Financial Accountability Office of Ontario

Nuclear Refurbishment

An Assessment of the Financial Risks of the Nuclear Refurbishment Plan

Fall 2017

About this Document

Established by the *Financial Accountability Officer Act, 2013*, the Financial Accountability Office (FAO) provides independent analysis on the state of the Province's finances, trends in the provincial economy and related matters important to the Legislative Assembly of Ontario.

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This report was prepared at the direction of the Officer in response to a request from a member of the Assembly. In keeping with the FAO's mandate to provide the Legislative Assembly of Ontario with independent economic and financial analysis, this report makes no recommendations concerning policy choices.

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Table of Abbreviations

Abbreviation	Term
BNGS	Bruce Nuclear Generating Station
CANDU	CANada Deuterium-Uranium
CCGT	Combined Cycle Gas Turbine
DNGS	Darlington Nuclear Generating Station
DVA	Deferral and Variance Accounts
FAO	Financial Accountability Office
HOEP	Hourly Ontario Energy Price
IESO	Independent Electricity System Operator
KWh	Kilowatt hour
LUEC	Levelized Unit Electricity Cost
MMBtu	One million British Thermal Units
MW	Megawatt
MWh	Megawatt hour
NGS	Nuclear Generating Station
OEB	Ontario Energy Board
OPG	Ontario Power Generation
PNGS	Pickering Nuclear Generating Station
SBG	Surplus Baseload Generation
TW	Terawatt
TWh	Terawatt hour

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ESSENTIAL POINTS

- The Government of Ontario (the Province) has decided to refurbish 10 nuclear reactors at the Bruce and Darlington Nuclear Generating Stations (BNGS and DNGS) and extend the life of the Pickering Nuclear Generating Station (PNGS) (collectively, the Nuclear Refurbishment Plan). The refurbishments are scheduled to take place from 2016 to 2033 and the total capital cost is estimated to be $25 billion in 2017 dollars.

- The purpose of this report is to review how the Nuclear Refurbishment Plan will impact ratepayers and the Province and to identify how financial risk is allocated among ratepayers, the Province, Ontario Power Generation (OPG) and Bruce Power.

- If the Nuclear Refurbishment Plan is executed as planned:

    - The FAO estimates that the Plan will result in nuclear generation supplying a significant proportion of Ontario electricity demand from 2016 to 2064 at an average price of $80.7/MWh in 2017 dollars. (For reference, the 2017 Nuclear Price is $69/MWh and the current price of electricity for most residential and small business ratepayers is $114.9/MWh.)

    - The Nuclear Price will be higher than the average price of $80.7/MWh during the majority of the time that the reactors are being refurbished from 2016 to 2033. Post refurbishment, ratepayers will benefit from a lower than average Nuclear Price.

- Overall, despite near-term Nuclear Price increases, the Plan is projected to provide ratepayers with a long-term supply of relatively low-cost, low emissions electricity.
- OPG will realize a financial return from the operation of the DNGS and PNGS. OPG is owned by the Province and any return would improve the Province's fiscal position. There is no significant fiscal impact to the Province from the refurbishment of reactors at the BNGS as it is operated by Bruce Power, a private sector organization.

Risk Analysis. The FAO analyzed the allocation of risk to ratepayers and the Province for four key financial risks to the Nuclear Refurbishment Plan.

- **Refurbishment cost risk:** The risk that the cost of refurbishing the reactors will be higher or lower than planned.
  - Ratepayers bear the risk of cost increases for BNGS reactors until 12 months before each reactor refurbishment begins. At that time, the risk of cost increases is transferred to Bruce Power.
  - Ratepayers bear the risk of all cost increases prudently incurred (as determined by the Ontario Energy Board) by OPG and the benefit of any cost savings. The Province bears the risk of any cost increases not prudently incurred by OPG.
  - The FAO estimates that a 30% increase in refurbishment costs on all BNGS and DNGS reactors would increase the average Nuclear Price by 5.4%, and a 50% increase in refurbishment costs would increase the average Nuclear Price by 8.9%.
  - To mitigate the risk of cost overruns, the Province has options to terminate refurbishments (known as "off-ramps"). The FAO concludes that the Province's options to terminate refurbishments due to refurbishment cost increases have limited value to ratepayers due to economies of scale at nuclear generating stations and the current cost of low emissions alternative generation options.
- **Station performance risk:** The risk that the cost of operating the reactors will be higher or lower than planned.
  - Bruce Power's contract with the Independent Electricity System Operator (IESO) transfers most BNGS station performance risk to Bruce Power. Ratepayers will receive 50% of operating cost savings.
  - Ratepayers and the Province (OPG) combined bear the risk and receive

all benefit of increasing or decreasing costs of operating PNGS and DNGS. The primary method of protection to ratepayers from increases in OPG operating costs is Ontario Energy Board (OEB) oversight. The OPG Nuclear Price is set by the OEB every five years after a public regulatory proceeding. Once the OPG Nuclear Price is set, most station performance risk is transferred to the Province.

The final two financial risks refer to unfavourable market conditions emerging. The Nuclear Refurbishment Plan requires a $25 billion capital investment and price projections are based on costs being spread over a large amount of electricity generation over a long period of time. As a result, reducing nuclear generation or shutting down nuclear reactors in response to unfavourable market conditions is not always economical.

- **Demand risk:** The risk of insufficient electricity grid demand for nuclear generation. If there is insufficient demand for electricity, the Province could be forced to curtail nuclear generation, export electricity at low or negative prices, or permanently shut down one or more reactors.
    - Ratepayers bear the risk that nuclear generation will be curtailed or exported at low or negative prices due to insufficient electricity demand in the market. Ratepayers also bear the risk of a higher Nuclear Price if a reactor is required to be shutdown.
    - The Province bears the risk of lower OPG net income if a reactor at DNGS is shutdown.
    - The FAO identified a number of demand-side and supply-side mitigations that could limit demand risk, including increased electrification through the Province's *Climate Change Action Plan*, actions that smooth out demand fluctuations, the planned shutdown of PNGS by 2024 and the staged shutdown of BNGS and DNGS reactors starting in 2043.
- **Opportunity cost risk:** The risk that the Province's commitment to nuclear refurbishment will preclude it from taking advantage of alternative, lower cost, low emissions grid-scale electricity generation options.
    - Ratepayers bear the risk of not benefiting, or a reduced benefit (in the event of a unit termination), from lower cost grid-scale generation alternatives.
    - The Province bears the risk of lower OPG net income if a reactor at DNGS is shutdown.

- There are currently no alternative generation portfolios that could provide the same supply of low emissions baseload electricity generation at a comparable price to the Nuclear Refurbishment Plan. To the extent that alternative generation options emerge over the life of the Plan, opportunity cost risk is mitigated somewhat by economic off-ramps in the Bruce Contract and the Province’s ability to terminate any DNGS refurbishments.

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EXECUTIVE SUMMARY

The Government of Ontario (the Province) has decided to secure a long-term supply of electricity generation in Ontario by refurbishing ten nuclear reactors at the Bruce and Darlington Nuclear Generating Stations and extending the life of the Pickering Nuclear Generating Station. The FAO refers to the following three elements collectively as the Nuclear Refurbishment Plan (or the Plan).

- Ontario Power Generation's (OPG) plan to refurbish the four reactors at the Darlington Nuclear Generating Station (DNGS) and operate the station to the end of 2055.

- Bruce Power's contract[1] (the Bruce Contract) with the Independent Electricity System Operator[2] (IESO) to refurbish six reactors at the Bruce Nuclear Generating Station (BNGS) and sell electricity into the Ontario market to the end of 2063.[3]

- OPG's plan to extend the operation of the Pickering Nuclear Generating Station (PNGS).[4] Two reactors at Pickering A will be extended to 2022 and four reactors at Pickering B will be extended to 2024.[5]

The refurbishments are scheduled to take place from 2016 to 2033 and the total capital cost is estimated to be $25 billion in 2017 dollars.[6] The Nuclear Refurbishment Plan will result in nuclear generation continuing to supply a large portion of Ontario's

1 The Amended and Restated Bruce Power Refurbishment Implementation Agreement effective January 1, 2016.
2 The IESO operates and settles the electricity wholesale market in Ontario.
3 The BNGS has eight reactors, two of which were refurbished under a previous agreement. All electricity generated by Bruce Power will be sold at a single price under the Bruce Contract.
4 The PNGS was originally scheduled to be shut down in 2020.
5 The FAO has analyzed the Plan based on the assumption of Pickering A shutdown in 2022 and Pickering B in 2024. However, OPG has filed an application to the Canadian Nuclear Safety Commission which would allow for Pickering A to operate to 2024.
6 FAO analysis of Ontario Energy Board Case EB-2016-0152 & Bruce Power. "Amended Agreement Secures Bruce Power's Role in Long-Term Energy Plan." 3 Dec. 2015. Web. 8 Apr. 2017.

electricity and will significantly impact electricity prices paid by Ontario ratepayers for decades. The Plan will also directly impact the Province's fiscal position due to its ownership of OPG.

The purpose of this report is to review how the Nuclear Refurbishment Plan will impact ratepayers and the Province and to identify how financial risk is allocated among ratepayers, the Province, OPG and Bruce Power. The report first establishes base case estimates of the price and production of nuclear generation and explains how those estimates will affect electricity prices and the Province's fiscal position. The report then outlines four key risks to the Nuclear Refurbishment Plan, and assesses how the potential financial impact of the key risks, if realized, is allocated to ratepayers and the Province.

See chapter 3 and appendix D for more background information on this report.

Base Case Ratepayer Impact

This section outlines how the Nuclear Refurbishment Plan is expected to affect ratepayers and the Province based on the FAO's projections of the price and production of nuclear generation. The projections are referred to as the Base Case Plan and will serve as the basis of the risk analysis in the following section.

Under the Nuclear Refurbishment Plan, Bruce Power and OPG will recover the cost of refurbishing and operating the nuclear reactors by generating and selling electricity into the Ontario market. The amounts paid to OPG and Bruce Power will be incorporated into electricity prices and recovered from Ontario ratepayers.

The FAO estimates that the Base Case Plan will result in an average price for nuclear generation (the Nuclear Price) of $80.7/MWh in 2017 dollars[7] from 2016 to 2064. For reference, the current price of electricity for most residential and small business ratepayers is $114.9/MWh,[8] and the current cost of each generation source which comprise the price of electricity are shown in Table 2-1.

7 All dollar figures are in 2017 dollars unless otherwise indicated.
8 This amount does not include the effect of the Province's Fair Hydro Plan. Due to the Fair Hydro Plan, the price most residential and small business ratepayers pay is $97.6/MWh. Ontario Energy Board. "Regulated Price Plan Price Report." 20 Apr. 2017.

Table 2-1: Unit Cost of Ontario Electricity Generation Sources May 2017 – April 2018

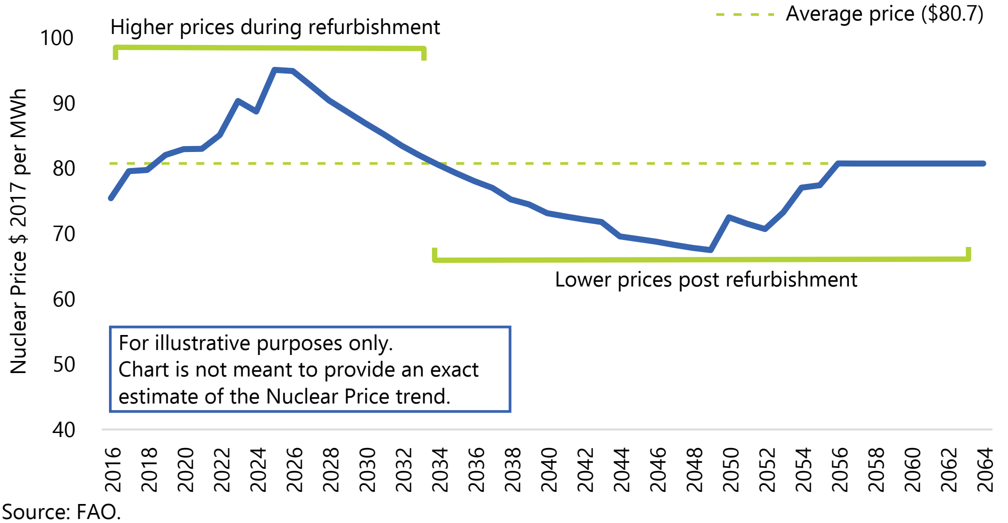
Generation Source	Percent of Total Supply	Unit Cost ($/MWh)
Nuclear	60%	69
Hydro	24%	58
Wind	8%	173
Gas	6%	205
Solar	2%	480
Bio Energy	0%	131

Source Ontario Energy Board. "Regulated Price Plan Price Report." 20 Apr. 2017. Web. 15 Jun. 2017.

Note: The unit costs represent the cost of in service generation, they are not necessarily representative of the cost of new generation which could replace refurbished nuclear generation. See appendix C for further information.

The FAO projects both the price and production of nuclear generation to vary throughout the life of the Plan. As a result, the effect of the Plan on overall electricity prices will vary as well. The FAO projects that the Nuclear Price will be higher than the average price of $80.7/MWh during the majority of the time that reactors are being refurbished from 2016 to 2033.[9] The Nuclear Price is expected to peak in 2027 at $95.4/MWh and then gradually fall (in real terms). Once the refurbishments are complete, the FAO projects a lower than average Nuclear Price (Figure 2-1).

Figure 2-1: Illustration of Base Case Nuclear Price Trend



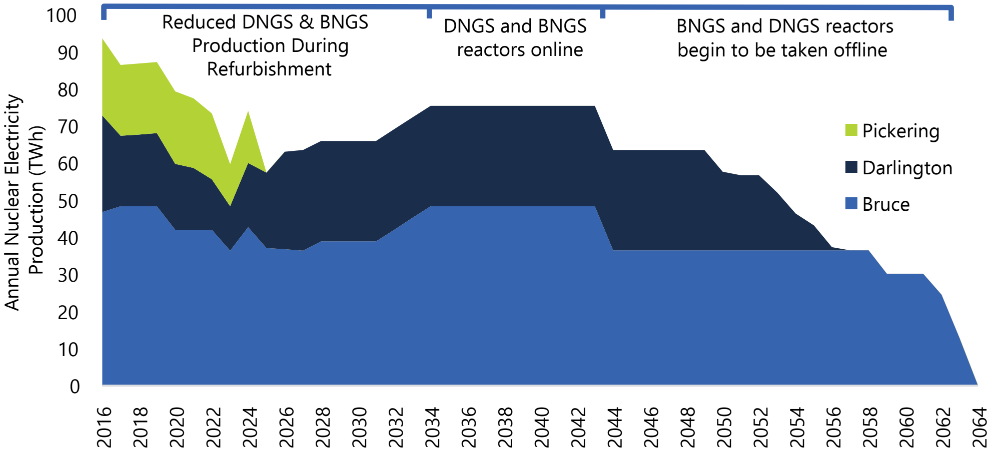
Source: FAO.

Note: The values in the above chart were calculated using the following method: in each year, the FAO calculated the production weighted average of the FAO's estimate of the actual OPG nuclear price and the average Bruce Nuclear Price of $80.6/MWh. The FAO is unable to include the actual Bruce Price estimate in the Base Case Nuclear Price trend due to disclosure restrictions under s.13 of the *Financial Accountability Officer Act, 2013*.

9 See appendix B for more detail on prices and price setting.

Over the life of the Nuclear Refurbishment Plan, the FAO projects the average annual production of electricity from the three nuclear generating stations (Nuclear Production) to be 62 terawatt hours (TWh).[10] However, based on the refurbishment and life cycle schedules of the reactors, the FAO projects annual production to vary over the life of the Plan (Figure 2-2). Nuclear Production will be reduced from 91.7 TWh in 2016 to 57.4 TWh by 2025 due to multiple reactors being offline for refurbishment and the shutdown of PNGS reactors in 2022 and 2024. Once the refurbishments are complete, annual production will be approximately 75 TWh until the reactors begin to be taken offline, beginning with BNGS units 1 and 2 in 2043.[11]

Figure 2-2: Nuclear Refurbishment Plan Estimated Electricity Production, 2016 to 2064



Source: FAO estimates based on OPG and Bruce Power refurbishment and life cycle schedules. The FAO projects the capacity factor of all refurbished reactors to be 88%.

Base Case Fiscal Impact

The Darlington and Pickering Nuclear Generations Stations are owned and operated by Ontario Power Generation, a regulated utility wholly owned by the Province of Ontario. As a result, any OPG income or loss from nuclear generation will be reflected in the Province's fiscal position.

OPG will finance the DNGS refurbishment with long term corporate debt and cash generated from operations (equity).[12] Once the reactors are back online following refurbishment, OPG will recover the cost of refurbishing and operating the reactors

10 For reference, electricity demand in Ontario was 137 TWh in 2016.
11 BNGS units 1 and 2 were refurbished from 2005 to 2012 under a previous agreement.
12 Ontario Power Generation. 2015 Annual Report.

by selling electricity to ratepayers at prices set by the Ontario Energy Board (OEB).[13]

The OPG Nuclear Price is set by the OEB every five years after a public regulatory process.[14] The OEB sets the OPG Nuclear Price in dollars per megawatt hour ($/MWh). The price is the same for electricity generated from both the Darlington and Pickering Stations. Prices are set every five years based on OPG's forecast revenue requirement and Nuclear Production for the following five-year period. The revenue requirement is OPG's operating, depreciation and tax expenses plus a return on OPG's rate base (cost of capital).[15] The rate base consists of OPG's nuclear assets.[16] When the refurbished reactors are put into service, the assets will be added to the rate base and expensed throughout their useful lives (depreciation). The depreciation expenses and return on the rate base will be incorporated into the revenue requirement, which is divided by OPG Nuclear Production to determine the OPG Nuclear Price (see appendix B for details).

