlington non-normalized rose by $24.63/MWh and Pickering non-normalized rose by $0.58/MWh.
- Darlington's non-normalized costs increased over the review period with a compound annual growth rate (CAGR) of 11.4%.
- Pickering largely managed cost increases and remained flat over the review period with a CAGR of 0.2% whereas the best and median quartile levels had a CAGR of -1.7% and -0.7% respectively.

Factors Contributing to Performance

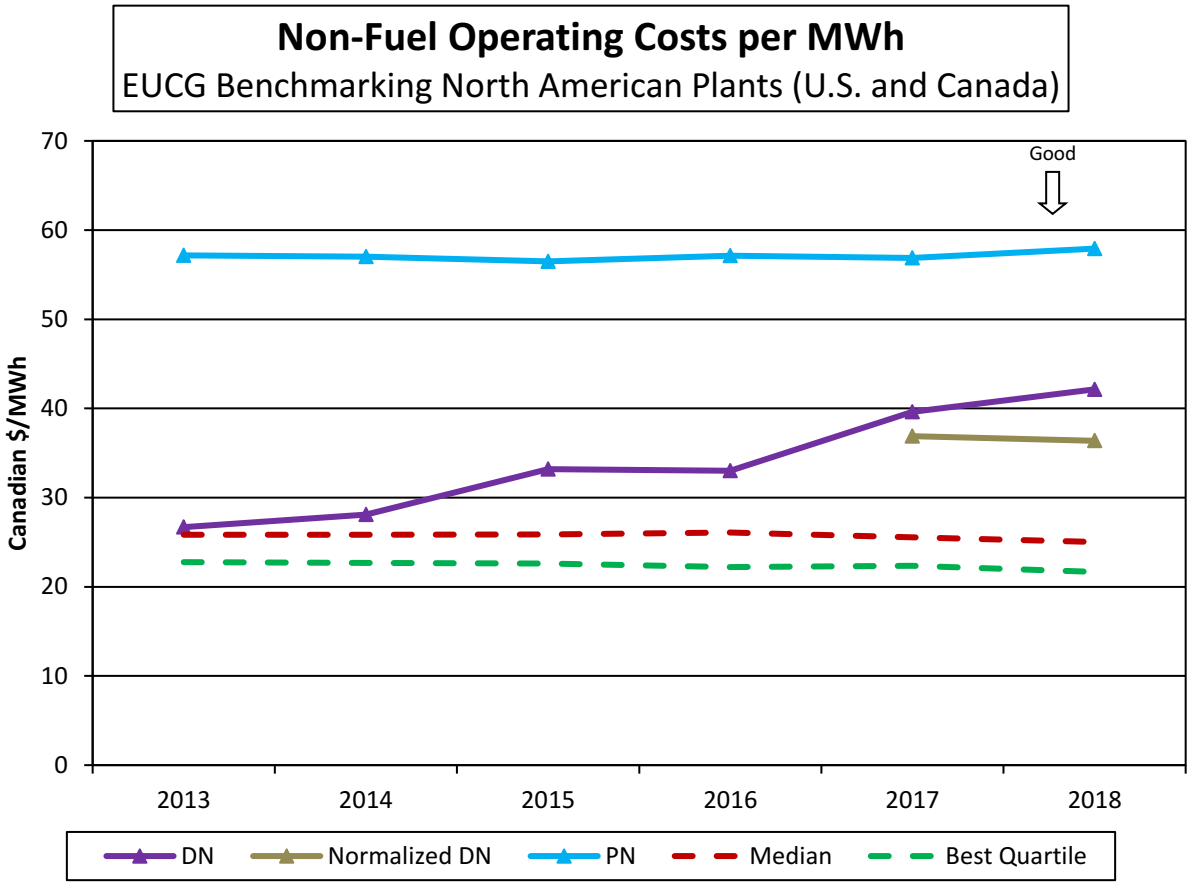
Darlington

- 3-Year Rolling Average for Darlington (non-normalized) from 2017 to 2018 rose $4.66/MWh. Primary drivers being lower generation (3,109 GWh) as well as approximately 20% increase in Capital from 2015 – 2018, an investment that will serve the station in its life post-refurbishment.
- Unit 2 being in Refurbishment significantly reduces generation. This lost generation was partially offset by the decrease in Planned Outage days by 157 days for the 2016-2018 period versus the 2015-2017 period mainly due to the Vacuum Building Outage (VBO) in 2015.
- Darlington performed within the best quartile for Fuel Cost per MWh while performing worse than the median for the Capital per MWh DER and Non-Fuel Operating Cost per MWh.
- For Non-Fuel Operating Cost, the larger equipment inventory in a CANDU unit compared to the pressurized water reactors and boiling water reactors units represents a net increase in maintenance and operations workload, which requires additional staff.

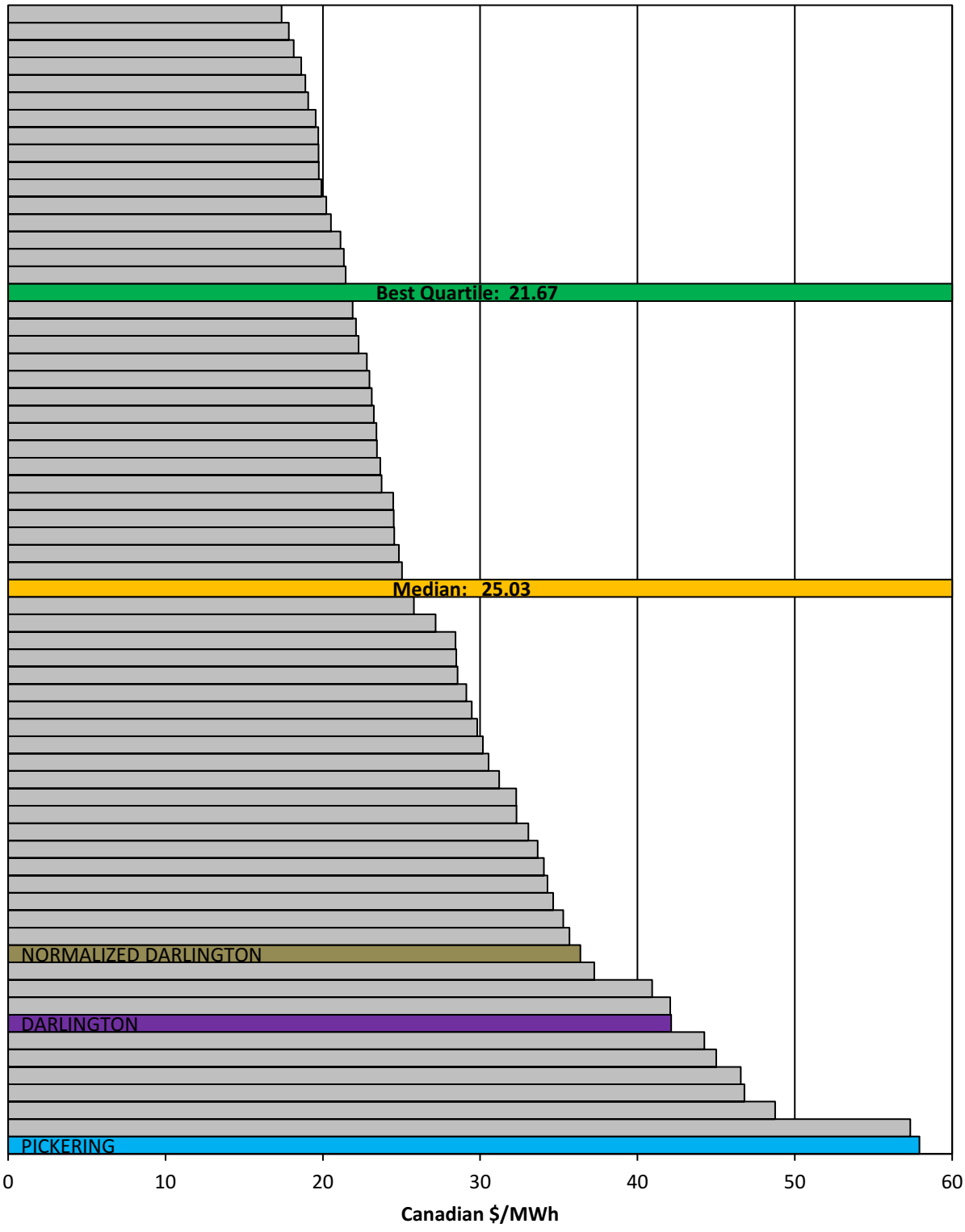
Pickering

- 3-Year Rolling Average for Pickering (non-normalized) from 2017 to 2018 rose by $0.53/MWh. Primary drivers being lower generation (379 GWh) and labour escalation & other inflationary impacts, which is mainly offset by improved Fuel Costs per MWh.
- Planned Outage days were essentially the same for years 2015-2017 and 2016-2018
- 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.
- For Non-Fuel Operating Cost, performance gap drivers for Pickering include capability factor, site capacity reflecting unit size, age of the plant, and the fact that Pickering was built based on first generation CANDU technology. 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.

3-Year Non-Fuel Operating Cost per MWh



2018 3-Year Non-Fuel Operating Costs per MWh
EUCG Benchmarking North American Plants (U.S. and Canada)



Observations – 3-Year Non-Fuel Operating Cost per MWh (All North American Plants)

2018 (3-Year Rolling Average)

- Best quartile plants had Non-Fuel Operating Costs per MWh (NFOC/MWh) at or below $21.67 while the median plant level threshold was $25.03/MWh.
- Darlington's non-normalized NFOC per MWh, at $42.14/MWh, was $20.47/MWh higher than best quartile and $17.11/MWh higher than the median. Darlington's normalized NFOC per MWh was $36.37/MWh
- Pickering's NFOC per MWh, at $57.92/MWh, was $36.25/MWh higher than best quartile and $32.89/MWh higher than median.

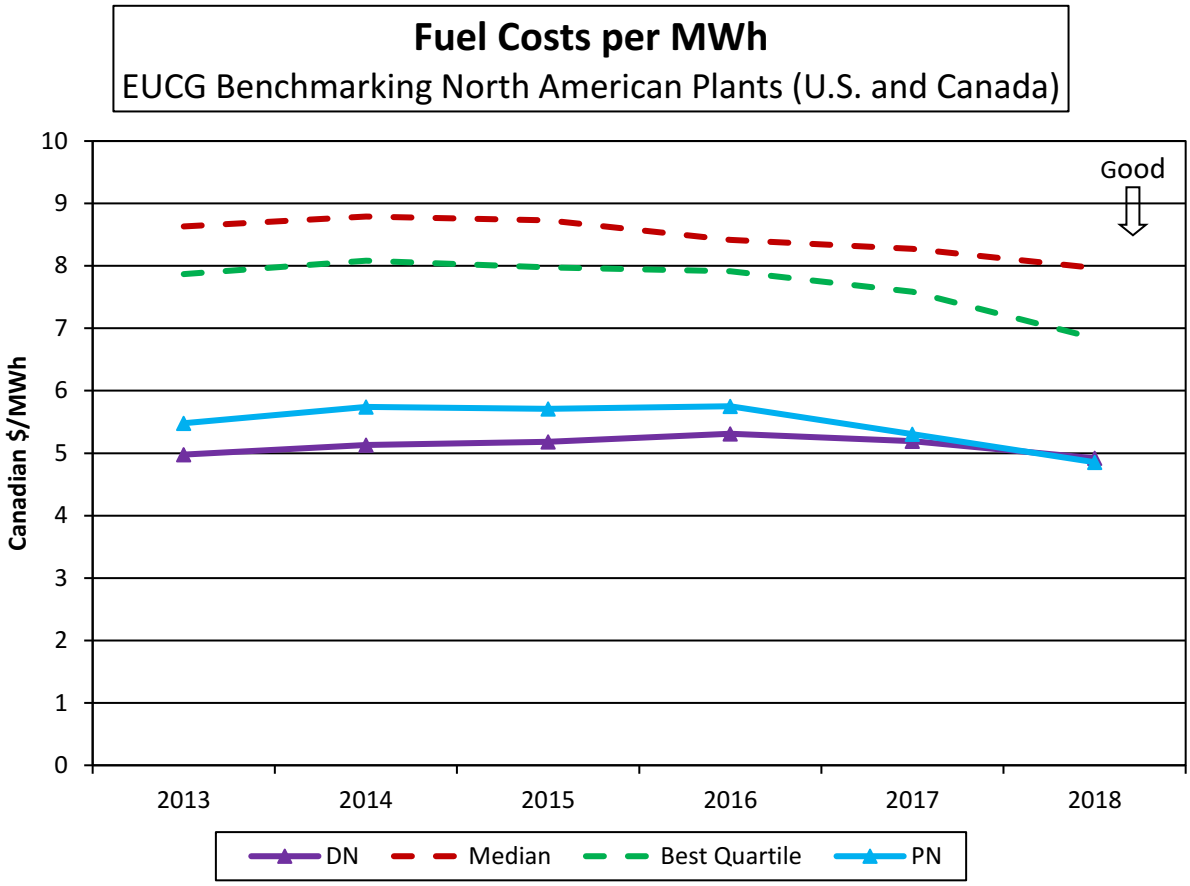
Trend

- Over the 2013-2018 review period the best quartile cost decreased by $1.09/MWh and the median also decreased by $0.80/MWh. Darlington non-normalized rose by $15.45/MWh and Pickering rose slightly by $0.77/MWh.
- Darlington's non-normalized NFOC/MWh had an annual compound growth rate (CAGR) of 9.6% from 2013 to 2018 as compared to -1.0% for the best quartile and -0.6% for median levels. The 2018 increase in Darlington's NFOC/MWh from 2017 is primarily due to lower generation associated with refurbishment.
- Pickering largely managed cost increases and remained relatively flat over the review period with a CAGR of 0.3% whereas both the best and median quartile levels had a CAGR of -1.0% and -0.6% respectively.

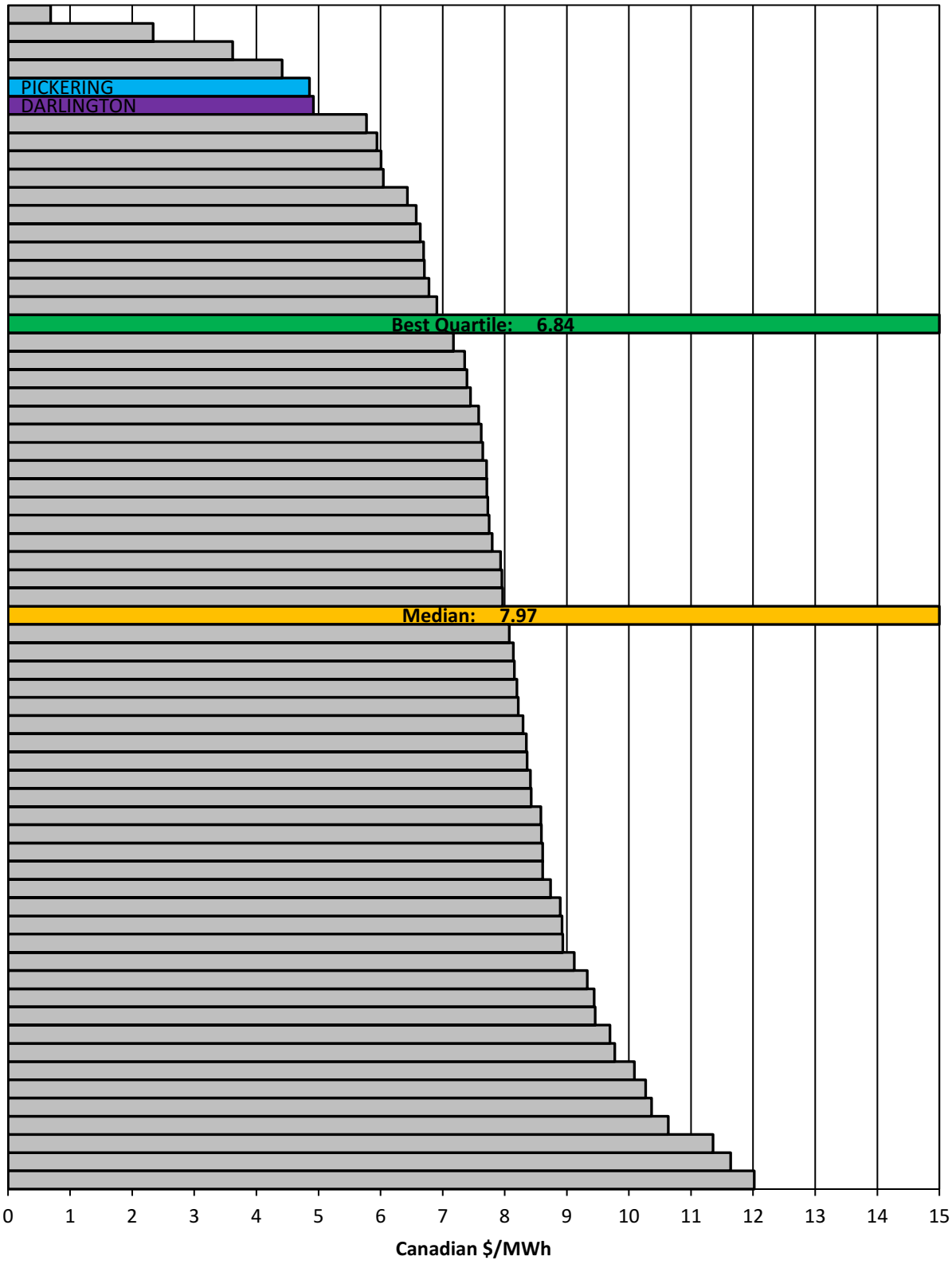
Factors Contributing to Performance

- 3-Year Rolling Average for Darlington (non-normalized) from 2017 to 2018 rose $2.52/MWh. Primary drivers is lower generation (3,109 GWh) associated with Darlington Refurbishment.
- Darlington's Planned Outage days decreased by 157 days for the 2016-2018 period versus the 2015-2017 period mainly due to the Vacuum Building Outage (VBO) in 2015.
- 3-Year Rolling Average for Pickering from 2017 to 2018 rose by $1.03/MWh. The primary drivers are lower generation (379 GWh) and labour escalation & other inflationary impacts.
- Pickering's Planned Outage days were essentially the same for years 2015-2017 and 2016-2018
- Performance in Non-Fuel Operating Cost per MWh drives the majority of OPG's financial performance. Overall, the biggest drivers include: capability factor, site capacity reflecting unit size and CANDU technology. 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 site capacity driver is the combined effect of number of units and size of units which can have a significant impact on performance.
    - The 'CANDU technology' driver reflects specific cost requirements related to the overall engineering, maintenance, and inspection costs. 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 study also found that labour for CANDU stations is approximately 20% higher than in benchmarked PWR stations.

