Business Case Summary: Optimization of Pickering Units' Operational Lives

August 14, 2019

Contents

Recommendations & Executive Summary
Pickering Safe Operation
Alternatives Analysed
Technical Assessment Summary
Regulatory Approvals
Staffing and Leadership
Cost and Generation Assumptions
Economic Assessment Summary
Risk Overview
Recommendations

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EXECUTIVE SUMMARY:

Background:

OPG assesses the projected safe operating lives of its nuclear units as part of normal work program. These routine assessments focus on the fitness-for-service of major life-limiting components such as fuel channels, feeders and steam generators, and provide assurance to Management and the CNSC that the units will remain fit-for-service until the forecasted end-of-commercial operations dates. These on-going life cycle management and aging management programs have progressed OPG's understanding of the key degradation mechanisms on the major components.

The 2019 to 2021 Business Plan assumed Pickering Units 1 & 4 would shutdown at the end of 2022 and Pickering Units 5 to 8 would shutdown at the end of 2024. However, as a result of the life cycle management and aging management assessments, an opportunity to further optimize the operational lives of the Pickering units has been identified.

In addition, with the extensive refurbishment program on both the Bruce and Darlington units combined with the planned shutdown of Pickering Units in 2022 and 2024, the IESO is projecting a significant and growing capacity deficit on the Ontario system beginning in 2023. The IESO's Fall 2018 Outlook showed summer peak capacity deficits of approximately 1400 MW, 1700 MW, 3700 MW and 3100 MW in 2023, 2024, 2025 and 2026 respectively. Optimizing the Pickering units' end-of-commercial operation dates can help to partially address these projected capacity deficits.

As the opportunity to optimize Pickering's end-of-commercial operation dates beyond 2022 and 2024 was identified, OPG completed a preliminary technical and economic assessment of multiple alternatives for operation beyond those assumed shutdown dates. These alternatives are listed in Table E1.

Table E1: Alternative Cases Assessed for Pickering End-of-Commercial Operations

Case	Description		
	P1	**P4**	**P5-8**
Base Case	End 2022	End 2022	End 2024
Case 1	End 2023	End 2023	End 2024
Case 2	Sept 2024	Dec 2024	End 2024
Case 3	Sept 2024	Dec 2024	End 2025
Case 4	Sept 2024	Dec 2024	End 2026

Data on these alternatives was provided to the Independent Electricity System Operator (IESO) to facilitate their independent assessment of the value to the Ontario system. The results of the IESO's assessment were presented to OPG in June of 2019 and are summarized below.

Preferred Alternative and Summary Assessment:

OPG's preliminary technical and economic assessment demonstrate that optimizing the life of the Pickering units is technically feasible and would have economic and qualitative benefits to the province and to OPG. Based on results of the assessments, the Preferred Alternative is Case 3:

1. Continue to operate Pickering Units 1 & 4 until September 2024 and December 2024 respectively, and
2. To assume a shutdown date for Pickering Units 5 to 8 of December 2025.

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The planned changes to Pickering's end-of-commercial operations dates per the Preferred Alternative are expected to:

a. Optimize generation and asset value by providing 29.8 TWh of incremental generation over the period 2023 to 2025.
b. Yield a value to ratepayers in the range of $177 million to $328 million (2019PV$), and as high as $576 million (2019 PV$) if a value of $50/tonne were placed on the avoided CO_2 emissions
c. Yield additional net income to OPG and higher returns to the Shareholder over the 2023 to 2025 period
d. Enable OPG to submit a rate application for the 2022 – 2026 period with overall lower nuclear rates than had been previously forecast.
e. Require an incremental work program at an estimated cost of $50M to enable the optimization of Pickering's end-of-commercial operations dates
f. Provide "insurance value" to the electricity system during a period of significant uncertainty and change due to the nuclear refurbishment activities. Optimization of Pickering's end-of-commercial operations will provide the IESO with a short lead-time and an easily implemented option to meet a portion of Ontario's system capacity needs during this time.
g. Result in a reduction of CO_2 emissions of approximately 6.8 million tonnes
h. Reduce levels of business disruption and more closely align closure of Pickering to the target completion dates for Darlington Refurbishment
i. Defer the loss of a significant number of highly skilled jobs in Durham region by 1 to 2 years
j. Defer the incurrence of severance and related costs associated with the end of commercial operations and provide additional opportunities to minimize these costs
k. Defer the incurrence of expenditures for safe-storing and dismantling of the units

The estimated Levelized Unit Energy Cost (LUEC) for the incremental 29.8 TWh of generation is 4.7 ¢/kWh (2019), which is very competitive with other potential generation sources.

Based on data OPG provided in February and March of 2019, the IESO completed its assessment of the four alternative cases shown in Table E1 above. The IESO concluded that, of the four alternatives presented, Case 3 was preferred from an economic standpoint. The IESO concurred with OPG's assessment and noted the following for the Preferred Alternative:

a. Result is characterized by the IESO as "breakeven" within an electricity system in Ontario that has a value in excess of $20 billion annually. The IESO also made it clear that certain economic factors, namely the benefit of delaying decommissioning expenditures, and any implicit or assumed societal value of carbon free generation was not included in the economic analysis they performed. OPG's analysis does take these factors into account especially since a price for carbon is needed to ensure a fulsome analysis for the future. In addition, OPG's analysis reflects a different discount rate, capacity value and replacement energy value as compared to the IESO.
b. Would provide operational benefits by supporting outage management and managing transmission constraints resulting in a forecast of less frequent congestion on the transmission system at two key interfaces.
c. Would reduce production from gas-fired generators, reduce electricity imports and increase electricity exports
d. Would increase baseload generation according to the IESO's definition of surplus, which is calculated on a closed system (without imports and exports).