The return (cost of capital) that is incorporated into the OPG Nuclear Price is set to compensate OPG's debt and equity holders that provide the capital to finance OPG's capital investments. This return is set by the Ontario Energy Board to allow OPG to pay interest on its debt and earn a return on its equity investment in nuclear assets. The return on equity is the portion of the revenue requirement that represents OPG's profit on nuclear generation.

OPG's return on equity is not guaranteed, but it is set such that OPG can earn a return[17] given the successful operation of its nuclear generating stations. This return will be reflected in OPG's net income and consolidated into provincial revenues.[18]

Bruce Power is a private sector organization which receives payments for generating and selling electricity into the Ontario market. There is no direct connection between Bruce Power and the fiscal position of the Province. Bruce Power does make payments to OPG to lease the BNGS. However, when the OEB sets the OPG Nuclear Price, the OPG revenue requirement is reduced by OPG's net lease revenues. As a result, the lease revenues benefit the ratepayer not the Province. Therefore, there is no fiscal impact to the Province resulting from the life extension of the BNGS that is within the scope of this report.[19]

13 The Ontario Energy Board regulates the province's electricity and natural gas sectors.
14 The FAO assumes that OPG will continue to file five-year applications.
15 A 7% return on capital is projected which is a weighted average of OPG's projected regulated return on debt and equity.
16 From the OPG 2015 Annual Report: Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital.
17 The OEB determines OPG's return on equity based on a formulaic approach as set out in Report EB-2009-0084.
18 The Province also accounts for its investment in OPG as a financial asset. Therefore, any increase in OPG net assets would reduce the Province's net debt.
19 The impact and risks of decommissioning nuclear reactors is outside the scope of this report.

Risks to Ratepayers and the Province

The FAO has analyzed the exposure of ratepayers and the Province to four key financial risks to the Plan. The FAO has categorized the financial risks into internal and market categories.

Internal Financial Risks

Internal financial risks refer to changes from the assumptions included in the Base Case Nuclear Refurbishment Plan regarding the cost of refurbishing and operating the nuclear reactors. The differences in ownership and rate setting of Bruce Power and OPG mean that the ratepayer's and Province’s exposure to internal financial risks differ with respect to Bruce Power and OPG costs.

Refurbishment Cost Risk

Refurbishment cost risk is the risk that the cost of refurbishing the reactors will be higher or lower than the Base Case Nuclear Refurbishment Plan assumptions.

Bruce Power Refurbishment Cost Risk Allocation

The price Bruce Power is paid for electricity (the Bruce Nuclear Price) that it generates and sells into the Ontario market is set in accordance with the terms of the Bruce Contract. The Bruce Contract provides for transfers of refurbishment cost risk from the ratepayer to Bruce Power. As Bruce Power is a private sector entity, any transfer of risk to Bruce Power reduces the exposure of ratepayers.

The Bruce Nuclear Price will be adjusted 12 months prior to the start date of each of the six BNGS refurbishments to reflect the estimated cost of the refurbishment. At that time, the cost of the refurbishment will be locked-in and the risk of refurbishment cost increases will be transferred to Bruce Power. In addition, if the completed refurbishments are less than the locked-in refurbishment cost, 50% of any savings would be passed on to the ratepayer.[20]

To further mitigate the risk of increasing refurbishment costs to ratepayers, the Province has options to terminate BNGS refurbishments called off-ramps. The off-ramps can be exercised by the IESO before the Bruce Nuclear Price is adjusted 12 months prior to each refurbishment start date.

20 Bruce Contract Exhibit 4.3.

The Bruce contract has two types of off-ramps, threshold and economic:

- Threshold off-ramps give IESO the option to terminate refurbishments if the estimates provided by Bruce Power prior to each refurbishment exceed cost or duration thresholds.[21] The cost threshold is a 30% increase over the refurbishment cost amount that is reflected in the base case Nuclear Price estimate (or 20% for one-time costs).

- Economic off-ramps can only be exercised prior to the third and fifth refurbishment. Economic off-ramps provide IESO with the option to terminate all remaining refurbishments due to reduced electricity demand or the emergence of more cost-effective electricity generation resources.[22]

OPG Refurbishment Cost Risk Allocation

As OPG is owned by the Province, refurbishment cost risk for the four nuclear reactors at the DNGS is distributed between ratepayers and the Province. The price OPG receives for nuclear generation is set by the OEB. The OEB must ensure that OPG recovers planned and unplanned expenses relating to the DNGS refurbishments that are prudently incurred.[23] As a result, any cost overruns that are prudently incurred would be approved by the OEB and recovered from ratepayers. Any costs not approved by the OEB would reduce OPG's net income and hence lower the Province's revenue. Conversely, the FAO expects that 100% of savings on refurbishment costs would be passed on to the ratepayer.

To help mitigate refurbishment cost risk for both the ratepayer and the Province, the Ministry of Energy can terminate refurbishments for any reason at any time.

Table 2-2: Refurbishment Cost Risk Allocation Summary

	Ratepayers	Province
Exposure to Bruce Power Refurbishment Cost Risk	Bear risk of cost increases until the refurbishment cost estimate for each reactor is locked in 12 months before refurbishment begins (subject to off-ramps). Benefit from 50% of any refurbishment cost savings.	None.
Exposure to OPG Refurbishment Cost Risk	Bear risk of cost overruns prudently incurred by OPG. Benefit from 100% of refurbishment cost savings.	Bears risk of cost overruns not prudently incurred by OPG.

21 Duration thresholds are 54 months for first unit, 48 months for second unit, 42 months for remaining units.
22 Bruce Contract Article 9.2, p. 125.
23 O Reg 53/05, s 6(2).

Financial Impact of Refurbishment Cost Overruns

To illustrate the potential financial impact of refurbishment cost increases, the FAO has modeled two scenarios of increased refurbishment costs relative to the base case. Both scenarios assume the refurbishment cost of all reactors increase by the same amount and all cost increases are passed on to ratepayers.

- If the refurbishment cost of all reactors increases 30%, the average Nuclear Price would increase 5.4% from $80.7/MWh to $85.0/MWh.
- If the refurbishment cost of all reactors increases 50%, the average Nuclear Price would increase 8.9% from $80.7/MWh to $87.9/MWh.[24]

Final Off-Ramp Considerations

The off-ramps are the key risk mitigation strategy to protect ratepayers from increases in refurbishment costs. The primary value of the off-ramps to ratepayers is to serve as an incentive for Bruce Power to provide estimates within the pre-defined thresholds and OPG to deliver units on time and on budget.

However, in order to make the off-ramp the most economical option, the refurbishment cost increase would have to be large enough to not only cause the Nuclear Price to be higher than alternative generation options, but also to overcome the loss of economies of scale which would occur as a result of a unit termination. Of note is that the final off-ramp does not expire until 2029 and changes in technology, energy policy or electricity demand could impact the viability of alternative generation options which could increase the value of the off-ramps.

Station Performance Risk

Station performance risk refers to the risk of higher non-refurbishment costs or lower Nuclear Production relative to the base case. This includes changes to expected post-refurbishment operating, fuel and capital costs, unanticipated reactor outages, or shorter-than-planned reactor service lives.

The Bruce Contract transfers most station performance risk to Bruce Power. The ratepayer is exposed to:

- The risk of fuel costs, which are set monthly, separate from other operating costs.[25]

24 See chapter 5 for more detailed analysis.
25 Fuel costs are set through a long-term procurement strategy and represent approximately 12% of the 2016 Bruce Nuclear Price. In addition, only a portion of fuel costs are exposed to the market price of uranium.

- The incremental cost of replacement generation if Bruce Nuclear Production is less than projected in the Base Case Plan.[26]

In addition, the ratepayer receives 50% of the benefit if operating costs are less than projected at the BNGS.[27]

OPG station performance risk is borne by both ratepayers and the Province. The OEB sets the OPG Nuclear Price in five-year increments based on five-year cost and production forecasts. This feature of the rate-setting mechanism means that within the five-year periods, most station performance risk is transferred from ratepayers to OPG (the Province).[28] Outside the five-year rate setting period, the allocation of OPG station performance risk between ratepayers and the Province is subject to the decisions of the OEB.

Table 2-3: Station Performance Risk Summary

	Ratepayers	Province
Exposure to Bruce Power Station Performance Risk	Bear risk of fuel costs and 50% of operating cost upside risk (i.e. savings).	None.
Exposure to OPG Station Performance Risk	Bear upside and downside risk outside five-year rate setting period with the exception of costs recoverable through deferral and variance accounts.	Bears upside and downside risk inside five-year rate setting period with the exception of costs recoverable through deferral and variance accounts.

Market Financial Risks

Market financial risks refer to market conditions of insufficient electricity demand or the emergence of lower cost generation alternatives during the life of the Nuclear Refurbishment Plan. Market financial risks are magnified by the economics of nuclear generation. Nuclear generation requires a large upfront capital investment and base case Nuclear Price projections are based on costs being spread over a large amount of electricity generation over a long period of time. As a result, shutting down reactors in response to market conditions of insufficient demand or the emergence of lower cost generation alternatives is not always economical. The Nuclear Refurbishment Plan is a long-term and relatively inflexible commitment to buy baseload electricity. But this inflexibility is balanced by relatively low and stable costs (post refurbishment), reliable production, and low emissions.

26 The Bruce Contract does not outline Bruce Nuclear Price adjustments for lost revenue due to reactor performance issues or increasing operating costs beyond the adjustments outlined above and in appendix B.
27 Bruce Contract Exhibit 4.3.
28 However, for certain expenses, OPG is permitted to record variances in planned and actual costs in deferral and variance accounts and to recover those costs from ratepayers in the future (see appendix B for more details).

Demand Risk

Demand risk is the risk that there is insufficient demand for Nuclear Production. Insufficient demand could lead to the curtailment (short-term shut down) of Nuclear Production or the permanent shut down of one or more reactors, both of which could affect ratepayers and, in the case of DNGS, the Province.

The IESO estimates that the impact of electricity conservation initiatives and distributed generation reduced grid electricity demand by 17.0 TWh (11%) from 2005 to 2015.[29] Over the same time period, there has been a 20% increase in installed grid-connected generation capacity.[30] As a result, there have been increased occurrences of surplus electricity supply in the Ontario market. Electricity that is generated for the most part cannot be stored, therefore, to manage surplus supply, the Province can export electricity to other jurisdictions and/or curtail production, both of which can negatively affect ratepayers.

In the longer-term, when refurbishments are complete, the BNGS and DNGS combined will produce about 75 TWh of electricity per year. By 2035, this would represent between 38% and 56% of forecast electricity demand.[31] Furthermore, the Province also has approximately 30 TWh of annual baseload hydroelectric generation, which is more cost effective than nuclear generation.[32] Finally, declining prices for solar, wind and electricity storage (e.g. batteries) will likely accelerate the growth of distributed generation.[33]

Overall, a combination of low electricity demand and larger portions of that demand being supplied by the growth of distributed generation present the risk of increased forced exports of electricity to other jurisdictions, curtailment of Nuclear Production or one or more reactors being shut down due to insufficient grid demand.

On the other hand, the FAO has identified a number of demand-side and supply-side mitigations that could limit demand risk, including:[34]

- the potential for increased baseload electricity demand in Ontario that could result from increased electrification due to climate change initiatives;

- economic off-ramps in the Bruce Contract and the Province's options to off-ramp

29 Conservation refers to investments in technology that reduce per capita electricity consumption. Distributed generation is electricity generated and used locally which offsets grid demand.
30 IESO. "2016 Ontario Planning Outlook." 1 Sept. 2016, pp. 3. Web. 8 Sept. 2016.
31 IESO. "2016 Ontario Planning Outlook." 1 Sept. 2016, pp. 3. Web. 8 Sept. 2016.
32 In 2016 OPG's regulated hydroelectric facilities generated 29.5 TWh at a price of $43.39/MWh ($2016) Source: OPG 2016 Annual Report.
33 FAO analysis of Government of Ontario. "Ontario's Long-Term Energy Plan 2017". Ministry of Energy. Oct. 2017. Web. 26 Oct. 2017.
34 See Table 5-7 and Table 5-8 for more details.

DNGS reactors prior to each refurbishment; and

- the Province's flexibility to manage non-nuclear electricity supply, such as by not renewing expiring generation contracts.

Table 2-4: Demand Risk Summary

	Ratepayers	Province
Exposure to Bruce Power Demand Risk	Bear risk from curtailment or surplus electricity supply. Bear risk of increased Nuclear Price due to reactor shutdown.	None.
Exposure to OPG Demand Risk	Bear risk from curtailment or surplus electricity supply. Bear risk of increased Nuclear Price due to reactor shutdown.	Bear risk of reduced OPG net income due to reactor shutdown or curtail-ment of Nuclear Production.

Opportunity Cost Risk

Opportunity cost refers to the loss of potential benefit from alternatives that are given up when a decision is made. By refurbishing nuclear reactors, the Province is effectively committing to nuclear generation supplying a significant portion of the Province's electricity from 2016 to 2064. This commitment will limit the Province's ability to adjust the generation mix to take advantage of lower cost grid-scale alternative generation options which could emerge over the life of the Nuclear Refurbishment Plan. The opportunity cost of this commitment would be the foregone savings if a lower cost and low emissions alternative generation option emerges.

The level of opportunity cost risk is impacted by three key factors:

- The post refurbishment cost of nuclear, the risks of which are outlined in the analysis of Internal Financial Risks.

- Current and projected costs of alternative electricity generation options.

- Provincial policy regarding the pricing of carbon emissions and electricity generation from fossil fuels.

Two of the primary benefits of nuclear generation are that it is both relatively low-cost and emits very low amounts of greenhouse gases. There are alternative generation portfolios which the Province could use to replace nuclear generation. However, currently none of the alternative generation portfolios could provide the same supply of low emissions baseload electricity generation at a comparable price to the Base Case Plan (see appendix C for a more detailed analysis of alternative generation options).

Economic off-ramps in the Bruce Contract somewhat mitigate opportunity cost risk by allowing the IESO to terminate refurbishments if there is a more "economic alternative."[35] The economic off-ramps expire prior to the third and fifth units in 2024 and 2027. At those times, the IESO will have fully scoped cost estimates for multiple BNGS units and can make a more informed decision by comparing a more accurate Nuclear Price estimate to alternatives. Similarly, the Province's ability to terminate any DNGS refurbishment allows the Province to make more informed decisions in the future.

Table 2-5: Opportunity Cost Risk Summary

	Ratepayers	Province
Exposure to Bruce Power Opportunity Cost Risk	Bear all opportunity cost risk once reactors are online after refurbishment.	None.
Exposure to OPG Opportunity Cost Risk	Bear risk of not benefiting or a reduced benefit (in the event of a unit termination) from lower cost alternatives.	Bear risk of reduced OPG net income in the event of unit termination.

35 Bruce Contract Article 9.2.

3

INTRODUCTION

In Ontario, there are 18 active nuclear reactors spread across three nuclear generating stations that supply over 60% of the electricity used by Ontario's homes and businesses. With 16 of the 18 reactors approaching the end of their useful lives, the Government of Ontario (the Province) evaluated options to meet the future electricity needs of Ontarians. The Province decided to secure a long-term supply of electricity generation by refurbishing ten reactors at the Bruce and Darlington Nuclear Generating Stations, which should extend the lives of the reactors by 30 to 35 years. In addition to the refurbishments, the Province plans to extend the operation of six reactors at the Pickering Nuclear Generating Station to help meet the province's electricity needs while the other reactors are offline for refurbishment.[36]

For the purposes of this report, the FAO refers to the following three elements collectively as the Nuclear Refurbishment Plan (or the Plan).

- Ontario Power Generation's (OPG) plan to refurbish the four reactors at the Darlington Nuclear Generating Station (DNGS) and operate the station to the end of 2055.

- Bruce Power's contract[37] (the Bruce Contract) with the Independent Electricity System Operator (IESO)[38] to refurbish six reactors at the Bruce Nuclear

36 Government of Ontario. "Ontario Moving Forward with Nuclear Refurbishment at Darlington and Pursuing Continued Operations at Pickering to 2024." Ministry of Energy. 11 Jan. 2016. Web. 8 March 2016.
37 The Amended and Restated Bruce Power Refurbishment Implementation Agreement effective January 1, 2016.
38 The IESO operates and settles the electricity wholesale market in Ontario.

Generating Station (BNGS) and sell electricity into the Ontario market to the end of 2063.[39]

- OPG's plan to extend the operation of the Pickering Nuclear Generating Station (PNGS).[40] Two reactors at Pickering A will be extended to 2022 and four reactors at Pickering B will be extended to 2024.[41]

For background details on the Nuclear Refurbishment Plan please see appendix A.

