ONTARIO ENERGY BOARD

EB-2016-0152

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

AND IN THE MATTER OF an application by Ontario Power Generation (OPG) pursuant to section 78.1 of the *Ontario Energy Board Act*, 1998 for payment amounts for the period from January 1, 2017 to December 31, 2021.

ENVIRONMENTAL DEFENCE COMPENDIUM FOR PANEL 3B CROSS-EXAMINATION

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ONTARIO POWER GENERATION

November 2015

File: P-BCS-00970-0001 REV: 000

Technical and Economic Assessment of Pickering Extended Operations beyond 2020

October 2015

Contents

QUALITATIVE CONSIDERATIONS

The following qualitative considerations associated with Extended Operations are of significant potential value to OPG and Ontario:

- **Deferral of Job Losses:** Would defer direct job losses of approximately 4,000 in OPG, affecting the GTA and Durham Region; there would also be impacts on indirect and induced jobs and the economy, particularly in Durham Region.
- **Strategic Capacity Hedge during Nuclear Refurbishments:** Ontario's Long-Term Energy Plan has endorsed Pickering as a strategic hedge against uncertainties in the costs and schedule of refurbishment of the Bruce and Darlington units. Also, extended operation avoids the risk that unneeded gas-fired capacity would be built to address temporary capacity shortfalls during the period of intense nuclear refurbishments.
- **Emissions Reductions:** The Preferred Alternative is expected to result in a net reduction of 16 - 18 million tonnes of CO_2 relative to the operation of the electricity system with replacement energy and capacity for Pickering, which would come primarily from gas-fired generation and increased imports. Therefore, extending Pickering operations aligns with Provincial Government policies to reduce greenhouse gas emissions.
- **Increased Flexibility:** Extending some Pickering units to 2024 provides a more natural transition point for reducing OPG staff levels, as the transition would occur near the end of Darlington Refurbishment, thereby minimizing disruption for both Darlington Operations and Darlington Refurbishment.
- **Planning for Safe Store**: Would provide a longer period to plan for the safe storage of the units, allowing plans and costs to be further optimized.
- **Decommissioning and Used Fuel Funds**: A reduction of the present value of the decommissioning liability for the Pickering units (decommissioning activities can be deferred by several years) could create a larger surplus in the decommissioning fund, decreasing risks around adequacy of the funds and potentially providing future opportunities to utilize that surplus to "top-up" OPG's Used Fuel Fund.

RISK OVERVIEW

Risks associated with the Preferred Extended Operations Alternative are summarized as follows:

1. Reputational Risk (High): e.g. the risk is that interest groups that are opposed to nuclear power will contest Extended Operations, particularly during the next license renewal process, and thereby cause increased community concern. *Mitigating Actions:* Ongoing demonstration of the value and safety of Pickering through external communications, hearings and stakeholder relations.
2. Regulatory Risks (Medium): e.g. the risk that the proposed disposition for one or more known issues is not accepted by the CNSC. *Mitigating Actions:* Completion of the PSR and a pro-active approach with the CNSC to demonstrate technical fitness-for-service and maintenance of high safety standards.
3. Technical/Fitness-for-service Risks (Medium): e.g. the risk that a major component, e.g. fuel channels, does not continue to meet fitness-for-service requirements. *Mitigating Actions:* A comprehensive inspection program has been developed and included in the work program; on-going detailed life cycle management of major components.
4. System Value Assessment (Medium) – changes to Ontario system parameters such as flat or declining load growth impact, reduction in the cost of competing generation or changes to baseload supply (e.g. refurbishment schedules change) could impact the overall

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Exhibit L Tab 6.5
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Ontario

NEWS

Ministry of Energy

Ontario Moving Forward with Nuclear Refurbishment at Darlington and Pursuing Continued Operations at Pickering to 2024

Projects will Boost Economic Activity, Create Jobs and Help Fight Climate Change

January 11, 2016 2:00 P.M.

Ontario is moving forward with nuclear refurbishment at Darlington Generating Station, securing 3,500 megawatts of affordable, reliable, and emission free power.

Nuclear refurbishment at Darlington will contribute $15 billion to Ontario's gross domestic product (GDP) throughout the project and create up to 11,800 jobs annually. The refurbishment of all four units is expected to involve about 30 million hours of work over 10 years and will support Ontario's globally recognized CANDU nuclear supply chain, with more than 180 companies employing thousands of highly skilled workers.

Ontario Power Generation (OPG) is on track to begin refurbishment of the first unit at Darlington in October 2016. To best protect Ontario ratepayers and ensure OPG delivers refurbishment on-time and on-budget, the government has established off-ramps that require OPG to obtain government approval prior to proceeding with each of the remaining unit refurbishments. The budget for the project is $12.8 billion, about $1.2 billion less than originally projected by OPG, and all four units are scheduled for completion by 2026.

The Province has also approved OPG's plan to pursue continued operation of the Pickering Generating Station beyond 2020 up to 2024, which would protect 4,500 jobs across the Durham region, avoid 8 million tonnes of greenhouse gas emissions, and save Ontario electricity consumers up to $600 million. OPG will engage with the Canadian Nuclear Safety Commission and the Ontario Energy Board to seek approvals required for the continued operation of Pickering Generating Station.

Securing clean, reliable power for decades to come is part of the government's plan to build

Ontario up. The four-part plan includes investing in people's talents and skills, making the largest investment in public infrastructure in Ontario's history, creating a dynamic, innovative environment where business thrives and building a secure retirement savings plan.

QUOTES

" Proceeding with the refurbishment at Darlington will ensure that nuclear continues to be Ontario's single largest source of power. The Darlington refurbishment project will create up to 11,800 jobs annually and contribute $15 billion to Ontario's GDP. Continuing operations at Pickering will protect 4,500 jobs across the Durham region, provide emissions-free electricity, and save Ontario electricity consumers up to $600 million."
- Bob Chiarelli
Minister of Energy

" Refurbishing Darlington is an investment in Ontario. It's good for the customers, it's good for the economy and it's good for the environment. We're confident we have done the work and have the people in place to deliver this project safely, on schedule and on budget."
- Jeffrey Lyash
President and CEO, Ontario Power Generation

" With these investments, nuclear will continue its role in ensuring Ontarians have enough power when and where they need it. The plan to refurbish the Darlington nuclear units and to keep Pickering in operation longer during the refurbishment period is a cost effective way to meet our future power needs."
- Bruce Campbell
President and CEO, Independent Electricity System Operator

QUICK FACTS

- Nuclear energy plays a fundamental role in Ontario's electricity system. Ontario's nuclear fleet currently supplies enough power to meet about 60 per cent of Ontario's daily electricity needs, and is our largest source of reliable, affordable power.
- OPG electricity rates are regulated by the Ontario Energy Board (OEB). All costs for the Darlington refurbishment will be subject to review and approval by the OEB through a public and transparent process to ensure they are prudently incurred. The average cost

of power from Darlington nuclear units post-refurbishment is estimated to range between $72/MWh and $81 MWh, or 7 and 8 cents per kilowatt hour.

- The average cost of power from Darlington after refurbishment is within the range assumed in the 2013 Long-Term Energy Plan for refurbished nuclear energy and lower than the average price of electricity generation in Ontario, which in 2015 was $92/MWh.
- The Pickering Generating Station employs about 4,500 people and is the largest employer in Durham Region.
- Continuing operations at Pickering Generating Station will avoid 8 million tonnes of greenhouse gas emissions, which is the equivalent to taking 490,000 cars off Ontario roads.

LEARN MORE

- Learn about OPG's Darlington Refurbishment Project
- Read the Conference Board of Canada's report on the economic impact of the Darlington Refurbishment
- Read Ontario's 2013 Long-Term Energy Plan

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Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2016-0152** **Ontario Power Generation Inc.**

VOLUME: **Technical Conference**

DATE: **November 15, 2016**

nature of what the minister does and doesn't do and what the Board does with it, I think is something we can argue about before the Board.

MR. ELSON: Well, what we are looking for is different than what you’ve described. But I do agree that we will need to address this on motions day.

If we can turn to IR 26, please, there is a reference here to 4500 jobs. Where does that number come from? And let me just be more clear for the record, if you don't mind. There is a reference here to 4500 jobs that would be protected through the extended operation of Pickering, and I am just wondering where the number 4500 comes from.

MR. BLAZANIN: So OPG, in its economic assessment, provided a value; that is Exhibit F2-2-3, attachment 2. We quoted a number at the time of the business case of approximately 4,000 OPG jobs.

I believe the additional 500 jobs reflected a potential impact within the community, in terms of if Pickering was shut down, that it would affect further jobs that were induced within the community that would be potentially affected.

MR. ELSON: So that's OPG's estimate, is that there would be 500 job impacts from a community basis?

MR. BLAZANIN: It was not OPG's estimate. OPG's estimate for the impact on OPG was 4,000 potential jobs.

MR. ELSON: No, sorry. Was the 500 OPG's estimate of the impact on the community, aside from its own employees? Maybe I am misunderstanding, but --

MR. BLAZANIN: The estimate that OPG prepared was 4,000 jobs. What was reported in the government announcement was 4,500 jobs. My understanding is that there was a report conducted looking at the economic impact potentially within the community, and the value that was identified there was 4,500 jobs in total, which would have been induced jobs within the community as well.

MR. ELSON: Do you have a copy of that report that you could file?

MR. KEIZER: The 4,500 jobs is in the context of if Pickering shuts down. That's the correct basis of your question?

MR. ELSON: No, it's part of the cost-benefit analysis that it has -- the job savings have been cited, and I am just wondering what the underlying numbers are.

MR. BLAZANIN: So for OPG, the basis was 4,000 jobs that would be deferred or saved within OPG. That would include permanent staff and temporary staff, and my understanding is there’s an additional potential 500 jobs that could be affected within the community.

MR. ELSON: And can you file that report that underlies that? You just referred to a report. I am just wondering if you can file it as an undertaking.

MR. KEIZER: I don't know if that report is under the control of OPG, or whether -- or what the nature of it is.

MR. ELSON: Best efforts would be fine.

MR. KEIZER: I think the only thing we could do is consider whether or not that's a report we have, and which were included or excluded from the economic assessment of Pickering, including the calculation of the 6.5 cents per kilowatt-hour?

MR. BLAZANIN: We will take that undertaking.

MR. MILLAR: Is that part of the same undertaking, Mr. Elson?

MR. ELSON: Let's do another undertaking.

MR. MILLAR: JT2.5.

UNDERTAKING NO. JT2.5: OF THE COSTS INCLUDED IN ED 18, BOARD STAFF 116, AND GEC 38, TO ADVISE WHICH WERE INCLUDED OR EXCLUDED FROM THE ECONOMIC ASSESSMENT OF PICKERING, INCLUDING THE CALCULATION OF THE 6.5 CENTS PER KILOWATT-HOUR

MR. ELSON: And could you explain, in each case when numbers were not included in the economic assessment, why that was the case?