In conclusion, the IESO communicated to OPG that it is in favour of the optimized Pickering operational lives, given that it is breakeven from a system cost perspective, provides the system operational benefits and there are other qualitative and non-quantified benefits.

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The Business Plan for 2020 to 2026, to be approved in November 2019, is expected to incorporate the end-of-commercial operations dates consistent with the Preferred Alternative, subject to approval of this Business Case. Upon Board approval, OPG will seek CNSC approval of the Preferred Alternative.

Recommendations

1. Plan to safely and reliably operate Pickering Units 1 and 4 to September 2024 and December 2024 respectively, and Pickering Units 5 to 8 to December 2025.
2. Continue and enhance on-going life cycle management and aging management programs in order to further progress understanding of the key degradation mechanisms on the major components. This is expected to achieve high confidence in safe and reliable operation of the Pickering units to the new target dates. In addition, final shutdown dates and sequence for Units 5 to 8 based on projected technical fitness-for-service will be established.
3. Receive regulatory concurrence for the Preferred Alternative by adjusting regulatory work programs. This will require a number of long lead time assessments to be prepared, including a re-assessment of the continued validity of the Periodic Safety Review results.

The costs to enable this optimization of the operational lives of the Pickering units are estimated at approximately $50M ("Pickering Optimization enabling costs"). No release of funds is required at this time. The changes and enhancements to work programs to enable this optimization of the units' lives are being developed and refined. Management will seek a release in November 2019, following finalization of the details of the work programs required to achieve optimization of the unit lives.

Next Steps

1. Life cycle management and aging management programs for the major components will continue to be refined and enhanced, in order to develop the phased shutdown sequence for Pickering Units 5 – 8.
2. Work will continue as required with the IESO and the Ministry of Energy, Northern Development and Mines in respect of Shareholder concurrence.
3. Changes to regulatory work programs to enable the Preferred Alternative will be incorporated and engagement of the CNSC at the appropriate time will take place.

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SIGNATURES

Recommended by:

July 26, 2019

Sean Granville Date
Chief Nuclear Officer

Finance Approval:

July 26, 2019

John Mauti Date
Chief Financial Officer (Acting)

Line Approval per OAR Element 1.1:

July 26, 2019

Ken Hartwick Date
President & Chief Executive Officer

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BACKGROUND:

OPG assesses the projected safe operating lives of its nuclear units as part of normal work program. These routine assessments focus on the fitness-for-service of major life-limiting components such as fuel channels, feeders and steam generators, and provide assurance to Management and the CNSC that the units will remain fit-for-service until the forecasted end-of-commercial operations dates. These on-going life cycle management and aging management programs have progressed OPG's understanding of the key degradation mechanisms on the major components.

The 2019 to 2021 Business Plan assumed Pickering Units 1 & 4 would shutdown at the end of 2022 and Pickering Units 5 to 8 would shutdown at the end of 2024. However, as a result of the life cycle management and aging management assessments, an opportunity to further optimize the operational lives of the Pickering units has been identified.

In addition, with the extensive refurbishment program on both the Bruce and Darlington units combined with the planned shutdown of Pickering Units in 2022 and 2024, the IESO is projecting a significant and growing capacity deficit on the Ontario system beginning in 2023. The IESO's Fall 2018 Outlook showed summer peak capacity deficits of approximately 1400 MW, 1700 MW, 3700 MW and 3100 MW in 2023, 2024, 2025 and 2026 respectively. Optimizing the Pickering units' end-of-commercial operation dates can help to partially address these projected capacity deficits.

OPG has approached both the IESO and the Ministry of Energy, Northern Development and Mines to explore the benefits to the Ontario system of further optimizing the forecasted end-of-commercial operations dates of the Pickering units. Technical and economic assessments have been undertaken for a number of alternatives to optimize the end-of-commercial operations dates, and a Preferred Alternative has been identified. This Preferred Alternative demonstrates that further optimization of the dates would be safe, technically feasible and have economic and qualitative benefits. This business case summarizes the preliminary technical and economic assessment of the Preferred Alternative. The business case also outlines the work program adjustments required, the expected incremental costs, the projected generation benefits, the estimated economic value to the Ontario system and other quantitative and qualitative benefits of implementing the Preferred Alternative.

PICKERING SAFE OPERATION

Safety is priority at OPG. To assure OPG Management and the CNSC that the plant is, and will continue to be, safe to operate in the future, there are numerous on-going assessments of the condition of plant equipment. As the plant ages and certain components are operated beyond their original nominal design life, these assessments become even more critical. The assessment of the condition of the major components such as fuel channels, feeders and steam generators are the most critical, and are primarily accomplished through extensive inspection programs during planned outages. The required inspections and maintenance activities of major components are specified in life cycle management plans.