The refurbishments are scheduled to take place from 2016 to 2033 and the total capital cost is estimated to be $25 billion in 2017 dollars.[42] The Darlington and Pickering Nuclear Generating Stations are owned and operated by OPG, a utility owned by the Province. The Bruce Nuclear Generating Station is owned by OPG but is leased to plant operator Bruce Power.[43] Bruce Power and OPG will finance the refurbishment projects and will recover the cost of refurbishing and operating the reactors by generating and selling electricity into the Ontario market. The Plan will result in nuclear generation continuing to supply a large portion of Ontario's electricity and will significantly impact electricity prices paid by Ontario ratepayers for decades. The Plan will also directly impact the Province's fiscal position due to its ownership of OPG.

There is a history of cost overruns on nuclear capital projects in Ontario, including recent life extension projects at both the Bruce and Pickering Nuclear Generating Stations.[44] The complexity of the projects combined with the history of cost overruns means that cost and price projections for nuclear generation are subject to uncertainty. There is also uncertainty with respect to future electricity demand and prices for competing electricity generation technology in the Ontario market. The risks to the Plan are also magnified by the large upfront capital investment required to refurbish reactors and the significant impact nuclear generation will have on electricity prices.

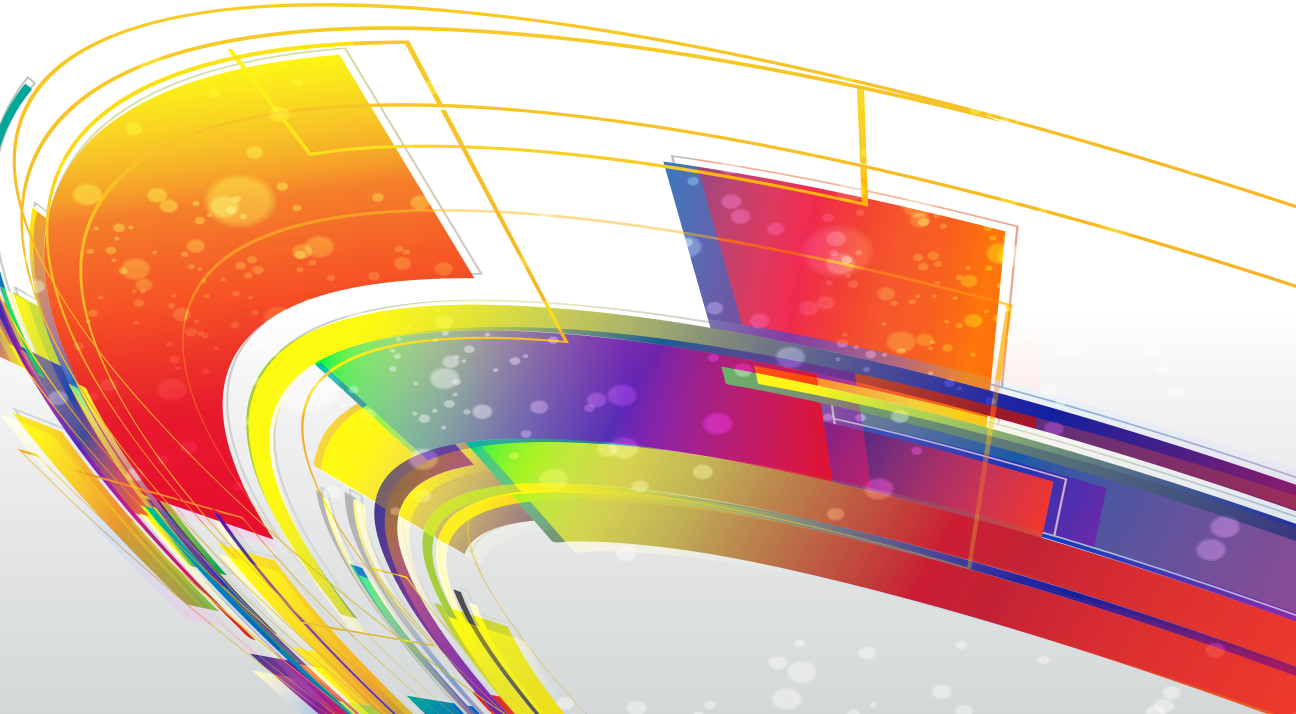
39 The BNGS has eight reactors, two of which were refurbished under a previous agreement. All electricity generated by Bruce Power will be sold at a single price under the Bruce Contract.
40 The PNGS was originally scheduled to be shut down in 2020.
41 The FAO has analyzed the Plan based on the assumption of Pickering A being shut down in 2022 and Pickering B in 2024. However, OPG has filed an application to the Canadian Nuclear Safety Commission which would allow for Pickering A to operate to 2024.
42 FAO analysis of Ontario Energy Board Case EB-2016-0152 & Bruce Power. "Amended Agreement Secures Bruce Power's Role in Long-Term Energy Plan." 3 Dec. 2015. Web. 8 Apr. 2017.
43 Bruce Power is a limited partnership between Borealis Infrastructure, a trust established by the Ontario Municipal Employees Retirement System (OMERS), TransCanada Corporation, the Power Workers' Union and the Society of Energy Professionals.
44 See chapter 5.

The purpose of this report is to review how the Nuclear Refurbishment Plan will impact ratepayers and the Province and to identify how financial risk is allocated among ratepayers, the Province, Ontario Power Generation (OPG) and Bruce Power. The report first establishes base case estimates of the price and production of nuclear generation, and outlines how the base case estimates will affect electricity prices and the Province's fiscal position. The report then identifies four key risks to the Nuclear Refurbishment Plan, and assesses how the potential financial impact of the key risks, if realized, is allocated to ratepayers and the Province. The report analyzes the Plan over a period lasting from the beginning of 2016 until the last refurbished reactor is scheduled to be taken offline at the end of 2063 and refers to the 48-year period from 2016 to 2064 as the life of the Plan.

This report does not seek to:

- Evaluate non-financial risks associated with the Nuclear Refurbishment Plan such as public health or security.
- Evaluate the appropriateness of the risk exposure of ratepayers and the Province.
- Evaluate risks specific to the Pickering Nuclear Generating Station life extension.
- Evaluate risks specific to the decommissioning of nuclear reactors.
- Evaluate risks arising from externalities relating to nuclear waste and radiological risk.
- Evaluate the impact of risks not directly related to the Nuclear Refurbishment Plan (e.g. changes in regulation or electricity market structure).

Appendix D provides more information on the development of this report.



4

THE BASE CASE NUCLEAR REFURBISHMENT PLAN

This chapter outlines how the Nuclear Refurbishment Plan is expected to affect ratepayers and the Province based on the FAO's projections of the price and production of nuclear generation. The projections are referred to as the Base Case Plan and were calculated using current estimates of the cost of refurbishing and operating the reactors, as well as reactor performance. The Base Case Plan will serve as the basis for the risk analysis in the following chapter.

Base Case Ratepayer Projections

Ontario ratepayers pay a price for each megawatt hour of electricity they use which is reflected in the electricity section of their monthly bills. That price is set based on the cost of generating enough electricity to supply Ontario's electricity demand. Electricity generators, including OPG and Bruce Power, are paid a price for each megawatt hour of electricity they generate and sell into the Ontario market. The amounts paid to generators are incorporated into the price of electricity and recovered from ratepayers.

The impact of nuclear generation on the price of electricity will depend on the prices OPG and Bruce Power are paid for electricity and the proportion of total electricity demand supplied to ratepayers by nuclear generation. The FAO estimates that the Base Case Plan will result in an average price for nuclear generation (the Nuclear Price) of $80.7/MWh in 2017 dollars[45] from 2016 to 2064. This is an average of the FAO's estimate of the average OPG Nuclear Price of $80.7/MWh and the average Bruce

45 All dollar figures are in 2017 dollars unless otherwise indicated.

Nuclear Price of $80.6/MWh. For reference, the current price of electricity for most residential and small business ratepayers is $114.9/MWh,[46] and the current cost of each generation source which comprise the price of electricity are shown in Table 4-1.

Table 4-1: Unit Cost of Ontario Electricity Generation Sources May 2017 – April 2018

Generation Source	Percent of Total Supply	Unit Cost ($/MWh)
Nuclear	60%	69
Hydro	24%	58
Wind	8%	173
Gas	6%	205
Solar	2%	480
Bio Energy	0%	131

Source Ontario Energy Board. "Regulated Price Plan Price Report." 20 Apr. 2017. Web. 15 Jun. 2017.

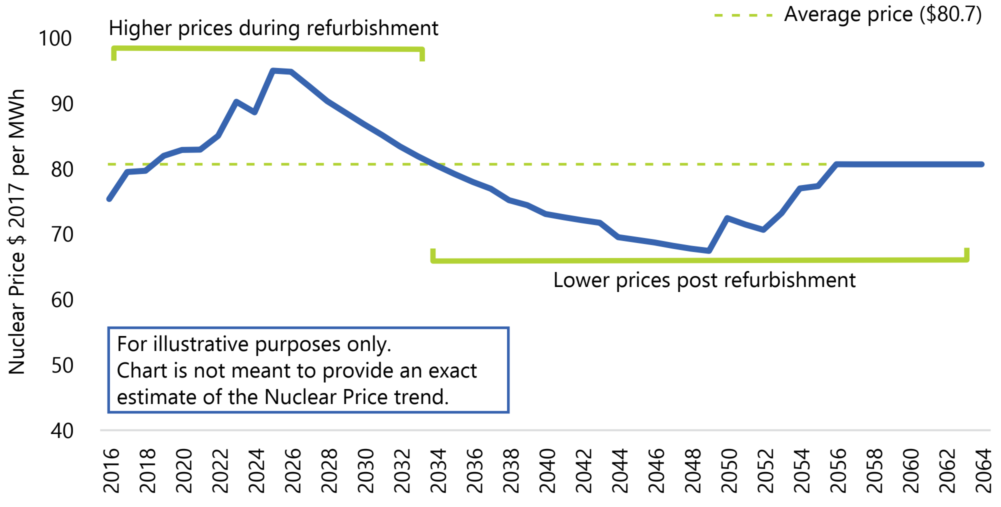
Note: The unit costs represent the cost of in service generation, they are not necessarily representative of the cost of new generation which could replace refurbished nuclear generation. See appendix C for further information.

The FAO projects both the price and production of nuclear generation to vary throughout the life of the Plan. As a result, the effect of the Plan on overall electricity prices will vary as well. The FAO projects that the Nuclear Price will be higher than the average price of $80.7/MWh during the majority of the time that reactors are being refurbished from 2016 to 2033.[47] The Nuclear Price is expected to peak in 2027 at $95.4/MWh and then gradually fall (in real terms). Once the refurbishments are complete, the FAO projects a lower than average Nuclear Price (Figure 4-1).

46 This amount does not include the effect of the Province's Fair Hydro Plan. Due to the Fair Hydro Plan, the price most residential and small business ratepayers pay is $97.6/MWh. Ontario Energy Board. "Regulated Price Plan Price Report." 20 Apr. 2017.

47 See appendix B for more detail on prices and price setting.

Figure 4-1: Illustration of Base Case Nuclear Price Trend



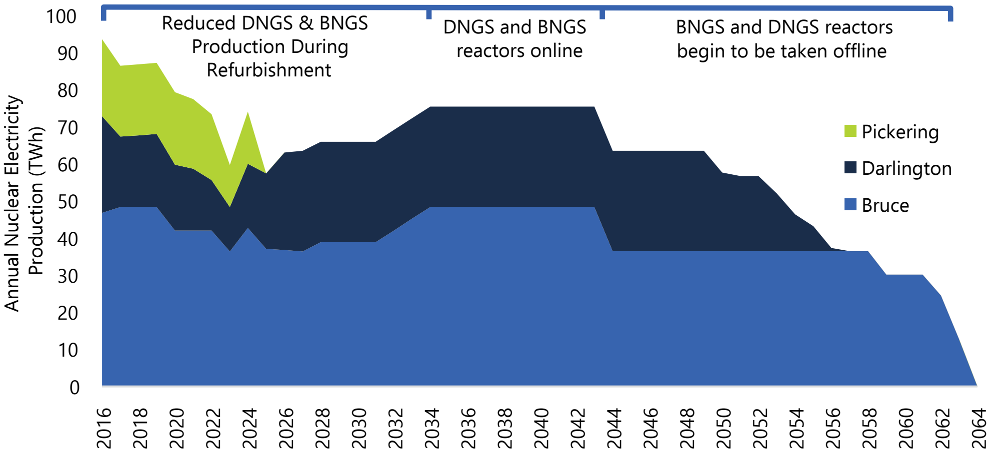
Source: FAO.

Note: The values in the above chart were calculated using the following method: in each year, the FAO calculated the production weighted average of the FAO's estimate of the actual OPG nuclear price and the average Bruce Nuclear Price of $80.6/MWh. The FAO is unable to include the actual Bruce Price estimate in the Base Case Nuclear Price trend due to disclosure restrictions under s.13 of the *Financial Accountability Officer Act, 2013*.

Over the life of the Nuclear Refurbishment Plan, the FAO projects the average annual production of electricity from the three nuclear generating stations (Nuclear Production) to be 62 terawatt hours (TWh).[48] However, based on the refurbishment and life cycle schedules of the reactors, the FAO projects annual production to vary over the life of the Plan (Figure 4-2). Nuclear Production will be reduced from 91.7 TWh in 2016 to 57.4 TWh by 2025 due to multiple reactors being offline for refurbishment and the shutdown of PNGS reactors in 2022 and 2024. Once the refurbishments are complete, annual production will be approximately 75 TWh until the reactors begin to be taken offline, beginning with BNGS units 1 and 2 in 2043.[49]

48 For reference, electricity demand in Ontario was 137 TWh in 2016.
49 BNGS units 1 and 2 were refurbished from 2005 to 2012 under a previous agreement.

Figure 4-2: Nuclear Refurbishment Plan Estimated Electricity Production, 2016 to 2064



Source: FAO estimates based on OPG and Bruce Power refurbishment and life cycle schedules. The FAO projects the capacity factor of all refurbished reactors to be 88%.

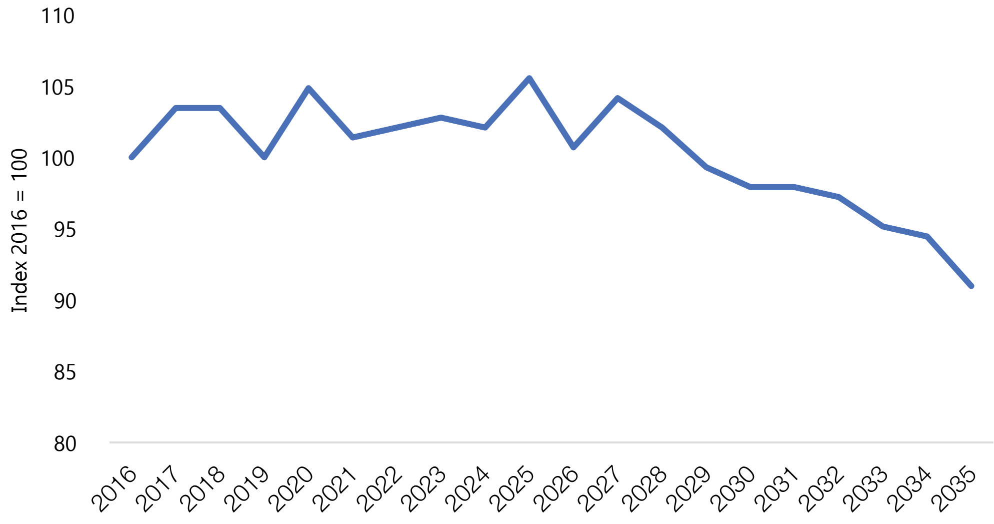
Impact of the Base Case Plan on the Price of Electricity

The overall impact of nuclear generation on the price of electricity will depend on the Nuclear Price and the proportion of demand supplied by Nuclear Production. During the refurbishment period (2016 to 2033), the FAO projects the Nuclear Price to be highest when Nuclear Production is lowest, which somewhat mitigates the impact of the higher Nuclear Prices on the price of electricity. For example, in 2016, Nuclear Production supplied 61% of electricity in Ontario at a price of $69/MWh. In 2027, when the price is projected to peak at $95.4/MWh, the FAO estimates Nuclear Production will represent 40-50% of supply. However, ratepayers will also bear the cost of replacement generation. When the refurbishments are complete in 2033, the FAO projects ratepayers will benefit from high production and lower prices.[50] The effect of the lower post refurbishment prices on the price of electricity will be reduced as reactors at the Bruce and Darlington stations begin to reach the end of their lives.

Figure 4-3 shows the IESO's 20-year projection of electricity prices indexed to 2016. The FAO estimates that the cost of nuclear generation will comprise only 25-35% of the total cost of electricity from 2016 to 2035.[51] Overall, the cost of electricity is projected to remain stable through the mid-2020s. However, consistent with the FAO's projection of nuclear prices, the cost of electricity is projected to begin to decrease gradually starting in 2027 (in real terms).[52]

50 In real dollars.
51 Total cost of electricity includes generation, transmission, distribution and other costs.
52 The unit cost of electricity does not take into account the Province's Fair Hydro Plan.

Figure 4-3: IESO Projection of Unit Electricity Cost



Source FAO Analysis of IESO. "2016 Ontario Planning Outlook." 1 Sept. 2016, pp. 3. Web. 8 Sept. 2016.