3-Year Fuel Cost per MWh



2018 3-Year Fuel Costs per MWh
EUCG Benchmarking North American Plants (U.S. and Canada)



Observations – 3-Year Fuel Cost per MWh (All North American Plants)

2018 (3-Year Rolling Average)

- Fuel Cost per MWh for all Canadian CANDU plants are better than the best quartile threshold ($6.84/MWh) for the panel of North American EUCG plants.
- The three CANDU plants in the peer panel ranked in the top six lowest fuel cost plants in the North American panel.

Trend

- The best quartile Fuel Cost per MWh has trended lower over 2017 and 2018.
- Fuel Cost per MWh for all OPG plants decreased in 2018. The decrease in the Fuel Cost per MWh is due to a combination of lower input uranium costs offset by general escalation in the fuel conversion and fuel fabrication costs.

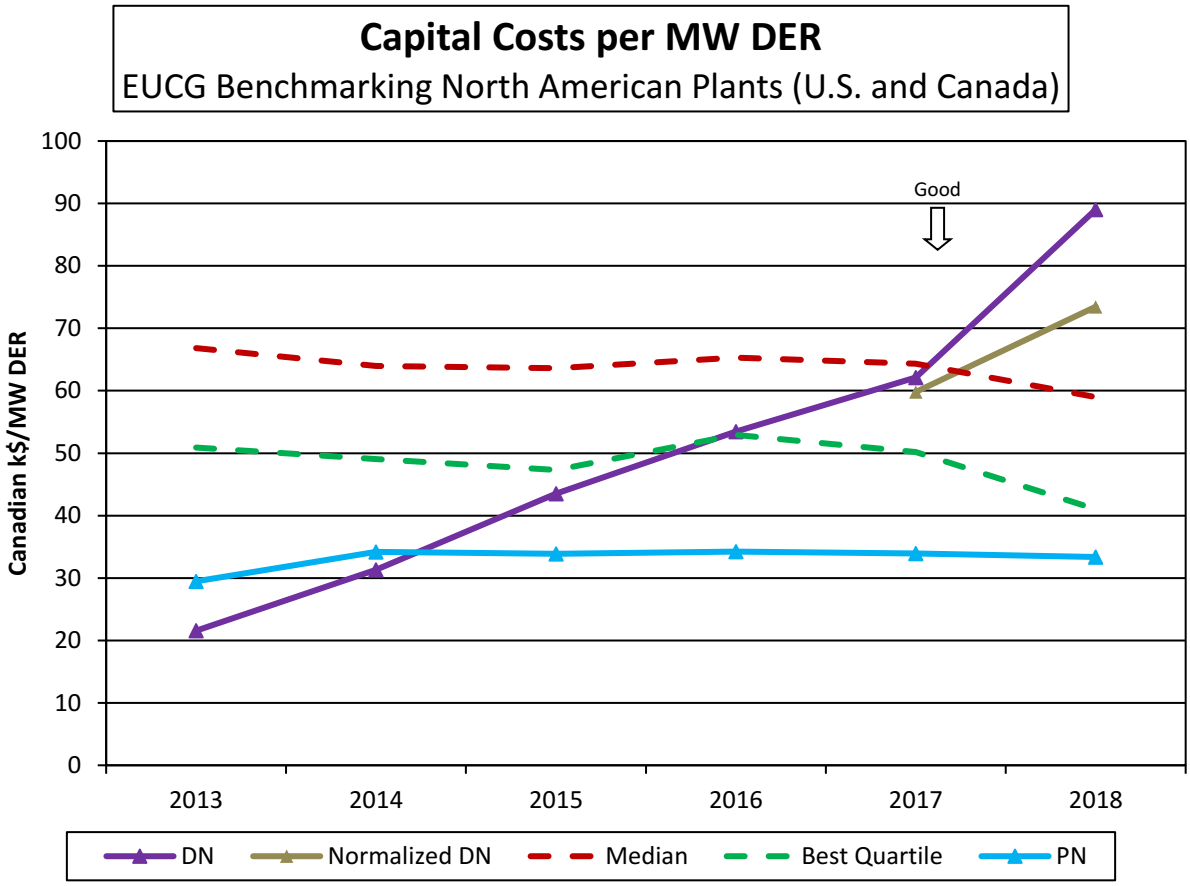
Factors Contributing to Performance

- Fuel costs, primarily driven by the technological differences in CANDU technology, are lower for OPG than most 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.

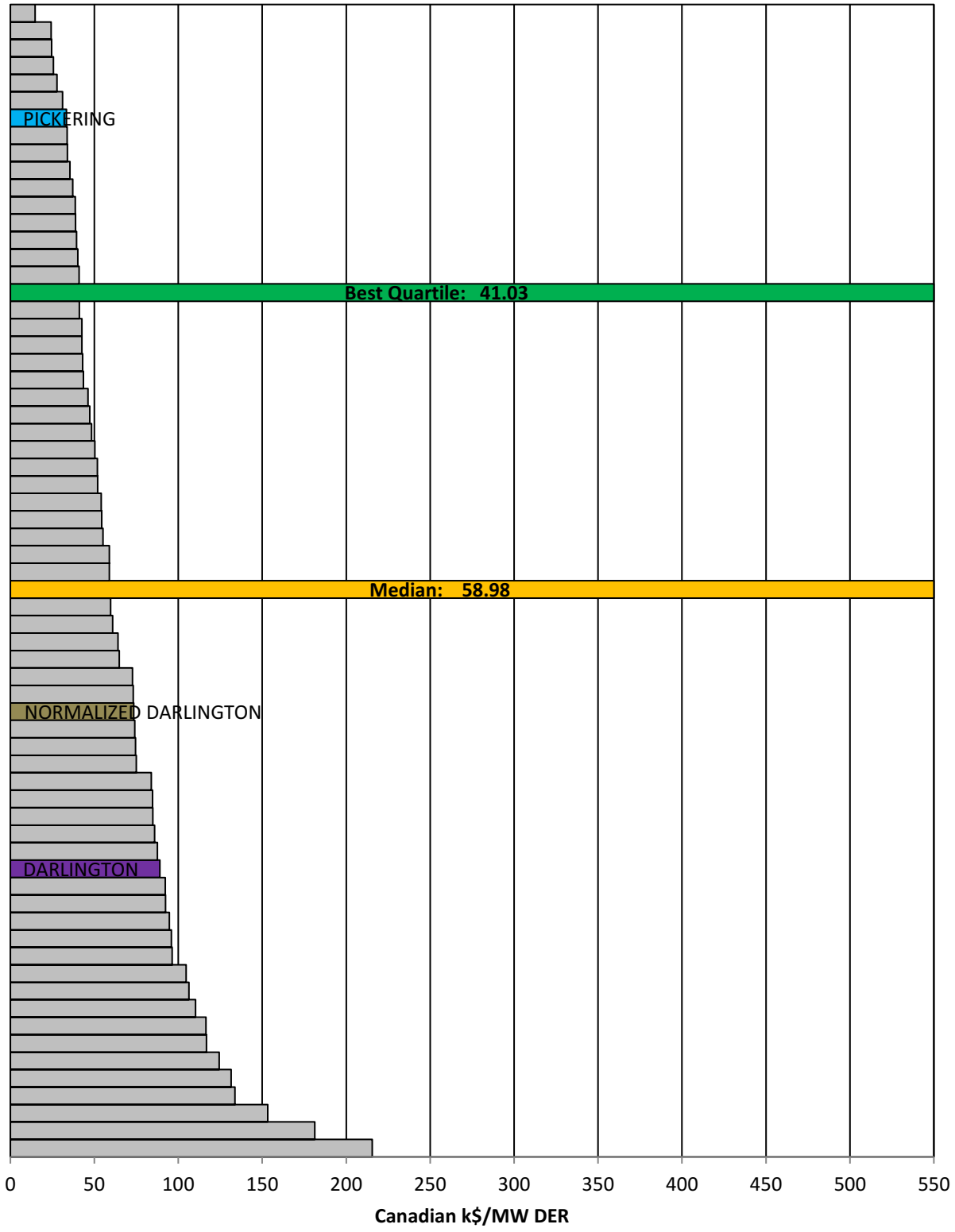
Best quartile fuel cost performance noted above is due to the following factors:

- 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. The advantage due to fuel costs also includes 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.

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



2018 3-Year Capital Costs per MW DER
EUCG Benchmarking North American Plants (U.S. and Canada)



Observations – 3-Year Capital Cost per MW DER (All North American Plants)

2018 (3-Year Rolling Average)

- The first quartile threshold for Capital Cost per MW DER across US and Canadian EUCG peer plants was $41.03 k/MW DER.
- Median cost for the panel was $58.98 k/MW DER.
- Pickering was lower than the first quartile threshold at $33.39 k/MW DER, whereas Darlington is in the third quartile at $89.03 k/MW DER. Darlington normalized is $73.46 k/MW DER.

Trend

- The first quartile and median thresholds decreased in 2018 due primarily to reduced regulatory spending on Fukushima response and NFPA 805 implementation as well as reduced sustaining spending, partially offset by increased spending on reliability improvements, information technology and infrastructure.
- Pickering's Capital Cost per MW DER declined marginally in 2018.
- Darlington's Capital Cost per MW DER increased to make necessary capital investments for Darlington's post-Refurbishment life, performance improvements, sustaining investments, capital spares and Fukushima response.

Factors Contributing to Performance

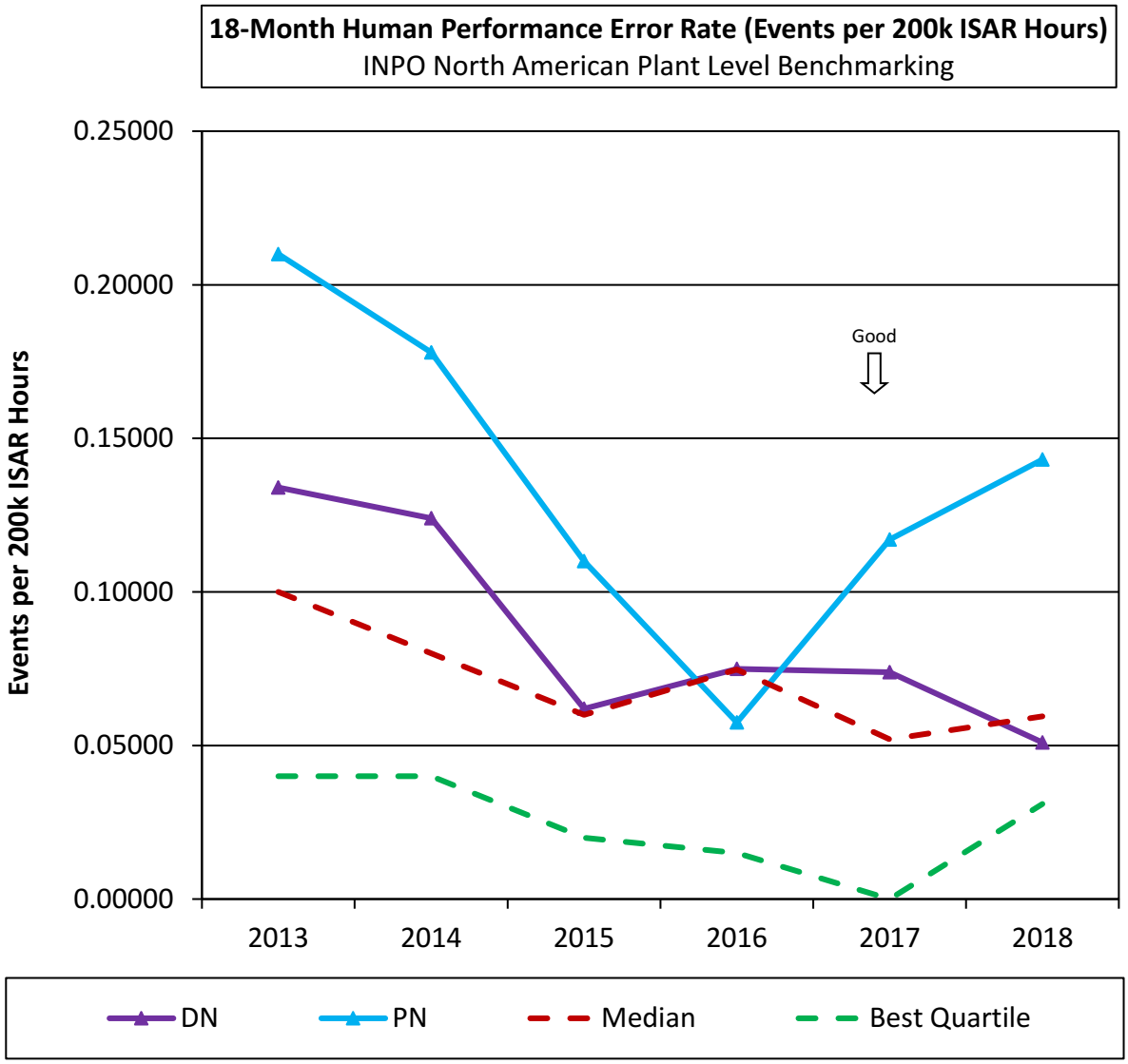
- Pickering is performing in the first quartile for the period. This reflects steady spending to maintain reliable operations in the period leading up to the end of commercial operations.
- Darlington is performing in the third quartile for the period. This reflects increased spending on enhancements, regulatory projects (including Fukushima response), sustaining investments, and capital spares to support post-refurbishment operations.

5.0 HUMAN PERFORMANCE

Methodology and Sources of Data

The Human Performance Error Rate metric is used to benchmark the performance of OPG's Nuclear fleet against other INPO utilities in the area of Human Performance. This will ensure a continued focus on improving Human Performance.