At the end of outage inspections, fitness-for-service assessments are completed to confirm that the components are able to function as designed at least until the next scheduled inspection campaign. If the assessments cannot demonstrate that component condition is acceptable, the component will be replaced or repaired. If the work required is significant, for example, a large scale replacement of a significant number of fuel channels in a unit, Management may determine that while the work is technically feasible, the economic case to implement the work is not acceptable and the unit may be declared at end-of-life, and removed from service. The frequency of inspections and assessments is such that this determination would be made and a decision would be taken long before there is a credible risk of component failure, thereby preventing any nuclear safety event. The fitness-for-service assessments must be accepted by staff from the Canadian Nuclear Safety Commission and,

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if warranted, OPG could be requested to take appropriate action to address any issues. This would normally not be required, as OPG would not propose that any equipment or components continue to be operated, unless OPG had high confidence in the fitness-for-service of that equipment.

In addition to routine inspections and analyses of those results during and after planned outages, OPG updates various assessments regarding a nuclear station's safety to operate on a regular basis, using sophisticated models which involve probabilistic modelling of various accident sequences and which can predict the consequences of the failure of certain plant equipment on employee and public health. These safety assessments are required under the CNSC regulations, and are a key submission during the re-licensing process.

ALTERNATIVES ANALYSED

As summarized in Table 1, four alternatives, in addition to the current planning reference of operating Units 1 and 4 to the end of 2022 and Units 5 to 8 to the end of 2024, were analyzed.

Table 1: Pickering Optimized Operations Alternatives Analysed

Case	Description			
	P1	P4	P5-8	Comments
Base	Dec 2022	Dec 2022	Dec 2024	Base Case for the 2019 to 2021 Business Plan with two units shutdown in 2022 and four units shutdown in 2024. Base Case mitigation for fuel channel degradation and steam generator degradation (Unit 4) required
Case 1	Dec 2023	Dec 2023	Dec 2024	Enhanced mitigation of fuel channel elongation on Unit 1 and enhanced mitigation of steam generator degradation on Unit 4 required. Same mitigation of fuel channel degradation mechanisms as in Base Case for Units 5 to 8.
Case 2	Sep 2024	Dec 2024	Dec 2024	Enhanced mitigation of fuel channel elongation on Unit 1 and enhanced mitigation of steam generator degradation on Unit 4 required. Sept 2024 projected as limit of high confidence fitness-for-service of Unit 1. Same mitigation of fuel channel degradation mechanisms as in Base Case for Units 5 to 8.
Case 3	Sep 2024	Dec 2024	Dec 2025	Same mitigation of degradation mechanisms as in Case 2 for Units 1 and 4. For Units 5 to 8, enhanced mitigation over and above work done in Cases 1 and 2 regarding fuel channel degradation mechanisms will be required to provide high confidence fitness-for-service.
Case 4	Sep 2024	Dec 2024	Dec 2026	

As outlined in the table above, every alternative to the Base Case would require enhanced inspections, monitoring and mitigation of, in particular, fuel channel degradation mechanisms. For Pickering Unit 4, additional mitigation of steam generator degradation would be necessary. These details are discussed in the Technical Assessment section below. As also shown in Table 1, Cases 3 and 4 involve additional regulatory effort, as there would need to be an update of the Periodic Safety Review and a public hearing would need to be conducted. The cost of the incremental life cycle management inspections and monitoring, as well as the incremental regulatory effort comprise the major portion of the "Enabling" costs for each alternative.

Preferred Alternative:

Based on OPG's internal analysis, the Preferred Alternative, based on a balance of technical achievability, costs and economics is Case 3. The IESO was provided with data and information for all of the Cases and their assessment was presented to OPG in June of 2019, which also indicated that Case 3 was preferred. The IESO's conclusion was based on a balance of the system economics

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and other factors, for example, operational benefits to the Ontario system such as supporting outage management and managing transmission constraints, including less frequent congestion on the transmission system at two key interfaces. A summary of the IESO's assessment is provided later in this document.

Table 2: Preferred Alternative Selected

Preferred Alternative: Case 3			
P1	**P4**	**P5-8**	**Comments**
Sep 2024	Dec 2024	Dec 2025	P1: Limited by elongation of the fuel channels; this date assumed physical modifications implemented P4: Limited by fitness-for-service of the steam generators and prohibitive economics of operating one unit on the "A" side for an extended period of time P5-8: Confidence in fuel channel life of P5-8 varies by unit. Additional data and analysis from on-going monitoring programs will be enhanced and the high confidence fitness-for-service limits refined.

TECHNICAL ASSESSMENT SUMMARY

As part of the normal on-going life cycle management and aging management programs, routine assessments are carried out in order to be able to project the remaining safe and reliable operating lives of the Pickering units. A preliminary technical assessment of the projected fitness-for-service of the Pickering units to the dates set out in Cases 1 to 4 has been completed for the major components, specifically the fuel channels, feeder pipes and the steam generators. In addition, Balance of Plant components have been assessed for projected fitness-for-service. It is important to note that these assessments are on-going and continuously refined. The following sections discuss the issues required to be managed to continue to assure fitness-for-service of the major components to the optimized operational dates for the Preferred Alternative.