Base Case Plan Fiscal Impact

The Darlington and Pickering Nuclear Generating Stations are owned and operated by Ontario Power Generation, a regulated utility wholly owned by the Province of Ontario. The Bruce Nuclear Generating Station is owned by OPG but is leased to Bruce Power, a private sector entity. OPG's net income and net assets are consolidated into the Province's financial statements. As a result, any OPG income or loss from nuclear generation will be reflected in the Province's fiscal position.

Ontario Power Generation

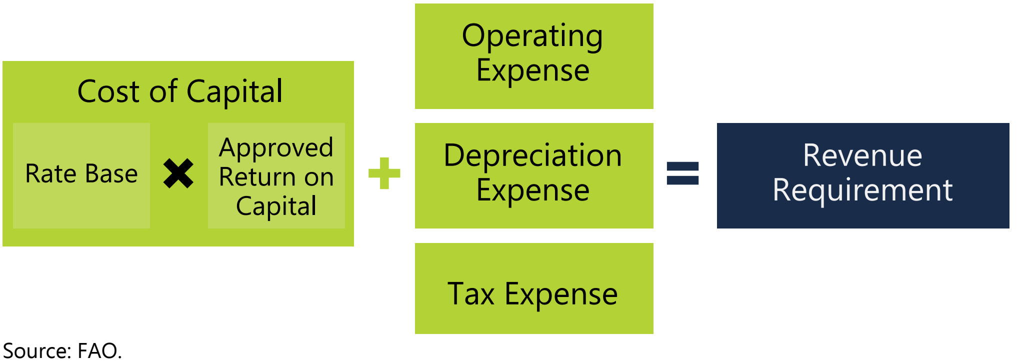
OPG will finance the DNGS refurbishment with long-term corporate debt and cash generated from operations (equity).[53] Once the reactors are back online following refurbishment, OPG will recover the cost of refurbishing and operating the reactors by selling electricity to ratepayers at prices set by the Ontario Energy Board (OEB).[54]

The OPG Nuclear Price is set by the OEB every five years[55] after a public regulatory process. The OEB sets the OPG Nuclear Price in dollars per megawatt hour ($/MWh). The price is the same for electricity generated from both the Darlington and Pickering Stations. Prices are set every five years based on OPG's forecast revenue requirement and Nuclear Production for the following five-year period. The revenue requirement is OPG's operating, depreciation and tax expenses plus a return on OPG's rate base

53 Ontario Power Generation. 2015 Annual Report.
54 The Ontario Energy Board regulates the province's electricity and natural gas sectors.
55 The FAO assumes that OPG will continue to file five-year applications.

(cost of capital) (Figure 4-4).[56] The rate base consists of OPG's nuclear assets.[57] When the refurbished reactors are put into service, the assets will be added to the rate base and expensed throughout their useful lives (depreciation). The depreciation expenses and return on the rate base will be incorporated into the revenue requirement, which is divided by OPG Nuclear Production to determine the OPG Nuclear Price (see appendix B for details).

Figure 4-4: OPG Revenue Requirement Calculation



Source: FAO.

The return (cost of capital) that is incorporated into the OPG Nuclear Price is set to compensate OPG's debt and equity holders that provide the capital to finance OPG's capital investments. This return is set by the Ontario Energy Board to allow OPG to pay interest on its debt and earn a return on its equity investment in nuclear assets. The return on equity is the portion of the revenue requirement that represents OPG's profit on nuclear generation.

Table 4-2 outlines OPG's return on equity requested in its current five-year rate application to the OEB. The return is based on a proposed capital structure of 49% equity and 51% debt and a return on equity of 8.78%. The large increase in the rate base in 2020 reflects the projected addition of the first refurbished Darlington reactor. OPG's rate base will increase as the refurbished reactors are returned to service and will decrease as the reactors are depreciated.[58]

56 A 7% return on capital is projected which is a weighted average of OPG's projected regulated return on debt and equity.
57 From the OPG 2015 Annual Report: Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital.
58 OPG's rate base will also be affected by non-refurbishment capital investment.

Table 4-2: OPG Five-Year Projected Return on Equity

($ millions)	2017	2018	2019	2020	2021
Rate Base	3,114	3,161	3,114	7,159	7,647
Return on Equity*	134	136	134	308	329

Source: FAO analysis of Ontario Energy Board Case EB-2016-0152 (figures are nominal).

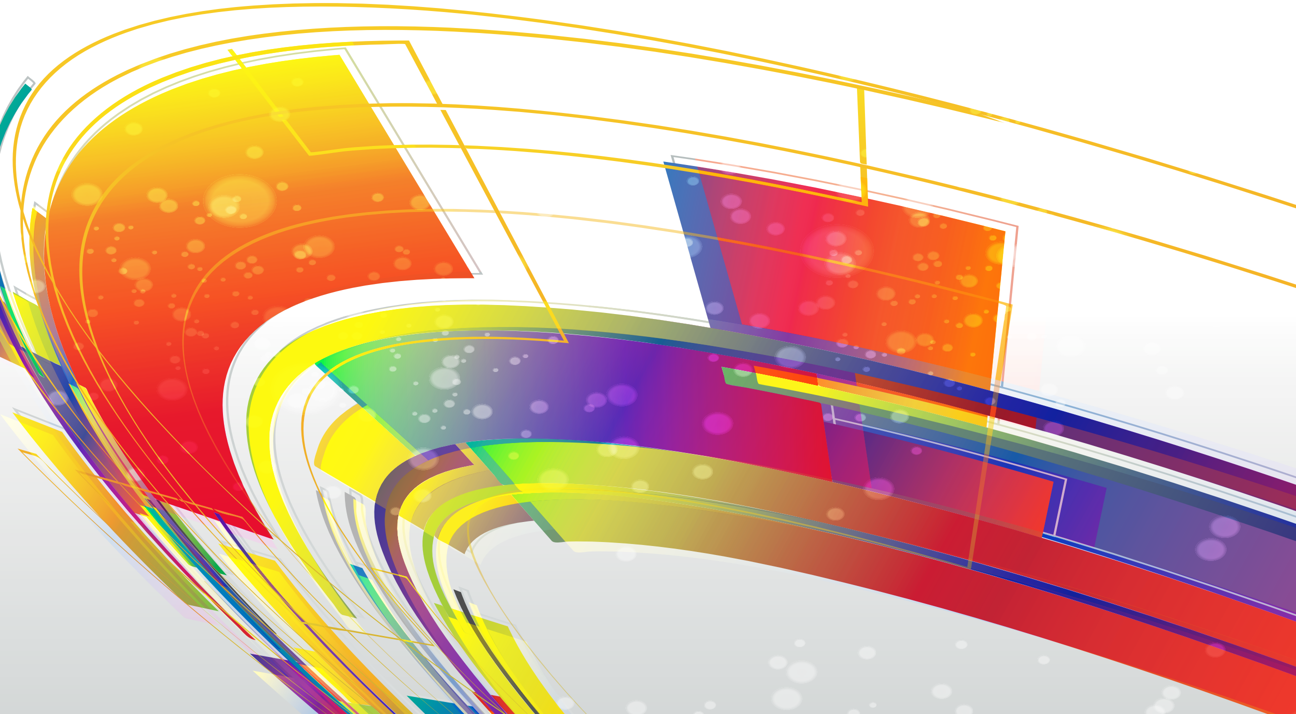
* Return on equity is equal to 8.78% of 49% of the rate base

OPG's return on equity is not guaranteed, but it is set such that OPG can earn a return[59] given the successful operation of its nuclear generating stations. OPG is requesting a total return on equity of $1.04 billion[60] to be priced into the OPG Nuclear Price from 2017 to 2021.[61] This return, if realized, would be reflected in OPG's net income which would be consolidated into provincial revenues and impact the Province's fiscal position.[62]

Bruce Power

Bruce Power is a private sector organization which receives payments for generating and selling electricity into the Ontario market. There is no direct connection between Bruce Power and the fiscal position of the Province. Bruce Power does make payments to OPG to lease the BNGS. However, when the OEB sets the OPG Nuclear Price, the OPG revenue requirement is reduced by OPG's net lease revenues. As a result, the lease revenues benefit the ratepayer not the Province. Therefore, there is no fiscal impact to the Province resulting from the life extension of the BNGS that is within the scope of this report.[63]

59 The OEB determines OPG's return on equity based on a formulaic approach as set out in Report EB-2009-0084.
60 Nominal value.
61 Ontario Energy Board Case EB 2016-0152.
62 The Province also accounts for its investment in OPG as a financial asset. Therefore, any increase in OPG net assets would reduce the Province's net debt.
63 The impact and risks of decommissioning nuclear reactors is outside the scope of this report.



5

RISKS TO THE BASE CASE NUCLEAR REFURBISHMENT PLAN

This chapter analyzes the exposure of ratepayers and the Province to four key financial risks of the Nuclear Refurbishment Plan. The FAO has categorized the financial risks into internal and market categories.

Internal Financial Risks	Market Financial Risks
Refurbishment Cost Risk	Demand Risk
Station Performance Risk	Opportunity Cost Risk

Internal Financial Risks

Internal financial risks refer to changes from the assumptions included in the Base Case Nuclear Refurbishment Plan regarding the cost of refurbishing and operating the nuclear reactors. The differences in ownership and rate setting of Bruce Power and OPG mean that the ratepayer's and Province’s exposure to internal financial risks differ with respect to Bruce Power and OPG costs.

Refurbishment Cost Risk

Refurbishment cost risk is the risk that the cost of refurbishing the reactors will be higher or lower than the Base Case Nuclear Refurbishment Plan assumptions. Since 1999, there have been two major nuclear refurbishment projects in Canada (BNGS A Units 1 & 2 and Point Lepreau[64]) and one major life extension project (Pickering A units 1 & 4). As described in Table 5-1, each project experienced substantial cost overruns.

Table 5-1: Summary of Nuclear Life Extension Planned and Actual Costs

Project	Timeline	Budget	Actual Cost*
Point Lepreau	2008-2012	$1.40 billion	$2.40 billion
BNGS A Units 1 & 2	2005-2012	$2.75 billion	$4.80 billion
PNGS A Unit 4	1999-2003	$0.46 billion	$1.25 billion
PNGS A Unit 1	1999-2005	$0.21 billion	$1.00 billion

*All figures are current (nominal) dollars.

Source: Epp, Jake, Peter Barnes and Dr. Robin Jeffrey. "Report of the Pickering "A" Review Panel" and information provided to the FAO.

Note: A recent $200 million life extension project to extend the life of the PNGS from 2016 to 2020 was completed on budget.

The scale and complexity of the Nuclear Refurbishment Plan combined with the history of nuclear project cost overruns suggests that there is significant risk to achieving the base case financial projections described in chapter 4. The price setting mechanisms of Bruce Power and OPG outline how refurbishment cost risk is allocated to ratepayers, the Province, Bruce Power and OPG.

Bruce Power Refurbishment Cost Risk Allocation

The price Bruce Power is paid for electricity (the Bruce Nuclear Price) that it generates and sells into the Ontario market is set in accordance with the terms of the Bruce Contract. Bruce Power receives the same price for all nuclear generation including BNGS units 1 and 2, which were refurbished under a previous agreement. The Bruce Contract provides for transfers of refurbishment cost risk from the ratepayer to Bruce Power. As Bruce Power is a private sector entity, any transfer of risk to Bruce Power reduces the exposure of ratepayers.

The Bruce Contract contemplates the refurbishment of up to six nuclear reactors. The start date of each refurbishment will be staggered, and the Bruce Nuclear Price

64 The Point Lepreau Nuclear Generating station is located in Point Lepreau New Brunswick and is owned and operated by NB Power, which is wholly owned by the province of New Brunswick.

will be adjusted prior to each refurbishment based on the estimated cost of the refurbishment. Not later than 15 months prior to the scheduled refurbishment of each reactor unit, Bruce Power must provide IESO with a fully scoped refurbishment cost and schedule for the unit. IESO then has until 12 months before refurbishment begins[65] to verify the estimate.[66] Once IESO verifies the fully scoped refurbishment cost for each unit, the Bruce Nuclear Price will be adjusted to allow Bruce Power to recover the IESO verified cost of the refurbishment and a return on capital.[67] As a result, the risk of refurbishment cost increases beyond the IESO verified cost is transferred from the ratepayer to Bruce Power 12 months prior to each refurbishment. If the completed refurbishments are less than the fully scoped refurbishment cost, 50% of any savings would be passed on to the ratepayer.[68] Therefore, the ratepayer also benefits from some upside risk after the Bruce Nuclear Price is locked in.

Bruce Power Refurbishment Off-Ramps

Prior to the price adjustment for each reactor, the IESO has options to terminate the refurbishments (off-ramps) under certain conditions. The Bruce Contract includes two types of off-ramp, threshold and economic. In the event the refurbishment of one or more units is terminated by the IESO, the Bruce Nuclear Price would be adjusted to reflect Bruce Power's new generation profile.[69]

Threshold Off-Ramps – Threshold off-ramps provide IESO with the option to terminate one or all remaining reactor refurbishments if the fully-scoped refurbishment cost or duration estimates provided by Bruce Power 15 months prior to each refurbishment start date exceed the pre-defined cost or unit outage duration thresholds.[70] The cost threshold is 130% of the unit base amount (120% for one-time costs), or a 30% (20%) increase.[71]

65 Earlier of 12 months before refurbishment or four months after estimate is provided.
66 Bruce Contract Article 2.5, p. 55.
67 Bruce Contract Article 4.8, p. 99.
68 Bruce Contract Exhibit 4.3.
69 Bruce Contract Exhibit 4.11, p. 3.
70 Duration thresholds are 54 months for first unit, 48 months for second unit, 42 months for remaining units.
71 IESO and Bruce Power have not made the cost threshold unit base amounts public.

Threshold Off-Ramp Example

Fifteen months before a unit refurbishment, Bruce Power provides IESO with a fully scoped cost estimate that is 150% of the base amount (50% increase in refurbishment cost). IESO would then have the option to:

Elect Bruce Power to proceed with the refurbishment, in which case the fully scoped base estimate (150% of the base threshold) would be incorporated into the Bruce Nuclear Price.

or

Exercise the off-ramp option and terminate the refurbishment.*

If IESO exercises the off-ramp option, Bruce Power can still elect to proceed with the refurbishment, however, costs beyond the cost overrun threshold would not be incorporated into the Bruce Nuclear Price. In this case, the Bruce Nuclear Price would be adjusted to incorporate 130% of the base amount and the difference between 130% and 150% of the base amount would be paid by Bruce Power.

Once IESO verifies the cost estimate 12 months before refurbishment begins, the refurbishment cost portion of the Bruce Nuclear Price is locked in for that unit.

* IESO can terminate all remaining refurbishments as well.

Source FAO analysis of the Bruce Contract.

Economic Off-Ramps – The economic off-ramps provide IESO with the option to terminate refurbishments due to changing market conditions. The IESO has the option to exercise economic off-ramps prior to the third (Unit 4) and fifth (Unit 7) refurbishments.[72] If the IESO has determined, acting reasonably, that changes in electricity demand or the emergence of lower cost resources results in there no longer being a need to refurbish nuclear reactors, the IESO can terminate all remaining refurbishments.[73]

72 Bruce Contract Article 9.2, p. 125.
73 Bruce Contract Article 9.2, p. 125.

Table 5-2: Summary of Bruce Contract Off-Ramps

Unit	Exercise Date	Off-Ramp Description
Unit 6	January 1, 2019	Threshold
Unit 3	January 1, 2022	Threshold
Unit 4	January 1, 2024	Threshold and Economic
Unit 5	July 1, 2025	Threshold
Unit 7	July 1, 2027	Threshold and Economic
Unit 8	July 1, 2029	Threshold

Source: FAO Analysis of the Bruce Contract.

Ontario Power Generation Refurbishment Cost Risk Allocation

As OPG is owned by the Province, refurbishment cost risk for the four nuclear reactors at the DNGS is distributed between ratepayers and the Province. As outlined in chapter 4, the price OPG is paid for nuclear generation is set by the Ontario Energy Board (OEB). The OEB operates under the *Ontario Energy Board Act, 1998*.[74] *Ontario Regulation 53/05* made under section 78.1 of the *Ontario Energy Board Act, 1998* states that the OEB must ensure that OPG recovers planned and unplanned expenses relating to the DNGS refurbishment that are prudently incurred.[75] As a result, any cost overruns that are prudently incurred would be approved by the OEB and recovered from ratepayers. Any costs not approved by the OEB would reduce OPG's net income and hence lower the Province's revenue. Conversely, the FAO expects that 100% of savings on refurbishment costs would be passed on to the ratepayer.

Ontario Power Generation Refurbishment Off-Ramps

OPG must obtain approval from the Ministry of Energy to proceed with each refurbishment.[76] This provides the Province with options to terminate refurbishments that are similar to the off-ramps outlined in the Bruce Contract. However, in the case of DNGS, the Ministry of Energy can terminate refurbishments for any reason at any time.

74 *Ontario Energy Board Act, 1998, SO 1998*, c 15, Sched B.
75 O Reg 53/05, s 6(2).
76 FAO analysis of Government of Ontario. "Ontario's Long-Term Energy Plan." Ministry of Energy. Dec. 2013. Web. 11 July. 2016.