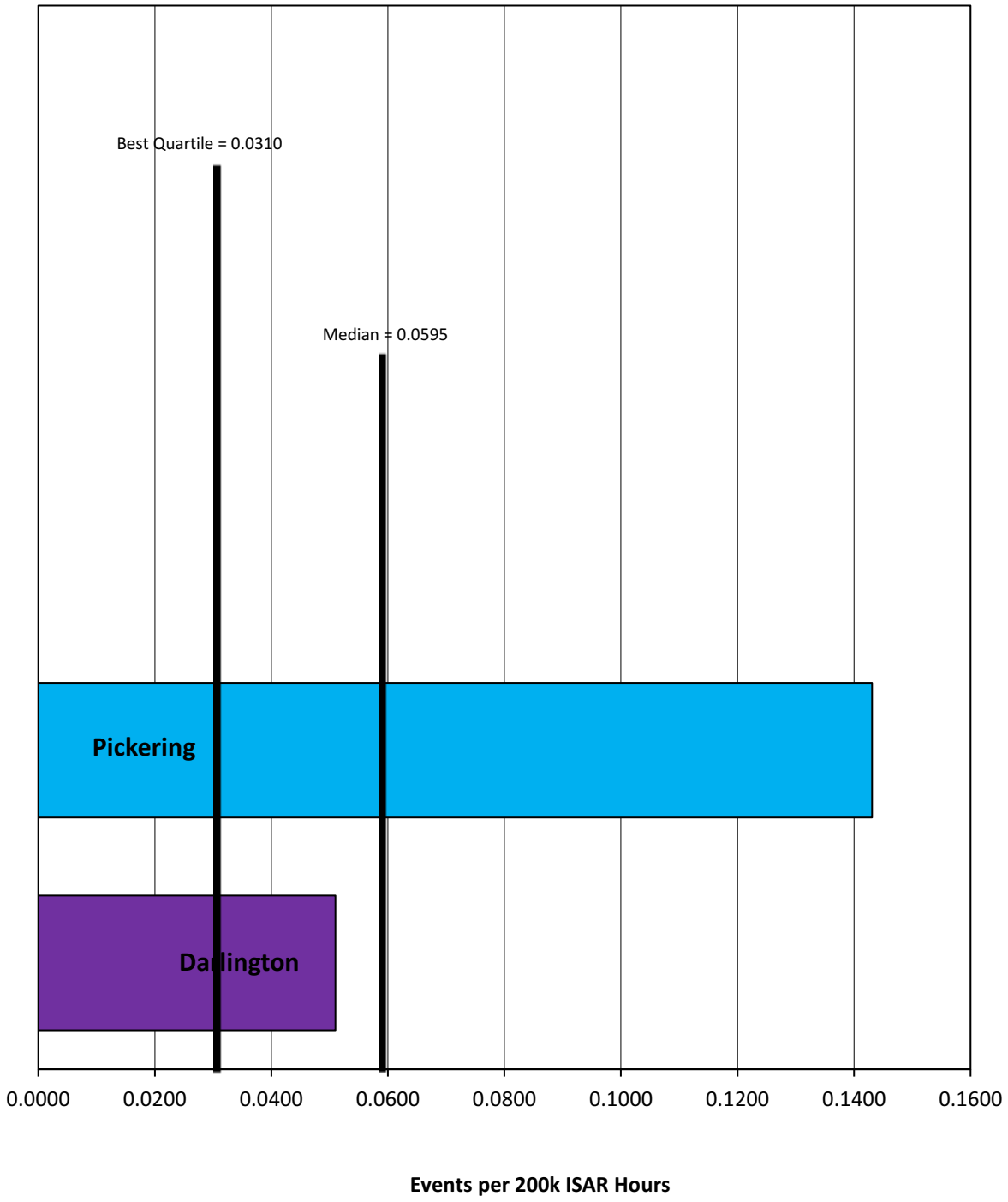
18-Month Human Performance Error Rate



** The 2016 and 2017 Darlington values have been updated to reflect the exclusion of Refurbishment hours and the 2016 Pickering value has also been corrected.*

2018 18-Month Human Performance Error Rate

INPO North American Plant Level Benchmarking



Observations – 18 Month Human Performance Error Rate (INPO North American Plants)

2018 (18 Month Rolling Average)

- The industry 18-month Human Performance Error Rate (HPER) has shown a decline in performance in the INPO top quartile performance. The 2018 INPO best quartile is 0.0310 compared to 0.000 in 2017 representing a decline in performance which was steadily improving from 2015 to 2017, reaching 0.000. The median quartile has also increased since 2017 when it was 0.0520 and currently at 0.0595 representing an overall slight decline in performance in 2018. However, the overall trend since 2012 is showing improvement in the median.
- Compared to the INPO peer group OPGN performance for Pickering and Darlington performance is as follows:
    - Pickering station performance has declined with the HPER at the end of 2018 of 0.1431, compared to 0.117 in 2017, and compared to the best industry quartile of 0.0310, and the industry median of 0.0595.
    - Darlington station performance continues to show improvement with the HPER at the end of 2018 at 0.051, compared to 0.0738 in 2017, and 0.07498 in 2016. It is worse than the best quartile performance of 0.0310, and better than the median of 0.0595.

Trend

- The industry 18-month Human Performance Error Rate (HPER) has shown improved performance year over year in the INPO top quartile performance. The 2017 INPO best quartile achieved 0.0000 representing continued improvement in performance since 2012. However, at the end of 2018 the Top Quartile result has risen to 0.031 indicating a decline in Human Performance (HU).
- The median quartile increased in 2018 from 0.052 in 2017 to currently 0.059 also showing a decline in performance. The overall trend since 2012 was showing improvement in the top quartile and median performance for 5 years, however in 2018, both rates are showing a decline in performance.
- Pickering was showing improvement in HU since 2013 to 2016 when it had reached its' lowest rate of 0.0575 at the end of 2016, below the industry median. However, in 2017 and 2018 the performance has declined to 0.117 and 0.1431 respectively showing a declining trend.
- Darlington performance since 2013 has shown an improving trend, with a slight increase in rate in 2016 to 0.07498 followed by 0.0738 in 2017, and 0.051 in 2018 which is better than the Median rate of 0.0595. The overall trend is in the positive direction.
- The fleet (Pickering and Darlington) target for Site Event Free Day Resets (S-EFDRs) for 2018 was four and five S-EFDRs occurred. One S-EFDR occurred at Refurbishment against a target of 2.
- Note: Refurbishment S-EFDRs are not included in overall fleet S-EFDR targets.

Factors Contributing to Performance

- The top 3 gaps to industry excellence in Human Performance are:
  - Proficiency in application of technical fundamentals across line organizations (Operations, Maintenance, Radiation Protection, etc). Line organizations are addressing these gaps through targeted training, and Observation and Coaching (O&Cs). The new Pre Job Brief/Safe Work Plan/Post Job Debrief (PJB/SWP/PJD) process includes enhanced focus on application of technical fundamentals during PJBs.
  - Consistent, robust application of Procedure Use and Adherence (PU&A) practices and inconsistent focus on rapid revision process and quality of procedures. Targeted O&Cs are being used to monitor PU&A practices and provide reinforcing and coaching to strengthen PU&A behaviours. The HU Advocates are being trained in delivering O&Cs to provide additional peer-to-peer coaching.
  - Consistent, robust application of verification practices. A verification practices fleet Self Assessment was completed and an improvement plan is being implemented that includes Dynamic Learning Activities (DLAs), targeted O&Cs, and industry benchmarking.

- The 2019-2021 HU Fleet Excellence Plan is being implemented and is on-track. It promotes a continuous learning culture fostered by a collaboration between a high performing HU Peer Team and line organizations that drives continuous improvement in targeted focus areas across the fleet. The site HU plans are aligned with the fleet HU Excellence Plans such that the key strategic initiatives to improve fleet performance are reinforced.
- The action plan is on track. The 2019-2021 HU Excellence Plan targets five areas of strategic focus:
  - Nuclear Professionals (NPs) Driving Business Results (NP/HU integration, PJB improvements)
  - One Team with Vendor Partners (Improve vendor HU proficiency)
  - People Powering the Future (HU training improvements)
  - Innovation for the Future (Innovation to improve HU trending)
  - Right Work, Right Time, Right Value (Simplify event evaluation tools)

Key improvement areas in 2018:

- Self assessments results have been used to develop strategic actions to drive improvements in HU areas such as verification practices, HU advocates, HU training, pre-CNSC Type II Inspection, HU Event Communication and Analysis, O&Cs, error rates, Accountability Analysis, and Operational Decision-making.
- The Pre Job Brief/Safe Work Plan/Post Job Debrief (PJB/SWP/PJD) governance was revised to strengthen risk awareness and mitigation, streamline and improve the process, and engage key stakeholders in developing improvements.
- The HU Event Communication and Analysis governance was revised and produced several enhancements to the Accountability Analysis Tool. This process is contributing positively toward a learning culture as recognized by WANO, NSRB, and One OPG Culture Survey.
- HU Advocate Program improvements include enhanced selection and training, and it was recognized as a good practice during a Pickering Organizational Effectiveness WANO visit to strengthen peer-to-peer coaching and engagement.
- The HU Vulnerability Index has been implemented as a proactive tool to identify early stages of HU decline, and several proactive interventions have been used to prevent station events.
- A Flight Simulator is being assembled onsite to provide an innovative training tool to strengthen Nuclear Professional (NP) and HU behaviours.
- An iConnect O&C mobile application has been implemented across most of the fleet to document and trend O&C results in efficiently. It includes Power BI trending functions for analysis and trending.

Careful change management and acknowledgement of vulnerability periods with appropriate mitigation strategies are needed by line managers.

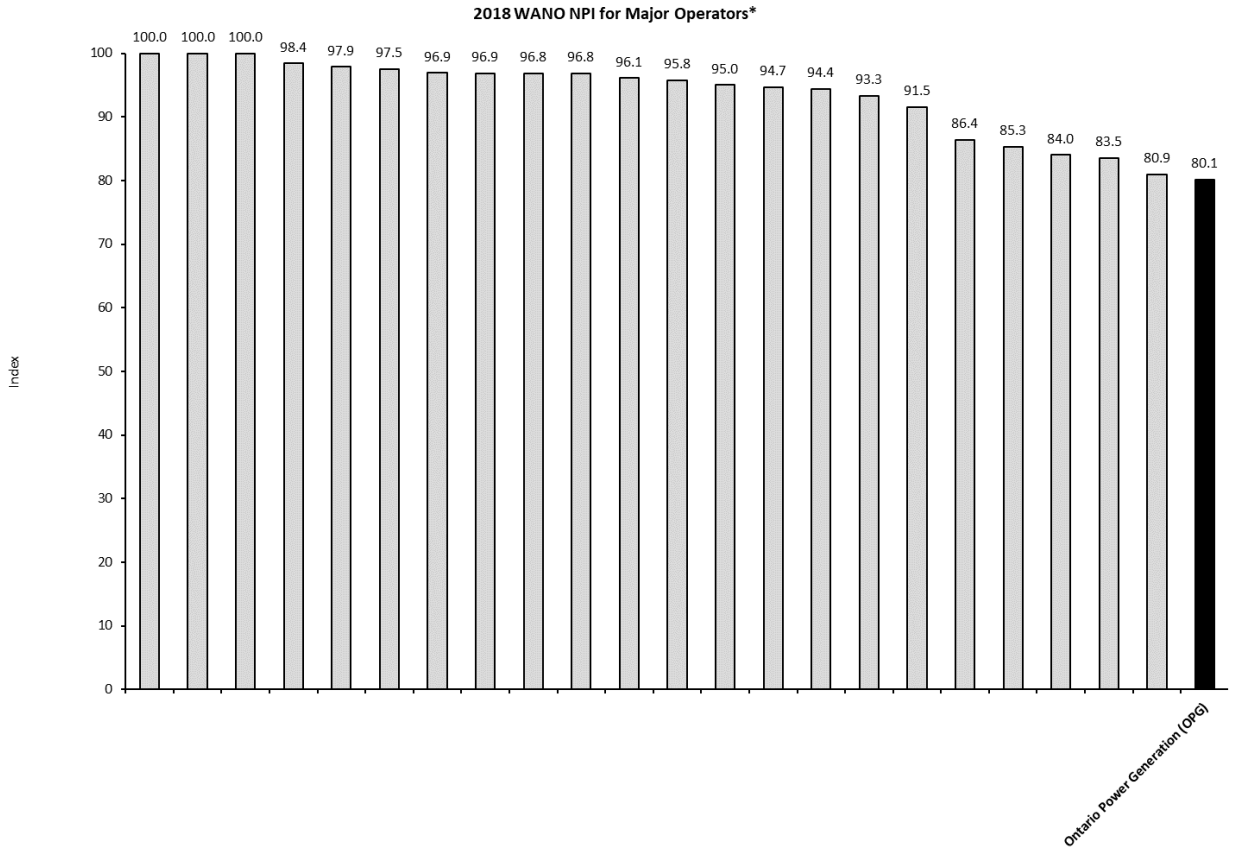
6.0 MAJOR OPERATOR SUMMARY

Purpose

This section provides a 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 compares 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.

WANO Nuclear Performance Index Analysis

The WANO Nuclear Performance Index (NPI) results for the operators in 2018 are illustrated in the graph below. OPG Nuclear performance ranking remained the same from 2017 shown in Table 2.



*See Table 7 in the Appendix for listing of operators and plants.
**OPG Nuclear unit values averaging to a WANO NPI of 80.1 in 2018 are shown below:

Unit	2018 WANO NPI
Pickering 1	68.4
Pickering 4	73.5
Pickering 5	82.6
Pickering 6	68.6
Pickering 7	85.0
Pickering 8	71.1
Darlington 1	91.3
Darlington 2	N/A
Darlington 3	87.4
Darlington 4	93.5

OPG ranked 23rd, with an NPI of 80.1. OPG's NPI performance increased by 1.6 compared to the 2017 ranking.

The NPI rankings of the major operators from 2013 to 2018 are listed in Table 2. The list and ranking of operators has been updated to reflect any industry developments if applicable.

Table 2: Average WANO NPI Rankings

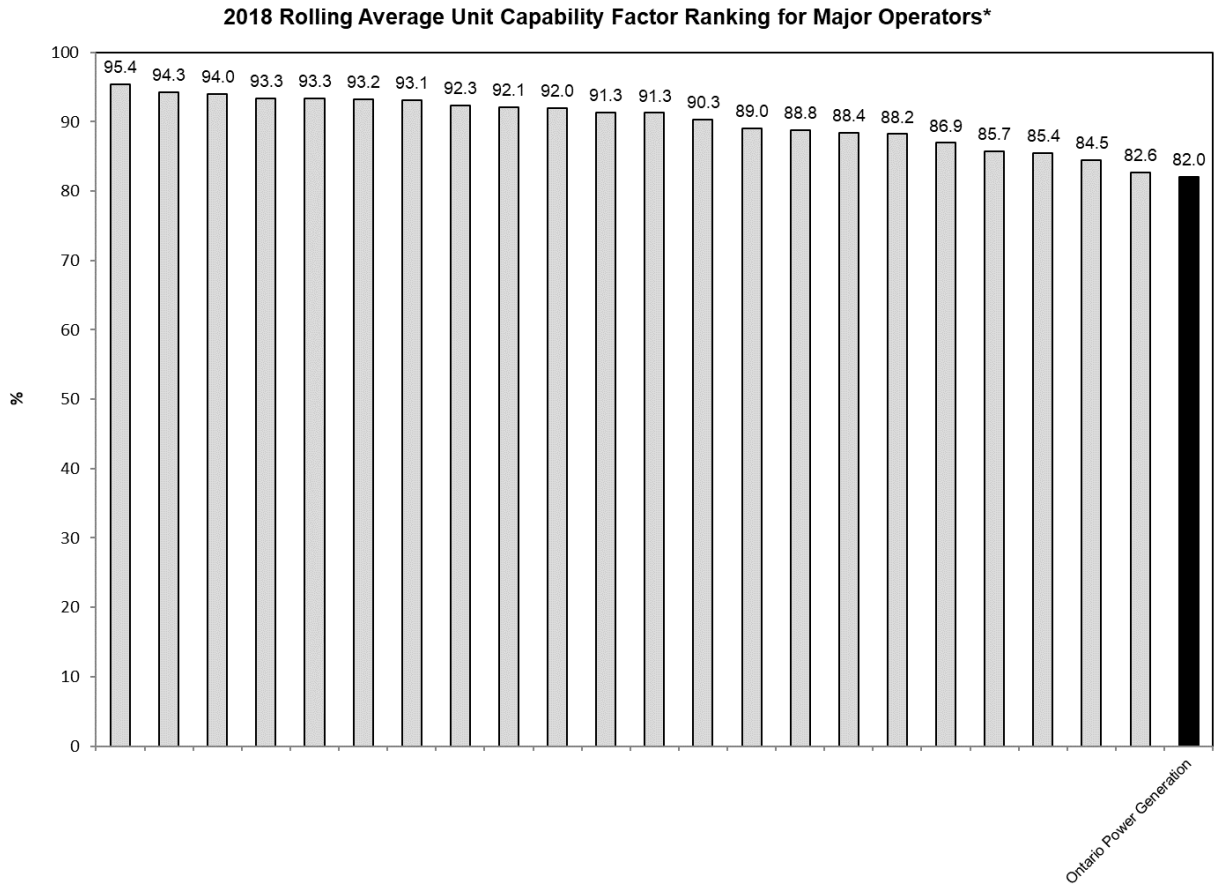
Operator	2013	2014	2015	2016	2017	2018
	10	5	5	3	1	1
	13	2	4	13	2	2
	15	18	21	15	6	3
	5	4	6	6	7	4
	4	7	10	7	5	5
	1	13	9	9	9	6
	23	19	7	11	14	7
	6	10	8	10	8	8
	9	12	16	14	3	9
	8	9	2	2	4	10
	24	3	15	16	12	11
	18	20	20	12	10	12
	12	16	1	8	13	13
	3	17	19	22	22	14
	7	6	17	17	11	15
	17	15	12	4	15	16
	25	24	24	23	18	17
	16	8	3	1	16	18
	21	21	22	19	19	19
	14	1	14	18	21	20
	19	11	11	20	17	21
	2	14	13	5	20	22
Ontario Power Generation	22	22	23	21	23	23
	20	23	18	NA	NA	NA
	11	NA	NA	NA	NA	NA

Note: Two operators are no longer ranked in 2018 (reason for 25 ranked operators in 2013 vs. 23 in 2018). These operators were removed as a result of plant acquisitions or closures. All 2013-2017 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 key to operating and financial performance.