Fuel Channels:

Technical assessment of the fuel channels' fitness-for-service for operation to the current planning reference dates of 2022/2024 is on-going under the Fuel Channel Life Assurance Project. Any enhancements to the scope of work of this project which will be required to further optimize the end-of-commercial operation dates in accordance with Case 3, will be funded from the Pickering Optimization Business Case.

There are four degradation mechanisms of particular concern for the fuel channels' fitness-for-service (other known degradation mechanisms continue to be monitored, but the projected dates at which these mechanisms may limit operations are later than the projected dates under the four mechanisms of concern):

a) Calandria tubes to Liquid Injection Shutdown System (CT-LISS) nozzles contact - can occur because as the fuel channels age, deformation (sag) of the fuel channels can lead to the calandria tubes contacting the LISS nozzles which are installed horizontally between the rows of fuel channels, leading to concerns about calandria tube integrity. This mechanism is of particular concern for Units 5 and 6 as current projections show this to be the leading fitness-for-service issue to be resolved on these units in order to achieve the optimized dates under the Preferred Alternative. Mitigation includes de-tensioning of the LISS nozzles to increase the gap between the calandria tubes and the LISS nozzles.

b) Exceeding Terminal Solid Solubility for Dissolution (TSSD) – this degradation mechanism refers to the fact that there is hydrogen ingress into the pressure tubes of the fuel channels as the unit is operated. Beyond a certain threshold concentration of hydrogen, there is a risk of hydrides being present in the body of the pressure tube at operating temperatures making

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the pressure tube more susceptible to rupture at operating temperatures. Mitigation includes obtaining more samples of pressure tube material during outages and measuring the hydride content in order to allow refinement of the models which predict the time at which hydride concentration will exceed acceptable levels. This degradation is of particular concern for Unit 7.

c) Axial elongation of the fuel channels - this degradation mechanism refers to the fact that as the unit is operated, the fuel channels grow axially, and a number of fuel channels are expected to reach the limits of available bearing travel (i.e. when the leading pressure tubes will no longer be supported on their bearings). This mechanism is of concern primarily on Unit 1. Plans have been developed to install a hardware modification on Unit 1, which will allow safe operation until September 2024. Units 5 to 8 are currently projected to reach the limits of bearing travel beyond the date in the Preferred Alternative. Fuel channel measurements taken during outages allow the rate-of-elongation assumptions to be refined. Current plans for all units are to continue to monitor and inspect in upcoming outages, and to continue to update projections of when the leading fuel channels in each unit will no longer be supported on their bearings.

d) Annulus spacer integrity – this degradation mechanism relates to the projected degradation of material properties on the annulus spacers, which are a spring-like component which are installed in the annulus space between the pressure tube and the calandria tube in the fuel channels to preclude contact between the pressure tube and the calandria tube. Contact could result in an initiation point for a potential fracture of the pressure tube. This mechanism is of particular concern for 30 fuel channels in Unit 8, which are equipped with spacers of a particular material type that has been found to be susceptible to degradation of material properties as the units age. Mitigation includes: a) obtaining spacers from the operating units and testing the material properties to be able to predict more accurately when the material properties will no longer be acceptable; b) artificially aging spacers in test facilities to simulate their expected condition in the future then testing the material properties of those spacers to determine acceptability for continued service; c) procedural modifications to reduce stress on the spacers.

Feeders

Preliminary assessments indicate that feeders are not a significant issue regarding continued fitness-for-service for the Preferred Alternative of operating the units to 2024 and 2025. Routine inspection and monitoring of feeder condition is an on-going life cycle management activity and will continue.

Steam Generators:

Aside from Unit 4, steam generators are not expected to present risks to demonstrating fitness-for-service. Maintenance and inspection campaigns are appropriately planned for the Preferred Alternative. There are known degradation mechanisms on two steam generators in Unit 4 which are well understood and which are being addressed in upcoming planned outages on the unit. Based on the information to date, there is medium confidence that the steam generators on Unit 4 will be operated safely until the end of 2024.

Balance of Plant:

Balance of plant main process equipment (e.g., turbine-generator sets, condensers, heat exchangers, major motors, transformers, etc.) and their supporting systems, structures and components have also been assessed based on current Life Cycle Management Plans, health

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reports and recent condition assessments. These assessments will continue to be updated, but no significant issues are expected to challenge the safe and reliable operation to 2025. Normal maintenance activities are expected to be sufficient and will continue.

REGULATORY APPROVALS

The current Power Reactor Operating Licence for Pickering was issued in August 2018 for a 10 year term (expiring in 2028). The licence will see Pickering through operations until the end of 2024, followed by defueling/safe storage activities and transition to the safe-stored state between 2024 and 2028.

As part of Pickering's re-licensing, a Periodic Safety Review (PSR) was completed that evaluates the plant against the requirements that would apply to a newly-built nuclear power plant. The evaluation identifies potential nuclear safety enhancements to the plant design or programmes. The safety enhancements are then assessed to identify the alternatives that can be reasonably and practicably implemented to improve safety, and these results are documented in the Integrated Implementation Plan (IIP). The licence issued in August 2018 commits OPG to implement the results of the PSR to ensure the continued safe and reliable commercial operation of Pickering NGS to the end of 2024.