MR. BLAZANIN: We will provide the basis for not including certain values in the economic assessment.

MR. ELSON: And could you please calculate the LUEC that would include all of the costs that were included in each of those, in each of those interrogatory responses for the test period years as another undertaking?

MR. KEIZER: I don't think we are going to do that.

MR. ELSON: I am just trying to have a comparison between what was included and what wasn't. So it could be by way of a LUEC, or just somehow a monetary figure to let us know the difference between the total costs and what were included in the economic assessment. Can you provide

Numbers may not add due to rounding.

Filed: 2016-05-27
EB-2016-0152
Exhibit F2
Tab 1
Schedule 1
Table 3

Table 3

Nuclear Staff Summary - Regular and Non-Regular (FTEs)[1]

Line No.	Group	2013 Actual[2]	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	NUCLEAR OPERATIONS:									
1	**Regular Staff**	5,870.7	5,626.7	5,430.4	5,788.6	5,710.8	5,666.2	5,602.1	5,504.1	5,394.7
2	**Non-Regular Staff**	496.9	578.1	670.0	666.7	614.4	646.6	632.2	526.8	420.4
3	**Subtotal Nuclear Operations**	6,367.6	6,204.8	6,100.4	6,455.3	6,325.2	6,312.8	6,234.3	6,030.9	5,815.1
	DARLINGTON REFURBISHMENT:									
4	**Regular Staff**	282.0	307.2	329.7	427.6	587.2	599.9	620.5	589.5	597.8
5	**Non-Regular Staff**	24.6	35.3	60.7	73.5	153.2	152.2	137.4	157.7	230.1
6	**Subtotal Nuclear Generation Development**	306.6	342.5	390.4	501.1	740.4	752.1	757.9	747.2	827.9
7	**Total Nuclear**	6,674.2	6,547.3	6,490.8	6,956.4	7,065.6	7,064.9	6,992.2	6,778.1	6,643.0

1 Nuclear Operations and Darlington Refurbishment FTEs are aligned to where costs related to the FTEs are incurred.

2 The 2013 Actual FTEs shown are adjusted from those provided in EB-2013-0321, Ex. J7.3, Attachment 1. The adjustment increases the number of FTEs by excluding the impact of banked overtime (overtime taken as time off rather than pay) and shows the 2013 Actual FTEs on a consistent basis with the remaining years in the table.

Numbers may not add due to rounding.

Filed: 2016-05-27
EB-2016-0152
Exhibit E2
Tab 1
Schedule 1
Table 1

Table 1
Production Forecast Trend - Nuclear (TWh)

Line No.	Prescribed Facility	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Darlington NGS**	25.1	28.0	23.3	26.0	19.0	19.3	19.7	17.7	16.6
2	**Pickering NGS**	19.6	20.1	21.2	20.8	19.1	19.2	19.4	19.6	18.8
3	**Total**	44.7	48.1	44.5	46.8	38.1	38.5	39.0	37.4	35.4

Filed: 2016-12-22
EB-2016-0152
Exhibit L Tab 6.5 Schedule 7 ED-027
Attachment 2

Pickering Life Extension Benefit Analysis Model

December 2016

Purpose of Model:

This model was prepared to support OPG's response to interrogatory question Ex. L-6.5-7 ED-27 from OPG's Reply to Motions (EB-2016-0152 — OPG 2017-2021 Payment Amounts) submitted on December 13, 2016. The model presents a breakdown of the components of OPG's economic analysis of Pickering Life Extension, and allows the user to perform sensitivities around Pickering's costs.

Description of Scenarios:

OPTION 1: Pickering generates an incremental 64.5 TWh with life extended to 2022/24

OPTION 2: Pickering generates an incremental 61.5 TWh with life extended to 2022/24

Description of Worksheets (Tabs):

Results: Presents the Present Value of the Net Savings to the Ontario Electricity System from extending Pickering's life to 2022/24 for Option 1 & Option 2. Includes a breakdown of the contributing components including System Savings (e.g. avoided gas generation, imports, CO2 emissions, etc.) and incremental Pickering costs.

NOTE: The user may change the values in the yellow shaded cells (in percentage terms) to perform sensitivities around Pickering costs.

Pick OM&A: Presents Pickering's projected annual Operations, Maintenance and Administration (OM&A) costs both with and without life extension.

Pick Fuel: Presents Pickering's projected annual fuel costs both with and without life extension.

Sensitivity %			OPTION 1	OPTION 2
	Incremental Pickering Energy	(TWh)	64.5	61.5
	Ontario System Savings (excl. Pickering)*	(2015PV C$M)	$3,022	$2,924
0%	Pickering Incremental OM&A	(2015PV C$M)	($2,519)	($2,519)
0%	Pickering Avoided Severance Costs	(2015PV C$M)	$247	$247
0%	Impact on Pickering Decommissioning Liability Credit	(2015PV C$M)	$100	$100
	Pickering Incremental Fuel Consumption	(2015PV C$M)	($238)	($226)
	Net Savings to Ontario	**(2015PV C$M)**	**$610**	**$530**

*includes reduced gas generation and imports, new capacity requirements, value of reduced CO2 emissions, etc.

- all costs presented in 2015 Present Value (PV) Canadian $ millions
- PV of future cash flows discounted at a nominal rate of 7%
- yellow shaded can be changed by the user to adjust estimated costs
- blue font indicates hardcoded data

		Year #	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Base PV/Escalation Year	2015											
Nominal Discount Rate/Factors	7%		1.000	0.934	0.872	0.814	0.760	0.710	0.663	0.619	0.578	0.539
CPI Escalation Rate/Factors	2%	***TOTAL***	1.000	1.020	1.040	1.061	1.082	1.104	1.126	1.149	1.172	1.195

INCREMENTAL PICKERING OPS, MAINT & ADMIN (OM&A) EXPENSES - October 2015 estimate

Blue font indicates imported data (hardcoded)

		TOTAL	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Pickering OM&A (excl. fuel, pension/OPEB, severance) in Real 2015 $M												
Base Case (2020 end of life)	2015C$M	4,628		1,048	953	959	909	759				
Extended Operations (2022/24 end of life)	2015C$M	8,125		1,055	987	1,038	1,054	977	987	902	631	494
Incremental Cost (Extended Ops - Base Case)	2015C$M	3,497	-	7	35	79	145	218	987	902	631	494
Pickering OM&A (excl. fuel, pension/OPEB, severance) in Nominal $M												
Base Case (2020 end of life)	Nom C$M	4,900	-	1,069	991	1,018	984	838	-	-	-	-
Extended Operations (2022/24 end of life)	Nom C$M	8,901	-	1,076	1,027	1,101	1,141	1,079	1,111	1,036	739	590
Incremental Cost (Extended Ops - Base Case)	Nom C$M	4,001	-	7	36	84	157	241	1,111	1,036	739	590

INCREMENTAL PICKERING OM&A Expenses - With Sensitivity % Applied

Sensitivity % **0% %**

		TOTAL	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Pickering OM&A (excl. fuel, pension/OPEB, severance) in Real 2015 $M												
Base Case (2020 end of life)	2015C$M	4,628	-	1,048	953	959	909	759	-	-	-	-
Extended Operations (2022/24 end of life)	2015C$M	8,125	-	1,055	987	1,038	1,054	977	987	902	631	494
Incremental Cost (Extended Ops - Base Case)	2015C$M	3,497	-	7	35	79	145	218	987	902	631	494
Pickering OM&A (excl. fuel, pension/OPEB, severance) in Nominal $M												
Base Case (2020 end of life)	Nom C$M	4,900	-	1,069	991	1,018	984	838	-	-	-	-
Extended Operations (2022/24 end of life)	Nom C$M	8,901	-	1,076	1,027	1,101	1,141	1,079	1,111	1,036	739	590
Incremental Cost (Extended Ops - Base Case)	**Nom C$M**	**4,001**	**-**	**7**	**36**	**84**	**157**	**241**	**1,111**	**1,036**	**739**	**590**

2015 Present Value of Pickering Incremental OM&A

2015PV Incremental OM&A	**2,519**	**2015PV C$M**

Filed: 2016-10-26
EB-2016-0152
Exhibit L
Tab 6.5
Schedule 7 ED-022
Page 1 of 1

ED Interrogatory #22

Issue Number: 6.5
Issue: Are the test period expenditures related to extended operations for Pickering appropriate?

Interrogatory

Reference:
Reference: "OPG expects to incur severance and related costs following the eventual shutdown of Pickering. Extended Operations will defer the costs associated with the closure of the station." Ex F2, Tab 2, Schedule 3, Page 8.

Could the immediate decommissioning and dismantling of Pickering, after it is shutdown, also defer severance costs associated with the closure of the station? If "no", please explain why not. If yes, approximately what percentage of those costs could be deferred?

Response

No.

Adopting an immediate dismantlement strategy for Pickering is not a viable means of deferring severance costs, as the staff that would otherwise be severed upon station closure could not be used to dismantle the plant. This is due to the fact that an immediate dismantlement strategy for a nuclear plant does not result in an immediate physical process. In accordance with Canadian Nuclear Safety Commission requirements, nuclear fuel consumed in the generation process must remain within the station's wet fuel bay storage facilities for a minimum of 10 years prior to removal. Dismantlement cannot occur while irradiated nuclear fuel is being contained within the station. Therefore, under an immediate dismantlement strategy, the physical act of dismantlement would not begin until in the order of 12 years after station closure, in order to account for cooling of fuel in wet bays and the full emptying of those wet bays into dry storage containers. It is not a viable option to retain employees for that period of time to execute dismantlement instead of severing them upon station closure.

UNDERTAKING JT1.17
ATTACHMENT F

Undertaking

ED INTERROGATORY #22

According to this interrogatory response, dismantlement of the Pickering Nuclear Station cannot occur "while the irradiated nuclear fuel is being contained within the station. Therefore, under an immediate dismantlement strategy, the physical act of dismantlement would not begin until in the order of 12 years after the station closure, in order to account for cooling of fuel in wet bays and the full emptying of those wet pays into dry storage containers."

(a) Is the Darlington Re-Build proceeding while nuclear fuel is being contained within the Darlington Nuclear Station? If yes, why can a re-build proceed in the presence of irradiated fuel while a dismantling cannot?

(b) Please explain why immediate decommissioning is allowed in other jurisdictions and not in Ontario? Is there anything unique about the technology used by OPG that would prevent immediate decommissioning?

Response

(a) The refurbishment of a reactor, such as Darlington, is fundamentally different than decommissioning. Decommissioning involves large scale demolition of structures which surround the reactor and the wet bays in which the used fuel is stored. Demolition of facilities and structures adjacent to the wet bays while the irradiated nuclear fuel was still present would represent risk of compromising structural integrity thereby restricting conventional methods of dismantlement and increases cost significantly. By comparison, refurbishment does not involve removal of safety related plant structures.