A comparison of UCF values for major nuclear operators is presented in the graph below. The list and ranking of operators has been updated to reflect any industry developments if applicable. 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 82.0% and ranked 23 out of 23 operators in the WANO data set.



* See Table 7 in the Appendix for listing of operators and plants.

**OPG unit values averaging to a rolling average UCF of 82.0% in 2018 are shown below:

Unit	2018 Rolling Average UCF
Pickering 1	76.2
Pickering 4	75.7
Pickering 5	81.2
Pickering 6	80.0
Pickering 7	91.0
Pickering 8	73.1

Unit	2018 Rolling Average UCF
Darlington 1	86.1
Darlington 2	N/A
Darlington 3	86.2
Darlington 4	88.4

Rankings for the major operators for UCF over the past six years are provided in Table 3 below.

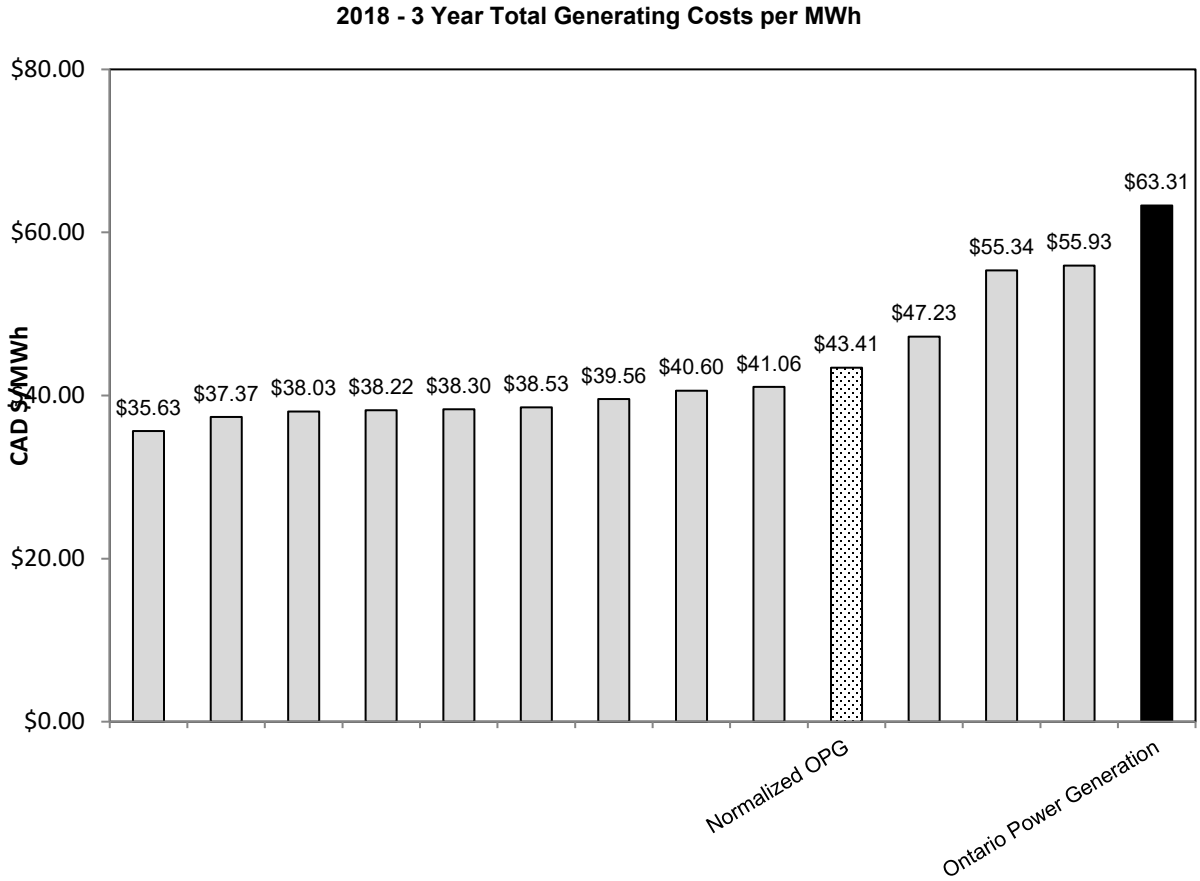
Table 3: Rolling Average Unit Capability Factor Rankings

Operator	2013	2014	2015	2016	2017	2018
	4	1	1	1	1	1
	2	6	5	8	5	2
	9	10	14	10	7	3
	20	18	20	20	13	4
	6	2	7	2	3	5
	22	23	22	21	12	6
	8	8	6	5	2	7
	7	4	9	11	6	8
	12	13	12	4	8	9
	21	20	17	14	4	10
	23	16	15	13	10	11
	10	7	2	7	9	12
	5	14	19	19	21	13
	3	9	8	18	15	14
	13	19	4	6	20	15
	17	15	18	17	17	16
	1	5	10	3	14	17
	24	22	24	23	19	18
	14	17	3	12	18	19
	16	11	11	15	16	20
	15	3	13	16	23	21
	11	12	21	9	11	22
Ontario Power Generation	19	21	23	22	22	23
	25	24	16	NA	NA	NA
	18	NA	NA	NA	NA	NA

Note: Two operators are no longer ranked in 2018 (reason for 25 ranked operators in 2013 vs. 23 in 2018). These operators were removed as a result of plant acquisitions or closures. All 2013-2017 rankings and numbers are carried over from previous Benchmarking reports.

Total Generating Cost/MWh Analysis

The 3-year Total Generating Cost/MWh results for the major operators in 2018 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 operated in 2016-2018. This value is divided by the total net generation of all plants that the operator operated for the same period and is provided as a three-year average. OPG Nuclear ranked 10th, with a 3-year Total Generation Cost of $43.41 per MWh (normalized).



*OPG plant values of 3-year rolling average TGC per MWh are shown below:

Unit	2018 3-Year TGC
Darlington (non-normalized)	$59.06/MWh
Darlington (normalized)	$37.65/MWh
Pickering (non-normalized)	$67.76/MWh
Pickering (normalized)	$49.29/MWh

Table 4: Three-Year Total Generating Cost per MWh (Non-Normalized) Rankings

	2013	2014	2015	2016	2017	2018
	10	11	11	9	3	1
	4	4	2	1	2	2
	1	1	1	2	1	3
	2	2	4	5	4	4
	14	12	8	7	8	5
	11	7	7	6	6	6
	3	3	5	4	7	7
	6	5	3	3	5	8
	5	8	9	10	9	9
	7	6	6	8	10	10
	9	9	10	11	11	11
	13	13	13	13	13	12
Ontario Power Generation	8	10	12	12	12	13
	12	NA	NA	NA	NA	NA

Note: One operator has been removed due to acquisition by another operator in the panel (reason for 14 ranked operators in 2013 vs. 13 in 2018).

Table 5 shows the relative contribution of Non-Fuel Operating Costs, Fuel Costs and Capital Costs to Total Generating Cost and compares OPG's non-normalized costs to those of all EUCG operators.

Table 5: 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	$ 49.85	$ 24.43	$ 23.30	CAD $/MWh
3-Yr. Fuel Costs per MWh	$ 4.89	$ 7.53	$ 6.95	CAD $/MWh
3-Yr. Capital Costs per MWh	$ 8.57	$ 8.57	$ 6.17	CAD $/MWh
3-Yr. Total Generating Costs per MWh	$ 63.31	$ 39.56	$ 38.22	CAD $/MWh

*See Table 8 in the appendix for list of operators included.

7.0 APPENDIX

Acronyms

Acronym	Meaning
ALARA	As Low As Reasonably Achievable
BWR	Boiling Water Reactor
CANDU	CANada Deuterium Uranium (type of PHWR)
CEA	Canadian Electricity Association
COG	CANDU Owners Group
DER	Design Electrical Rating
EUCG	Electric Utility Cost Group
INPO	Institute of Nuclear Power Operators
OPG	Ontario Power Generation
PHWR	Pressurized Heavy Water Reactor
PWR	Pressurized Water Reactor
WANO	World Association of Nuclear Operators

Safety and Reliability Definitions

The following definitions are summaries extracted from industry peer group databases.

Total Recordable Injury Frequency is the average number of fatalities, lost time injuries, medical treatment injuries and restricted work injuries per 200,000 hours worked.

Industrial Safety Accident Rate is defined as the number of accidents for all utility personnel (permanently or temporarily) assigned to the station, that result in one or more days away from work (excluding the day of the accident) or one or more days of restricted work (excluding the day of the accident), or fatalities, per 200,000 man-hours worked. The selection of 200,000 man-hours worked or 1,000,000 man-hours worked for the indicator will be made by the country collecting the data, and international data will be displayed using both scales. Contractor personnel are not included for this indicator.

Collective Radiation Exposure, for purposes of this indicator, is the total external and internal whole body exposure determined by primary dosimeter (thermoluminescent dosimeter (TLD) or film badge), and internal exposure calculations. All measured exposure should be reported for station personnel, contractors, and those personnel visiting the site or station on official utility business.

Visitors, for purposes of this indicator, include only those monitored visitors who are visiting the site or station on official utility business.

Airborne Tritium Emissions per Unit: Tritium emissions to air.

Fuel Reliability Index is inferred from fission product activities present in the reactor coolant. Due to design differences, this indicator is calculated differently for different reactor types. For PHWR's, the indicator is defined as the steady-state primary coolant iodine-131 activity (Becquerels/gram or Microcuries/gram), corrected for the tramp uranium contribution and power level, and normalized to a common purification rate.

Unplanned automatic reactor trips (SCRAMS) is defined as the number of unplanned automatic reactor trips (reactor protection system logic actuations) that occur per 7,000 hours of critical operation. The indicator is further defined as follows:

- Unplanned means that the trip was not an anticipated part of a planned test.
- Trip means the automatic shutdown of the reactor by a rapid insertion of negative reactivity (e.g., by control rods, liquid injection shutdown system, etc.) that is caused by actuation of the reactor protection system. The trip signal may have resulted from exceeding a set point or may have been spurious.
- Automatic means that the initial signal that caused actuation of the reactor protection system logic was provided from one of the sensors' monitoring plant parameters and conditions, rather than the manual trip switches or, in certain cases described in the clarifying notes, manual turbine trip switches (or pushbuttons) provided in the main control room.
- Critical means that, during the steady-state condition of the reactor prior to the trip, the effective multiplication factor (k_{eff}) was essentially equal to one.
- The value of 7,000 hours is representative of the critical hours of operation during a year for most plants, and provides an indicator value that typically approximates the actual number of scrams occurring during the year.

The **safety system performance indicators** include the following:

- Auxiliary boiler feedwater system
- Emergency AC power
- High pressure emergency coolant injection system

These systems were selected for the safety system performance indicator based on their importance in preventing reactor core damage or extended plant outage. They include the principal systems needed for maintaining reactor coolant inventory following a loss of coolant, for decay heat removal following a reactor trip or loss of main feedwater, and for providing emergency AC power following a loss of plant off-site power. (Gas cooled reactors have an additional decay heat removal system instead of the coolant inventory maintenance system)

The **Nuclear Performance Index** Method 4 is an INPO sponsored performance measure, and is a weighted composite of ten WANO Performance Indicators related to safety and production performance reliability.

The **Forced Loss Rate (FLR)** is defined as the ratio of all unplanned forced energy losses during a given period of time to the reference energy generation minus energy generation losses corresponding to planned outages and any unplanned outage extensions of planned outages, during the same period, expressed as a percentage.

Unplanned energy losses are either unplanned forced energy losses (unplanned energy generation losses not resulting from an outage extension) or unplanned outage extension of planned outage energy losses.

Unplanned forced energy loss is energy that was not produced because of unplanned shutdowns or unplanned load reductions due to causes under plant management control when the unit is considered to be at the disposal of the grid dispatcher. Causes of forced energy losses are considered to be unplanned if they are not scheduled at least four weeks in advance. Causes considered to be under plant management control are further defined in the clarifying notes.

Unplanned outage extension energy loss is energy that was not produced because of an extension of a planned outage beyond the original planned end date due to originally scheduled work not being completed, or because newly scheduled work was added (planned and scheduled) to the outage less than four weeks before the scheduled end of the planned outage.

Planned energy losses are those corresponding to outages or power reductions which were planned and scheduled at least four weeks in advance (see clarifying notes for exceptions).

Reference energy generation is the energy that could be produced if the unit were operated continuously at full power under reference ambient conditions throughout the given period. Reference ambient conditions are environmental conditions representative of the annual mean (or typical) ambient conditions for the unit.

Unit Capability Factor is defined as the ratio of the available energy generation over a given time period to the reference energy generation over the same time period, expressed as a percentage. Both of these energy generation terms are determined relative to reference ambient conditions.

Available energy generation is the energy that could have been produced under reference ambient conditions considering only limitations within control of plant management, i.e., plant equipment and personnel performance, and work control.

Reference energy generation is the energy that could be produced if the unit were operated continuously at full power under reference ambient conditions.

Reference ambient conditions are environmental conditions representative of the annual mean (or typical) ambient conditions for the unit.

The **Chemistry Performance Indicator** compares the concentration of selected impurities and corrosion products to corresponding limiting values. Each parameter is divided by its limiting value, and the sum of these ratios is normalized to 1.0. If an impurity concentration is equal to or better than the limiting value, the limiting value is used as the concentration. This prevents increased concentrations of one parameter from being masked by better performance in another. As a result, if a plant is at or below the limiting value for all parameters, its indicator value would

be 1.0, the lowest chemistry indicator value attainable under the indicator definition. The following is used to determine each unit's chemistry indicator value for PHWRs:

- *Inconel-600 or Monel tubes
  - Steam generator blowdown chloride
  - Steam generator blowdown sulfate
  - Steam generator blowdown sodium
  - Final feedwater iron
  - Final feedwater copper
  - Final feedwater dissolved oxygen
- Incoloy-800 tubes
  - Steam generator blowdown chloride
  - Steam generator blowdown sulfate
  - Steam generator blowdown sodium
  - Final feedwater iron
  - Final feedwater dissolved oxygen

- PHWRs on molar ratio control
  - Steam generator blowdown chloride
  - Steam generator blowdown sulfate
  - Final feedwater iron
  - Final feedwater copper
  - Feedwater dissolved oxygen
  - Steam generator molar ratio target range (by reporting the upper and lower range limits (as "from" and "to" values)
  - Steam generator actual molar ratio

Online Deficient Maintenance Backlog is the average number of active on-line maintenance work orders per operating unit classified as Deficient Critical (DC) or Deficient Non-Critical (DN) that can be worked on without requiring the unit shutdown. This metric identifies deficiencies or degradation of plant equipment components that need to be remedied, but which do not represent a loss of functionality of the component or system.