For the Pickering 5 – 8 units to operate beyond the end of 2024 as contemplated in the Preferred Alternative, OPG is required to complete a reassessment of the continued validity of the PSR results, revise the IIP actions as required and notify the CNSC by December 31, 2022. There would then be a mandatory public hearing at which stakeholders would be able to make representations to the CNSC about the continued safe operation of the Pickering units.

STAFFING & LEADERSHIP

On-going staffing risks will continue to require close management attention in order to ensure safe operation under the Preferred Alternative. Attrition of experienced staff is an on-going issue which will be managed and mitigated. Hiring and training plans will be updated as part of the Business Planning process in order to accommodate the longer period of staffing required under the Preferred Alternative.

Leadership development and succession planning will also be revisited as part of the Business Planning process with a view to mitigating any increased risks around senior leadership which may be triggered by adoption of the Preferred Alternative.

COSTS AND GENERATION ASSUMPTIONS

In developing the Preferred Alternative, OPG's objective is to establish with medium to high confidence the incremental work and related costs required to enable the optimized operational period of Pickering. OPG's approach is summarized in the following steps:

1. Resources and associated costs (Base OM&A, Outage OM&A, Project OM&A and Capital, Nuclear and Corporate Support Costs) are continued at normal levels during the optimized operation period.
2. Additional inspections and maintenance scope for major components (fuel channels, steam generators, feeders and reactor components) are identified in detail and the impacts on outage durations and costs (primarily fuel channel inspections and maintenance) are assessed.
3. Additional "Balance of Plant" scope is identified, estimated and the impact on outages and costs (if any) are assessed.

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4. Additional sustaining investments (Capital and OM&A projects) are identified, and impacts on outages and costs (if any) are assessed.
5. Additional analytical scope (primarily regulatory and engineering) is identified and costs and resources estimated.
6. Any other additional enabling scope (e.g. additional staff training costs) is identified and estimated. Nuclear Support and Corporate Support costs are assessed.
7. Amounts are estimated to address known uncertainties

Based on the above, costs and outage impacts have been estimated and included in the assessment of the Preferred Alternative. Incremental costs will be incurred over the period of 2019-2022 for Pickering Units 1 and 4, and 2019 to 2024 for Pickering Units 5 to 8. These costs have been characterized in the following categories:

a) Pickering Optimization Enabling Costs are costs associated with work programs that enable Pickering to operate beyond the current planning assumption dates. The preliminary estimate, pending final 2020-2026 Life Cycle Management Plan review, of these costs for the Preferred Alternative are approximately $50M and relate primarily to additional inspections and analysis required on the fuel channels and additional regulatory support work.

b) Restoration and Normal Operating Costs: As the planned shutdown dates of the units are deferred, the planned wind down of costs would be deferred as well. Costs will be incurred to restore on-going operating programs in the latter years of the Base Case to normal levels. Incremental costs required to operate the units beyond the dates in the current Base Case assumption will also be incurred. The estimate, pending final 2020-2026 Business Plan review, of Restoration and Normal Operating Costs for the Preferred Alternative is $1.57B.

Costs are summarized in Table 3.

Table 3: Estimated Incremental Costs to Enable Extended Operations

Work Program	2021 to 2025 ($M)	Comments
Restoration and Normal Operating Costs: Base & Outage OM&A, Projects, Nuclear and Corporate Support	1,565	Restoring resources to normal levels pre-2022/2024, plus costs to operate post-2022/2024
Total Costs to Enable Preferred Alternative (Pickering Optimization Enabling Costs)	50	Incremental work program costs required to enable operations beyond dates in current planning assumptions.
Grand Total	**1,615**	

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Table 4 summarizes the generation impacts of the Preferred Alternative.

Table 4: Estimated Generation Impacts of the Preferred Alternative

Generation Plan	2019 - 2022	Post 2022	Total
Additional Planned Outage Days for P1 & P4	83	129	**212**
Incremental TWh for P1 & P4	-1.0	14.7	**13.7**

Generation Plan	2019 - 2024	Post 2024	Total
Additional Planned Outage Days for P5 – P8	90	0	**90**
Incremental TWh for P5 – P8	-1.1	17.2	**16.1**

Total Incremental Planned Outage Days	**173**	**129**	**302**
Total Incremental TWh	**-2.1**	**31.9**	**29.8**

The additional outage days in the period 2019 to 2024 are associated with:

a. Incremental inspections required to enable the Preferred Alternative and
b. Restoration of normal planned outages and durations in the latter years that would not be required under the assumed shutdown dates of the Base Case.

ECONOMIC ASSESSMENT SUMMARY

The Levelized Unit Energy Costs (LUEC) of the Preferred Alternative, i.e. the LUEC associated with the incremental costs and generation relative to the Base Case, is 4.7 ¢/kWh. LUEC calculations exclude the benefit of deferring severance and related costs and are calculated using incremental costs only, i.e. costs that would not be incurred if the Preferred Alternative were not pursued. Fully allocated costs are not used for LUEC calculation as they include a portion of costs that will be not be eliminated with the shutdown of Pickering. As Pickering shuts down, there is a loss in economies of scale on fully allocated costs. A portion of these fully allocated costs will be absorbed by the remaining operating units. These costs are primarily in the “support costs” categories and have not been included in the LUEC calculation.