Table 5-3: Refurbishment Cost Risk Allocation Summary

	Ratepayers	Province
Exposure to Bruce Power Refurbishment Cost Risk	Bear risk of cost increases until the refurbishment cost estimate for each reactor is locked in 12 months before refurbishment begins (subject to off-ramps). Benefit from 50% of refurbishment cost savings.	None.
Exposure to OPG Refurbishment Cost Risk	Bear risk of cost increases prudently incurred by OPG. Benefit from 100% of refurbishment cost savings.	Bears risk of cost overruns not prudently incurred by OPG.

Financial Impact of Refurbishment Cost Overruns

As outlined above, the ratepayer bears a significant portion of the risk of refurbishment cost overruns.[77] To illustrate the potential financial impact of refurbishment cost overruns on ratepayers, the FAO has modelled two scenarios of increased refurbishment costs relative to the base case. Both scenarios assume the refurbishment cost of all reactors increase by the same amount and all cost increases are passed on to ratepayers.

- All reactor refurbishments experience a 30% increase in refurbishment costs relative to the base case.[78]
- All reactor refurbishments experience a 50% increase in refurbishment costs relative to the base case.

As described in Table 5-4, the FAO estimates that a 30% increase in refurbishment costs for each reactor at the BNGS and DNGS would result in an average Nuclear Price of $85.0/MWh from 2016 to 2064, or a 5.4% increase over the base case Nuclear Price of $80.7/MWh. The FAO estimates that a 50% increase in refurbishment costs for each reactor would result in an average Nuclear Price of $87.9/MWh from 2016 to 2064, or an 8.9% increase over the base case Nuclear Price of $80.7/MWh.

Table 5-4: Refurbishment Cost Overrun Impact Summary

	Base Case	Scenario 1 30% Cost Overrun	Scenario 2 50% Cost Overrun
Nuclear Price	$80.7/MWh	$85.0/MWh	$87.9/MWh
% Change from Base Case		5.4%	8.9%

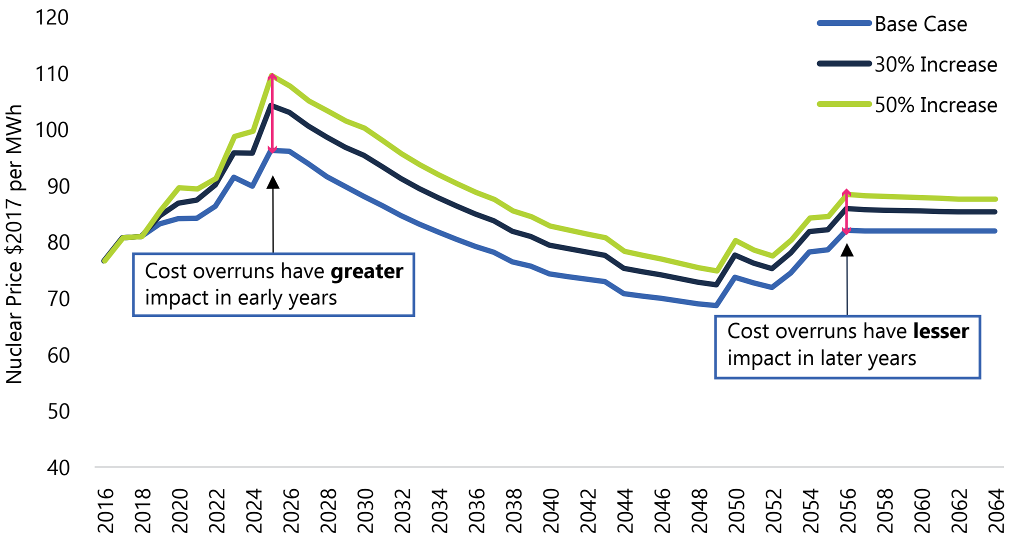
77 When referring to BNGS cost overruns, the FAO is referring to increases in the fully scoped refurbishment cost estimates. The ratepayer is not exposed to increases in refurbishment costs once the fully scoped estimate is verified for each unit and the Bruce Nuclear Price is adjusted 12 months prior to the start of each refurbishment.

78 The BNGS refurbishment costs are assumed to be at the cost overrun off-ramp threshold.

The reason that the Nuclear Price increases less proportionally with the cost of refurbishing the reactors is that the cost of refurbishing the reactors represents a minor portion of the overall cost of refurbishing and operating the reactors throughout their useful lives.[79] In addition, the Nuclear Price estimate includes the PNGS generation and the pre-refurbishment DNGS and BNGS generation.

Figure 5-1 shows the FAO's estimation of the effect of cost overruns on the Nuclear Price over the life of the Plan. Increases in refurbishment costs would not affect the Nuclear Price until the reactors return to service in the case of OPG or until the Bruce Nuclear price is adjusted prior to each BNGS refurbishment. Owing to how the Nuclear Prices for OPG and Bruce Power are set, the FAO projects cost overruns would have the most significant impact on the Nuclear Price in the early portion of the refurbished reactors useful lives. For example, the FAO estimates that a 30% or 50% increase in refurbishment costs would increase the Nuclear Price by 7.2% or 12.1%, respectively, in 2027, but the Nuclear Price would only increase by 4.3% or 7.2% in 2060.

Figure 5-1: Illustration of Nuclear Price Trend Under Different Refurbishment Cost Overrun Scenarios



Source: FAO.

Note: The values in the above chart were calculated using the following method: in each year, the FAO calculated the production weighted average of the FAO's estimate of the actual OPG nuclear price and the 48-year average Bruce Nuclear Price under each scenario. The FAO is unable to include the actual Bruce Price estimate in the Base Case Nuclear Price trend due to disclosure restrictions under s.13 of the *Financial Accountability Officer Act, 2013*.

79 OPG estimates that the refurbishment investment represents 37% of the Levelized Unit Energy Cost of refurbishing and operating the DNGS: Ontario Energy Board Case EB-2013-0321.

Final Off-Ramp Considerations

The Bruce Contract off-ramps and the Province's options to terminate DNGS refurbishments are key risk mitigation measures to protect ratepayers from refurbishment cost overruns. The primary value of the off-ramps to ratepayers is to serve as an incentive for Bruce Power to provide estimates within the pre-defined thresholds and OPG to deliver units on time and on budget. However, if refurbishment cost estimates at either Bruce Power or OPG increase and the electricity is still needed to meet demand, the IESO/Ministry of Energy will have two options:

- Have Bruce Power and/or OPG proceed with the refurbishments in which case cost overruns would be recovered from ratepayers; or

- Exercise off-ramps and use alternative generation options.

In order to make the off-ramp the most economical option, the refurbishment cost overrun would have to be large enough to not only cause the Nuclear Price to be higher than alternative generation options but also to overcome the loss of economies of scale which would occur as a result of a unit termination (see discussion below). Of note is that the final off-ramp does not expire until 2029 and changes in technology, energy policy or electricity demand could impact the viability of alternative generation options which could increase the value of the off-ramps.

Loss of economies of scale at nuclear generating stations – The refurbishment of DNGS Unit 2 began in October 2016 and BNGS units 1 and 2 have already been refurbished. Therefore, terminating future refurbishments at either station will force the station to operate with less than the full complement of reactors. Nuclear generating stations are subject to significant economies of scale. The cost per megawatt hour of electricity generated decreases as capital and fixed operating costs are spread across the production of multiple reactors.[80] Therefore, any future unit refurbishment terminations at a plant would result in a loss of economies of scale, which would increase the corresponding Nuclear Price for electricity generated at that plant.[81]

In addition, there are disproportionate and one-time project planning and preparation costs associated with refurbishing the first unit at each station.[82] For example, the FAO estimates that once the first refurbished DNGS unit returns to service, approximately 45% of the total cost of OPG's four reactor refurbishments will have already been added to the rate base. Therefore, once the first unit at the BNGS

80 Nuclear Energy Institute. "Nuclear Costs in Context." April 2016. Web. 9 April 2017.
81 In the event a BNGS unit is terminated by the IESO, there are Bruce Nuclear Price adjustments to reflect changes to the cost of operating the BNGS as a result of the termination of one or more refurbishments.
82 FAO analysis of Ontario Energy Board Case EB-2016-0152.

(2023) and DNGS (2020) is brought back online, the incremental cost of additional units will be significantly lower.

The cost of alternative generation options – The FAO assumes that the threshold for terminating a unit would be if the cost of nuclear generation exceeds the cost of a generation portfolio with comparable levels of risk and emissions. Taking into account the policy decisions of the Province to end coal-fired generation and implement carbon pricing, the only generation portfolios available to the Province that have the ability to replace nuclear at a comparable cost consist largely of natural gas generation (appendix C discusses alternative generation options). There is currently no portfolio of alternative low emissions generation which could replace nuclear generation at a comparable cost.[83]

Station Performance Risk

Station performance risk refers to the risk of higher non-refurbishment costs or lower Nuclear Production relative to the base case. This includes changes to expected post-refurbishment operating, fuel and capital costs, unanticipated reactor outages, or shorter-than-planned reactor service lives.

Bruce Power

The Bruce Contract transfers most station performance risk to Bruce Power. The ratepayer is exposed to:

- The risk of fuel costs, which are set monthly, separate from other operating costs.[84]
- The incremental cost of generating electricity through other sources if Bruce Nuclear Production is less than projected in the Base Case Plan.[85]

In addition, the ratepayer receives 50% of the benefit if operating costs are less than projected at the BNGS.[86]

83 See Appendix C for more details.
84 Fuel costs are set through a long-term procurement strategy and represent approximately 12% of the 2016 Bruce Nuclear Price. In addition, only a portion of fuel costs are exposed to the market price of uranium.
85 The Bruce Contract does not outline Bruce Nuclear Price adjustments for lost revenue due to reactor performance issues or increasing operating costs beyond the adjustments outlined above and in appendix B.
86 Bruce Contract Exhibit 4.3.

Ontario Power Generation

To reduce the volatility of electricity prices for ratepayers, the OEB sets the OPG Nuclear Price in five-year increments based on five-year cost and production forecasts. This feature of the rate-setting mechanism means that within a five-year period, most station performance risk is transferred from ratepayers to OPG (the Province). However, for certain expenses, OPG is permitted to record variances in planned and actual costs in deferral and variance accounts and to recover those costs from ratepayers in the future (see appendix B for more details).

Table 5-5: Station Performance Risk Summary

	Ratepayers	Province
Exposure to Bruce Power Station Performance Risk	Bear risk of fuel costs and 50% of operating cost upside risk (i.e. savings).	None.
Exposure to OPG Station Performance Risk	Bear upside and downside risk outside five-year rate setting period with the exception of costs recoverable through deferral and variance accounts.	Bears upside and downside risk inside five-year rate setting period with the exception of costs recoverable through deferral and variance accounts.

Market Financial Risks

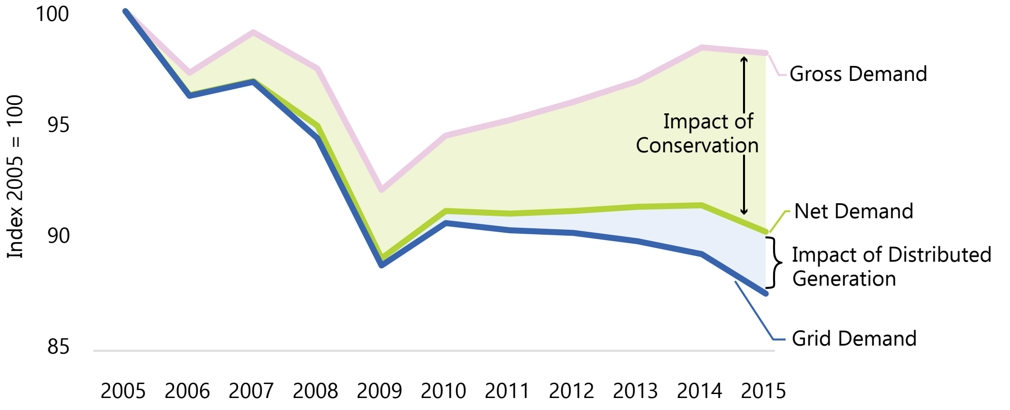
Market financial risks refer to market conditions of insufficient electricity demand or the emergence of lower cost generation alternatives during the life of the Nuclear Refurbishment Plan. Market financial risks are magnified by the economics of nuclear generation. Nuclear generation requires a large upfront capital investment and base case price projections are based on costs being spread over a large amount of electricity generation over a long period of time. As a result, shutting down reactors in response to market conditions of insufficient demand or the emergence of lower cost generation alternatives is not always economical. The Nuclear Refurbishment Plan is a long-term and relatively inflexible commitment to buy baseload electricity. But this inflexibility is balanced by relatively low and stable costs (post refurbishment), reliable production, and low emissions.

Demand Risk

Demand risk is the risk that there is insufficient demand for Nuclear Production. Insufficient demand could lead to the curtailment (short-term shut down) of Nuclear Production or the permanent shut down of one or more reactors, both of which would affect ratepayers and, in the case of DNGS, the Province.

The IESO estimates that the impact of electricity conservation initiatives and the growth of distributed generation reduced grid electricity demand by 17.0 TWh (11%) from 2005 to 2015 (Figure 5-2). Conservation initiatives refer to investments in technology that reduce per capita electricity consumption. Distributed generation is electricity generated and used locally which offsets grid demand.[87] In Ontario, distributed generation is mostly small scale solar and wind generation that is connected to local distribution systems.

Figure 5-2: Impact of Conservation and Distributed Generation on Grid Electricity Demand in Ontario



Source IESO. "2016 Ontario Planning Outlook." 1 Sept. 2016, pp. 3. Web. 8 Sept. 2016.

Short-Term Demand Risk

Despite the reduction in grid demand, installed capacity of grid connected generation increased by approximately 20% from 2005 to 2016.[88] The combined result of decreasing demand and increasing supply has led to more frequent occurrences of a market condition known as surplus baseload generation (SBG). Generally, electricity demand fluctuates throughout the day and the IESO adjusts the Province's electricity supply to meet demand by adjusting the output of load-following electricity sources such as natural gas plants. SBG occurs when electricity demand is lower than the baseload supply provided by Ontario's hydroelectric, nuclear and wind generators. Baseload generation sources are designed and priced to continuously output enough electricity to meet minimum daily demand.

For the most part, electricity that is generated cannot be stored, therefore, to manage surplus supply, the Province exports electricity to other jurisdictions and/or curtails

87 IESO. "A Progress Report on Contracted Electricity Supply First Quarter 2016." 21 June 2016. Web. 19 Aug. 2016.
88 Source IESO. "2016 Ontario Planning Outlook." 1 Sept. 2016, pp. 3. Web. 8 Sept. 2016.

production, both of which can be costly to ratepayers. Electricity that is exported to other jurisdictions is sold at the Hourly Ontario Energy Price (HOEP). The HOEP is a market clearing price that changes in response to supply and demand for electricity. During conditions of SBG, the oversupply of electricity causes the Hourly Ontario Energy Price (HOEP) to be very low or even negative. When the HOEP is negative, the Province pays other jurisdictions to take Ontario's electricity while charging ratepayers regulated/contracted rates. According to the Auditor General, 47% of the power exported in 2014 was related to SBG and exporting power from 2009 to 2014 cost ratepayers $3.1 billion.[89]

With respect to curtailment, the BNGS has a unique (called "dynamic") capability to reduce production by 300 MW per reactor (2,400 MW total).[90] Although the dynamic capabilities of the BNGS provide flexibility to the market, Bruce Power is paid based on deemed generation.[91] Therefore, when the IESO curtails BNGS production, the ratepayer still pays Bruce Power for the electricity that the BNGS could have supplied to the grid had curtailment not occurred.[92]

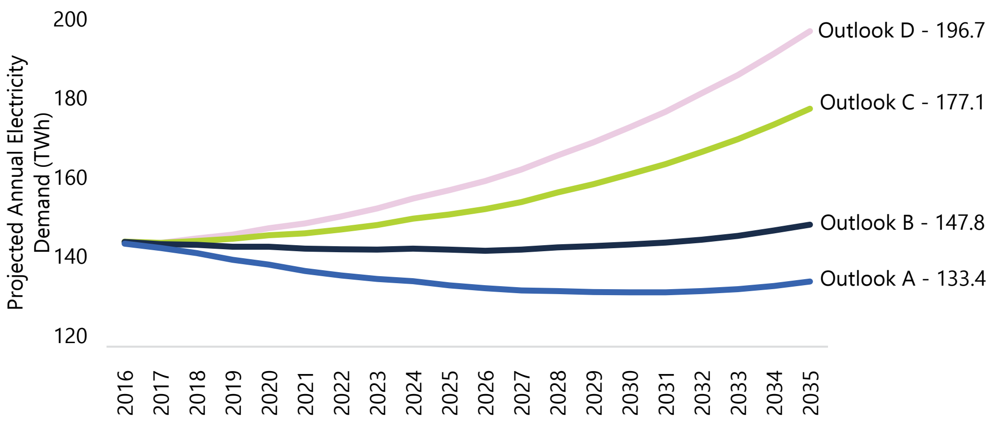
Long-Term Demand Risk

Over the long-term, demand risk refers to the risk of factors such as conservation and the growth of distributed generation reducing grid demand leading to the shut-down of one or more reactors. In September 2016, the IESO released a 20-year Ontario Planning Outlook which forecast four net demand (grid demand + distributed generation) scenarios for Ontario: a low demand outlook, flat demand outlook and two high demand outlooks (Figure 5-3). The four demand outlooks show that there is significant uncertainty with respect to future grid demand in Ontario, with projected annual demand ranging from 133 to 197 TWh by 2035 (Figure 5-3). The high demand outlooks were introduced in part to reflect the Province's *2016 Climate Change Action Plan* which promotes the electrification of home and commercial heating, and transportation. The IESO believes that such initiatives could significantly increase grid demand in Ontario over the next 20 years.[93]

The Nuclear Refurbishment Plan extends well beyond the IESO's current planning outlook. When refurbishments are complete, the BNGS and DNGS combined will

89 Auditor General of Ontario. "Electricity Power System Planning." Annual Report 2015, Queens Printer for Ontario 2015.
90 The total installed capacity of the BNGS is 6,300 MW.
91 As outlined in Article 6 of the Bruce Contract.
92 OPG currently manages surplus conditions by curtailing its hydroelectric facilities, which are also sources of baseload electricity. OPG also recovers the costs of curtailed generation from ratepayers.
93 Government of Ontario. "Climate change action plan." 8 June 2016. The IESO does not project electricity demand beyond 2035.