(b) Immediate decommissioning is not prohibited in Ontario or Canada. OPG has chosen deferred decommissioning as the best approach to minimize workers exposure to radiation. This approach is consistent with international practice. There is nothing unique about OPG's technology that would prevent immediate decommissioning. The only limitations to immediate dismantling are the safety of fuel stored in the wet bays as described in part (a) above.

Unclassified **NEA/RWM/WPDD(2006)1/REV1**

Organisation de Coopération et de Développement Economiques
Organisation for Economic Co-operation and Development

31-Oct-2006

English - Or. English

NUCLEAR ENERGY AGENCY
RADIOACTIVE WASTE MANAGEMENT COMMITTEE

NEA/RWM/WPDD(2006)1/REV1
Unclassified

Working Party on Decommissioning and Dismantling (WPDD)

SELECTION OF STRATEGIES FOR DECOMMISSIONING OF NUCLEAR FACILITIES

A status report prepared on behalf of the WPDD by its Task Group on Strategy Selection

English - Or. English

JT03216884

Document complet disponible sur OLIS dans son format d'origine
Complete document available on OLIS in its original format

SELECTION OF STRATEGIES FOR DECOMMISSIONING OF NUCLEAR FACILITIES

A Review by the WPDD of NEA

1. SUMMARY OF KEY POINTS

The OECD/NEA Working Party on Decommissioning and Dismantling (WPDD) developed a Status Report on "Selection of Strategies for Decommissioning of Nuclear Facilities" which is based on an international seminar held in Tarragona, Spain on 1-4 September 2003. The following key points were developed from this report.

There are three main strategies for decommissioning of nuclear facilities.
The three main decommissioning strategies are "immediate dismantling", "deferred dismantling", also called "safe enclosure", and "entombment". In the first case, a facility is dismantled right after the removal materials and waste from the facility. In the second case, after the removal of materials and waste, the facility is kept in a state of safe enclosure for 30–100 years followed by dismantling. In the third case a facility is encapsulated on site and kept isolated until the radionuclides decayed to levels that allow a release from nuclear regulatory control. The present trend is in favour of immediate dismantling.

Many factors have to be taken into account when decisions on strategy selection have to be made.
The large number of factors to be taken into account can be grouped into the following three categories: (a) Policy and socio-economic factors; (b) Technological and operational factors; and (c) Long-term uncertainties. The assessment of these factors is a challenge, in particular in cases where long time periods are involved. Most of these factors are not of a quantitative nature and need subjective assessment. Also taking into account that policies differ in many instances it is not surprising that different strategies are selected for similar facilities.

Policy and socio-economic factors are dominated by the national and/or the local situation.
National policies on nuclear matters vary considerably from country to country and with time. Policies may range from increasing nuclear power generation to continued operation of existing nuclear power plants and to phasing out of nuclear power generation.

The judgement, for example on the availability of qualified staff, is strongly policy dependent. It is an argument for immediate dismantling in a phase out situation. The lack of availability of a repository for decommissioning waste may be an argument for the deferral of decommissioning and keeping a nuclear facility in safe enclosure until a repository is available.

Implementing appropriate legislation and regulation, in particular regarding the definition of an end state for decommissioning and the cost/funding arrangements are important national policy issues. Decommissioning end states are defined by providing clearance levels and establishing levels for the release of sites. International recommendations for clearance levels were published by the IAEA. Funding arrangements must ensure that funds will be available when needed. This includes careful cost assessments, a collection of funds during operation and setting up a funding system to ensure a proper management of the funds until they are needed.

The closure of a nuclear facility and its subsequent removal has a major impact on local employment and economy. Immediate dismantling is more likely associated with a smooth transition and could ease local implications. In the local public opinion immediate dismantling often has the better acceptance as deferral might result in an abandonment of the facility and a failure to ensure continuing safety.

Although decommissioning technology is available, technological and operational factors will influence the choice of strategy.

In the past radiological aspects, in particular the decay of radionuclides during the period of safe enclosure, were a determining factor in the selection of a decommissioning strategy. In the meantime, techniques are available and have been successfully applied for immediate dismantling of nuclear facilities without compromising radiological safety. In most instances, e.g. in the case of light water reactors, radiation levels would remain too high to allow manual dismantling, even after 100 years of safe enclosure.

The volume of radioactive waste is primarily influenced by the implementation of a clearance policy. It will also depend on the decay period. Calculations show that a decay period of about 100 years would result in a 30% decrease of the mass of radioactive waste.

Good information on radionuclide inventories of materials and waste is necessary for clearance, handling, storage, processing and disposal. The practical approach consists of (a) establishing a correlation between gamma emitters (e.g. Co-60, Cs-137) and the other radionuclides and (b) of measuring the respective gamma emitters and (c) calculating the full radionuclide inventory with the established correlations. This task becomes more difficult as Co-60 and Cs-137 decay with time.

Uncertainties increase with time.

Long term uncertainties are of particular importance when a decommissioning strategy is selected. Although the radiological hazards decrease, the uncertainties increase with time. Policies and legal / regulatory frameworks are subject to change. The direction of change is uncertain although regulatory standards have tended to become more stringent with time.

The funds for decommissioning must be available when needed. Due to uncertainties in cost development and fund management over time, immediate dismantling may be the preferred strategy, if funds are available. Calculating the decommissioning costs is associated with uncertainties that will be exacerbated over longer periods of time. The risk for potential loss of funds will increase with time. Experience from the last 100 years illustrates that funds were badly affected, e.g. by inflation and warfare.

The availability of an operator and of qualified staff influences the decommissioning strategy. Over long periods of time operators may change or even disappear and qualified staff may not be available, in particular in the case of phasing out nuclear power.

It is an implication of the complex decision making process that national decommissioning strategies are different and that they change with time.
Several distinct and decisive factors can be identified from the assessment of situations in selected countries. Countries continuously using nuclear power tend to dismantle obsolete plants immediately in order to use the sites for the construction of new facilities. The local public opinion became a decisive factor for changing national strategies from deferred to immediate dismantling.

Decommissioning costs are very important for strategy selection as preference will be given to the cheaper option. Cost calculations are neither trivial nor straight forward and cost calculations for similar plants in different countries came to different results. The often substantial differences in labour costs, disposal costs and decommissioning end points may explain the diverging findings and thereby the choice of decommissioning strategy.

Different approaches have been taken to funding decommissioning activities. Some countries require operators to set aside funds in a national funding system based on the estimated present-day costs for carrying out the decommissioning activities. This approach assumes that inflation and interest rates are at a comparable level. Other countries allow operators to set aside funds based on a net present value approach, which takes into account the growth of current day investments, through the accrual of interest, up to the planned time for decommissioning. The fraction of the total cost that needs to be invested today is dependent on a number of factors, including the number of years of safe enclosure until decommissioning occurs and the assumed interest rate over that time period. Uncertainties in such an approach will ultimately rest with the national government. Regardless, it is not good practice to use the lower current-day funding requirements associated with a net present value calculation as justification for taking a deferred dismantling approach.

In a phase out situation immediate dismantling would help to maintain nuclear technology and qualified staff.

Pickering Generating Station OM&A Costs

OPG's Fully Allocated Costs vs. Costs Provided for the IESO Analysis

	2021	**2022-2024**	**Total**
Fully Allocated Costs[1]	$1,394,500,000	$2,860,200,000	$4,254,700,000
Costs Provided to IESO[2]	$1,111,000,000	$2,365,000,000	$3,476,000,000
Difference	$283,500,000	$495,200,000	$778,700,000
Difference as % of Costs Provided to the IESO	26%	21%	22%

[1] Ex. L, Tab 6.5, Schedule 1 Staff-118.
[2] Ex. L, Tab 6.5 Schedule 7 ED-027, Attachment 2, Pick OM&A sheet, Row 15, Cols P-S.

Pickering Generating Station Full Time Equivalent ("FTE") Employee Assumptions In Net Benefit Analyses

FTEs Corresponding to: Fully Allocated Costs vs. Incremental Costs vs. Non-Incremental Costs

	2021	**2022**	**2023**	**2024**
Assumed FTEs corresponding to fully allocated costs[1]				
Assumed FTEs corresponding to costs included in net benefit analyses (incremental)[2]				
Assumed FTEs corresponding to costs excluded from net benefit analyses (non-incremental)[3]				

[1] The fully allocated costs are listed in Ex. L, Tab 6.5, Schedule 1 Staff-118. They amount to $4,354,700,000 over 2021 to 2024.
[2] The incremental costs used in the OPG and IESO net befefits analyses are listed in Exhibit L Tab 6.5 Schedule 7 ED-027, Attachment 2. They amount to $3,476,000,000 over 2021 to 2024.
[3] The non-incremental costs are the difference between the fully allocated costs and the incremental costs. They amount to $878,700,000 over 2021 to 2024.

Extended Operations involves incremental activities comprised of additional outage scope (inspections and maintenance), projects (plant modifications), work to respond to potential regulatory requirements and other necessary improvements. The estimated cost of this incremental work, above normal operating costs, is $307M over 2016-2020.[3] Normal operating activities and their associated costs will continue through to 2024 with amounts forecast for 2017 through 2021 included in the test period costs. The incremental investment will allow OPG to generate approximately 62 additional TWh over the remaining life of the plant, which equates to a levelized unit energy cost ("LUEC") of about 6.5 cents/KWh for the additional production.

The IESO has conducted an independent analysis for the Ministry of Energy that calculates the Ontario Electricity System benefits of Extended Operations at between $300M and $500M. Copies of the IESO's updated October 2015 and original March 2015 analyses are included as Attachment 1 to this exhibit. Extending the operation of Pickering mitigates capacity uncertainties during the refurbishments of the Darlington and Bruce stations. The overall system economic value is positive because Pickering's availability reduces the need to construct and operate more expensive gas-fired capacity. It is also projected to reduce CO_2 emissions by approximately 17 million tonnes over the 2021 to 2024 period. On January 11, 2016, the Government of Ontario announced the approval of OPG's plan to operate Pickering to 2024.

3.0 EXTENDING PICKERING OPERATIONS

3.1 The Decision to Extend Pickering Operations

In November 2015, the OPG Board of Directors approved Pickering Extended Operations.

247,000 EFPH. (See EB-2013-0321, Ex. F2-2-3, page 1). The Fuel Channel Life Management project was successfully completed in 2015 and provided the information necessary to enable a high confidence fitness-for-service statement for the Pickering fuel channels to reach 247,000 EFPH as the project intended. This work also underpinned OPG's successful application to the CNSC to allow Pickering to operate to 247,000 EFPH.

OPG subsequently commenced the Fuel Channel Life Extension ("FCLE)" project. While the majority of the cost of the FCLE project relates to Darlington, not Pickering, the project did help to provide high confidence for Pickering Fuel Channels to achieve 261,000 EFPH, allowing all units to operate until December 2020 without life management outages. (See EB-2013-0321, Ex. F2-3-3, Attachment 1, Tab 11, page 3).