Along with LUEC, OPG also assessed the incremental value to the Ontario System of each alternative, i.e. Cases 1 to 4 relative to the Base Case. The results are shown under the following differing assumptions:

a) Replacement cost of Pickering’s capacity would be low, and no value is placed on carbon reduction – this value for Case 3 is assessed at $177M in 2019 present value.

b) Replacement cost of Pickering’s capacity would be high, and no value placed on carbon reduction – this value for Case 3 is assessed at $328M in 2019 present value

c) Replacement cost of Pickering’s capacity would be high, and a $50/tonne value placed on carbon reduction – this value for Case 3 is assessed at $576M in 2019 present value.

The factors which influence the economic assessment are explained in detail in Appendix 1.

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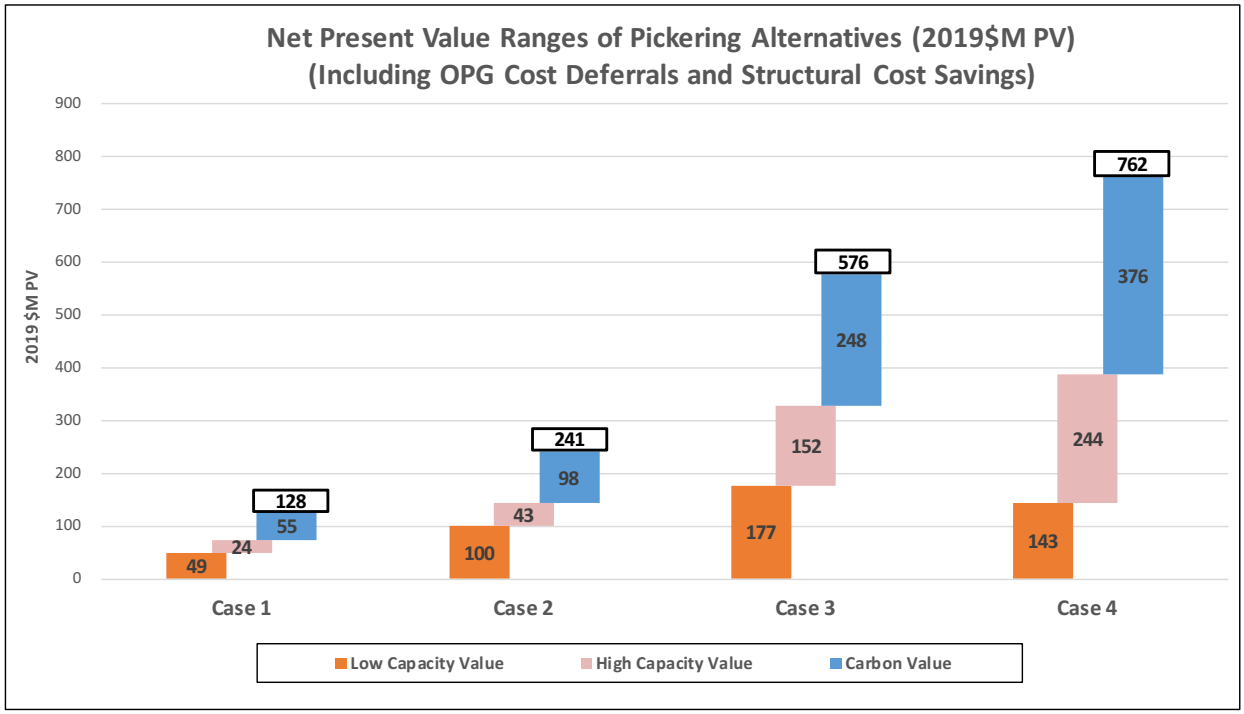
Figure 1: Net Present Value Ranges for Pickering Alternatives (2019$M PV)



Case 1	P1& 4 Dec 2023	P5-8 Dec 2024	Case 3	P1/4 Sept/Dec 2024	P5-8 Dec 2025
Case 2	P1/4 Sept/Dec 2024	P5-8 Dec 2024	Case 4	P1/4 Sept/Dec 2024	P5-8 Dec 2026

In addition to yielding a value to ratepayers in the range of $177 million to $328 million, and as high as $576 million, if a value of $50/tonne were placed on the avoided CO_2 emissions, the Preferred Alternative would also provide a number of quantitative and qualitative advantages for both the ratepayer and OPG as follows:

a) Generation and asset value would be optimized, as 29.8 TWh of incremental generation would be produced from the Pickering plant over the period 2023 to 2025
b) OPG would earn additional net income and the Shareholder would obtain higher returns from OPG over the 2023 to 2025 period
c) Provide "insurance value" to the electricity system during a period of significant uncertainty and change due the nuclear refurbishment activities. Optimization of Pickering's end-of-commercial operations will provide the IESO with a short lead-time and an easily implemented option to meet a portion of Ontario's system's capacity needs in 2023, 2024 and 2025
d) CO_2 emissions in Ontario will be approximately 6.8 million tonnes lower compared to the Base Case.
e) OPG will be able to submit a rate application for the 2022 – 2026 period with overall lower nuclear rates than had been previously forecast
f) There will be reduced levels of business disruption as Pickering closure would be more closely aligned to the target completion dates for Darlington Refurbishment
g) The loss of a significant number of highly skilled jobs in Durham region would be deferred by 1 to 2 years
h) The incurrence of severance and related costs associated with end of commercial operations of Pickering would be deferred and more time would be available to seek out and implement additional opportunities to minimize these costs, thereby benefitting the ratepayer
i) The planned expenditures for safe-storing and dismantling of the units would be deferred, yielding a present value benefit.