Figure 5-3: IESO Ontario Electricity Demand Forecast, 2016-2035



Source IESO. "2016 Ontario Planning Outlook." 1 Sept. 2016, pp. 3. Web. 8 Sept. 2016.

produce about 75 TWh of electricity per year, which by 2035 would represent about 38% of forecast electricity demand in the high demand outlook (Outlook D) but 56% of forecast electricity demand in the low demand outlook (Outlook A). Furthermore, the Province also has approximately 30 TWh of annual baseload hydroelectric generation, which is more cost effective than nuclear generation.[94] Finally, declining prices for solar, wind and electricity storage (e.g. batteries) will likely accelerate the growth of distributed generation.[95]

In summary, a combination of low electricity demand (Outlook A) and larger portions of that demand being supplied by the growth of distributed generation present the risk of increased forced exports of electricity to other jurisdictions, curtailment of Nuclear Production or one or more reactors being shut down due to insufficient grid demand.

Table 5-6: Demand Risk Summary

	Ratepayers	Province
Exposure to Bruce Power Demand Risk	Bear risk from curtailment or SBG. Bear risk of increased Nuclear Price due to reactor shutdown.	None.
Exposure to OPG Demand Risk	Bear risk from curtailment or SBG. Bear risk of increased Nuclear Price due to reactor shutdown.	Bear risk of reduced OPG net income due to reactor shutdown or curtail-ment of Nuclear Production.

94 In 2016, OPG's regulated hydroelectric facilities generated 29.5 TWh at a price of $43.39/MWh ($2016) Source: OPG 2016 Annual Report.
95 FAO analysis of Government of Ontario. "Ontario's Long-Term Energy Plan 2017." Ministry of Energy. Oct. 2017. Web. 26 Oct. 2017.

Demand Risk Mitigation

The FAO has identified a number of demand-side and supply-side mitigations that could limit demand risk. Demand-side mitigations could increase and smooth-out grid demand (Table 5-7).

Table 5-7: Demand Risk: Demand-Side Mitigations

Mitigation	Description
Electrification	Through the Climate Change Action Plan the Province is promoting increased electrification which would tend to increase electricity demand. There is considerable potential for increased electricity demand due to the electrification of heating and transportation. For context, 62% of household energy (not just electricity) use in Ontario is natural gas for home heating and cooking.* * Natural Resources Canada. "Households and the Environment: Energy Use." 2011. Web. 3 Jan. 2017.
Demand response	The IESO is promoting demand response initiatives which aim to smooth out demand fluctuations by incenting consumers to shift electricity consumption to off-peak times. Demand response should increase the minimum daily demand, which would reduce SBG conditions.
Export markets	Although forced exporting to manage SBG conditions is not economical, planned exporting of electricity can be a cost effective measure to mitigate surplus electricity supply.
Regulatory control	This report assumes that Ontario's current legal and regulatory framework surrounding the production, transmission, distribution and import/export of electricity remains in place over the life of the Plan. The Province has the ability to limit the growth of distributed generation and protect the revenue stream of its nuclear assets using the regulatory framework.

Supply-side mitigations could reduce the total supply of electricity in Ontario (Table 5-8).

Table 5-8: Demand Risk: Supply-Side Mitigations

Mitigation	Description
Built-in decline in Nuclear Production	Approximately 20 TWh of annual baseload generation will leave the market by 2024 when the PNGS is taken offline. Short-term curtailment and the occurrence of SBG conditions would decrease significantly once the PNGS is offline, all else being equal. In the long run, the staged shut down of refurbished reactors will mitigate demand risk starting with Bruce 1 and 2 in 2043.
Non-nuclear generation market flexibility	Despite nuclear being an inflexible generation source, in the 2017 Long-Term Energy Plan, the Province has made flexibility in other areas of the market a priority to respond to both low and high demand scenarios. Should low demand scenarios materialize, there are many non-nuclear generation contracts that will expire before 2035.
Off-ramps	The Bruce Contract has economic off-ramps before the refurbishment of Unit 4 (2024) and Unit 7 (2027) which allow the IESO to terminate refurbishments if market conditions change. The Province can terminate any of the DNGS unit refurbishments due to changing market conditions. In scenarios of reduced demand, the off-ramps could have significant value.

Opportunity Cost Risk

Opportunity cost refers to the loss of potential benefit from alternatives given up when a decision is made. By refurbishing nuclear reactors, the Province is effectively committing to nuclear generation supplying a significant portion of the Province's electricity from 2016 to 2064. This commitment will limit the Province's ability to adjust the generation mix to take advantage of lower cost grid-scale alternative generation options which could emerge over the life of the Nuclear Refurbishment Plan. The opportunity cost of this commitment will be the foregone savings if a lower cost and low emissions generation option emerges.

Opportunity cost risk refers to the likelihood of the opportunity cost of forgoing the option to adjust the supply mix in the future being greater than the benefit of refurbishing nuclear reactors. The level of opportunity cost risk is impacted by three key factors:

- The post refurbishment cost of nuclear, the risks of which are outlined in the analysis of Internal Financial Risks.
- Current and projected costs of alternative electricity generation options.
- Provincial policy regarding the pricing of carbon emissions and use of fossil fuel generation.

Two of the primary benefits of nuclear generation are that it is both relatively low-cost and emits very low amounts of greenhouse gases. There are alternative generation portfolios which the Province could use to replace nuclear generation. However, currently none of the alternative generation portfolios could provide the same supply of low emissions baseload electricity generation at a comparable price to the Base Case Plan (see appendix C for a more detailed analysis of alternative generation options).

The FAO assumes that the Province would not shut down BNGS units due to the emergence of lower cost resources once the final Bruce Contract economic off-ramp expires in 2027. Therefore, once BNGS reactors are online, the ratepayer bears all opportunity cost risk.

With respect to the DNGS, the ratepayers and the Province combined bear all opportunity cost risk. As discussed above, terminating a single unit would likely increase the price of electricity from remaining units, offsetting part of the benefit of switching to lower cost resources. Shutting down the DNGS would reduce the time period over which capital expenses are spread, offsetting part of the benefit of switching to lower cost resources. In either case, the Province would lose future income from the offline reactor(s). If the Province continues to operate the DNGS despite lower cost generation options becoming available, the ratepayer would not benefit from the lower cost generation options.

Table 5-9: Opportunity Cost Risk Summary

	Ratepayers	Province
Exposure to Bruce Power Opportunity Cost Risk	Bear all opportunity cost risk once reactors are online after refurbishment.	None.
Exposure to OPG Opportunity Cost Risk	Bear risk of not benefiting or a reduced benefit (in the event of a unit termination) from lower cost alternatives.	Bear risk of reduced OPG net income in the event of unit termination.

Opportunity Cost Risk Mitigation

Economic off-ramps in the Bruce Contract somewhat mitigate opportunity cost risk by allowing the IESO to terminate refurbishments if there is a more "economic alternative."[96] The economic off-ramps expire prior to the third and fifth units in 2024 and 2027. At those times, the IESO will have fully scoped cost estimates for multiple BNGS units and can make a more informed decision by comparing a more accurate Nuclear Price estimate to alternatives. Similarly, the Province's ability to terminate any DNGS refurbishment allows the Province to make more informed decisions in the future.

96 Bruce Contract Article 9.2.

6

CONCLUSION

The purpose of this report was to review how the Nuclear Refurbishment Plan will impact ratepayers and the Province and to identify how financial risk is allocated among ratepayers, the Province, Ontario Power Generation (OPG), and Bruce Power.

The FAO estimates that the Base Case Plan will result in nuclear generation supplying a significant proportion of Ontario electricity demand from 2016 to 2064 at an average price of $80.7/MWh. However, the effect of the Plan on electricity prices will vary as the Nuclear Price and Nuclear Production fluctuate throughout the life of the Plan. Overall, despite near term Nuclear Price increases, the Base Case Plan is projected to provide ratepayers with a long-term supply of relatively low-cost, low emissions electricity.

The Base Case Plan will also affect the Province’s fiscal position through its ownership of OPG. Any increase/decrease in OPG net income/equity from nuclear generation will be consolidated into the Province’s finances.

The FAO analyzed the allocation of risk to ratepayers and the Province from four key financial risks to the Plan. The risks internal to the Plan are refurbishment cost and station performance risk.

The exposure of ratepayers to increases in BNGS refurbishment costs is mitigated by contract off-ramps and the Bruce Nuclear Price setting mechanism, which transfers the risk of cost overruns to Bruce Power 12 months prior to each refurbishment. The risk to ratepayers of increasing DNGS refurbishment costs is mitigated by OEB oversight and the Ministry of Energy's options to terminate refurbishments. However, OPG is wholly owned by the Province, therefore, any risk that is transferred from the ratepayer to OPG is effectively transferred to the Province.

The FAO estimates that a 30% increase in refurbishment costs on all Bruce and OPG reactors would increase the average Nuclear Price by 5.4%, and a 50% increase in refurbishment costs would increase the average Nuclear Price by 8.9%. In addition, due to economies of scale at nuclear generating stations and the cost of alternative generation options, the FAO projects that refurbishment cost increases would have to be very significant to make the exercise of an off-ramp economical, limiting the effectiveness of off-ramps.

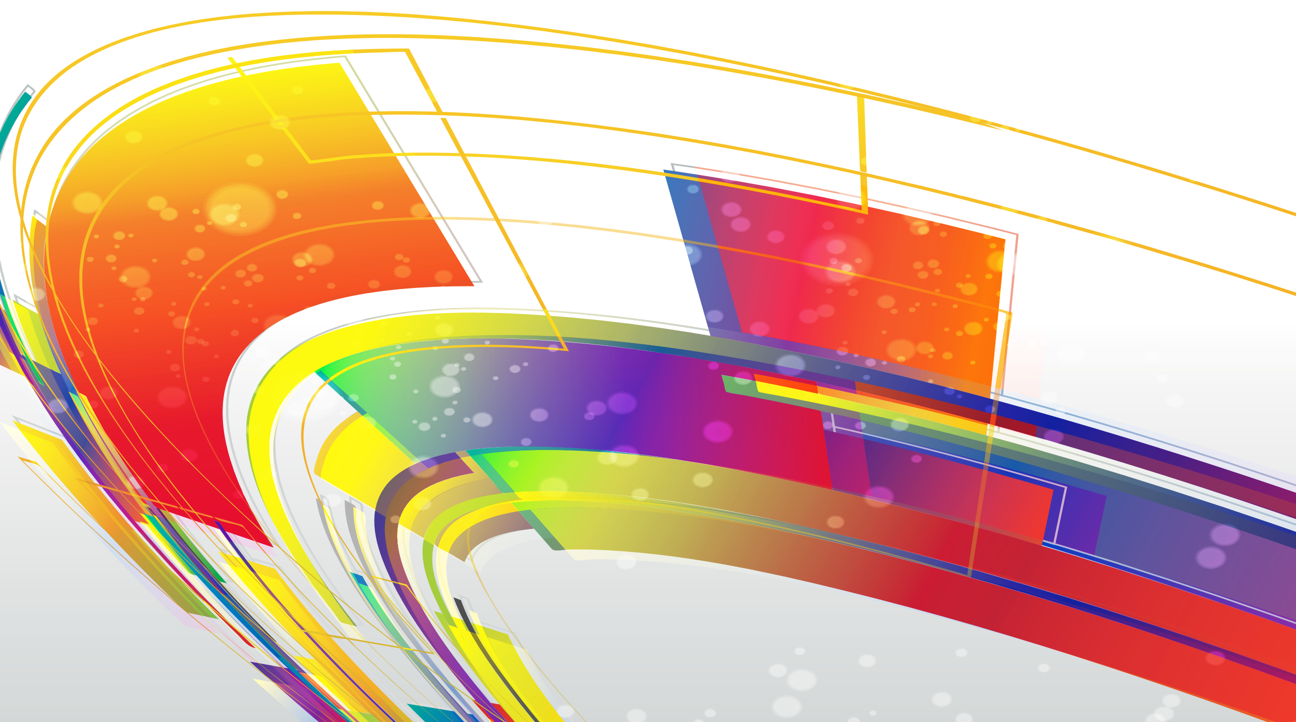
Station performance risk refers to the risk that Nuclear Production will be lower, or post-refurbishment costs higher, than projected in the Base Case Plan. The Bruce Contract transfers most station performance risk to Bruce Power. OPG rates are set by the OEB in five-year increments meaning that most station performance risk is transferred to OPG (the Province) within the five-year rate setting periods.

The FAO analyzed two market financial risks, demand risk and opportunity cost risk. Demand risk refers to the risk that there is insufficient demand for nuclear generation. Insufficient demand can arise due to conditions of surplus baseload generation, or a reduction in grid demand due to increased conservation and distributed generation. Opportunity cost risk refers to the risk of the long-term commitment to nuclear generation preventing the Province from pursuing lower cost, low emissions alternative generation options that could emerge during the life of the Plan.

Both risks are magnified by the generation characteristics of nuclear power. Nuclear generation requires a long-term commitment to recover capital investments and nuclear generation is not load-following, meaning that it is not economical to reduce output due to demand fluctuations. Therefore, curtailment or abandonment of Nuclear Production would negatively impact ratepayers and / or the Province.

The FAO identified a number of demand-side and supply-side mitigations that could limit demand risk. On the demand-side, increased electrification through the Province's Climate Change Action Plan, actions that smooth out demand fluctuations, planned exporting of electricity and regulatory actions could all work to ensure sufficient demand for nuclear generation. On the supply side, the planned shutdown of PNGS by 2024, the staged shutdown of reactors starting in 2043, nuclear refurbishment off-ramps and flexibility in other areas of the electricity generation market could also work to mitigate demand risk.

Finally, there are currently no alternative generation portfolios that could provide the same supply of low emissions baseload electricity generation at a comparable price to the Base Case Nuclear Refurbishment Plan. To the extent that alternative generation options emerge over the life of the Plan, opportunity cost risk is mitigated somewhat by economic off-ramps in the Bruce Contract and the Province's ability to terminate DNGS refurbishments.



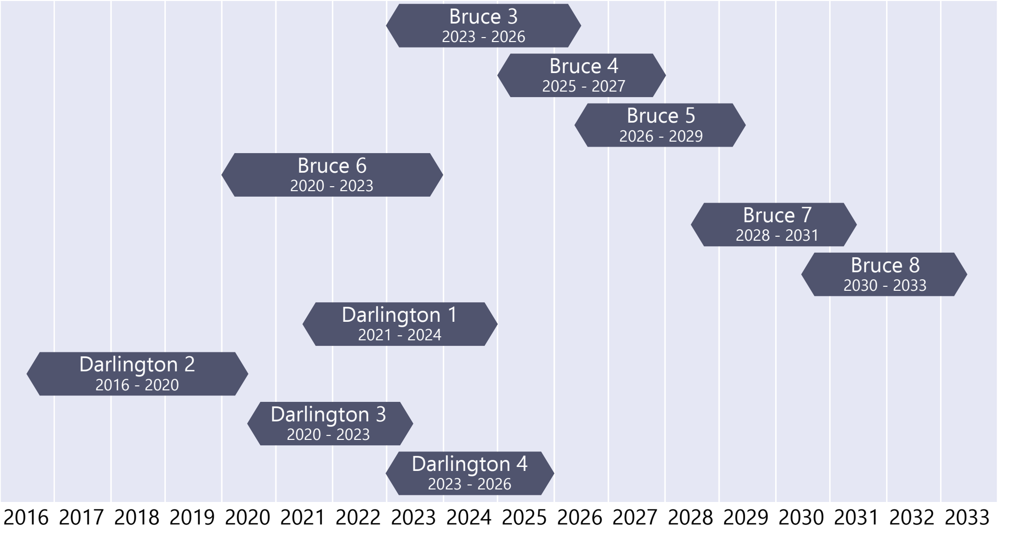
7 APPENDICES

A: Nuclear Refurbishment Plan Background Schedule

Schedule

The Plan involves the sequential refurbishment of reactors at each plant with the first refurbishment having commenced at Darlington (reactor number) 2 in 2016, and the last refurbishment, Bruce 8, scheduled for completion in 2033 (Figure 7-1).