[3] Of this amount, about $290M is expected to be expended in the 2017-21 test period.

Ontario Reserve Margin Requirements

2017 - 2021

December 30, 2016

Connecting Today.
Powering Tomorrow.

Appendix A: Key Modelling Assumptions

A.1 GENERATION RESOURCES

This study considers all existing resources as well as planned resources expected to come into service over the period from 2017 to 2021. Planned resources include those that are committed (signed contracts) and directed as of December 2015. Any major changes since December 2015 were also captured, for example, the recently contracted LRP I resources have been included. Planned retirements expected to occur over this timeframe are also considered, as are the refurbishment schedules of Ontario's nuclear fleet.

Wind

Wind generation is expected to grow in the period of the study. By the end of 2021, about 5,000 MW of grid-connected wind-powered generation is expected to be in-service in Ontario. Given the variability of wind speeds, wind generators are modelled probabilistically on a zonal basis as energy-limited resources with a cumulative probability density function (CPDF) that represents the likelihood of zonal wind contribution being at or below various capacity levels during peak demand hours. The CPDFs vary by month and season.

The CPDFs are constructed based on the contribution of wind resources during a contiguous five-hour window of highest daily demand for the summer and winter seasons, and for each month of spring and fall. Previously, in the absence of sufficient historical (actual) wind production data to confidently estimate expected wind contribution during peak hours, both historical and simulated wind production data were utilized for developing the CPDFs. However, this year the IESO has accumulated 10 years of historical (actual) wind production data so that simulated data will no longer be relied upon when developing the CPDF's.

In the analysis referred to above, the determination of the five-hour window with the highest average demand is based on an analysis of the last five years of historical demand data.

Solar

Grid-connected solar resources are modelled on an aggregated zonal basis in three separate zones. For each zone, the contribution of solar resources is modelled as a fixed hourly profile that varies by month and season. The MW production is calculated from projected installed capacities and hourly solar contribution factors applicable to each zone and for each month or season. Hourly solar contribution factors are in turn determined from an analysis of 10 years of simulated historical data by calculating the hourly median solar contribution for each month and season. As actual solar facility production data is accumulated over the coming years, the IESO will gradually make a transition to full reliance on actual operating history when determining zonal solar capacity factors.

Hydroelectric

Hydroelectric resources are modelled in MARS as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity and monthly energy values are determined on an aggregated basis for each electrical zone. Maximum capacity values are based on historical median monthly production plus the contribution of hydro resources to the operating reserve market at the time of system weekday peaks. Minimum capacity values are based on the 25th percentile of historical production during hours ending one through five for each month. Monthly energy values are based on historical monthly median energy production since market opening.

For new hydroelectric projects, the maximum capacity value is derived based on the average monthly capacity factor at the time of system peak in the zone where the new project is located. The minimum capacity value and the monthly energy value are calculated using the methodology described above based on the historical production data of a similarly sized generator in the zone where the new project is located.

Thermal Resources

Nuclear, gas, oil and biomass resources are modelled as thermal resources, with their capacity values based information provided by market participants.

Previously, the IESO calculated the availability of thermal units using Equivalent Forced Outage Rates (EFOR). However, starting in 2016Q4, the IESO has transitioned to using Equivalent Forced Outage Rate on demand ($EFOR_d$). $EFOR_d$ is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate[1]. It is the most appropriate metric for modelling the forced outage rates given the capabilities of the assessment tools used by the industry. $EFOR_d$ of existing units are derived based on an analysis of a rolling five-year history of actual forced outage data and the generator's energy production data. For existing units with insufficient historical data, and for new units, $EFOR_d$ values of existing units of similar size and technical characteristics are used while recognizing the higher failure rate during the early operating period.

Demand Measures

Demand measures, i.e. Dispatchable Loads, peaksaver Plus and Demand Response (DR) are not incorporated into the demand forecast; they are treated as generation resources.

The effective capacity available from Dispatchable Loads is determined based on an analysis of historical bid-quantity data for peak demand hours submitted by market participant. In MARS, Dispatchable Loads are modelled as resources that are available at all times and are represented as monthly capacity values aggregated for each transmission zone.

[1] IEEE Std 762 - IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity

Table 6 summarizes the generation forecasts developed for the extended operations Preferred Alternative.

Table 6: Estimated Generation Impacts of the Preferred Alternative

Generation Plan		2016 - 2020	Post 2020	Total
OPTION 1	Additional Planned Outage Days	630	1,103	**1,734**
	Incremental TWh	-7.4	71.9	**64.5**
OPTION 2	Additional Planned Outage Days	637	1,354	**1,991**
	Incremental TWh	-7.5	68.9	**61.5**

The additional outage days in the period 2016 to 2020 are associated with incremental inspections required to enable the Preferred Alternative, as well as restore normal planned outages and durations in 2020 that would have been reduced or not necessary in the Base Case (planned shutdown in 2020).

The planned outage days in the period 2021 to 2024 are associated with operation of the units for the additional 2 and 4 calendar years (a total of 20 additional unit-years). The two options reflect the range of outcomes required to execute inspection and maintenance activities necessary to maintain fitness for service of plant equipment.

ECONOMIC ASSESSMENT SUMMARY

The Levelized Unit Energy Costs (LUEC) of the Preferred Alternative, i.e. the LUEC associated with the incremental costs and generation relative to the Base Case, is evaluated at 6.2 ¢/kWh to 6.5 ¢/kWh for the two options. LUEC calculations exclude the benefit of deferring severance and related costs.

The Preferred Alternative also provides a number of quantitative economic advantages for both the ratepayer and OPG. The major economic advantages are:

- **Financial Impacts:** Extending Pickering operations would improve OPG's cash flow by $4 Billion in the 2021 to 2024 period compared to the alternative of shutting down in 2020 and assuming that OPG implements a rate smoothing deferral account. Extending Pickering operations also provides incremental net income to OPG.

- **Rate Impacts:** Figure 2 shows the impact of the Preferred Alternative on OPG Nuclear rates. Extending Operations moderates the rate impacts associated with the refurbishment and return to service of the Darlington units and the earlier shutdown of Pickering which would occur in the Base Case. This occurs because extending Pickering Operations results in a larger OPG generation base over which to spread the impacts of the Darlington Refurbishment costs being placed into the rate base and because the severance and related closure costs of Pickering would be deferred.

Board Staff Interrogatory #125

Issue Number: 6.5
Issue: Are the test period expenditures related to extended operations for Pickering appropriate?

Below are interrogatories on the IESO's analysis (Exh F2-2-3 Attachment 1) of Pickering Extended Operations. In order to provide complete responses to all OEB staff interrogatories please consult the IESO as necessary.

Interrogatory

Reference:
Ref: Exh F2-2-3 page 7

a) It is indicated that OPG conducted its own internal economic evaluation of PEO. Please provide the study.

b) Please compare the assumptions relied on in both studies, particularly with respect to assumptions related to load growth, price of gas-fired generation, Pickering production forecast, and Pickering operating and capital costs.

Response

a) The results of OPG's internal economic evaluation are documented in the Pickering Extended Operations Technical and Economic Assessment at Ex. F2-2-3 Attachment 2.

b) A comparison of the major assumptions used in the development of the economic assessments conducted by OPG and the IESO are documented below. Chart 1 has been prepared by OPG and Chart 2 has been prepared by the IESO:

Chart 1: OPG Assumptions

OPG Assumptions (Pickering Extended Operations - Economic Assessment)

Line No.		2016	2017	2018	2019	2020	2021	2022	2023	2024
1	System Demand (TWh)	**143**	**143**	**144**	**146**	**147**	**148**	**149**	**150**	**152**
2	Gas Prices (Dawn, 2015C$/mmBtu)	**3.9**	**4.2**	**4.3**	**4.2**	**4.3**	**4.4**	**4.5**	**4.6**	**4.7**
3	CO2 Credit (2015C$/Mg CO2e)	**20.3**	**23.1**	**24.7**	**26.2**	**27.7**	**29.3**	**30.8**	**32.4**	**34.0**
4	Pickering Production Forecast (TWh)	**Refer to L-1-6.5 Staff 126 for Cost and Production Data**								
5	Pickering Operating Costs ($M)									
6	Pickering Capital Costs ($M)									

	Cost of New Gas Capacity (2015 US$)	Heat Rate (MMBtu/kWh)	Capital Cost (US$/kW)	Fixed Cost (US$/kW-yr)	Variable Non-fuel (US$/MWh)
7	Combined Cycle Gas Turbine (CCGT)	**6,800**	**$1,100**	**$26**	**$3**
8	Single Cycle Gas Tubine (SCGT)	**9,500**	**$800**	**$21**	**$5**

Chart 2: IESO Assumptions

Line No.		2016	2017	2018	2019	2020	2021	2022	2023	2024
1	System Demand (TWh) (a range of demands were considered, this is the medium demand)	146	146	147	147	148	150	151	153	155
2	Gas Prices (Dawn, 2015C$/mmBtu)	4.7	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
3	CO2 Credit (2015C$/Mg CO2e)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4	Pickering Production Forecast (TWh) (This corresponds to the Pickering extended operations, 65 TWh scenario)	21.3	19.2	19.3	19.6	20.9	19.7	21.3	14.8	16.7
5	Total OM&A & Capital ($M)	1,055	987	1,038	1,054	977	987	902	631	494
6	Fuel & Fuel Related Costs ($M)	126	121	118	125	115	119	122	85	93

	Cost of New Gas Capacity (2015 US$)	Heat Rate (MMBtu/kWh)	Capital Cost (US$/kW)	Fixed Cost (US$/kW-yr)	Variable Non-fuel (US$/MWh)	
7	Combined Cycle Gas Turbine (CCGT)	**NA (No new CCGTs were assumed. Instead, capacity (MW) was addressed by peaking facilities at the net revenue requirement below, energy (TWh) was made up from the existing Ontario system)**				
8	Single Cycle Gas Tubine (SCGT)	**~10,500**	**NA**	**130 (Net Revenue Requirement for a capacity**	**NA**	

UNDERTAKING J8.5

Undertaking

To confirm that the Nymex future prices (see also Ex. K8.1, p.2, footnote 3), and the IESO Price Premium numbers in the chart found at Ex. K8.1, p.2 are accurate.