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The IESO completed its preliminary assessment of the four alternative cases based on data and information OPG provided in February and March of 2019. The IESO's conclusions were presented to OPG In June of 2019. In summary, the IESO concluded that, of the four alternatives presented, Case 3 was preferred from an economic standpoint, which aligns with OPG's Preferred Alternative. The IESO also concluded that OPG's Preferred Alternative:

1) Would reduce the amount of additional capacity that needs to be acquired to meet resource adequacy requirements in 2023, 2024 and 2025
2) Result is characterized as "breakeven" within an electricity system in Ontario that has a value in excess of $20 billion annually. The IESO also made it clear that certain economic factors, namely the benefit of delaying decommissioning expenditures, and any implicit or assumed societal value of carbon free generation was not included in the economic analysis they performed. OPG's analysis provided in Figure 1 above does take these factors into account especially since a price for carbon is needed to ensure a fulsome analysis for the future. In addition, OPG's analysis reflects a different discount rate, capacity value and replacement energy value as compared to the IESO.
3) Would provide operational benefits by supporting outage management and managing transmission constraints resulting in a forecast of less frequent congestion on the transmission system at two key interfaces.
4) Would reduce production from gas-fired generators, would reduce electricity imports and would increase electricity exports
5) Would reduce greenhouse gas emissions by approximately 4 million tonnes.
6) Would increase surplus baseload generation, but within manageable levels.

On balance, the IESO communicated to OPG that it is in favour of the optimized Pickering operational lives, given that it is breakeven from a system cost perspective, provides the system operational benefits and other non-quantified factors.

Rate Impacts:

Figure 2 depicts the impact of the Preferred Alternative on OPG Nuclear rates. Optimizing Pickering operations moderates the rate impacts associated with the return-to-service of the Darlington units following refurbishment. This occurs because:

1. Extending Pickering operations results in a larger OPG generation base over which to spread the impacts of the Darlington Refurbishment costs included in the rate base, and
2. Severance and related closure costs of Pickering are deferred.

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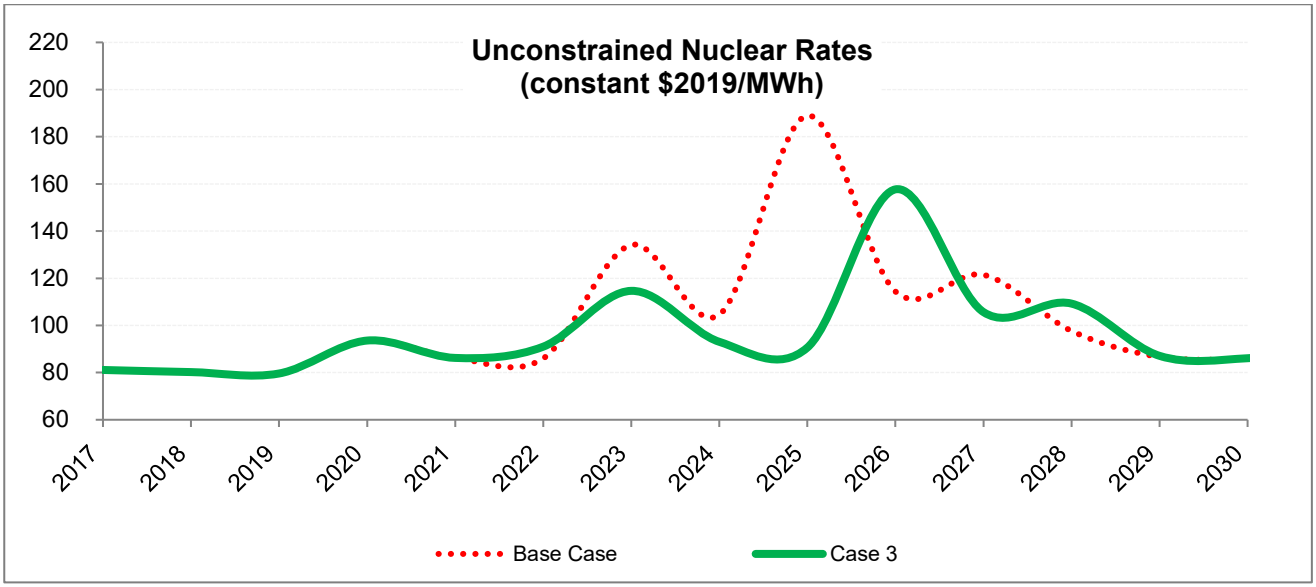
Figure 2: OPG Nuclear Rate Impacts of Preferred Alternative



RISK OVERVIEW

The key risks associated with the Preferred Alternative are summarized below:

1. Social License Risk: e.g. the risk that interest groups that are opposed to nuclear power will contest this further optimization of the Pickering Units' lives, particularly during the public hearing process that will be required in 2023, should any units' lives be extended beyond 2024. These interest groups may stoke community concerns and this could potentially impair OPG's ability to achieve the optimization.