Figure 7-1: Nuclear Refurbishment Plan: Reactor Refurbishment Schedule



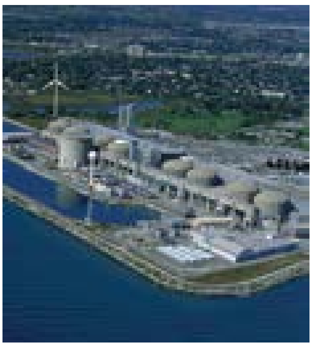
Note: There is no overlap between Darlington Units 2 & 3.

Source: FAO Analysis of the Bruce Contract and OEB case EB-2016-0152.

Ontario's Nuclear Generating Stations

Ontario's three nuclear generating stations (NGS) have provided 56-62% of Ontario's electricity supply over the past five years, and represent 36% of Ontario's installed generating capacity (Table 7-1).[97]

Table 7-1: Ontario's Nuclear Generating Stations

Nuclear Generating Station	Installed Generating Capacity		Electricity Production, 2015	
	MW	Share of Ontario Total	TWh	Share of Ontario Total
Pickering A (2 Units) & B (4 Units) (PNGS) 	3,094 (Net)* 3,244 (Gross)	8.6%	21.3	13.9%
Darlington (4 Units) (DNGS) 	3,512 (Net) 3,740 (Gross)	9.7%	23.3	15.1%
Bruce A (4 Units) & B (4 Units) (BNGS) 	6,300* (Net) 6,610 (Gross)	17.5%	47.6	31.0%
Total	**12,906**	**35.8%**	**92.2**	**60.0%**

Source: OPG.com; Brucepower.com; CANDU Owners Group.

*Net is smaller than gross as the plants consume electricity themselves.

**Under peak conditions Bruce Power is capable of producing 6,400 MW.

97 IESO. "Power Supply Data." n.d. Web. 31 Aug. 2016. Note: The Bruce and Pickering sites each include two separate generating stations, Bruce includes Bruce A and Bruce B, as well as other facilities. Bruce A and B are collectively referred to in this report as the Bruce Nuclear Generating Station (BNGS). Pickering includes Pickering A and Pickering B, and are collectively referred to in this report as the Pickering Nuclear Generating Station (PNGS).

All three plants use CANDU reactors,[98] which are designed to be refurbished after approximately 30 years. Refurbishment involves the replacement of life limiting reactor components and should extend the life of each reactor by 30-35 years.[99] The four Bruce B reactors and the four Darlington reactors were brought online between 1984 and 1993. Reactors at the two plants will reach 30 years of operation between 2014 and 2023. The four Bruce A reactors were brought online between 1977 and 1979; two Bruce A reactors (Bruce 1 and 2) were refurbished between 2005 and 2012. Bruce 3 and 4 reached 30 years in 2008 and 2009, however, the reactors were shut down in 1998 for about six years. The Pickering NGS currently has six operating reactors and was scheduled to be shut down in 2020, but is undergoing work to extend the life of the reactors to 2022 and 2024 (Table 7-2).[100]

Table 7-2: Ontario Nuclear Timeline

Reactor	Capacity (MW)	In Service	Status
Darlington 1	881	1992	Refurbishment from 2021 to 2024: End of life 2054
Darlington 2	881	1990	Refurbishment from 2016 to 2020: End of life 2050
Darlington 3	881	1993	Refurbishment from 2020 to 2023: End of life 2053
Darlington 4	881	1993	Refurbishment from 2023 to 2026: End of life 2055
Bruce A 1	772	1977	Refurbishment completed in 2012: End of life 2043
Bruce A 2	772	1977	Refurbishment completed in 2012: End of life 2043
Bruce A 3	730	1978	Refurbishment from 2023 to 2026: End of life 2055
Bruce A 4	730	1979	Refurbishment from 2025 to 2027: End of life 2057
Bruce B 5	817	1985	Refurbishment from 2026 to 2029: End of life 2059
Bruce B 6	817	1984	Refurbishment from 2020 to 2023: End of life 2053
Bruce B 7	817	1986	Refurbishment from 2028 to 2031: End of life 2061
Bruce B 8	817	1987	Refurbishment from 2030 to 2033: End of life 2063
Pickering A 1	515	1971	Undergoing life extension: End of life 2022
Pickering A 2	515	1971	Shutdown in 1997
Pickering A 3	515	1972	Shutdown in 1997
Pickering A 4	515	1973	Undergoing life extension: End of life 2022
Pickering B 5	516	1983	Undergoing life extension: End of life 2024
Pickering B 6	516	1984	Undergoing life extension: End of life 2024
Pickering B 7	516	1985	Undergoing life extension: End of life 2024
Pickering B 8	516	1986	Undergoing life extension: End of life 2024

Source: Canadian Nuclear Society.

98 CANDU, short for CANadian Deuterium Uranium is a reactor designed by a Canadian consortium.
99 Ontario Energy Board Case EB 2013-0321 Exhibit D2-2-1, p.1.
100 Government of Ontario. "Ontario Moving Forward with Nuclear Refurbishment at Darlington and Pursuing Continued Operations at Pickering to 2024." Ministry of Energy. 11 Jan. 2016. Web. 8 March 2016.

B: Details of Pricing

This appendix provides additional details on the mechanisms in place to set the Bruce and OPG Nuclear Prices.

Ontario Power Generation

Price Projections

Over the life of the Plan, the FAO projects the average OPG Nuclear Price will be $80.7/MWh. This price includes the PNGS and the pre-refurbishment DNGS production. During the refurbishment period (2016 to 2026), OPG is projecting higher Nuclear Prices for two reasons. First, lower OPG Nuclear Production while DNGS units are shut down for refurbishment. Second, an increased Revenue Requirement once the first refurbished unit ($4.8 billion) is added to the rate base in 2020.[101]

To mitigate the volatility of the OPG Nuclear Price during the DNGS refurbishment, OPG will smooth prices (rate smoothing) by deferring revenue while DNGS reactors are being refurbished and recovering the deferred revenue with interest post refurbishment.[102]

Details of Price Setting

The OPG Nuclear Price[103] (called the Nuclear Payment Amount by the OEB) has two components: a Nuclear Base Rate and a Nuclear Rate Rider. Planned refurbishment costs will be incorporated into the Nuclear Base Rate.

Figure 7-2: OPG Nuclear Price (Rate) Calculation

Nuclear Base Rate + Nuclear Rate Rider = Nuclear Rate

Source: FAO.

The subsections that follow describe how the Nuclear Base Rate and Nuclear Rate Rider are calculated.

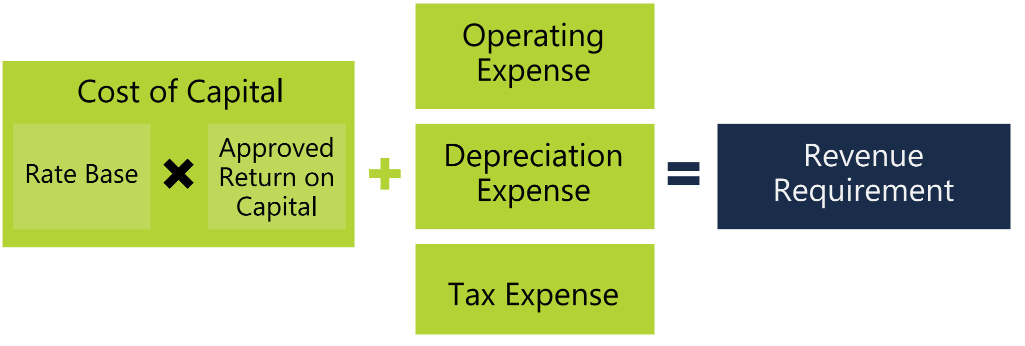
Nuclear Base Rate

The Nuclear Base Rate is a combination of two estimates: The revenue requirement and OPG Nuclear Production. The revenue requirement is OPG's estimated expenses

101 Ontario Energy Board case EB-2016-0152 Exhibit D2-2-1.
102 Rate smoothing is required under O Reg 53/05, s 6(2). As of the writing of this report, the OEB has not finalized the rate smoothing methodology.
103 The price ratepayers pay to OPG for electricity generated at OPG nuclear generating stations.

plus a return on capital (cost of capital). OPG Nuclear Production is OPG's estimated electricity production from its nuclear generating stations. The cost of capital reflects the cost of financing the assets being used for nuclear generation; it is the product of the OEB-approved Nuclear Rate Base (OPG's nuclear assets) and the OEB-approved Return on Capital. To the cost of capital are added operating expenses, depreciation (reflecting the using up of OPG's capital assets), and taxes. These elements add up to OPG's nuclear revenue requirement, which, when divided by Nuclear Production gives the Nuclear Base Rate (Figure 7-3).

Figure 7-3: OPG Revenue Requirement Calculation



Source: FAO.

Table 7-3 shows the calculation of the Nuclear Base Rate for 2014 and 2015.

Table 7-3: OPG Nuclear Base Rate Calculation

Description	2014	2015	Total
Cost of Capital ($M)	233.5	231.4	464.9
Operating Expenses ($M)	2,293	2,367	4,660
Depreciation and Amortization ($M)	274	289	562
Income Tax ($M)	-9	-9	-19
Revenue Requirement ($M)	**2,790**	**2,878**	**5,668**
Approved Production (TWh)	49	46.6	95.6
Nuclear Base Rate ($/MWh)	56.95	61.75	59.29

Source FAO analysis of OEB Case EB-2013-0321.

Nuclear Rate Riders

Nuclear Rate Riders are the other component of the Nuclear Rate that OPG charges to ratepayers. Nuclear Rate Riders allow OPG to recover balances in OEB-approved Deferral and Variance Accounts (DVA). DVAs are established to record variances in actual and approved revenues under many different categories. Variances are recorded on OPG's balance sheet as an asset or liability, and OPG periodically applies to the OEB to have these balances liquidated.[104]

When actual refurbishment capital costs vary from financial commitments, OPG will recognize an asset or liability. If the refurbishment costs exceed the amount which OPG has requested, and the OEB approves, OPG will recognize amounts as an asset in the DVA known as the Capacity Refurbishment Variance Account. Those amounts, once approved by the OEB, will be applied to the rate as a rate rider.

In October 2015, the OEB approved the recovery of $1,558 million from 13 DVAs, with $777.1 million to be recovered over the 18-month period from July 2015 to December 2016. Based on the approved forecast production of 71.7 TWh, the rate rider was set to $10.84/MWh (Table 7-4). The rate rider was approved in October; therefore, the rate rider was pro-rated to $13.01/MWh to make up for the lost recovery from July to September, 2015.

The $59.29/MWh base rate plus the $13.01/MWh rate rider make up the 2016 OPG Nuclear Price of $72.30/MWh.

104 One example is the Capacity Refurbishment Variance Account. This account was established to record differences between actual capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility.

Table 7-4: Rate Rider Calculation

Account	Approved Recovery ($M)	Recovery Period ($M)	Recovery from Jly 2015 - Dec 2016 ($M)
Nuclear Liability Deferral	285.7	18	285.7
Nuclear Development Variance	2.3	18	2.3
Ancillary Services Net Revenue Variance - Nuclear	1.7	18	1.7
Capacity Refurbishment Variance - Nuclear – Non Capital Portion	7.6	18	7.6
Capacity Refurbishment Variance - Nuclear - Capital Portion	1.3	18	1.3
Bruce Lease Net Revenues Variance - Derivative Sub-Account	153.8		53.7
Bruce Lease Net Revenues Variance - Derivative Sub-Account - EB-2012-0002	37.3	18	37.3
Bruce Lease Net Revenues Variance - Derivative Sub-Account - Post 2012 Additions	123.8	18	123.8
Income and Other Taxes Variance - Nuclear	-13.2	18	-13.2
Pension and OPEB Cost Variance - Nuclear - Future (Dec 31, 2012 Balance)	214.7	120	42.9
Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions	678.6	72	169.6
Pickering Life Extension Depreciation Variance	7.8	18	7.8
Nuclear Deferral and Variance Over/Under Recovery Balance	56.4	18	56.4
Total	**1,557.8**		**777.1**
Approved 18 Month Production			71.7 TWh
Rate Rider			10.84/MWh

Bruce Power

Price Projections

On December 3, 2015, Bruce Power and IESO signed a contract for the refurbishment of six BNGS reactors. In exchange for refurbishing the reactors, Bruce Power has the right to sell electricity generated at the BNGS at a price set in accordance with the terms of the Bruce Contract (Bruce Nuclear Price) until 2064.

The Bruce Contract's effective date was January 1, 2016, and at that time the Bruce Nuclear Price was set at $65.7/MWh.[105] Bruce Power and IESO have not publicly released annual Bruce Nuclear Price projections. The FAO estimates the average Bruce Nuclear Price over the entire life of the Bruce Contract to be $80.6/MWh. This price estimate includes BNGS units 1 and 2, which were refurbished under a previous agreement.[106]

105 Nominal value.
106 Bruce Power. "Amended Agreement Secures Bruce Power's Role in Long-Term Energy Plan." 3 Dec. 2015. Web. 4 Aug. 2016. Converted from 77/MWh ($2015).

Details of Price Setting

Bruce Power generates revenue by selling electricity into the market at the HOEP. Each month Bruce is compensated for the difference between the HOEP and the Contract Price for each megawatt hour of power it generates.

The monthly payment is equal to the difference between the Contract Price multiplied by the energy produced each hour and the HOEP multiplied by the energy produced each hour. If that number is positive, it is called the Contingent Support Payment, if it is negative, it is called the Revenue Sharing Payment. The contract price at the beginning of 2016 was $56.4/MWh ($2016).

$$\text{Monthly Payment} = \sum_{H=1}^{H=n_m} BE_H \times CP_M - \sum_{H=1}^{H=n_m} BE_H \times HOEP_H$$

In addition, Bruce receives a payment for offering dynamic capabilities which is the ability of the BNGS to reduce output in response to oversupply in the market as discussed in chapter 5. The dynamic capabilities (DC) payment equals the DC Fee multiplied by hourly production. The DC fee at the beginning of 2016 was $1.33/ MWh.

$$\text{Dynamic Capabilities Payment} = \sum_{H=1}^{H=n_m} BE_H \times DCF_m$$

Finally, the IESO makes payments to Bruce for fuel costs as mentioned in chapter 5.

The sum of the contract price ($56.4/MWh), the DC fee ($1.33/MWh) and the fuel costs ($8.00/MWh) make up the 2016 Bruce Nuclear Price of $65.7/MWh.[107]

Price Adjustments

The Contract Price is subject to the following annual adjustments according to Exhibit 4.4 of the Bruce Contract.

- Inflation – a portion of the contract price and the DC Fee is adjusted by the annual percentage change in the CPI.
- Wages – a portion of the contract price is adjusted based on growth in wages.[108]
- Fuel costs – fuel costs are determined on a monthly basis.

107 This was the price as of January 1, 2016.
108 The adjustment is based on the Wage Rate Escalator which is defined in the Bruce Contract as the Survey of Employment, Payrolls and Hours (SEPH) (Canada, all Employees, including overtime) (industrial aggregate excluding unclassified businesses) published by Statistics Canada.

C: Alternative Generation Options

This section analyzes alternative electricity generation options to the Nuclear Refurbishment Plan.

Overview and Approach

IESO evaluates alternatives primarily on cost and emissions. Although each form of generation is discussed individually, in reality, replacing nuclear generation would likely require a combination of alternative generation options. Currently available options include:

- Natural gas generation
- Renewable generation (hydro, solar, wind)
- Imports
- Conservation, Storage, and Demand Response

Both IESO and OPG compare different technologies for generating electricity using the levelized unit electricity cost (LUEC). The LUEC is the real (inflation-adjusted) cost per MWh of all construction, operating and decommissioning costs as well as financing and tax costs.[109] While the LUEC is a good way to compare different electricity generation technologies, LUEC does not necessarily provide a good indication of electricity prices. Table 7-5 displays the LUEC estimates of new generation for various resources.

109 Ayres, Matt, et al. "Levelised Unit Electricity Cost Comparison of Alternate Technologies for Baseload Generation in Ontario." Canadian Nuclear Association. Aug. 2004 pp. 1. Web. 9 Aug. 2016.

Table 7-5: Levelized Unit Electricity Cost Estimates for New Capacity

Resource	LUEC (2016 $/MWh)	Construction Lead Time
Nuclear Generation		
Large new nuclear	$120	10 years
Refurbished nuclear: Darlington*	$82	
Refurbished nuclear: average Bruce Contract Price**	$78	
Natural Gas Generation		
Baseload Natural Gas (CCGT)***	$60-110	
Renewable Generation		
Hydro	$140	10 years
Wind	$86	3 years
Solar (photovoltaic)	$140-290	3 years
Bioenergy	$164	3 years
Imports		
Firm imports (<1,250 MW)	$120	5 years
Firm imports (up to 3,300 MW)	$160	10 years

Source: FAO analysis of IESO Ontario Planning Outlook, 2016 & EB-2016-0512 Rate Application.

*Darlington LUEC refurbishment from EB-2016-0152 Exhibit D2-2-8 converted to $2016. This ignores sunk costs. The "going forward" Darlington Refurbishment LUEC would be much lower.

**Bruce contract price is not a LUEC.

***FAO estimate.

The sections that follow analyze each option. The final section reviews conservation, storage and demand response options.