Response

Ex. K8.1, p.2 presented the following table:

	2017	2018	2019	2020	2021	2022	2023	2024
IESO Forecast (2015 real U.S. $/MMBTU)	5.45	5.45	5.44	5.44	5.43	5.43	5.43	5.43
IESO Forecast (nominal U.S. $/MMBTU)	5.67	5.78	5.89	6.01	6.12	6.24	6.36	6.49
NYMEX Future Prices ($/MMBtu)	3.35	3.05	2.99	3.02	3.01	3.03	3.08	3.16
IESO Price Premium	69%	90%	97%	99%	103%	106%	106%	105%

1 Ex. L, Tab 6.5, Sch. 7 ED-028, Page 5
2 Conversion from 2015 real $ based on assumed 2% annual inflation rate.
3 As of March 6, 2017: http:www.cmegroup.com/trading/energy/natural-gas/natural-gas.html

The specific NYMEX Future Prices presented in the table above cannot be confirmed as those instantaneous quotes no longer exist on the website cited. However, a comparison of the futures prices available on the website as of March 13, 2017 to those in the table above indicates there has not been a significant deviation in gas futures prices over the previous seven days (see table below).

NYMEX Future Prices ($USD/MMbtu)	2017	2018	2019	2020	2021	2022	2023	2024
March 6, 2017 (Tab 2)	3.35	3.05	2.99	3.02	3.01	3.03	3.08	3.16
March 13, 2017	3.37	3.07	2.99	2.99	3.00	3.01	3.04	3.11

The percentage by which the IESO nominal forecast exceeds the NYMEX future price illustrated in the table at Ex. K8.1, p.2 appears to be calculated correctly using the March 6, 2017 NYMEX future prices.

UNDERTAKING J8.6

Undertaking

To advise on the differential that was assumed in the analysis between Henry Hub and Dawn amounts.

Response

The following table summarizes the price differential between Dawn Hub and Henry Hub assumed in the analysis, consistent with the publicly available natural gas forecast used. Note that the basis differential used is positive, indicating that the Dawn price is more expensive than Henry Hub.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2016	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2017	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2018	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2019	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2020	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2021	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2022	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2023	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2024	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2025	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2026	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2027	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2028	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2029	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2030	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2031	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2032	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27

Source: Sproule.

Navigant Natural Gas Price Forecast[1]

Month	**Henry Hub (US$/MMBtu)**	**Exchange Rate**[2]	**Henry Hub (C$/MMBtu)**	**Dawn (C$/MMBtu)**	**Dawn Price Differential (C$/MMBtu)**
Nov-16	$3.03	1.369	$4.15	$4.11	-$0.04
Dec-16	$3.22	1.369	$4.41	$4.29	-$0.12
Jan-17	$3.34	1.342	$4.48	$4.44	-$0.04
Feb-17	$3.35	1.342	$4.50	$4.47	-$0.03
Mar-17	$3.30	1.342	$4.43	$4.35	-$0.08
Apr-17	$3.05	1.329	$4.05	$3.94	-$0.11
May-17	$3.02	1.329	$4.01	$3.87	-$0.14
Jun-17	$3.05	1.329	$4.05	$3.78	-$0.27
Jul-17	$3.07	1.317	$4.04	$3.81	-$0.23
Aug-17	$3.08	1.317	$4.06	$3.80	-$0.26
Sep-17	$3.06	1.317	$4.03	$3.84	-$0.19
Oct-17	$3.08	1.304	$4.02	$3.84	-$0.18
Nov-17	$3.13	1.304	$4.08	$3.98	-$0.10
Dec-17	$3.26	1.304	$4.25	$4.10	-$0.15
Jan-18	$3.35	1.303	$4.37	$4.26	-$0.11
Feb-18	$3.32	1.302	$4.32	$4.18	-$0.14
Mar-18	$3.23	1.301	$4.20	$4.08	-$0.12
Apr-18	$2.83	1.300	$3.68	$3.57	-$0.11

Average Dawn Price Differential: -$0.13/MMBtu

[1] Navigant, *Ontario Wholesale Electricity Market Price Forecast For the Period Nov 1, 2016 through April 30, 2018*, (Oct 14, 2016), page 12.
[2] Email from Trent Winstone, Associate Director, Navigant to Jack Gibbons (February 28, 2017).

Board Staff Interrogatory #126

Issue Number: 6.5
Issue: Are the test period expenditures related to extended operations for Pickering appropriate?

Below are interrogatories on the IESO's analysis (Exh F2-2-3 Attachment 1) of Pickering Extended Operations. In order to provide complete responses to all OEB staff interrogatories please consult the IESO as necessary.

Interrogatory

Reference:
Ref: Exh F2-2-3 Attachment 1 page 3

At the above reference the IESO states in part: "Potential for cost savings although these depend on the outlook for Pickering production and operating costs (which have a lower degree of uncertainty and can be controlled to some degree)…."

a) Please provide the production and operating costs assumptions for Pickering for the period 2021-2024 that were used in the March 2015 study and the October 2015 update. Please provide this information in table format and by year. Please provide OPG's views on the appropriateness of the two assumptions including the rate of growth.

b) For comparison purposes please provide the production and operating costs for Pickering, for the period 2016-2020. Please provide this information in the same format and on the same basis as in part (a).

c) Does the IESO study also take into account capital expenditures that will be required during the 2021-2024 period? What were the assumptions in the study?

Response

a) & b) The production and cost data provided to the IESO that was used in the March 2015 and October 2015 studies are provided below in Chart 1 and Chart 2:

Chart 1

PICKERING EXTENDED OPERATIONS Assessment Data (Scenario ~ 73 TWh)
(March 2015)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Incremental Production (TWh)	**0.0**	**0.0**	**-0.5**	**-0.2**	**-2.6**	**22.1**	**22.6**	**15.1**	**16.5**	**72.9**

Incremental Operating Costs ($2015M)

Total OM&A	0	0	48	35	133	927	901	643	567	**3,254**
Total Capital	0	0	19	19	14	24	11	7	7	**102**
Total Operating Costs	**0**	**0**	**67**	**55**	**147**	**951**	**911**	**650**	**574**	**3,356**
Fuel	0	0	-3	-1	-14	119	122	85	93	**401**

Chart 2

PICKERING EXTENDED OPERATIONS Assessment Data (BCS Option 1 ~ 65 TWh)
(October 2015)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Incremental Production (TWh)	**0.0**	**-0.9**	**-1.2**	**-1.8**	**-3.4**	**19.6**	**21.2**	**14.6**	**16.5**	**64.5**

Incremental Operating Costs ($2015M)

Total OM&A	7	35	64	129	207	965	891	623	487	**3,408**
Total Capital	0	0	15	16	11	22	10	7	7	**89**
Total Operating Costs	**7**	**35**	**79**	**145**	**218**	**987**	**902**	**631**	**494**	**3,497**
Fuel	0	-5	-6	-9	-18	105	113	79	89	**347**

PICKERING EXTENDED OPERATIONS Assessment Data (BCS Option 2 ~ 62 TWh)
(October 2015)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Incremental Production (TWh)	**0.0**	**-0.9**	**-1.2**	**-1.6**	**-3.8**	**18.8**	**20.2**	**13.8**	**16.1**	**61.5**

Incremental Operating Costs ($2015M)

Total OM&A	7	35	64	129	207	965	891	623	487	**3,408**
Total Capital	0	0	15	16	11	22	10	7	7	**89**
Total Operating Costs	**7**	**35**	**79**	**145**	**218**	**987**	**902**	**631**	**494**	**3,497**
Fuel	0	-5	-6	-8	-19	101	108	74	87	**331**

UNDERTAKING JT2.5

Undertaking

OF THE COSTS INCLUDED IN ED 18, BOARD STAFF 116, AND GEC 38, TO ADVISE WHICH WERE INCLUDED OR EXCLUDED FROM THE ECONOMIC ASSESSMENT OF PICKERING, INCLUDING THE CALCULATION OF THE 6.5 CENTS PER KILOWATT-HOUR

Response

OPG notes that levelized unit energy cost (LUEC) is an economic measure and as such is based on incremental costs and generation. The approach used to calculate LUEC differs from a rate calculation. For example, LUEC calculations exclude "non-cash" items such as depreciation and amortization expense, and instead include the incremental capital expenditures in the year incurred. As well, LUEC calculations exclude non-incremental costs that are considered to be independent of the decision being made. Please see also OPG's response to Ex. L-04.3-6 EP-014. OPG's response to JT 1.17E Attachment 1 provides an explanation of the LUEC methodology.

The LUEC calculation referenced in the Pickering Extended Operations Economic Assessment (Ex. F2-2-3 Attachment 2) includes the following cost categories:

1. Base OM&A (Station and Nuclear Support)
2. Outage OM&A (Station Direct and Nuclear Support)
3. Project OM&A
4. Capital
5. Corporate Support
6. Fuel Costs

As directed by the OEB's February 16, 2017 Decision and Order on Motion Filed by Environmental Defence, Chart 1 below shows the reconciliation between total operating costs (reflected in OPG's 2016-2018 Business Plan, including total fuel costs, shown at Chart 1 line 19) and the incremental operating costs included in the Pickering Extended Operations Economic Assessment (including incremental fuel costs, shown at Chart 1 line 3) for 2016-2021.

Chart 1: Reconciliation Between Total Operating Costs and Incremental Operating Costs

	Constant 2015 M$	2016	2017	2018	2019	2020	2021	Source
Line No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Incremental Costs for Economic Assessment							
1	Incremental Operating Costs	7	35	79	145	218	987	Ex. L-6.5-1 Staff-126 Chart 2, Ex. L-6.5-7 ED-28 (i)
2	Incremental Fuel Costs (BCS Option 2 - 62 TWh)	0	-5	-6	-8	-19	101	Ex. L-6.5-1 Staff-126 Chart 2
3	Incremental Operating Costs and Incremental Fuel Costs	7	30	73	137	199	1,088	line 1 + line 2
	Changes in Forecast Between Economic Assessment and 2016-2018 Business Plan							
4	Incremental Operating Costs	8	5	3	6	9	-8	
5	Incremental Fuel Costs	0	0	0	0	0	4	
6	Changes in Incremental Costs Between Economic Assessment and 2016-2018 BP	8	5	3	5	10	-4	line 4 + line 5
	Incremental Costs per 2016-2018 Business Plan							
7	Incremental Operating Costs	15	39	82	151	228	979	line 1 + line 4
8	Incremental Fuel Costs	0	-5	-6	-8	-19	105	line 2 + line 5
9	Incremental Operating Costs and Incremental Fuel Costs	15	34	76	142	208	1,084	line 3 + line 6
	Escalated M$							
	Incremental Costs per 2016-2018 Business Plan							
10	Incremental Operating Costs	15	41	87	163	251	1,103	line 7 converted from constant to escalated dollars Ex. L-6.5-1 Staff-118 Table 1 line 12 (to 2020)
11	Incremental Fuel Costs	0	-5	-7	-9	-21	118	line 8 converted from constant to escalated dollars Ex. L-6.5-1 Staff-118 Table 2 line 1 (to 2020)
12	Incremental Operating Costs and Incremental Fuel Costs	15	36	81	154	230	1,221	
	Add: Excluded Non-Incremental Operating Costs							
13	Normal Operating Costs (Non-Incremental Station Direct)	781	739	674	641	508	0	
14	Normal Operating Costs (Non-Incremental Support)	568	572	590	587	579	292	
15	Non-Incremental Fuel Costs	120	119	122	126	142	0	
16	Total Operating and Fuel Costs	1,484	1,466	1,467	1,508	1,458	1,513	line 12 + line 13 + line 14 + line 15
	Total Operating Costs per 2016-2018 Business Plan							
17	Total Operating Costs	1,364	1,351	1,351	1,392	1,338	1,395	line 10 + line 13 + line 14 Ex. L-6.5-7 ED-18 Chart 1, Ex. L-6.5-8 GEC-38 Chart 1, Ex. L-6.5-1 Staff-116
18	Total Fuel Costs	120	114	116	117	120	118	line 11 + line 15 Ex. L-6.5-7 ED-18 Chart 1, Ex. L-6.5-8 GEC-38 Chart 1
19	Total Operating and Fuel Costs	1,484	1,466	1,467	1,508	1,458	1,513	line 17 + line 18
	Numbers may not sum due to rounding							