Online Corrective Maintenance Backlog is the average number of active on-line maintenance work orders per operating unit classified as Corrective Critical (CC) or Corrective Non-Critical (CN) that can be worked on without requiring the unit shutdown. This metric identifies deficiencies or degradation of components that need to be remedied, and represents a loss of functionality of a major component or system.

On-line maintenance is maintenance that will be performed with the main generator connected to the grid.

Value for Money Definitions

The following definition summaries are taken from the *January 2019 EUCG Nuclear Committee Nuclear Database Instructions*.

Capital Costs ($)
All costs associated with improvements and modifications made during the reporting year. These costs should include design and installation costs in addition to equipment costs. Other miscellaneous capital additions such as facilities, computer equipment, moveable equipment, and vehicles should also be included. These costs should be fully burdened with indirect costs, but exclude AFUDC (interest and depreciation).

Fuel ($)
The total cost associated with a load of fuel in the reactor which is burned up in a given year.

Net Generation (Gigawatt Hours)
The gross electrical output of the unit measured at the output terminals of the turbine-generator minus the normal station service loads during the hours of the reporting period, expressed in Gigawatt hours (GWh). Negative quantities should not be used.

Design Electrical Rating (DER)
The nominal net electrical output of a unit, specified by the utility and used for plant design (DER net expressed in MWe). Design Electrical Rating should be the value that the unit was certified/designed to produce when constructed. The value would change if a power uprate was completed. After a power uprate, the value should be the certified or design value resulting from the uprate.

Operating Costs ($)
All relevant costs to operate and maintain nuclear operations. It includes the cost of labour, materials, purchased services and other costs, including administration and general.

Total Generating Costs ($)
The sum of total operating costs and capital costs.

Total Operating Costs ($)
The sum of operating costs and fuel costs.

Note: Capital costs, fuel costs, operating costs and Total Generating Costs are divided by net generation to obtain per MWh results. Capital costs are also divided by MW DER to obtain MW results.

<u>Human Performance Definitions</u>

The following definition summary is taken from the Institute of Nuclear Power Operations (INPO) database.

Human Performance Error Rate (# per ISAR and Contractor Hours)
The Human Performance Error Rate metric represents the number of site level human performance events in an 18-month period per 200,000 ISAR hours worked (including on site supplemental personnel). The formula used is:

{(# of S-EFDRs) / (Total ISAR Hours + Total Contractor Hours)} x 200,000 Hours (Calculated as an 18-month rolling average)

INPO guidelines define non-utility personnel to include contractor, supplemental personnel assigned to perform work activities on site or at other buildings that directly support station operation. This includes personnel who deliver and receive equipment, deliver fuel oil, remove trash and radioactive waste, and provide building and grounds maintenance within the owner-controlled areas or facilities that support the station.

INPO defines an event to occur as a result of the following:

An initiating action (error) by an individual or group of individuals (event resulting from an active error) or an initiating action (not an error) by an individual or group of individuals during an activity conducted as planned (event resulting from a flawed defense or latent organizational weakness). They may be related to Nuclear Safety, Radiological Safety, Industrial Safety, Facility Operations or considered to be a Regulatory Event reportable to a regulator or governing agency. OPG Nuclear's criteria for defining station event free day resets have been developed based on INPO guidelines.

Table 6: Industry Peer Groups

	WANO/COG CANDUs	All North American PWR and PHWRs (WANO)	INPO AP-928 Workgroup	INPO	CEA	EUCG North American Plants (US and Canada)
Safety						
Total Recordable Injury Frequency					X	
Rolling Average Industrial Safety Accident Rate*		X				
Rolling Average Collective Radiation Exposure*	X					
Airborne Tritium Emissions per Unit	X					
Fuel Reliability Index*	X					
2-Year Reactor Trip Rate*	X					
3-Year Auxiliary Feedwater System Unavailability*	X					
3-Year Emergency AC Power Unavailability*	X					
3-Year High Pressure Safety Injection Unavailability*	X					
Reliability						
WANO NPI	X					
Rolling Average Forced Loss Rate*	X					
Rolling Average Unit Capability Factor*	X					
Rolling Average Chemistry Performance Indicator*	X					
1-Year On-line Deficient Maintenance Backlog			X			
1-Year On-line Corrective Maintenance Backlog			X			
Value for Money						
3-Year Total Generating Costs / MWh						X
3-Year Non-Fuel Operating Costs (OM&A) / MWh						X
3-Year Fuel Costs / MWh						X
3-Year Capital Costs / MW DER						X
Human Performance						
Human Performance Error Rate				X		

* Sub-indicator of WANO NPI

Data provided by the World Association of Nuclear Operators (WANO) is the primary source of benchmarking data for operational performance (Safety and Reliability) indicators. Eleven out of the twenty benchmarking metrics have been compared to the WANO/COG CANDU panel. All WANO performance indicators are presented at the unit and plant levels except the Industrial Safety Accident Rate and Emergency AC Power Unavailability which are only measured at the plant level.

Different peer groups were used for a few of the specialized operating metrics which are not tracked through WANO. For maintenance work order backlogs, the peer group consisted of all plants participating in the Institute of Nuclear Power Operations (INPO) AP-928 working group. For human performance comparisons, data was obtained from INPO. For the Total Recordable Injury Frequency metric, the Canadian Electricity Association (CEA) panel was used.

For financial performance comparisons, data compiled by the Electric Utility Cost Group (EUCG) was used. EUCG is a nuclear industry operating group and the recognized source for cost benchmark information. EUCG cost indicators are presented at the plant level and compared on a net megawatt hour generated basis and on a per megawatt (MW) design electrical rating (DER) basis. The only CANDU operators reporting data to EUCG were OPG Nuclear and Bruce Power which is not a sufficiently large panel to provide a basis for comparison; hence, the data sets were not limited to a CANDU specific panel. Should more CANDU operators choose to join EUCG in the future, comparisons to a CANDU specific panel will be reconsidered.

All data provided by the peer groups (WANO, INPO, CEA, and EUCG) is confidential. A redacted version of this report, which removes individual plant and unit names, is available from Nuclear Business Planning and Benchmarking should there be a requirement to publicly release this report.

Panels

Table 7: WANO Panel

Operator	Plant
Ameren Missouri	Callaway
American Electric Power Co.	Cook
Arizona Public Service Co.	Palo Verde
Bruce Power	Bruce A Bruce B
Dominion Generation	Millstone North Anna Surry
Duke Energy	Catawba Harris Mcguire Oconee Robinson
Entergy Nuclear	Arkansas Nuclear One Indian Point Palisades Waterford
Exelon Generation Co.	Braidwood Byron Three Mile Island Calvert Cliffs Ginna
FirstEnergy Nuclear Operating Co.	Beaver Valley Davis-Besse
Florida Power & Light Co.	St. Lucie Turkey Point

Operator	Plant
International CANDU	Cernavoda Embalse Qinshan 3 Wolsong A Wolsong B
Luminant Generation	Comanche Peak
New Brunswick Power	Point Lepreau
NextEra Energy Resources	Point Beach Seabrook
Northern States Power Company	Prairie Island
Ontario Power Generation	Darlington Pickering
Pacific Gas & Electric Co.	Diablo Canyon
Public Service Enterprise Group Nuclear	Salem
South Carolina Electric & Gas Co.	V.C. Summer
Southern Nuclear Operating Co.	Farley Vogtle
STP Nuclear Operating Co.	South Texas
Tennessee Valley Authority	Sequoyah Watts Bar
Wolf Creek Nuclear Operating Corp.	Wolf Creek

Table 8: EUCG Panel

Major Operator	Plant
Bruce Power	Bruce A Bruce B
Dominion Generation	Millstone North Anna Surry
Duke Energy	Brunswick Catawba Harris Mcguire Oconee Robinson
Entergy Nuclear	Arkansas Nuclear One Fitzpatrick Grand Gulf Indian Point Palisades Pilgrim River Bend Waterford
Exelon Generation Co.	Braidwood Byron Calvert Cliffs Clinton Dresden Lasalle Limerick Nine Mile Oyster Creek Peach Bottom Quad Cities Ginna Three Mile Island
FirstEnergy Nuclear Operating Co.	Beaver Valley David-Besse Perry
Florida Power & Light Co.	St Lucie Turkey Point
NextEra Energy Resources	Duane Arnold Point Beach Seabrook
Northern States Power Company	Monticello Prairie Island
Ontario Power Generation	Darlington Pickering
Public Service Enterprise Group Nuclear	Hope Creek Salem
Southern Nuclear Operating Co.	Farley Hatch Vogtle
Tennessee Valley Authority	Browns Ferry Sequoyah Watts Bar

Remaining EUCG Members

Operator	Plant	Operator	Plant
AmerenUE	Callaway	Nebraska Public Power District	Cooper
American Electric Power Co. Inc.	Cook	Pacific Gas & Co.	Diablo Canyon
Arizona Public Service Co.	Palo Verde	Talen Energy	Susquehanna
DTE Energy	Fermi	South Carolina Electric & Gas Company (SCE&G)	V.C. Summer
Energy Northwest	Columbia	STP Nuclear Operating Co.	South Texas
Luminant Generation	Comanche Peak	Wolf Creek Nuclear Operations Corp.	Wolf Creek

Table 9: COG CANDUs

Operator	Plant
Bruce Power	Bruce A Bruce B
China (CNNP)	Qinshan 3
NASA	Embalse
Korea (KHNP)	Wolsong A Wolsong B
New Brunswick Power	Point Lepreau
OPG	Darlington Pickering
Romania	Cernavoda

Table 10: CEA Members

Companies
Alectra Inc.
AltaLink
ATCO Electric
ATCO Power
BC Hydro and Power Authority
Brookfield Renewable Energy Group
Capital Power Corporation
City of Medicine Hat, Electric Utility
ENMAX
EPCOR
FortisAlberta Inc.
FortisBC Inc.
Hydro One
Hydro Ottawa
Hydro Quebec

Companies
Manitoba Hydro
Maritime Electric Company
Nalcor Energy
New Brunswick Power
Newfoundland Power
Northwest Territories Power Corp.
Nova Scotia Power
Oakville Hydro Corp.
Ontario Power Generation
Saint John Energy
Saskatoon Light & Power
SaskPower
Toronto Hydro Corp.
TransCanada
Yukon Energy Corp.

Table 11: INPO Members for Human Performance Error Rate

Plant	
Arkansas Nuclear One (ANO)	Monticello
Beaver Valley	Nine Mile Point
Braidwood	North Anna
Browns Ferry	Oconee
Brunswick	Oyster Creek
Byron	Palisades
Callaway	Palo Verde
Calvert Cliffs	Peach Bottom
Catawba	Perry
Clinton	Pilgrim
Columbia Gen	Point Beach
Comanche Peak	Prairie Island
Cook	Quad Cities
Cooper	River Bend
Davis-Besse	Robinson
Diablo Canyon	Salem
Dresden	Seabrook
Duane Arnold	Sequoyah
Farley	South Texas
Fermi 2	St. Lucie
Fitzpatrick	Summer
Ginna	Surry
Grand Gulf	Susquehanna
Harris	Three Mile Island
Hatch	Turkey Point
Hope Creek	Vermont Yankee
Indian Point	Vogtle
LaSalle	Waterford
Limerick	Watts Bar
McGuire	Wolf Creek
Millstone	

Table 12: INPO Members for On-Line Maintenance Backlogs

Plant	
Arkansas Nuclear One (ANO)	Monticello
Beaver Valley	Nine Mile Point
Braidwood	North Anna
Browns Ferry	Oconee
Brunswick	Oyster Creek
Byron	Palisades
Callaway	Palo Verde
Calvert Cliffs	Peach Bottom
Catawba	Perry
Clinton	Pilgrim
Columbia Gen	Point Beach
Comanche Peak	Prairie Island
Cook	Quad Cities
Cooper	River Bend
Davis-Besse	Robinson
Diablo Canyon	Salem
Dresden	Seabrook
Duane Arnold	Sequoyah
Farley	South Texas
Fermi 2	St. Lucie
Fitzpatrick	Summer
Ginna	Surry
Grand Gulf	Susquehanna
Harris	Three Mile Island
Hatch	Turkey Point
Hope Creek	Vermont Yankee
Indian Point	Vogtle
LaSalle	Waterford
Limerick	Watts Bar
McGuire	Wolf Creek
Millstone	

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

	2018 Actuals				
Indicator	**NPI Max**	**Best Quartile**	**Median**	**Pickering**	**Darlington**
Rolling Average Industrial Safety Accident Rate (#/200k hours worked)	0.20	0.00	0.02	0.05	0.04
Rolling Average Collective Radiation Exposure (person-rem per unit)	80.00	27.95	35.98	81.65	85.43
Fuel Reliability Index (microcuries per gram)	0.000500	0.000001	0.000003	0.000837	0.000187
2-Year Reactor Trip Rate (# per 7,000 hours)	0.50	0.00	0.00	0.33	0.15
3-Year Auxiliary Feedwater System Unavailability (#)	0.0200	0.0023	0.0039	0.0039	0.0000
3-Year Emergency AC Power Unavailability (#)	0.0250	0.0071	0.0121	0.0000	0.0026
3-Year High Pressure Safety Injection Unavailability (#)	0.0200	0.0015	0.0027	0.0000	0.0000
Rolling Average Forced Loss Rate (%)	1.00	0.34	0.99	5.20	1.94
Rolling Average Unit Capability Factor (%)	92.00	93.74	91.60	79.55	86.89
Rolling Average Chemistry Performance Indicator (Index)	1.01	1.00	1.00	1.02	1.03
WANO NPI (Index)	Not Applicable	100.0	95.8	74.9	90.7

OPG Nuclear Cost Performance Benchmarking

A Study of Factors Impacting TGC / MWh Performance with Normalizing Adjustments to Facilitate Closer Comparison

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1. BACKGROUND

Context

Pickering Nuclear Generating Station (PNGS) is one of two nuclear stations operated by Ontario Power Generation (OPG). PNGS has six operating units (two additional units ended commercial operations in 1997), a net output of 3,094 megawatts (MW) and produces about 14 percent of Ontario's electricity needs. The site has been operating since 1971.

Darlington Nuclear Generating Station (DNGS) is one of two nuclear stations operated by Ontario Power Generation (OPG). DNGS is a four-unit station with a net output of 3,512 megawatts (MW), and it has been producing almost 20 percent of Ontario's electricity needs since the early 1990s. OPG is performing a major mid-life refurbishment of the four reactors at DNGS (Refurbishment), which involves the replacement of certain life-limiting components. The execution of the Refurbishment "mega-project" started in October 2016 with breaker-open on Unit 2.

OPG tracks and benchmarks the performance of PNGS and DNGS against industry peers under its nuclear cornerstones of Safety, Reliability, Human Performance, and Value for Money. Value for Money is measured relative to an Electric Utility Cost Group (EUCG) panel of nuclear plants in North America using a suite of four cost metrics. One of these metrics, Total Generating Cost per Megawatt-Hour (TGC/MWh), has recently shown DNGS and PNGS ranking below the median relative to the panel.

OPG benchmarks performance in TGC/MWh relative to peers and sets goals for performance each year. Based on operating experience, OPG believes that certain characteristics that cannot be controlled by how well they operate DNGS and PNGS are having a meaningful influence on TGC/MWh performance. ScottMadden agrees that such static characteristics impact performance as measured by TGC/MWh. Thus, OPG asked ScottMadden to perform an independent study to determine whether and how such site characteristics influence TGC/MWh performance for a nuclear plant.

Current TGC/MWh Performance

Using the EUCG data provided by OPG, TGC/MWh performance for the most recent three-year time period (2015-2017) for PNGS and DNGS appear in the fourth quartile relative to the other sites. However, TGC/MWh performance for DNGS must be adjusted to account for the ongoing Refurbishment. ScottMadden provided OPG with a specific methodology for performing this adjustment under a separate study. The result of the adjustment was a relative improvement in TGC/MWh performance for DNGS to the third quartile, as illustrated below.