Natural Gas Generation

Based on FAO analysis, in the near term, baseload natural gas electricity generation (Combined Cycle Gas Turbine (CCGT) generation), is less expensive than refurbished nuclear generation. In addition, natural gas generation would provide the market with greater flexibility to respond to surplus baseload conditions. However, in the long-term, projected increases in the spot price of natural gas and the implementation of carbon pricing via the Province's cap and trade program significantly impact the attractiveness of natural gas generation relative to refurbished nuclear generation.

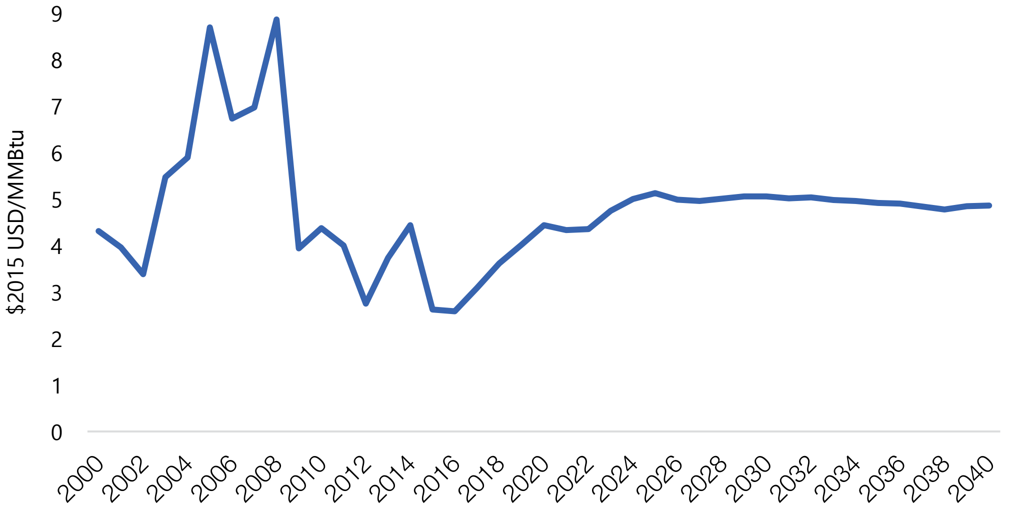
Forecast Spot Price of Natural Gas

Unlike nuclear generation, the cost of natural gas generation is very sensitive to fuel prices. Fuel costs comprise 60-70% of the LUEC of CCGT generation.[110] In 2016,

110 U.S. Energy Information Administration. "Levelized and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2016" Aug. 2016. Web. 6 Jan. 2017.

natural gas prices were the lowest in 20 years, ranging between USD $1.75-$3.75/MMBtu (CAD $2.30-$5.00/MMBtu).[111] The US Energy Information Administration[112] expects that long-term prices will increase to about USD $5.00/MMBtu by 2022 ($6.50 CAD assuming a 1.3 CAD/USD exchange rate) and remain close to that level (Figure 7-4).[113]

Figure 7-4: Historical and Forecast Natural Gas Spot Price



Source: US Environmental Information Administration Henry Hub forecast.

Note: IESO uses the Dawn Hub Spot price but the two track very closely.

Carbon Pricing

In 2017, the Province implemented a cap and trade program which prices carbon at approximately $18/tonne in 2017.[114] In October 2016, the Federal Government announced that Provinces must implement carbon pricing and that prices should start at $10/tonne in 2018 rising to $50/tonne in 2022. It is not clear exactly how the Government of Canada's policy will impact carbon pricing in Ontario.[115]

Natural gas electricity generation emits carbon dioxide, therefore, the price of carbon has a significant impact on the price of natural gas generation. The FAO estimates that carbon emissions priced at $50/tonne would increase the price of natural gas generation by $23/MWh and that carbon emissions priced at $20/tonne a would

111 U.S Energy Information Administration Natural Gas Database.
112 The EIA is the statistical and analytical agency within the U.S. Department of Energy.
113 U.S Energy Information Administration Natural Gas Database.
114 Sawyer, Dave, et al. "Impact Modelling and Analysis of Ontario's Proposed Cap and Trade Program." 12 May 2016. Web. 8 Feb. 2017.
115 Government of Canada. "Government of Canada Announces Pan-Canadian Pricing on Carbon Pollution." Environment and Climate Change Canada. 3 Oct. 2016. Web. 9 Feb. 2017.

increase the price of natural gas generation by \$9/MWh.[116]

Impact of Increasing Spot Prices and Carbon Pricing

The LUEC of CCGT generation is somewhat dependent on plant specific assumptions (size, capacity factor, heat rate, etc). At current gas prices, the FAO estimates the LUEC of baseload CCGT generation to be \$50-60/MWh. If gas prices rise to USD \$5/MMbtu, as the EIA is projecting, the FAO projects the LUEC of CCGT generation to be \$75-85/MWh.[117] Adding on carbon pricing of \$20/tonne to the current gas price estimate and \$50/tonne to the high gas price estimate, the LUEC estimate range increases to approximately \$60-\$110/MWh. Overall, it is important to note that lower or higher gas and carbon prices will have a significant impact on the cost of baseload natural gas electricity generation.

Conclusion

If natural gas and carbon prices remain low, baseload natural gas generation is less expensive than refurbished nuclear generation. However, projected increases in natural gas and carbon pricing have led the FAO to conclude that despite the near-term upsides of natural gas generation, the projected overall cost is comparable to refurbished nuclear generation but with higher greenhouse gas emissions.

Renewable Generation

Hydro

Existing hydroelectric generation is, on average, the lowest cost form of electricity generation in Ontario. The province currently has 8,800 MW of installed capacity with plans to increase capacity to 9,400 MW by 2032.[118] A study on hydro potential in Ontario conducted in 2005 identified total potential of approximately 14,600 MW (about 6,000 MW of new capacity).[119] The key issue with additional hydro development is that much of the potential is in remote northern areas of the province. According to the IESO, the cost and lead times for development would likely be higher than past projects. The estimated LUEC for new hydro is \$140/MWh (including transmission cost), considerably more than refurbished nuclear (Table 7-5).

116 Based on the assumption of .469 tonnes of carbon per megawatt hour.
117 FAO analysis of IESO, EIA, and OPG information.
118 Government of Ontario. "Ontario's Long Term Energy Plan." Ministry of Energy, Dec. 2013. Web. 11 July. 2016.
119 Hatch LTD. "Evaluation and Assessment of Ontario's Waterpower Potential." Ontario Waterpower Association. Oct. 2005, pp. 18. Web. 20 Aug. 2016.

Non-Hydro Renewable Generation

Non-hydro renewable generation comes primarily from wind and solar and represented 6.3% of Ontario electricity production in 2015. Historically, wind and solar have not been comparable with nuclear based on cost and intermittency.

Cost

Solar is currently, on average, the most expensive generation source in the Ontario. The IESO has awarded wind contracts through the Large Renewable Procurement program as low as $65.7/MWh, lower cost than refurbished nuclear. However, if wind/solar were to replace a significant portion of nuclear generation, a very large amount of capacity would be required. As more grid scale wind and solar capacity is added, the capacity would need to be located in areas which require more transmission investment, leading to higher costs. Although there are some wind contracts that are cheaper than refurbished nuclear generation, non-hydro renewables cannot currently replace nuclear capacity at a comparable cost.

Intermittency

Both solar and wind do not use fuel to generate electricity, and are only available under certain conditions (wind blowing and sun shining). This feature limits their ability to provide consistent generation and to adjust output to meet demand. Geographic diversification and storage can reduce aggregate system intermittency, but at present either option would come with very significant cost.

Non-hydro renewables are an important part of any replacement generation supply mix. However, cost, intermittency and transmission grid issues limit the practicality of relying on wind and solar to replace a significant portion of nuclear generation. There is potential for both wind and solar with storage to emerge as competitive alternatives to nuclear generation in the future as technology improves and costs fall.

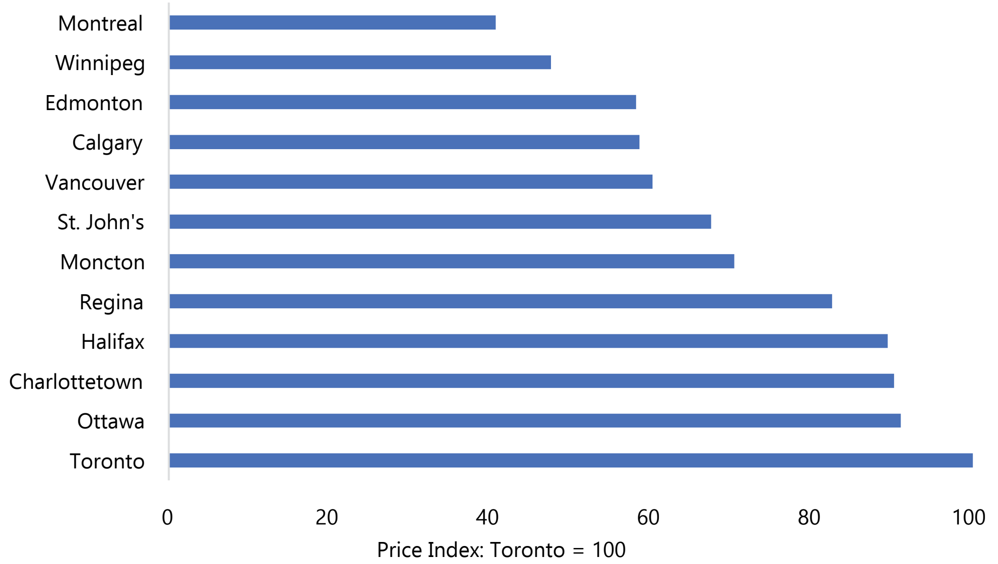
Imports

Ontario is directly connected to the transmission grids of Manitoba, Michigan, Minnesota, New York and Quebec. Because a significant portion of the US generation mix is coal, importing electricity from the United States is not consistent with the Ministry of Energy's clean generation goals.[120] Manitoba and Quebec both produce electricity primarily from hydro and sell electricity at rates that are among the lowest in North America (Figure 7-5). The proximity of Quebec to Ontario's major cities presents a particularly attractive opportunity to import clean hydroelectricity.

120 Government of Ontario. "Ontario's Long Term Energy Plan." Ministry of Energy. Dec. 2013, pp. 45. Web. 11 July. 2016.

In November, 2016, the IESO and Hydro-Quebec finalized an Electricity Trade Agreement for Ontario to import 2.3 TWh of electricity annually. [121]

Figure 7-5: Residential Electricity Price Index Comparing Major Canadian Cities



Source: FAO analysis of Hydro Quebec report: Comparison of Electricity Prices in Major North American Cities.

The IESO estimates the LUEC of firm imports to be $120/MWh to $160/MWh, higher than the LUEC estimate for the DNGS of $82/MWh.[122] The high cost of imports stems mainly from three factors: competition from US market; lack of transmission capacity; and a projected reduction of surplus electricity in Quebec in the future.

US Competition

In 2016, Quebec exported 32.6 TWh of electricity (more than the DNGS produces in a year), three quarters of which went to New England and New York.[123] The spot price of electricity in US markets is much higher than Ontario, which makes those markets more attractive for Quebec to sell into.[124] The spot price of electricity in neighboring markets and hence Quebec's export price is closely tied to the price of natural gas. Due to the decline in natural gas prices since 2008, Quebec's average export price has declined from $110/MWh in 2008 to an average of $57/MWh from 2014 to 2016 (the average Ontario spot price in 2016 was $16.6/MWh).[125] The IESO has stated that

121 Leslie, Keith. "Hydro deal with Quebec to save Ontario electricity grid $70M." CBC News. 21 Oct. 2016. Web. 5 Dec. 2016.
122 IESO. "2016 Ontario Planning Outlook." 1 Sept. 2016, pp. 12. Web. 8 Sept. 2016.
123 Hydro Quebec "Export Markets." n.d. Web. 10 April 2017.
124 Brouillette, Marc. "Renewables and Ontario/Quebec Transmission System Interties." Strategic Policy Economics. 16 June 2016. Web. 9 Apr. 2017.
125 Hydro Quebec. 2012, 2014, 2015 & 2016 Annual Reports.

based on discussions with neighboring jurisdictions it estimates the price of electricity imports at the border to be $70-100/MWh.[126]

Infrastructure Limitations

Transmission issues in the Ottawa area limit firm import capability from Quebec to 500 MW. The IESO estimates that the cost of upgrades to accommodate firm imports of up to 3,300 MW from Quebec would be $2 billion. The IESO has also stated that incremental transmission could add from $20-$30/MWh to upwards of $100/MWh to the price of imports.[127]

Quebec Competition

Lastly, Quebec is forecasting increasing domestic electricity demand due to climate change initiatives similar to those that are projected to increase Ontario demand.[128] As a result, Quebec is forecasting reductions in surplus electricity through 2026.[129]

Summary

The combination of American markets willing to pay higher prices for Quebec's current surplus electricity, transmission limitations, increasing domestic demand in Quebec, and the cost of new Quebec generation leads to the prospect of large scale imports from Quebec not being competitive with nuclear generation. IESO projects the LUEC of imports under 1,250 MW to be $120/MWh or $160/MWh for up to 3,300 MW (see Table 7-5). Both are significantly more expensive than the $82/MWh LUEC of the DNGS refurbishment.

Conservation, Storage, and Demand Response

With a LUEC of between $30 and $50, conservation is the least costly method of balancing the supply and demand for electricity in Ontario (by reducing demand rather than by increasing supply). The current conservation target is 31 TWh by 2035 and the latest demand outlooks incorporate achieving that target. The amount and cost of incremental conservation depends on future electricity demand and technology.[130]

126 IESO. "Review of Ontario Interties" 14 Oct. 2014. Web. 12 Oct. 2016.
127 IESO. "Review of Ontario Interties" 14 Oct. 2014. Web. 12 Oct. 2016.
128 Hydro Quebec. "Capacity and Energy Needs" n.d. Web. 5 Jan. 2017. & Brouillette, Marc. "Renewables and Ontario/Quebec Transmission System Interties." Strategic Policy Economics. 16 June 2016. Web. 9 Apr. 2017.
129 Hydro Quebec. "Plan D'approvisionnement 2017-2026" 1 Nov. 2016. Web. 26 Sept. 2017.
130 IESO. "2016 Ontario Planning Outlook." 1 Sept. 2016, pp. 8. Web. 8 Sept. 2016.

In addition to conservation, IESO has outlined programs to promote procurement of electricity storage starting at 50 MW as well as providing incentives to shift electricity demand from on-peak to off-peak hours.[131] Storage increases the consistency with which the output of intermittent generation can be provided to the grid and provides the market with the ability to use electricity when it is needed, not when it is produced. According to one source, the levelized cost of large scale energy storage technologies that can assist in the integration of large-scale renewable generation are in excess of $267/MWh.[132]

Conclusion

There are three key conclusions on the consideration of alternatives to the Nuclear Refurbishment Plan:

- There are no alternative scenarios that are comparable to refurbished nuclear generation in terms of both cost and emissions.
- There are alternative generation options for Ontario that involve primarily baseload natural gas supplemented by additional wind and imports that are comparable to the base case Nuclear Price.
- There are also combinations of renewables, imports and conservation that can replace nuclear generation at comparable emissions, but the cost of this scenario would be approximately 50% higher than the base case Nuclear Price.

D: Development of This Report

Authority

The Financial Accountability Officer accepted a request from a member of the Legislative Assembly to undertake the analysis presented in this report under paragraph 10(1)(b) of the *Financial Accountability Officer Act, 2013*.

Key Questions

The following key questions were used as a guide while undertaking research for this report:

- How will the costs of the Plan be recovered?

131 Government of Ontario. "Ontario's Long-Term Energy Plan." Ministry of Energy. Dec. 2013, pp. 14. Web. 11 July. 2016.
132 Lazard "Lazard's Levelized Cost of Storage Analysis" Nov. 2015. Web. 9 Dec. 2016. (Converted from USD $2015 to CAD $2016).

- What is the projected cost to ratepayers for nuclear electricity during and after refurbishment?
- What are the key financial risks the Nuclear Refurbishment Plan poses to ratepayers and the Province?
- What is the potential financial impact to ratepayers and/or the Province of those risks?

Scope and Approach

The present report is not a comprehensive cost-benefit or business case analysis of the Nuclear Refurbishment Plan relative to alternatives. Such an analysis would have to consider important issues such as economic, environmental, security factors and associated non-financial risks.

This report is a narrower analysis. It develops a financial model of the Plan called the base case. It then asks what could cause the financial results of the Plan to deviate from base case expectations. The focus is on providing Members of Provincial Parliament with a better understanding of the financial risks to the Plan and how those risks are allocated.

Methodology

This report has been prepared on the basis of publicly available information as of October 29, 2017 and consultations with, and information provided by, Bruce Power, the Independent Electricity System Operator, the Ontario Ministry of Energy and Ontario Power Generation.

The Nuclear Price estimate includes all electricity production from the Bruce, Darlington and Pickering Nuclear Generating Stations from 2016 to 2064.

All figures in this report are in 2017 dollars unless otherwise noted. That is, dollar figures pertaining to years other than 2017 have been adjusted for expected inflation so that they are equivalent in purchasing power to dollars in 2017. All Nuclear Price Estimates are levelized using a 2.5% real social cost of capital.

This report assumes that Ontario's current legal and regulatory framework surrounding the production, transmission, distribution and import/export of electricity remains in place throughout the period of analysis. The relevance of this assumption is noted as appropriate above.