The following discussion uses 2021 as an example to explain the operation of Chart 1 with references back to the associated interrogatory responses. The sum of the above economic assessment cost categories excluding Fuel Costs is $1,395M, which represents total operating costs on a fully allocated basis (Chart 1 line 17, col. (f) and as provided in Ex. L-06.5-1 Staff-116 and Ex. L-06.5-1 GEC-38, and the first line of Chart 1 in Ex. L-06.5-7 ED-018). With the exception of Fuel Costs, these categories are itemized in Ex. L-06.5-1 Staff-118 (a) & (b). Total Fuel Costs are $118M in 2021(Chart 1 line 18, col. (f)), as provided in Ex. L-06.5-7-ED-018 and Ex. L-06.5-1 GEC-38. In 2021, the sum of total operating costs and total Fuel Costs is equal to $1,513M (Chart 1 line 19, col (f)). All of these values are expressed in escalated dollars.

As described in the Pickering Extended Operations Economic Assessment, the financial evaluation and the related LUEC are calculated using incremental operating costs relative to a 2020 Pickering shutdown. The incremental OM&A and Capital costs are shown in constant 2015 M$ in Interrogatories Ex. L-6.5-7 ED-028 part (i) and Ex. L-6.5-1 Staff-126, Chart 2. For the year 2021, the non-fuel incremental Operating Costs assumed in the Pickering Extended Operations Economic Assessment are $987M (2015$) (Chart 1 line 1, col (f)). The difference in 2021 operating costs between the $987M and the $1,395M is related to escalation from constant to nominal dollars and the exclusion of non-incremental costs (i.e., the assumed non-incremental portion of nuclear and corporate support costs), as shown in Chart 1. Escalation and non-incremental costs also explain the difference in 2021 Fuel Costs between the $101M (Chart 1 line 2, col (f)) and the $118M (Chart 1 line 18, col (f)).

Cost categories shown in Ex. L-06.5-7 ED-018 that are not included in the economic assessment or LUEC calculation are provided below. Amounts provided below refer to 2021 values from Chart 1 in Ex. L-06.5-7 ED-018, for reference purposes:

1. Inventory Obsolescence ($12.4M) – These costs are excluded as a non-cash item.
2. Pickering Portion of Tritium Removal Facility ($12.8M) -- These costs are considered non-incremental as they would be borne by OPG in the absence of operating Pickering units.
3. OPEB and Pension excluded from Centrally Held Costs and Other Costs ($-12.7M) – These costs primarily represent non-current service components of pension and OPEB amounts that largely would be incurred whether or not the operation of the Pickering station were extended, as well as the pension and OPEB adjustment for cash to accrual differences shown at Ex. F4-4-1 Table 3 line 2.
4. IESO Non-Energy Charges ($22.3M) – If not paid by OPG, these costs (e.g., transmission charges or IESO administration fees) are assumed to be recovered from other transmission system customers and therefore are not incremental.
5. Depreciation and Amortization Pickering ($53.1M) – These costs are non-cash accounting transactions related to matching capital costs to the period when benefits are considered to be realized. Instead, incremental capital costs associated with the extending Pickering operations are reflected in the LUEC.
6. Depreciation and Amortization Pickering Generic ($20.4M) – These costs are non-cash accounting transactions related to matching capital costs to the period when benefits are considered to be realized.
7. Income Tax Pickering ($27.5M) – Income taxes are not directly related to costs of operating an asset; rather, they result from earning income from the asset.
8. Property Tax Pickering ($6.3M) – Property taxes for the Pickering site were assumed to be payable in the post-2020 period regardless of whether or not the operation of the station were extended, and are therefore not incremental.

Board Staff Interrogatory #118

Issue Number: 6.5
Issue: Are the test period expenditures related to extended operations for Pickering appropriate?

Interrogatory

Reference:
Ref: Exh F2-2-3 Attachment 2, Table E2

In Table E2, OPG provides the incremental costs of Pickering Extended Operations (PEO). According to this table, OPG has estimated costs of $240M for restoration of resources to normal levels to enable PEO.

a) Please update Table E2, such that it is consistent with OPG's rate application, especially in regards to the test year expenditures in the table.

b) Please provide a breakdown of costs under the category "Normal Extension of Base & Outage OMA, Projects, Nuclear and Corporate Support Costs" and present it in a format similar to that provided in Chart 2 at Exh F2-2-3 page 6. Please also provide a brief description explaining the work that is planned to be undertaken.

c) Please confirm that the costs noted in Table E2 are incremental and arise only as a result of the PEO project and would not be incurred in the absence of the PEO proposal.

d) In addition to the incremental costs noted in Table E2, are there any other incremental costs related to PEO that are included in the test year budgets? If there are, please identify the costs.

e) The costs shown under the column titled "Post 2020" are OPG's estimate of costs required to operate Pickering post 2020. Please describe in detail how this estimate was developed, identify the underlying assumptions used to develop the cost estimates, provide a breakdown of the costs by year and by major components, such as labour and comment on the major drivers for the costs. Please also comment on how OPG proposes to manage labour costs for the "Post 2020" period such that the operating costs are maintained at levels assumed in the IESO benefit analysis.

f) Please also comment on whether the Post 2020 operating costs noted in the referenced table are the same as that used by the IESO in its analysis.

g) Table E2 does not include any information on capital expenditures. Does the Business Case take into consideration the capital expenditures that are required in the test years and may be required in the 2021-2014 period?

Response

a) & b) Exhibit F2-2-3 Attachment 2 Table E2 sets out OPG's estimate of operating costs (excluding fuel) to enable Extended Operations. In Table 1 below, the estimated costs in Table E2 have been updated to be consistent with forecasts underpinning OPG's evidence in this application. Table 1 includes a breakdown of the forecast costs to restore normal operations at Pickering over the period 2016 to 2020 as a result of extending plant life to 2022/2024, consistent with Chart 2 at Ex. F2-2-3 page 6:

Table 1
Pickering Extended Operations Costs per Application ($M)

Line No.	Cost Item	2016	2017	2018	2019	2020	2016-2020 Total	2021	2022-2024	2016-2024 Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Enabling Costs									
	Nuclear Operations OM&A									
1	**Base OM&A**	11.0	1.0	0.0	0.0	0.0	12.0	0.0	0.0	12.0
2	**Outage OM&A**	0.0	22.1	37.3	88.7	85.5	233.6	0.0	0.0	233.6
3	**Project OM&A**	4.0	2.5	18.0	18.4	18.7	61.6	0.0	0.0	61.6
4	**Total Enabling Costs**	15.0	25.6	55.3	107.1	104.2	307.1	0.0	0.0	307.1
	Restoration / Normal Operating Costs									
	Nuclear Operations OM&A									
5	**Base OM&A**	0.0	7.9	13.5	28.4	61.6	111.4	765.5	1,818.9	2,695.8
6	**Outage OM&A**	0.0	0.0	0.0	0.0	47.2	47.2	244.2	376.8	668.2
7	**Project OM&A**	0.0	4.5	0.1	2.8	14.6	22.0	46.5	35.1	103.6
8	**Sub-total Nuclear Operations OM&A**	0.0	12.4	13.6	31.2	123.4	180.6	1,056.2	2,230.8	3,467.5
9	**Project Capital (including Minor Fixed Assets)**	0.0	0.0	15.5	17.6	13.1	46.2	23.1	6.7	75.9
10	**Corporate Support**	0.0	2.6	3.0	7.1	10.7	23.5	315.2	622.8	961.5
11	**Total Restoration of Normal Operating Costs**	0.0	15.0	32.1	55.9	147.2	250.3	1,394.5	2,860.2	4,504.9
12	**Total Pickering Extended Operations Costs**	15.0	40.6	87.4	163.0	251.4	557.4	1,394.5	2,860.2	4,812.1

As stated in Ex. F2-2-3, pp. 6 and 7, the restoration costs in this table are incremental as they are necessary to address the fact that with shutdown previously anticipated in 2020, ongoing operations and their costs were set to decline starting in 2017. With Extended Operations, OPG needs to restore ongoing operating and maintenance programs to normal levels for the 2017 to 2020 period. For example, outage requirements set to decline under the previous plan will now need to be reinstated. As well, both OM&A and capital projects need to be restored to the levels required to continue to operate safely for four additional years and to maintain or improve plant reliability during that time.

Normal operating are those required to maintain ongoing base operations, project and outage OM&A work as well as the capital projects necessary to continue the safe operation and maintenance of the plant.

The normal operating costs for Pickering are discussed extensively in the Base, Project and Outage OM&A exhibits (Ex. F2-2-1, Ex. F2-3-1 and Ex. F2-4-1) as well as in the project capital descriptions in (Ex. D2-1-3).