   Mitigation: Ongoing demonstration of the value and safety of Pickering through external communications, hearings and stakeholder relations.

2. Regulatory Risks: e.g. the risk that the proposed disposition for one or more known issues is not accepted by the CNSC.

   Mitigating Actions: Completion of the update to the Periodic Safety Review and the Integrated Implementation Plan, as well as a pro-active approach with the CNSC to demonstrate technical fitness-for-service and maintenance of high safety standards.

3. Technical/Fitness-for-Service Risks: e.g. the risk that a major component, e.g. fuel channels, does not continue to meet fitness-for-service requirements.

   Mitigating Actions: On-going comprehensive inspection and maintenance programs are included in the work program; life cycle management program of major components adjusted based on the extended end-of-life dates.

4. System Value Assessment: e.g. changes to Ontario system parameters such as flat or declining load growth, reduction in the cost of competing generation or changes to baseload supply (e.g. refurbishment schedules changes) could impact the overall economic system value negatively.

   Mitigating Actions: None that OPG can implement directly. Robust analysis across a range of scenarios and OPG ensuring that costs and generation forecasts are achieved.

Management assesses the overall risks associated with the optimization of Pickering operations as per the Preferred Alternative to be manageable. Technical fitness for service risks will evolve as additional on-going and enhanced inspections, monitoring and material testing in research facilities are performed and the data gathered is analysed.

RECOMMENDATIONS:

1. Plan to safely and reliably operate Pickering Units 1 and 4 to September 2024 and December 2024 respectively, and Pickering Units 5 to 8 to December 2025.
2. Continue and enhance on-going life cycle management and aging management programs in order to further progress understanding of the key degradation mechanisms on the major components in order to achieve high confidence in safe and reliable operation of the Pickering units to the new target dates. This includes formalizing the actual shutdown dates and sequence for Units 5 to 8, based on projected technical fitness-for-service.
3. Adjust work programs to address the regulatory scope of work required to assure regulatory concurrence with the optimized ends-of-commercial operations dates for the Pickering units. This will require a number of long lead time assessments to be prepared, including a re-assessment of the continued validity of the Periodic Safety Review results; therefore, it is critical that this work be launched as soon as possible.

The costs to enable this optimization of the operational lives of the Pickering units are estimated at approximately $50M. No release of funds is required at this time. The changes and enhancements to work programs to enable this optimization of the units' lives are being developed and refined. Management will seek a release in November 2019, following finalization of the details of the work programs required to achieve optimization of the unit lives.

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Appendix 1:
Preliminary Estimated Enabling Costs to Optimize Pickering's End-of-Commercial Operation Dates

Work Program	2020 $M	2021 $M	2022 $M	2023 $M	2024 $M	Total $M
Incremental Fuel Channel, Feeders, Steam Generators, and Balance of Plant Inspections & Maintenance and Outage Costs (including contingency)		2	23	15		**40**
Regulatory and Technical Assessments including Periodic Safety Review Update	2	2	2	4		**10**
Total	**2**	**4**	**25**	**19**		**50**

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Appendix 2:
Factors Influencing Economic Valuation of Pickering Optimization Alternatives

The economic value of Pickering optimization alternatives is primarily influenced by the following factors:

a) The need for, and forecast value of, capacity (MW) on the Ontario system. There must be sufficient capacity on the system to meet peak demands during the summer months, including operational reserve requirements.
   i. If projected capacity shortfalls can be met by purchases from neighbouring jurisdictions for the summer months only, the assumed costs of that capacity ($/MW) would be relatively low; therefore, the capacity value (avoided capacity costs) of optimizing the Pickering units' ends-of-commercial operations dates would be relatively low
   ii. If capacity shortfalls are more likely to require the building of new capacity on the Ontario system to meet the need, the assumed costs of that capacity would be quite high; therefore, the capacity value (avoided capacity costs) of optimizing the Pickering units' ends-of-commercial operations dates would be relatively high

b) The need for, and forecast value of, energy (MWh) on the Ontario system. There must be sufficient energy available to system to meet demands all year round. The Ontario electricity system is not expected to be short of energy through the mid-2020's, as the Combined Cycle Gas Turbines (CCGT's) currently operating at very low capacity factor are expected to continue to be available and produce additional energy. The cost of that additional energy is a function of the price of natural gas and the value placed on CO_2.

c) The value placed by society on carbon reduction. Optimizing the lives of the Pickering units would result in a reduction in CO_2 emissions in Ontario since the majority of the energy required to replace Pickering would be combined cycle gas-fired generation. Starting on April 1st of 2019, the Federal Government implemented a carbon tax of $20/tonne of CO_2, implying that there is a general societal value. The Federal carbon tax is expected to rise to $50/tonne by 2022. OPG has done a sensitivity analysis showing the additional value to society that would accrue to the Pickering optimized operations cases, if the societal value of $50/tonne were applied to avoided CO_2 emissions.

d) The forecast costs (Operations and Maintenance, Sustaining Capital, Fuel) of operating Pickering relative to other competing generation options.

e) The forecast generation performance of the Pickering units.

f) The value of deferring liabilities for severance and related costs which results in a reduction in the present value of the liability.

g) The value of deferring decommissioning costs of the Pickering units. Specifically, the costs of safe-storing and dismantling are delayed reducing the present value of the liability for these costs.

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