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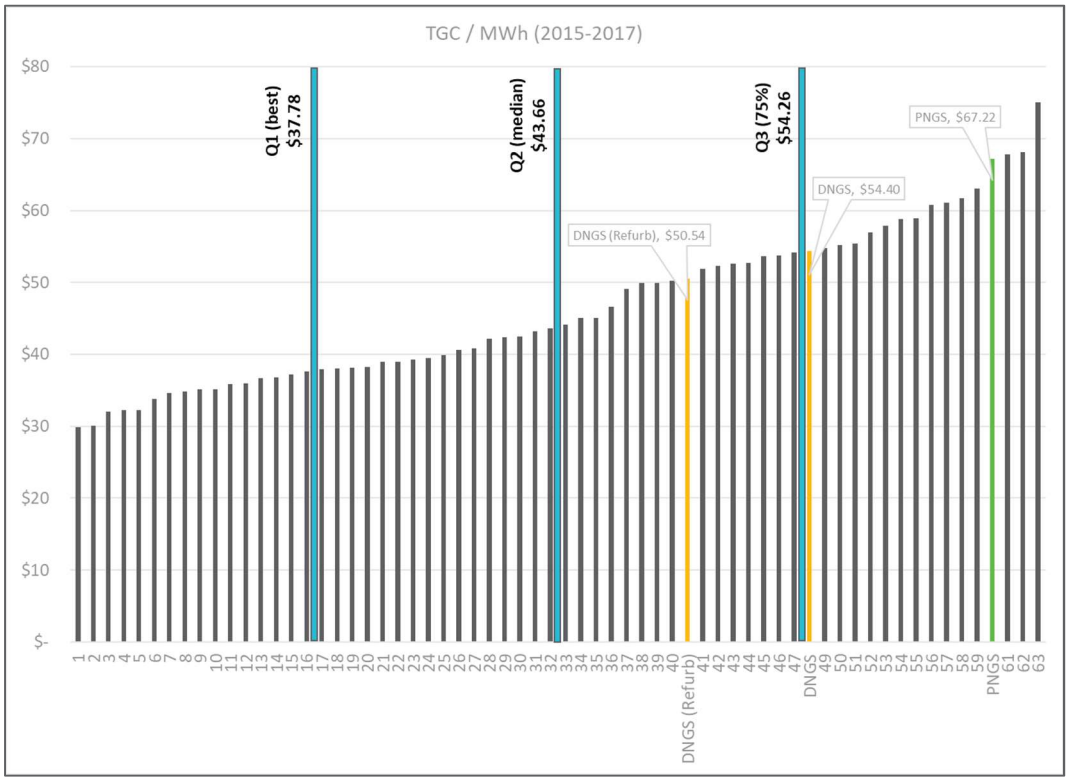
TGC/MWh performance 2015-'17 for EUCG Panel with DNGS Adjusted for Refurbishment



2. ABOUT THE SCOTTMADDEN APPROACH

Scope and Objectives

The ScottMadden study of the influence of site characteristics on TGC/MWh focused on two major areas of investigation:

- **Econometric Analysis** – analysis of EUCG data to understand and quantify the impact of certain site characteristics on total generating cost (TGC)
- **Custom Nuclear Outage Benchmarking Study** – primary research and analysis on nuclear outages across the industry to determine expected impacts on energy production (MWh)

The objectives of this investigation were to 1) determine whether and to what extent relatively static characteristics of a nuclear site influence TGC/MWh performance and 2) if possible, quantify and adjust for these characteristics to produce normalized TGC/MWh values that account for site characteristics that have a significant impact on TGC/MWh performance.

Assumptions and Qualifications

In performing this study and preparing this document, ScottMadden assumes that all EUCG data provided by OPG for this effort and all industry responses to the nuclear outage benchmarking study led by ScottMadden were complete and accurate.

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This ScottMadden report is also subject to the following qualifications:

- ScottMadden does not imply the performance of any additional, specific research beyond what is described in this document.
- ScottMadden does not express an opinion in this document on the effectiveness of management practices at OPG or the appropriateness of any of OPG's costs, outage durations, or other performance characteristics.
- The ScottMadden methodology was prepared for the benefit of OPG and is limited to the subject matter expressly stated in this document; no additional ScottMadden opinion is implied or may be inferred.

3. EXECUTIVE SUMMARY

ScottMadden focused on two major areas of investigation, econometric analysis and a custom nuclear outage benchmarking study.

In the econometric analysis, ScottMadden analyzed nine years of EUCG data (from 2009 to 2017) and 567 data points to understand which site characteristics most influence TGC over a sustained period and to what extent. We used multiple linear regression (MLR) to quantify the relationships between various combinations of reactor type, site capacity, number of units, unit size, and unit age (the independent variables) and the EUCG data for site costs (TGC, the dependent variable). Through this analysis, we were able to develop a powerful predictive model for TGC that explains ~79% of the variability in TGC across the dataset using reactor type, site capacity, and unit age. The model indicates:

- CANDU technology increases predicted TGC by over C$250[1] million per year relative to non-CANDU plants
- Each MW of site capacity increases predicted TGC by C$261 thousand per year
- Each month of average unit age increases predicted TGC by C$346 thousand per year

Once ScottMadden established a mathematically-sound quantification of the impact these site characteristics have on TGC, we adjusted for all sites in the EUCG dataset to account for these factors. However, to be conservative and ensure adjustments were easy to understand, we only performed adjustments for reactor type and unit age.

- The result of these adjustments on TGC/MWh performance was an improvement in relative performance for PNGS from 60th to 51st out of the 63 sites in the EUCG panel.
- DNGS improved from 48th to 31st after performing the same adjustments and also adjusting for refurbishment work, as previously documented and validated.

ScottMadden also initiated a custom nuclear outage benchmarking study to understand better how outage work differs across reactor technologies (BWR, CANDU, and PWR) and operators. The study used a variety of data sources, chief among them a direct survey of nuclear operators, in which

[1] All C$ values in this document are in 2017 dollars, unless otherwise indicated

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responses were confidential and participation was sufficient to represent each of the three reactor technologies (19 CANDU plants, 9 BWR plants, and 19 PWR plants) in the results.

ScottMadden focused only on quantifying and adjusting for the impact of regularly recurring, planned maintenance outages on power generation, taking steps to arrive at an average annual value for days offline due to these planned outages. The output of this exercise is represented in the table below.

Reactor Type	Outage Cycle	Median Average Planned Outage Days Per Year	Incremental Additional Outage Days Per Year Above Shortest Duration
BWR	18-month cycle[2]	Not represented in study	
	24-month cycle	14 days	
PWR	18-month cycle	19 days	5 days
	24-month cycle	14 days	0 days
CANDU	24-month cycle	18 days	4 days
	30-month cycle	36 days	22 days
	36-month cycle	27 days	13 days

ScottMadden adjusted for these outage requirements by normalizing the annual values for MWh of production at each plant. Specifically, if a plant in the dataset had a reactor type and outage cycle combination that, on average, required additional outage days above the shortest duration, we added those incremental additional days back to total production for the year using the site summer capacity[3] at 100% utilization. If a plant had a reactor type and outage cycle combination that did not require additional outage days (i.e., all BWRs and PWRs on 24-month outage cycles), we left total production values unchanged.

- The result of these adjustments on TGC/MWh performance was further improvement in relative performance for PNGS from 51st to 47th out of the 63 sites in the EUCG panel, or third quartile.
- DNGS also further improved from 31st to 29th, or second quartile, after performing the same adjustments.

[2] Of the 63 operators in the EUCG dataset, only two single-unit plants are reported to be on an 18-month maintenance cycle during the 2015-2017 timeframe, and these plants were not represented in our survey of nuclear operators. Thus, for the purposes of this study, we assumed that 18-month cycle BWRs have the same annualized median outage duration as 24-month cycle BWRs.

[3] From the EIA 860 form, retrieved through SNL database, as opposed to nameplate capacity or winter capacity, which are often higher values

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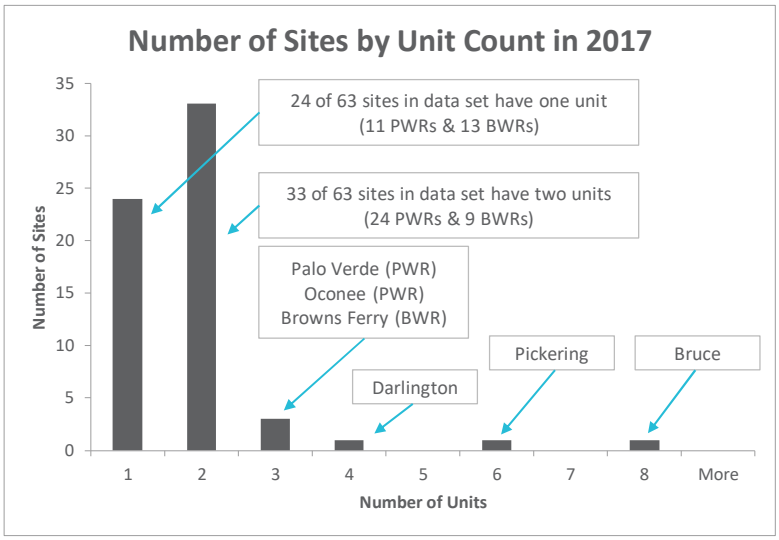
4. ECONOMETRIC ANALYSIS

About the Data

ScottMadden analyzed EUCG data to understand and quantify the impact of certain site characteristics on total generating cost (TGC) and cost performance (TGC/MWh). In this study, ScottMadden analyzed nine years of EUCG data (from 2009 to 2017) to understand which site characteristics most influence TGC over a sustained period and to what extent. The dataset used for this analysis includes:



- 63 nuclear sites and 567 total data points (one / site / year)
- Three reactor types:
  - PWRs – 37 sites
  - BWRs – 23 sites
  - CANDUs – 3 sites
- Nuclear sites with a median capacity of 1,737 MW, median unit capacity of 967 MW, and median average unit age of 397 months (~33 years)[4]
- Primarily sites with either one or two units (57 of 63), but:
  - Three sites (two PWRs and one BWR) with three units
  - One site with four units (CANDU – Darlington)
  - One site with six units (CANDU – Pickering)
  - One site with eight units (CANDU – Bruce)

It is worth noting that there are few CANDU plants in the EUCG data and the technology differs in important ways from the PWR and BWR plants. For example, CANDU plants

- Have greater numbers of smaller capacity units but larger total site capacities
- Have different online and outage maintenance requirements but can be refueled online
- Operate in Canada and are subject to a different regulatory and market environment than PWRs and BWRs operating in the US

ScottMadden used the EUCG data described above to analyze how certain site characteristics influence nuclear site costs. Before performing this analysis, ScottMadden adjusted dollar values for inflation to ensure that we could establish mathematical relationships that persisted across the nine-year dataset. Specifically, we adjusted Total Generating Costs (TGC) from 2009 to 2017 for inflation using the Gross Domestic Product Implicit Price Index Final Domestic Demand (GDP-IPI FDD) in Canada from Statistics Canada, converting all TGC values to 2017 dollars. ScottMadden found this a

[4] This number is not reflective of the current median average unit age of nuclear sites in the panel because average unit age was calculated for each year in the dataset at that specific point in time

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reasonable index to use and favored it over others for this application as it is preferred by the Ontario Energy Board (OEB).[5]

Predictive Model for Total Generating Costs

ScottMadden focused the analysis on characteristics that cannot be controlled by how well a site is operated but are likely to have a meaningful influence on site costs, including:

- Reactor type – CANDU, PWR, or BWR
- Site capacity – total site capacity across all operating units (MW)
- Number of units – total number of operating units at the site
- Unit size – average capacity of the units at the site (MW)
- Unit age – average age of the units at the site (months)

Specifically, ScottMadden used Multiple Linear Regression (MLR) to quantify the relationships between various combinations of the above site characteristics (the independent variables) and the EUCG data for, separately, site costs (TGC) and cost performance (TGC/MWh). While we were unable to develop a sufficiently predictive model for cost performance (TGC/MWh) directly, we were able to develop a powerful predictive model for site costs (TGC).

Our TGC model explains ~79% of the variability in TGC with reactor type, site capacity, and unit age and indicates:

- CANDU technology increases TGC relative to PWR and BWR reactor types
- Greater site capacity increases TGC
- Higher average unit age increases TGC

The specific, mathematical model for site costs in thousands of Canadian dollars (C$k) is: $f(TGC\ per\ year) = (-255{,}421 * (PWR)) + (-283{,}946 * (BWR)) + (261 * (site\ capacity)) + (346 * (unit\ age)) + 302{,}477$. Each coefficient in the formula is the estimated change in TGC corresponding to one unit change in that associated variable when all other variables are held constant. Specifically:

- If the PWR value is 1, indicating it is a PWR reactor, predicted TGC would decrease by C$255,421k (2017); If 0, it will remain unchanged
- If the BWR value is 1, indicating it is a BWR reactor, predicted TGC would decrease by C$283,946k (2017); If 0, it will remain unchanged
- For each MW of site capacity, predicted TGC would increase by C$261k (2017)
- For each month of average unit age, predicted TGC would increase by C$346k (2017)

[5] GDP-IPI FDD is an inflation factor that is commonly-used and frequently referenced by the OEB in multiple documents, including the most recent rate decision for OPG, EB-2016-0152.

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Put more simply, with all other variables held constant:

- CANDU technology increases predicted TGC by over C$250 million per year relative to non-CANDU plants
- Each MW of site capacity increases predicted TGC by C$261 thousand per year
- Each month of average unit age increases predicted TGC by C$346 thousand per year

Once we established a mathematically-sound quantification of the impact these site characteristics have on TGC, we adjusted for all sites in the EUCG data set to account for these factors. However, we only perform adjustments for reactor type and unit age, using the process below.[6]

- Reactor Type – if the reactor is a:
  - BWR, we assign no adjustment value
  - PWR, we assign an adjustment value of ~(28,525) in 2017C$k
  - CANDU, we assign an adjustment value of ~(283,946) in 2017C$k
- Unit Age – For each month of average unit age:
  - Above the median value in the dataset (call this value "a"), we assign an adjustment value of "a" multiplied by ~($346) in 2017C$k
  - Below the median value in the dataset (call this value "b"), we assign an adjustment value of "b" multiplied by ~$346 in 2017C$k
- Inflation – We sum all assigned adjustment values and then, for any year other than 2017, we use the appropriate GDP-IPI FDD value to inflate or deflate the cost adjustment to a value for that specific year

We do not adjust costs for differences in site capacity, despite this being a significant driver of cost, since this would also have required a complex adjustment to generation.[7]

Lastly, to adjust cost for a given year, we use the GDP-IPI FDD to modify the adjustment value to the appropriate year (e.g., to adjust TGC in 2015, we take the TGC impact from the model above, which is in 2017 dollars, modify it to 2015 dollars, and adjust the value for 2015). Finally, we divided the adjusted TGC by actual MWh of generation to get the updated comparison shown in the chart below.

[6] Precise adjustment values were C$(28,525,521.81) / yr for PWR, C$(283,946,104.12) / yr for CANDU, and C$346,088.63 per month of average unit age at the site by a multiple of (median of the average value in months across all sites minus the average value of the specific site in months)

[7] Adjusting for site capacity would follow the logic of other adjustments to cost. In this model, that would mean adjusting costs by ~C$261k per MW per year for each site by a multiple of (median capacity in MW across all sites minus the capacity of the specific site in MW). However, such an adjustment for site capacity would also require that we adjust the MWhs produced by the site in kind. This adjustment would require determination of, for example, the capacity factor to use when determining the change in MWh, further complicating the adjustment and magnifying differences across sites in certain periods. ScottMadden thus felt it more conservative and intuitive to adjust only for technology and age of equipment.