It should be noted that fuel costs do not appear in the referenced table but were included in the overall estimate and economic assessment for Pickering Extended Operations. Fuel cost forecasts underpinning OPG's evidence in this application are presented in part (d) below.

c) The costs in Table E2 are incremental and fully allocated.

   i. 2016-2020 Costs - Enabling and Restoration costs incurred during this period are fully incremental because the plant life is being extended beyond 2020. In the event that plant life was not extended and depending on when the decision was made, the Enabling and Restoration costs identified in Table E2 could be reduced or potentially eliminated.

   ii. Post 2020 Costs – Costs beyond 2020 are considered normal operating costs and are provided on a fully allocated basis in part (a) and (b) of this response. In the event that plant life was not extended beyond 2020, these costs could also be reduced but not fully eliminated. As described in EB-2013-0321 Ex. F2-2-3 Attachment 1 p. 19, it is OPG's assessment that as the nuclear fleet shrinks, losses of economies of scale will result in an effective increase in the cost of providing nuclear support services and corporate support services. As a result, these services and any fixed overheads would need to be reallocated across the remaining, smaller fleet.

d) In addition to the costs captured in Table 1in part (a) and (b), the following costs and cost reductions during the IR term that are attributable to Pickering are shown in Table 2:

Table 2
Other Incremental Costs ($M)

Line No.	Cost Item	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)
1	Fuel Expense	(5)	(7)	(9)	(21)	117
2	Inventory Obsolescence Charges	(10)	(10)	(10)	(10)	12
3	IESO Non-Energy Charges	0	0	0	0	35
4	Severance and Related Costs	0	0	0	0	(683)
6	Depreciation on Restoration Capital Expenditures	0	0	0	8	50
7	Cost of Capital for Working Capital Component of Rate Base	2	5	8	16	19
8	Property Tax	0	0	0	0	6
9	Income Tax	(0)	(0)	(0)	(11)	(32)
10	**Total**	(12)	(12)	(11)	(19)	(475)

e) The basis for developing the cost estimates is explained in Ex. F2-2-3 Attachment 2 pp. 14 and 15 under the heading, “COSTS AND GENERATION ASSUMPTIONS” steps 1 through 8. The major categories of expenditures are provided in part (a) and (b) of this response. Processes to control costs and stay within approved plans are described in Ex. L-6.5-1-Staff-129.

f) The Normal Operating Costs shown in Table 1 above for the post 2020 period were prepared on a consistent basis with the information provided to the IESO, but are not the same. The post 2020 costs shown in Table 1 represent the costs underpinning OPG’s application and are expressed on a fully allocated basis in escalated dollars whereas the information provided to the IESO was based on Ex. F2-2-3, Attachment 2 and is expressed in constant 2015$ and on an incremental basis as is explained in Ex. L-6.5-1 Staff-126.

g) The Business Case did take into consideration capital expenditures required during the test period and beyond 2020 as is shown in Ex. L-6.5-1 Staff-126 and explained in part c) of that response.

Assessment of Pickering Life Extension Options: October 2015 Update

Prepared for discussion with Ministry of Energy

Power System Planning

October 30, 2015

Updated November 4, 2015

Independent Electricity System Operator

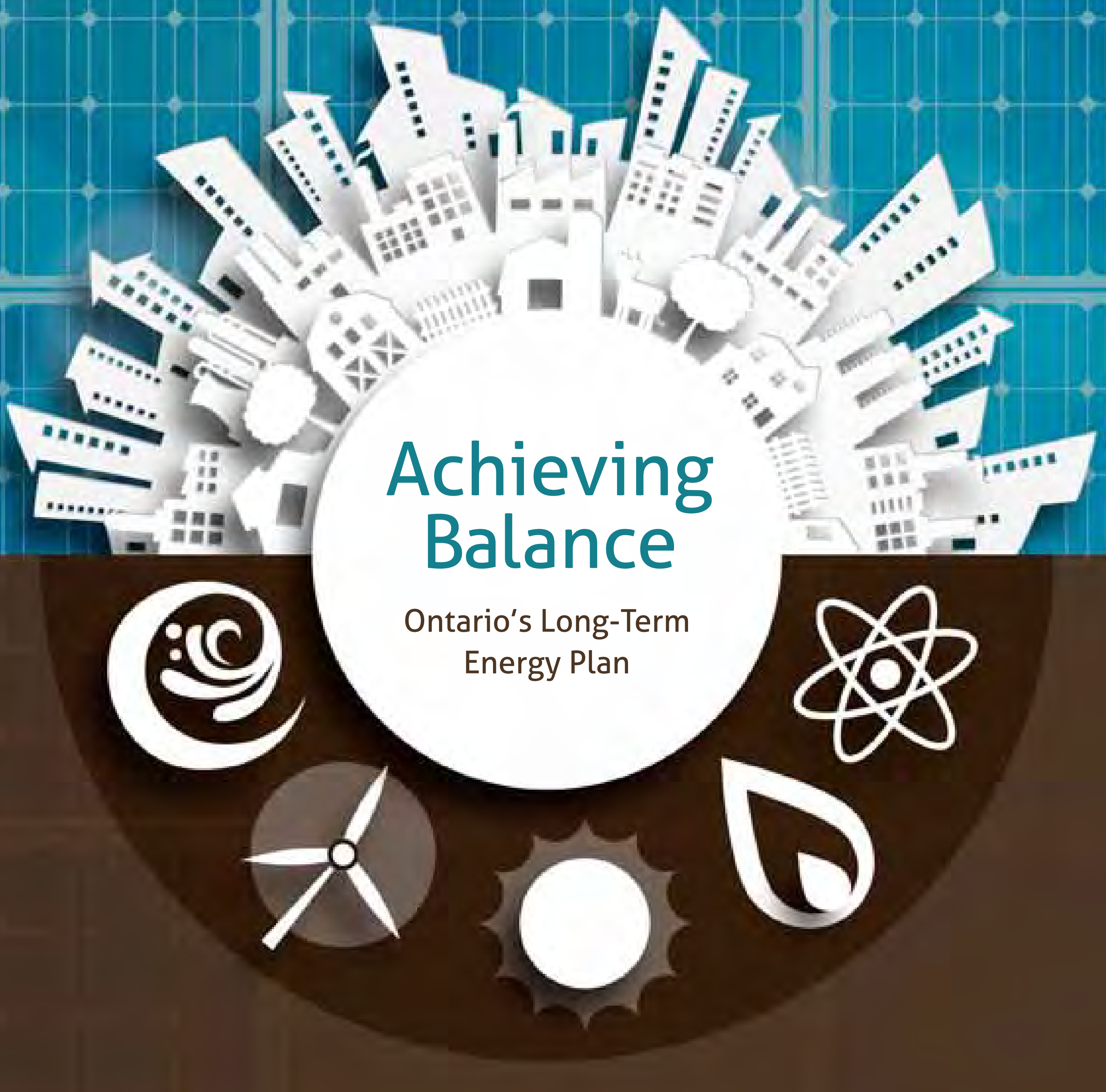
Summary of results

- The conclusions of the IESO's updated assessment of Pickering life extension to 2022/2024 are consistent with the IESO's March 2015 evaluation:
  - Defers timing of capacity needs by two to four years, providing more time for exercising procurement decisions in light of evolving electricity sector trends
  - Potential for cost savings although these depend on the outlook for Pickering production and operating costs (which have a lower degree of uncertainty and can be controlled to some degree) and natural gas/carbon prices (which have a higher degree of uncertainty and limited opportunity to control)
    - It shows value when natural gas or combined natural gas/carbon prices are above $4.2-$4.7/MMBtu
    - It shows a disbenefit when Pickering capital/operating costs are 15-22% greater than the estimates provided by OPG
    - Value of Pickering extension decreases as Pickering's energy production decreases. Value of life extension could also be lower if Pickering were unavailable at the time of system peak demand (due to extended outages for example).

- Extending Pickering operation beyond 2020 continues to defer some supply and transmission investments that would otherwise be required, defers decommissioning and severance costs, offsets production from natural gas-fired resources, increases export revenues and reduces carbon emissions

- Extending Pickering operation defers the increase in the total electricity costs that eventually takes place, generally leading to lower electricity costs for consumers in the period prior to 2024 and higher costs for a few years thereafter

- The IESO's assessment is illustrated in the following slides. Additional details can be found in Appendix 1.



Achieving Balance

Ontario's Long-Term Energy Plan

Ontario

In Summary

Nuclear

- Ontario will not proceed at this time with the construction of two new nuclear reactors at the Darlington Generating Station. However, the Ministry of Energy will work with Ontario Power Generation (OPG) to maintain the site licence granted by the Canadian Nuclear Safety Commission.
- Nuclear refurbishment is planned to begin at both Darlington and Bruce Generating Stations in 2016.
- During refurbishment, both OPG and Bruce Power will be subject to the strictest possible oversight to ensure safety, reliable supply and value for ratepayers.
- Nuclear refurbishment will follow seven principles established by the government, including minimizing commercial risk to the government and the ratepayer, and ensuring that operators and contractors are accountable for refurbishment costs and schedules.
- The Pickering Generating Station is expected to be in service until 2020. An earlier shutdown of the Pickering units may be possible depending on projected demand going forward, the progress of the fleet refurbishment program, and the timely completion of the Clarington Transformer Station.
- Ontario will support the export of our home-grown nuclear industry expertise, products and services to international markets.

Renewable Energy

- By 2025, 20,000 MW of renewable energy will be online, representing about half of Ontario's installed capacity.
- Ontario will phase in wind, solar and bioenergy over a longer period than contemplated in the 2010 LTEP, with 10,700 MW online by 2021.
- Ontario will add to the hydroelectricity target, increasing the province's portfolio to 9,300 MW by 2025.
- Recognizing that bioenergy facilities can provide flexible power supply and support local jobs in forestry and agriculture, Ontario will include opportunities to procure additional bioenergy as part of a new competitive process.
- Ontario will review targets for wind, solar, bioenergy and hydroelectric annually as part of the Ontario Energy Report.
- The Ministry of Energy and the OPA are developing a new competitive procurement process for future renewable energy projects larger than 500 kilowatts (kW), which will take into account local needs and considerations. The ministry will seek to launch this procurement process in early 2014.
- Ontario will examine the potential for the microFIT program to evolve from a generation purchasing program to a net metering program.

Natural Gas/Combined Heat and Power

- Natural gas-fired generation will be used flexibly to respond to changes in provincial supply and demand and to support the operation of the system.
- The OPA will undertake targeted procurements for Combined Heat and Power (CHP) projects that focus on efficiency or regional capacity needs, including a new program targeting greenhouse operations, agri-food and district energy.

Clean Imports

- Ontario will consider opportunities for clean imports from other jurisdictions when such imports would have system benefits and are cost effective for Ontario ratepayers.

Toronto Area

New Copeland Transformer Station (formerly Bremner Transformer Station)

Est. Cost: $195 million

Exp. In-Service: 2014*

Downtown Toronto's power distribution system is currently served by five transformer stations. The new Copeland Transformer Station will ensure reliable supply for the fast-growing downtown core, and take stress off the existing Windsor Transformer Station, which currently serves 9 of the 10 largest buildings in Toronto. It will also provide power to the redeveloped waterfront.

This new station in downtown Toronto will help to alleviate the strain on neighbouring stations and will help to serve the growing customer base. It will also permit critical asset renewal at neighbouring stations to take place.

*First Phase. Source: Toronto Hydro

Clarington Transformer Station

New Transformer Station

Est. Cost: $297 million

Exp. In-Service: 2017

The Pickering Nuclear Generating Station is a critical source of electricity for the eastern part of the Greater Toronto Area. The Clarington Transformer Station, which will connect high voltage 500 kV lines and 230 kV lines in the area, will be required to come into service before Pickering Generating Station can be shut down, to ensure reliable supply for customers in the Eastern Greater Toronto Area.

The station will also enhance the reliability of supply to parts of Durham region. The project is pending a decision from the Minister of the Environment on whether an individual Environmental Assessment is required.