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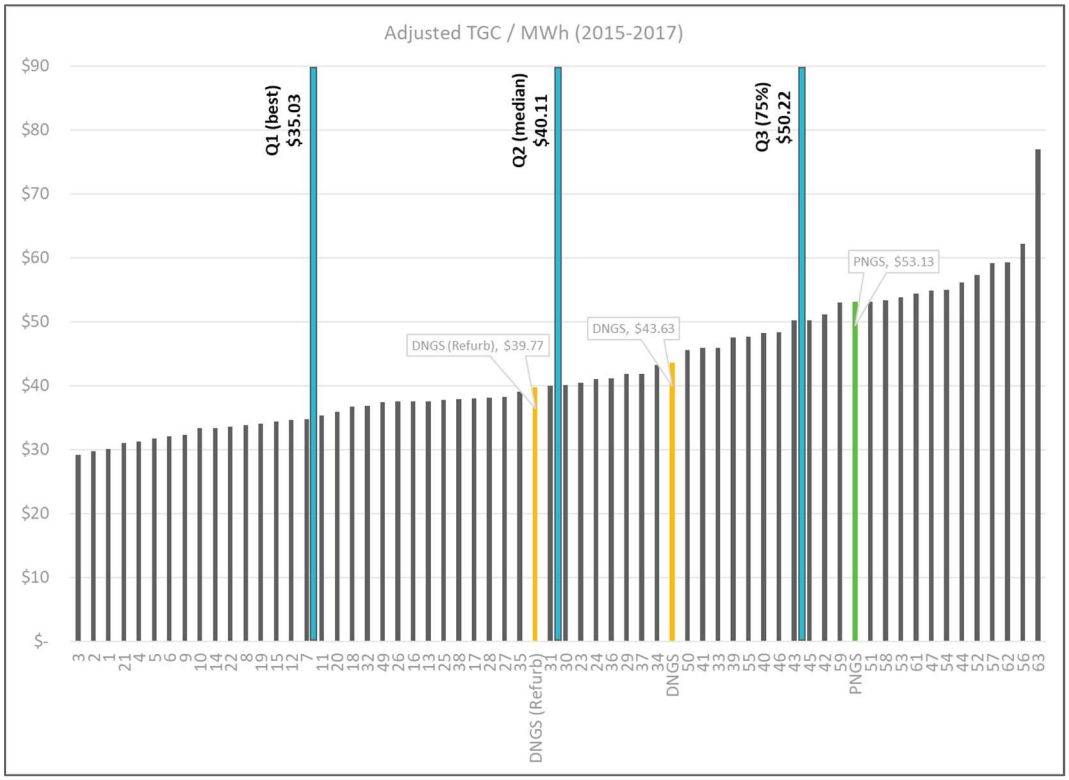
TGC/MWh performance 2015-'17 for EUCG Panel with All Sites Adjusted Based on Econometric Analysis and DNGS Also Adjusted for Refurbishment



By making these adjustments for reactor type and average unit age Pickering's relative performance improves from the 60th to 51st out of the 63 sites in the EUCG panel. Darlington's relative performance improves from 48th to 39th out of the 63 sites in the EUCG panel. Also adjusting for Darlington's refurbishment improves Darlington's relative performance to 31st out of the 63 sites in the EUCG panel.

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5. CUSTOM NUCLEAR OUTAGE BENCHMARKING STUDY

ScottMadden initiated a study of nuclear plant outages on behalf of OPG to better understand how outage work differs across reactor technologies (CANDU, PWR, and BWR) and operators. The study included research of various public and private sources[8], EUCG data provided by OPG, and confidential[9] responses to a custom ScottMadden survey from nine nuclear operators. Participants in the outage survey provided sufficient representation for each of the three reactor technologies and included 19 CANDU plants, 19 PWR plants, and 9 BWR plants. Operators were asked to provide information on:

- The overall refurbishment profile of each unit (including major component replacements, full refurbishments, etc.)
- Historical and future planned outages, including major scope, critical path and near-critical path activities, life-extension work, completion timelines, and costs
- Other, infrequent outages (e.g., vacuum building outages for CANDUs), including scope, schedule, and cost information

While some operators chose not to respond to cost information and other items in the survey, we received robust data on historical and future planned outage scopes and durations. From our various data sources and for this study, we focused on the differences in future planned outage durations across technology types and outage frequencies.

All reactor types have planned maintenance outages on either 18, 24, 30, or 36-month cycles. Planned maintenance outages for PWRs and BWRs are incorporated into refueling cycles and occur every 18 or 24 months. Planned maintenance outages for CANDU reactors occur every 24, 30, or 36 months. Work to significantly extend the operating life of a plant (life-extension activities) is also approached differently across technologies. For PWR and BWR plants, it is more common to complete this work as part of planned refueling and maintenance outages over a series of multiple outages to minimize time in outage. The scope for this work also differs from one plant to the next due to differences in plant design, market construct, and other factors. Comparable life-extension activities for CANDU plants largely occur during very long-duration refurbishment outages where multiple, major plant components are replaced, though some related work can also be incorporated into more frequently recurring planned maintenance outages.

Due to the higher variability and lower frequency of life-extension activities that occur across reactor technologies and operators, ScottMadden focused only on quantifying and adjusting for the impact of recurring, planned maintenance outages on power generation. We took the following steps to arrive at an average annual value for days offline due to these planned outages.

1. We calculated the median planned maintenance outage days for each technology type and maintenance cycle
2. We projected this schedule of outages over a 30-year period, which was the least common multiple in number of years for the different outage cycles, to determine planned maintenance outage days over a long period
3. We annualized these 30-year values into a number of days per year to determine the average annual outage days required for planned maintenance by technology type and outage cycle

[8] Primarily, S&P Global, US Nuclear Regulatory Commission, Ontario Energy Board, and New Brunswick Energy and Utilities Board

[9] ScottMadden acted as the blinding agent for all survey responses so that no participants, including OPG, would be able to view this sensitive data from other operators.

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4. Finally, we calculated the incremental additional annual outage days required for any technology (CANDU, PWR, and BWR) and cycle (18, 24, 30, or 36-month) combination compared to those technologies and cycles requiring the fewest average outage days per year (which were BWRs and PWRs on 24-month cycles)

We represent the output of this exercise in the table below.

Reactor Type	Outage Cycle	Median Average Planned Outage Days Per Year, Annualized	Incremental Additional Annualized Outage Days Per Year Above Shortest Duration
BWR	18-month cycle[10]	Not represented in study	
	24-month cycle	14 days	
PWR	18-month cycle	19 days	5 days
	24-month cycle	14 days	0 days
CANDU	24-month cycle	18 days	4 days
	30-month cycle	36 days	22 days
	36-month cycle	27 days	13 days

To adjust for these outage requirements, we normalized the annual values for MWh of production at each plant. Specifically, if a plant in the dataset had a reactor type and outage cycle combination that, on average, required additional outage days above the shortest duration, we added those incremental additional days back to total production for the year using the site summer capacity[11] at 100% utilization. If a plant had a reactor type and outage cycle combination that did not require additional outage days (i.e., all BWRs and PWRs on 24-month outage cycles), we left total production values unchanged.

Although the median average planned outage durations fall in the range of 14 days to 36 days annually per unit for all reactor types, historical outages between 2015-2019 have shown many outages extending beyond stated planning assumptions, mainly due to discovery or other emergent issues identified by the operator. This indicates that, while operators aim to complete outages on schedule, these planning assumptions have recently proven to be conservative estimates, at least for our purposes.

ScottMadden adjusted the MWh values for all 63 sites from 2015-2017, as described above, to account for the impact of differences in planned outage durations across technology types and outage frequencies. The chart below shows the adjusted TGC values from the econometric analysis divided by the adjusted MWh values from the custom nuclear outage benchmarking study.

[10] Of the 63 operators in the EUCG dataset, only two single-unit plants are reported to be on an 18-month maintenance cycle during the 2015-2017 timeframe, and these plants were not represented in our survey of nuclear operators. Thus, for the purposes of this study, we assumed that 18-month cycle BWRs have the same annualized median outage duration as 24-month cycle BWRs.

[11] From the EIA 860 form, retrieved through SNL database, as opposed to nameplate capacity or winter capacity, which are often higher values

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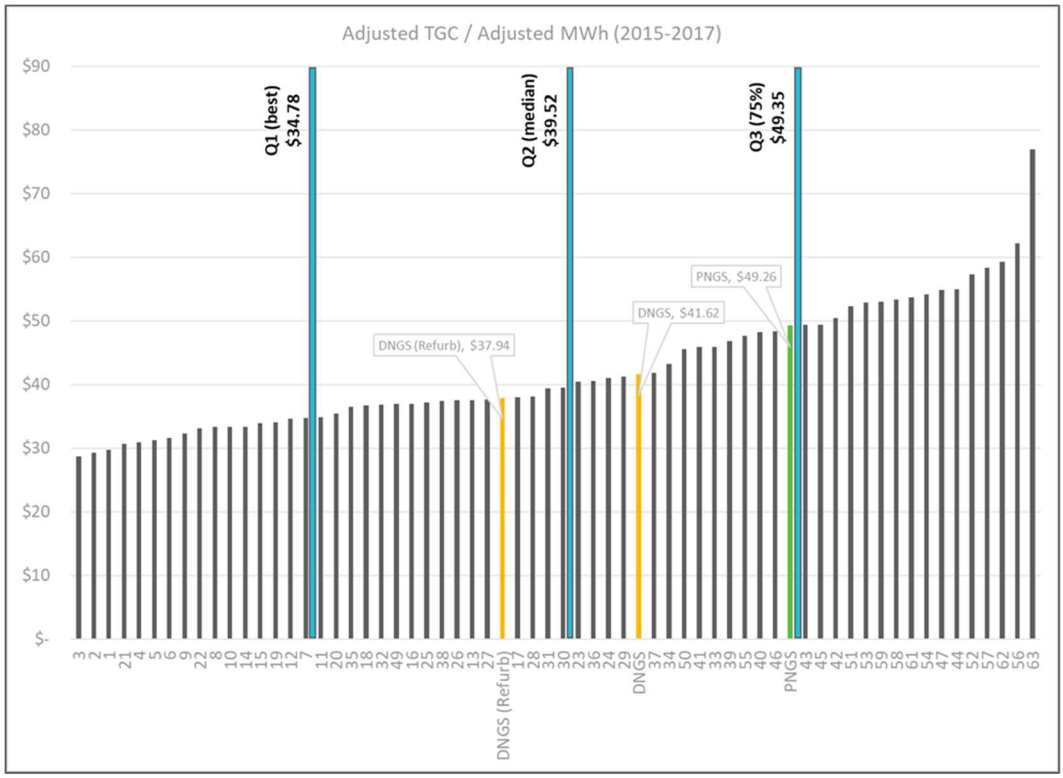
As a result of these adjustments:

- Pickering's relative performance improves further to 47th out of the 63 sites in the EUCG panel or third quartile
- Darlington's relative performance without accounting for Refurbishment improves to 37th out of the 63 sites in the EUCG panel; after accounting for Refurbishment, Darlington's relative performance is 29th out of the 63 sites in the EUCG panel or second quartile

TGC/MWh performance 2015-'17 for EUCG Panel with All Sites Adjusted Based on Econometric Analysis and Outage Study and DNGS Also Adjusted for Refurbishment



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OPG Nuclear Cost Performance Benchmarking

Methodology to Adjust for Refurbishment and Validation of Implementation

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1. BACKGROUND

Context and ScottMadden's View

Darlington Nuclear Generating Station (DNGS) is one of two nuclear stations operated by Ontario Power Generation (OPG). DNGS is a four-unit station with a net output of 3,512 megawatts (MW), and it has been producing almost 20 percent of Ontario's electricity needs since the early 1990s. OPG is performing a major mid-life refurbishment of the four reactors at DNGS (Refurbishment), which involves the replacement of certain life-limiting components. The execution of the Refurbishment "mega-project" started in October 2016 with breaker-open on Unit 2.

OPG tracks and benchmarks the performance of DNGS against industry peers under its nuclear cornerstone of value for money using a suite of four cost metrics. OPG believes that two of these cost metrics, Total Generating Cost per MWh (TGC per MWh) and Non-Fuel Operating Cost per MWh (NFOC per MWh), will not be comparable to prior site performance or industry peers during Refurbishment as a result of significantly reduced MWhs of generation with no corresponding decline in costs, which are largely fixed. In order to ensure that DNGS performance can be tracked and benchmarked during Refurbishment, OPG intends to "normalize," or adjust to facilitate comparison of these two cost metrics.

ScottMadden's view:

- Refurbishment is a unique "mega-project," and the experience and perspective of other industry professionals, while useful to consider, cannot provide established practice for normalizing cost metrics during this unique project
- ScottMadden concurs with OPG that Refurbishment will significantly impact station performance indicators for these two cost metrics and that normalization will be necessary to facilitate useful comparisons to past performance and industry peers
- ScottMadden supports OPG's decision to continue to report an unadjusted (i.e., not normalized) version of these cost metrics in conjunction with any normalized version
- ScottMadden found that a more strongly supported and conventional approach to normalization of cost metrics was to adjust the distribution of actual costs to reflect performance of the operating units while using actual MWhs generated in the denominator.

Explanation of the Specific Issue

Four different Value for Money (VFM) Metrics, hereafter referred to as Cost Metrics, are used by OPG to measure its Nuclear Stations' performance and to benchmark against industry standards.

1. Total Generating Cost (TGC) per MWh
2. Non-Fuel Operating Cost (NFOC) per MWh[1]
3. Fuel Cost per MWh
4. Capital Cost per MW Design Electrical Rating[2]

[1] Non-Fuel Operating Cost (NFOC) is "total operating, maintenance & administrative cost" which is comprised of station cost, as well as attributed centralized nuclear support cost and attributed corporate support and certain centrally-held costs

[2] "Capital cost per MW," as a standalone metric uses MW Design Electrical Rating (DER) as the denominator, but nominal dollars of capital cost also contribute to the numerator in the "Total Generation Cost (TGC) per MWh" metric

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For benchmarking purposes, Cost Metrics follow the guidance provided by the Electric Utility Cost Group (EUCG) in the Nuclear Committee Nuclear Database Instructions. The first two Cost Metrics, TGC per MWh and NFOC per MWh, will not be comparable to peers (or steady state operations) during the Refurbishment for two key reasons:

1. Lower generation (MWhs in the denominator) while the Darlington units are offline and not generating electricity
2. Fixed costs which do not scale up or down proportionally with how much electricity the Darlington units generate[3]

At OPG, the following non-fuel costs are attributed to the nuclear operating stations:

- Corporate support Operating, Maintenance and Administrative (OM&A) costs
- Nuclear centralized support OM&A costs
- Nuclear station OM&A costs (excluding Refurbishment OM&A costs)
- Nuclear capital costs (excluding Refurbishment capital costs)
- Minor fixed assets
- Certain centrally held costs

2. ABOUT THE SCOTTMADDEN APPROACH

Scope, Objectives, Assumptions and Qualifications

ScottMadden is leveraging prior work, including industry research, to outline a preferred methodology through which two of Darlington's cost performance benchmarks can be normalized:

- TGC per MWh
- NFOC per MWh

The objective of this work is to facilitate useful comparisons to past performance and industry peers for the operating plant at DNGS during the extended time periods in which certain units will be offline due to Refurbishment. ScottMadden intends to accomplish this objective by:

- Clarifying which types of costs for a unit in Refurbishment could be reasonably adjusted
- Explaining how such an adjustment might be performed
- Documenting this guidance for use by OPG

In preparing this document, ScottMadden assumed that OPG attributes costs in a manner that is consistent with the description OPG shared with ScottMadden outlining the cost attribution methodologies, particularly for corporate support and nuclear support.

ScottMadden's recommendation is subject to the following qualifications:

- ScottMadden does not imply the performance of any additional, specific research beyond what is described in this document

[3] Fuel Cost per MWh and Capital Cost will continue to be comparable because fuel cost varies proportionately with generation and Capital Cost per MW DER will not be impacted by lower generation during refurbishment

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- ScottMadden does not express an opinion in this document on the effectiveness of cost management practices at OPG or the appropriateness of any costs incurred by OPG
- The ScottMadden methodology was prepared for the benefit of OPG and is limited to the subject matter expressly stated in this document; no additional ScottMadden opinion is implied or may be inferred

About Cost Attribution

Like any major corporation, particularly one that employs a center-led model to provide functional support to the business, OPG employs cost attribution methods intended to appropriately assign costs to the business in a manner that is consistent with demands for the associated services.

As previously noted, TGC and NFOC at DNGS include station cost and as well as nuclear support and corporate support costs. To compare the cost performance per MWh of the operating plant to industry peers, OPG must adjust the distribution of these costs to focus only on the operating units.

In order to provide a methodology for making such an adjustment, ScottMadden developed an understanding of current cost attribution methods employed by OPG and accepted by the Ontario Energy Board (OEB). The scope of ScottMadden support did not include evaluation of the design or application of the current cost attribution methodologies.

3. METHODOLOGY TO ADJUST FOR REFURBISHMENT

Methodology Summary

As previously stated, TGC and NFOC at DNGS include station costs, nuclear support costs, and corporate support costs. The services provided by the support groups can be assigned directly to DNGS or attributed indirectly based on defined methodologies. In addition to these services, a relatively small amount of engineering and technical service OM&A costs is also attributed to DNGS from the Renewable Generation (RG) business.

The focus of the ScottMadden methodology is to allow OPG, after some detailed accounting work, to adjust the distribution of OM&A and capital costs to estimate what TGC and NFOC would look like if DNGS was presently a three-unit site rather than a four-unit site (as Unit 2 entered Refurbishment in October 2016 and remains offline). ScottMadden has examined OPG cost items and current attributions in order to identify costs that can be reasonably adjusted out to create a normalized TGC per MWh and NFOC per MWh.

The intent of normalizing the metric in this way is to facilitate useful comparisons to past performance and industry peers for the operating plant at DNGS during the extended time periods in which certain units will be offline due to Refurbishment. Within the methodology, ScottMadden provides specific guidance for each type of cost, taking into consideration how costs are currently attributed as well as the nature of the work associated with the cost.

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The normalization methodology makes provision to remove OM&A and capital costs from TGC that are reasonably attributable to the unit(s) in Refurbishment.[4] While a portion of Darlington's capital costs are captured by this provision, ScottMadden is aware of certain other capital expenditures intended to support post-refurbishment operations that have not been classified by OPG as Refurbishment capital and therefore have an unfavorable impact on Darlington's TGC/MWh performance.

ScottMadden is also aware of the lost generation impact for the station associated with bulkhead installation and removal as part of the Refurbishment program. While ScottMadden acknowledges that this activity would have an unfavorable impact on Darlington's TGC per MWh performance, this type of adjustment is outside the scope of the normalization methodology set out in this report, which focuses on adjusting the distribution of costs.

Corporate Support OM&A Cost Attribution

In this section, ScottMadden identifies how each type of Corporate Support cost[5] should be removed for the purposes of normalization for both the costs directly assigned to DNGS and the costs attributed to DNGS via the OPG methodology. There are multiple scenarios to consider, and each is described below along with the specific instructions for the recommended adjustment to the associated costs.

- **Scenario 1: Management Assignment or Proportionate Support Allocation**
  - The OPG methodology attributes certain costs to DNGS based on management assignment or proportionate support allocation. Management assignment includes direct assignment and management time estimates of FTEs or other resources. Proportionate support allocation attributes certain corporate support costs in the same ratio as other corporate support costs based on the OPG allocation methodology
  - In this case, the costs attributed to DNGS can be reduced to adjust for the impact of Refurbishment by "(number of operating units in Refurbishment) divided by (total number of operating units at DNGS)"
- **Scenario 2: Full-Time Equivalents**
  - The OPG methodology attributes certain costs to DNGS based on the number of FTEs at the station relative to the total number of FTEs supported
  - In this case, to the extent station FTEs are reasonably attributable to the unit(s) in Refurbishment, DNGS costs can be reduced by "(number of station FTEs supporting Refurbishment) divided by (total number of station FTEs)"
- **Scenario 3: OM&A and Capital Blend**
  - The OPG methodology attributes certain costs to DNGS based on OM&A and capital dollar blend specific to the station relative to total blended OM&A and capital costs[6]
  - In this case, to the extent OM&A and capital costs are reasonably attributable to the unit(s) in Refurbishment, DNGS costs can be reduced by "(OM&A and capital

[4] Normalization of centrally held OM&A costs included in the cost performance benchmarks is outside the scope of the normalization methodology set out in this report
[5] Includes OM&A components of asset service fees charged to the nuclear business unit for the use of common corporate assets.
[6] Capital costs used in the calculation of the OM&A and Capital Blend allocator exclude external purchased services

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costs attributable to Refurbishment) divided by (total OM&A and capital costs for DNGS)"

The following table sets out each group of costs and the associated cost attribution scenario, based on OPG's 2017 organizational structure. By applying the prescribed actions outlined above to each of the corresponding groups of costs, new TGC and NFOC values, adjusted for Refurbishment, can be calculated and divided by actual MWh of generation to produce the normalized measures of value for money.

Group	OPG Method of Cost Attribution to DNGS
Chief Administrative Office	
Environment	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 3: OM&A and Capital Blend
Law	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 3: OM&A and Capital Blend
Real Estate & Services	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 3: OM&A and Capital Blend
Regulatory Affairs	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 3: OM&A and Capital Blend
Supply Chain	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 3: OM&A and Capital Blend
Corporate Office	
Corporate Affairs	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 3: OM&A and Capital Blend
Executive Office	Scenario 3: OM&A and Capital Blend

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Group	OPG Method of Cost Attribution to DNGS
Finance	
Assurance and Enterprise Risk Management	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 3: OM&A and Capital Blend
Corporate Business Development and Strategy	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 3: OM&A and Capital Blend
Fund Management	Scenario 3: OM&A and Capital Blend
Treasury (including Insurance)	Scenario 3: OM&A and Capital Blend
Business Planning and Reporting	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 3: OM&A and Capital Blend
External Reporting and Policy	Scenario 3: OM&A and Capital Blend
Income Tax	Scenario 3: OM&A and Capital Blend
Nuclear Finance	Scenario 1: Management Assignment or Proportionate Support Allocation
Corporate Controllership	Scenario 3: OM&A and Capital Blend
Shared Financial Services	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 3: OM&A and Capital Blend
SVP Office and Chief Controller Office	Scenario 1: Management Assignment or Proportionate Support Allocation
Chief Information Office	
Infrastructure Management (outsourced)	Scenario 1: Management Assignment or Proportionate Support Allocation
Application Management (outsourced)	Scenario 1: Management Assignment or Proportionate Support Allocation
Data Center Services (outsourced)	Scenario 1: Management Assignment or Proportionate Support Allocation
Other IT Services (outsourced)	Scenario 1: Management Assignment or Proportionate Support Allocation
IT Support Costs (internal)	Scenario 1: Management Assignment or Proportionate Support Allocation
Projects	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 3: OM&A and Capital Blend
Business Infrastructure Services	Scenario 1: Management Assignment or Proportionate Support Allocation

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Group	OPG Method of Cost Attribution to DNGS
People & Culture	
Business Change and Talent	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 2: Full-Time Equivalents
Employee & Labor Relations	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 2: Full-Time Equivalents
Total Rewards & Solutions	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 2: Full-Time Equivalents
Business Partners	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 2: Full-Time Equivalents
Health and Safety	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 2: Full-Time Equivalents
Learning & Development	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 2: Full-Time Equivalents
SVP Office	Scenario 2: Full-Time Equivalents

Nuclear Support and Station OM&A Cost Attribution

In this section, ScottMadden identifies how each type of Nuclear Support or Station cost should be removed for the purposes of normalization for both the costs directly assigned to DNGS and the costs attributed to DNGS via the OPG methodology. As mentioned, ScottMadden assumed that OPG attributes costs in a manner that is consistent with the descriptions OPG provided to ScottMadden of the Nuclear cost attribution methodology. OPG indicated that the attribution methodology is driven by the two scenarios described below:

- **Scenario 1: Management Assignment or Proportionate Support Allocation**
  - The OPG methodology attributes certain costs to DNGS based on management assignment or proportionate support allocation. Management assignment includes direct assignment and management time estimates of FTEs or other resources. Proportionate support allocation attributes certain corporate support costs in the same ratio as other corporate support costs based on the OPG allocation methodology
  - In this case, the costs attributed to DNGS can be reduced to adjust for the impact of Refurbishment by "(number of operating units in Refurbishment) divided by (total number of operating units at DNGS)"
- **Scenario 4: Number of Operating Units**
  - The OPG methodology attributes certain costs to DNGS and PNGS at 40% and 60% based on the number of operating units between the two stations
  - Given this allocation approach is based on operating units, DNGS costs can be reduced by "(number of operating units in Refurbishment) divided by (total number of operating units at DNGS)"

The following table sets out each group of costs and the associated attribution scenario, based on OPG's 2017 organizational structure. By applying the prescribed actions outlined above to each of the corresponding groups of costs, new TGC and NFOC values, adjusted for

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Refurbishment, can be calculated and divided by actual MWh of generation to produce the normalized measures of value for money.

Group	OPG Method of Cost Attribution to DNGS
Nuclear Support	
Direct Report	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 4: Number of Operating Units
Fleet Ops Maintenance & Training	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 4: Number of Operating Units
Inspection & Maintenance Services	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 4: Number of Operating Units
Nuclear Engineering	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 4: Number of Operating Units
Nuclear Oversight	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 4: Number of Operating Units
Nuclear Reg Affairs & Stakeholder	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 4: Number of Operating Units
Nuclear Waste Management	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 4: Number of Operating Units
Projects & Modifications	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 4: Number of Operating Units
Security & Emergency Services	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 4: Number of Operating Units
Nuclear Station	
DNGS	Scenario 1: Management Assignment or Proportionate Support Allocation
PNGS	Scenario 1: Management Assignment or Proportionate Support Allocation Scenario 4: Number of Operating Units

Nuclear Sustaining Capital Cost Attribution

In this section, ScottMadden identifies how sustaining capital costs associated with DNGS should be removed for the purposes of normalization for both the costs directly associated with the unit(s) under Refurbishment and those that are common to all units of the station

- **Sustaining Capital Cost for Unit(s) under Refurbishment** – ScottMadden recommends that the sustaining capital costs attributed to DNGS that are directly associated with the unit(s) under refurbishment should be excluded in full for normalization purposes
- **Sustaining Capital Cost Common to All Units at DNGS** – ScottMadden recommends that the sustaining capital costs attributed to DNGS that are common to all units of the station be excluded on the basis of "(number of operating units in Refurbishment) divided by (total number of operating units at DNGS)"

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By applying the prescribed actions outlined above to each of the corresponding groups of costs, new TGC and NFOC values, adjusted for Refurbishment, can be calculated and divided by actual MWh of generation to produce the normalized measures of value for money.

4. SCOTTMADDEN VALIDATION OF OPG ADJUSTMENT

Adjustment Outcome

Following the documented methodology guidance, OPG independently performed the adjustment and normalized costs for 2017 by $263.3M, resulting in:

- Decrease of 3-year TGC/MWh from 54.40 to 50.54 for 2017
- Decrease of 3-year NFOC/MWh from 39.62 to 36.89 for 2017

ScottMadden has reviewed the work to validate that:

- The approach OPG followed was in accordance with ScottMadden guidance
- OPG accurately performed the calculations

Validation

ScottMadden reproduced the OPG implementation of the methodology, adhering to OPG's described methods of cost attribution to DNGS to closely compare subtotals. Comparison of OPG's total calculated reduction and ScottMadden's total calculated reduction revealed no variance. ScottMadden found that OPG correctly interpreted and implemented the guidance provided.

OM&A and Capital Costs Calculation

For several types of costs allocated to DNGS (Scenario 3), the methodology directs that DNGS costs in a given year can be reduced by a calculated percentage found by:

$$\frac{OM\&A\ and\ capital\ costs\ attributable\ to\ Refurb}{Total\ OM\&A\ and\ capital\ costs\ for\ DNGS}$$

OPG's calculation is displayed in the table below. ScottMadden validated that OPG implemented the methodology correctly to arrive at an adjustment value of 45% for OM&A and capital cost blend attributable adjustments:

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OM&A and Capital Costs Budget*		
	2017	%
Capital		
Refurb	375	64%
Darlington	207	36%
Total Capital	582	
OM&A		
Refurb	91	20%
Darlington	373	80%
Total OM&A	464	
Total Costs		
Refurb	466	45%
Darlington	580	55%
Total Costs	1,046	

** All Capital costs exclude External Purchased Services (EPS)*

FTE Calculation

For several types of costs allocated to DNGS (Scenario 2), the methodology directs that DNGS costs in a given year can be reduced by a calculated percentage found by:

$$\frac{Number\ of\ station\ FTEs\ supporting\ Refurbishment}{Total\ number\ of\ station\ FTEs}$$

OPG's calculation is displayed in the table below. ScottMadden validated that OPG implemented the methodology correctly to arrive at an adjustment value of 41% for adjustments attributable to number of FTEs at the station:

Budget FTE		
	2017	%
Refurb	862	41%
Darlington	1,253	59%
Total FTE	2,114	

Table of Adjustments

The table on the following two pages outlines the adjustments, organized by method of adjustment according to cost category and methodology.

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Group	OPG Method of Cost Attribution to DNGS	Reduction ($K)
Nuclear Station and Support	OM&A costs assigned to DNGS that are reasonably attributable to the unit(s) in Refurbishment should be removed: Cyclical Outage Costs	$ (57,894)
Chief Administrative Office		
Environment	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (685)
	Scenario 3: OM&A and Capital Blend	$ (629)
Law	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (590)
	Scenario 3: OM&A and Capital Blend	$ (1,531)
Real Estate & Services	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (8,553)
	Scenario 3: OM&A and Capital Blend	$ (319)
Regulatory Affairs	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (262)
	Scenario 3: OM&A and Capital Blend	$ (51)
Supply Chain	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (5,012)
	Scenario 3: OM&A and Capital Blend	$ (673)
Corporate Office		
Corporate Affairs	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (1,837)
	Scenario 3: OM&A and Capital Blend	$ (1,734)
Executive Office	Scenario 3: OM&A and Capital Blend	$ (465)
Finance		
Assurance and Enterprise Risk Management	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (290)
	Scenario 3: OM&A and Capital Blend	$ (682)
Corporate Business Development and Strategy	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (95)
	Scenario 3: OM&A and Capital Blend	$ (866)
Fund Management	Scenario 3: OM&A and Capital Blend	$ (256)
Treasury (including Insurance)	Scenario 3: OM&A and Capital Blend	$ (2,555)
Business Planning and Reporting	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (81)
	Scenario 3: OM&A and Capital Blend	$ (1,233)
External Reporting and Policy	Scenario 3: OM&A and Capital Blend	$ (959)
Income Tax	Scenario 3: OM&A and Capital Blend	$ (533)
Nuclear Finance	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (1,353)
Corporate Controllership	Scenario 3: OM&A and Capital Blend	$ (510)
Shared Financial Services	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (138)
	Scenario 3: OM&A and Capital Blend	$ (2,097)
SVP Office and Chief Controller Office	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (149)
Chief Information Office		
CIO	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (13,167)
	Scenario 3: OM&A and Capital Blend	$ (3,970)

Table continues on the next page.

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Group	OPG Method of Cost Attribution to DNGS	
People & Culture		
Business Change and Talent	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (567)
	Scenario 2: Full-Time Equivalents	$ (318)
Employee & Labor Relations and Health & Safety	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (315)
	Scenario 2: Full-Time Equivalents	$ (1,692)
Total Rewards & Solutions	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (364)
	Scenario 2: Full-Time Equivalents	$ (1,551)
Business Partners	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (443)
	Scenario 2: Full-Time Equivalents	$ (110)
Learning & Development	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (7,733)
	Scenario 2: Full-Time Equivalents	$ (252)
SVP Office	Scenario 2: Full-Time Equivalents	$ (618)
Nuclear Support		
Direct Report	Scenario 1: Management Assignment or Proportionate Support Allocation	
	Scenario 4: Number of Operating Units	$ (746)
Fleet Ops Maintenance & Training	Scenario 1: Management Assignment or Proportionate Support Allocation	
	Scenario 4: Number of Operating Units	$ (6,679)
Inspection & Maintenance Services	Scenario 1: Management Assignment or Proportionate Support Allocation	
	Scenario 4: Number of Operating Units	$ (4,363)
Nuclear Engineering	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (3)
	Scenario 4: Number of Operating Units	$ (25,041)
Nuclear Oversight	Scenario 1: Management Assignment or Proportionate Support Allocation	
	Scenario 4: Number of Operating Units	$ (532)
Nuclear Reg Affairs & Stakeholder	Scenario 1: Management Assignment or Proportionate Support Allocation	
	Scenario 4: Number of Operating Units	$ (3,772)
Nuclear Waste Management	Scenario 1: Management Assignment or Proportionate Support Allocation	
	Scenario 4: Number of Operating Units	$ (121)
Projects & Modifications and Enterprise Projects	Scenario 1: Management Assignment or Proportionate Support Allocation	
	Scenario 4: Number of Operating Units	$ (12,291)
Security & Emergency Services	Scenario 1: Management Assignment or Proportionate Support Allocation	$ (138)
	Scenario 4: Number of Operating Units	$ (9,776)
Nuclear Station		
DNGS	Scenario 1: Management Assignment or Proportionate Support Allocation	
PNGS	Scenario 1: Management Assignment or Proportionate Support Allocation	
	Scenario 4: Number of Operating Units	$ (5)
Nuclear Sustaining Capital Cost	Sustaining Capital Cost for Unit(s) under Refurbishment	$ (29,082)
	Sustaining Capital Cost Common to All Units at DNGS	$ (47,660)
Grand Total		**$ (263,342)**

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