In Summary

- Hydro One will be expected to begin planning for a new Northwest Bulk Transmission Line to increase supply and reliability to the area west of Thunder Bay. The area faces growth in demand, some of which is beyond what today's system can supply. Hydro One and Infrastructure Ontario will be expected to work together to explore ways to ensure cost-effective procurement related to the line.
- Connecting remote northwestern First Nation communities is a priority for Ontario. Ontario will continue to work with the federal government to connect remote First Nation communities to the electricity grid or explore on-site alternatives for the few remaining communities where there may be more cost-effective solutions to reduce diesel use.
- All regions of the province can expect timely local transmission enhancements as needs emerge. Upgrades and investments will meet system goals, such as maintaining or improving reliability or providing the infrastructure necessary to support growth.

Board Staff Interrogatory #126

Issue Number: 6.5
Issue: Are the test period expenditures related to extended operations for Pickering appropriate?

Below are interrogatories on the IESO's analysis (Exh F2-2-3 Attachment 1) of Pickering Extended Operations. In order to provide complete responses to all OEB staff interrogatories please consult the IESO as necessary.

Interrogatory

Reference:
Ref: Exh F2-2-3 Attachment 1 page 3

At the above reference the IESO states in part: "Potential for cost savings although these depend on the outlook for Pickering production and operating costs (which have a lower degree of uncertainty and can be controlled to some degree)…."

a) Please provide the production and operating costs assumptions for Pickering for the period 2021-2024 that were used in the March 2015 study and the October 2015 update. Please provide this information in table format and by year. Please provide OPG's views on the appropriateness of the two assumptions including the rate of growth.

b) For comparison purposes please provide the production and operating costs for Pickering, for the period 2016-2020. Please provide this information in the same format and on the same basis as in part (a).

c) Does the IESO study also take into account capital expenditures that will be required during the 2021-2024 period? What were the assumptions in the study?

Response

a) & b) The production and cost data provided to the IESO that was used in the March 2015 and October 2015 studies are provided below in Chart 1 and Chart 2:

Chart 1

PICKERING EXTENDED OPERATIONS Assessment Data (Scenario ~ 73 TWh)
(March 2015)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Incremental Production (TWh)	**0.0**	**0.0**	**-0.5**	**-0.2**	**-2.6**	**22.1**	**22.6**	**15.1**	**16.5**	**72.9**

Incremental Operating Costs ($2015M)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Total OM&A	0	0	48	35	133	927	901	643	567	**3,254**
Total Capital	0	0	19	19	14	24	11	7	7	**102**
Total Operating Costs	**0**	**0**	**67**	**55**	**147**	**951**	**911**	**650**	**574**	**3,356**
Fuel	0	0	-3	-1	-14	119	122	85	93	**401**

Chart 2

PICKERING EXTENDED OPERATIONS Assessment Data (BCS Option 1 ~ 65 TWh)
(October 2015)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Incremental Production (TWh)	**0.0**	**-0.9**	**-1.2**	**-1.8**	**-3.4**	**19.6**	**21.2**	**14.6**	**16.5**	**64.5**

Incremental Operating Costs ($2015M)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Total OM&A	7	35	64	129	207	965	891	623	487	**3,408**
Total Capital	0	0	15	16	11	22	10	7	7	**89**
Total Operating Costs	**7**	**35**	**79**	**145**	**218**	**987**	**902**	**631**	**494**	**3,497**
Fuel	0	-5	-6	-9	-18	105	113	79	89	**347**

PICKERING EXTENDED OPERATIONS Assessment Data (BCS Option 2 ~ 62 TWh)
(October 2015)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Incremental Production (TWh)	**0.0**	**-0.9**	**-1.2**	**-1.6**	**-3.8**	**18.8**	**20.2**	**13.8**	**16.1**	**61.5**

Incremental Operating Costs ($2015M)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Total OM&A	7	35	64	129	207	965	891	623	487	**3,408**
Total Capital	0	0	15	16	11	22	10	7	7	**89**
Total Operating Costs	**7**	**35**	**79**	**145**	**218**	**987**	**902**	**631**	**494**	**3,497**
Fuel	0	-5	-6	-8	-19	101	108	74	87	**331**

The March 2015 data was provided to the IESO in December 2014 and was expressed in 2014$. The March table referenced above was converted to 2015$ consistent with the October data for comparison purposes.

Total OM&A includes base, outage, projects, the station’s portion of incremental allocated nuclear and corporate support costs and estimated costs to enable extended operations.

Total Capital costs include Minor Fixed Asset expenditures.

OPG believes the production data reflecting approximately 62 TWh of incremental production estimated in October 2015 is achievable and most accurately reflects the planned outage activities required to extend Pickering operations. The cost data also estimated in October 2015 accurately reflects the forecast incremental costs required to execute the work program to extend Pickering operations as described in Ex. F2-2-3 Attachment 2.

c) Yes, the study includes capital expenditures. These amounts are reflected in the Total Capital rows in the Charts in parts a) and b) above.

E-10 E-10

ISSN 1181-6465

Legislative Assembly of Ontario
Second Session, 41st Parliament

Assemblée législative de l'Ontario
Deuxième session, 41e législature

Official Report of Debates (Hansard)

Wednesday 26 October 2016

Journal des débats (Hansard)

Mercredi 26 octobre 2016

Standing Committee on Estimates

Comité permanent des budgets des dépenses

Ministry of Energy

Ministère de l'Énergie

Chair: Cheri DiNovo
Clerk: Eric Rennie

Présidente : Cheri DiNovo
Greffier : Eric Rennie

Mr. Serge Imbrogno: Serge Imbrogno, Deputy Minister of Energy. The studies that are being undertaken are being done by MOECC and other ministries. The stage at which those studies are under way—I don't know. I think that's a question for MOECC and MNR and the other ministries that are undertaking those studies.

Mr. John Yakabuski: It's almost six years. It sounds to me like that's a delay tactic.

We'll move on. Let's talk about Northland Power and the $95-million award by a lower court, I guess it was, and then it went to the Ontario Court of Appeal, which dismissed the appeal, or stayed the appeal. Now the OEFC is taking it to the Supreme Court of Canada.

It's highly unlikely, if the Ontario Court of Appeal saw no reason to even proceed—they stayed the request, at the Court of Appeal, which leaves us on the hook for the money. In fact, that money, I believe, has been retroactively advanced to Northland. They may have to repay it if they lose, but the reality is that they're probably not going to lose. I know you won't comment on the court case, but every court along the line has ruled in their favour. That's another $95 million.

It was an Ontario regulation that led to the court case. It was a regulation passed by your government that led to the court case. This is another $95 million. We're hearing every minute about $70 million over seven years like it was the second coming. Now we have another $95 million that we could be on the hook for, if this goes through to its end.

Can you tell me—

The Chair (Ms. Cheri DiNovo): Mr. Yakabuski, you have about three minutes.

Mr. John Yakabuski: My, time flies, eh?

Can you tell me how many other Northland Powers are out there with respect to the decision—and I don't have the regulation. If I had faster eyes—there is a number of that regulation. I did have it—Ontario regulation 398/10. How many other Northland Powers are out there that are affected by this? What is the total amount that Ontario could be on the hook for, if all of those rulings go against us?

Hon. Glenn Thibeault: Thanks for the question. From my understanding, the Ontario Electricity Financial Corp., which is under the Ministry of Finance's purview, made a decision relating on how the NUGs were paid. They disagreed with that and went through the court process. Through the court process, it is now once again under appeal. From me having lots of lawyers giving me advice, I'm not able to comment on any of that, because it is under the appeal process right now.

Mr. John Yakabuski: But you could tell us what the total amount is that could be at stake here.

Hon. Glenn Thibeault: What I've been told very clearly is, because this is under appeal right now, it is not something that I'm able to comment on.

Mr. John Yakabuski: So you do know the total amount, but your lawyers are telling you not to comment on that.

The amount that is at stake with respect to Northland Power is public, and we asked questions on it today in the Legislature. You took one of those questions. It wasn't shuffled off to the Minister of Finance, so you took the question.

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Hon. Glenn Thibeault: And I answered the same way I just did.

Mr. John Yakabuski: Not exactly, but—

Hon. Glenn Thibeault: Well, I answered, and then I talked about some of our programs, but I don't think you want me to talk about our programs right now. I know you only have three minutes.

Mr. John Yakabuski: Not again, no. I'm fairly familiar with your programs at this point.

So are you saying you don't know how much is at stake, or that you just aren't able to disclose that based on lawyer's advice?

Hon. Glenn Thibeault: All I'm saying right now is that because the process is under appeal, I can't comment on anything to do with this file or this case.

Mr. John Yakabuski: Wow. It's just amazing how we can have this kind of—yesterday, we find out, and I noticed too that the Premier again said yesterday in the Legislature, "no additional financial impact." But how can you say that when you know that—no additional impact other than the original decision, award, change or whatever—

The Chair (Ms. Cheri DiNovo): I'm afraid your time is up, Mr. Yakabuski.

Mr. John Yakabuski: Can I get an extra minute?

The Chair (Ms. Cheri DiNovo): Sorry. We now move on to the third party: Mr. Tabuns.

Mr. Peter Tabuns: Good afternoon, Minister and Deputy Minister.

Hon. Glenn Thibeault: Good afternoon.

Mr. Peter Tabuns: I was asking yesterday about the Pickering life extension and whether or not the government had actually looked at the cost comparison between conservation on the one hand and the Pickering life extension on the other. You referred me to the Ontario Energy Board filings on the extension. I poked around. I found them. There is no mention of conservation. The only comparison for the Pickering life extension is to combined-cycle or single-cycle gas turbines, not conservation.

Conservation is much cheaper than gas. I understand that gas-fired power in Ontario is around 11 to 12 cents a kilowatt hour. I've seen your numbers showing 3 to 6 cents a kilowatt hour for conservation. Why did you not compare the Pickering life extension to the option of expanding our investment in conservation?

Hon. Glenn Thibeault: The deputy was the one who was explaining that piece, so I'll hand that back to the deputy.

Mr. Serge Imbrogno: Just a couple of points, Mr. Tabuns. The Pickering life extension: The government has given OPG the green light to pursue the approvals through the regulator, both the OEB and the CNSC, and then to return to the government after we have all the information. I just want to clarify that. They still have to report back once they have gone through the regulatory process with the OEB and the CNSC.

Mr. Peter Tabuns: I'll come back to that question. Your whole thing is conservation first. I hear that all the time. The minister spoke eloquently about it the other day. Why aren't you using conservation as a comparator when you're making decisions on generation?

Mr. Serge Imbrogno: When we do our long-term planning, we take into account conservation. When you look at the demand curve, it already takes into account all the conservation that we've put forward. In the $2 billion-plus that we're going to spend on conservation in this next framework, all that is taken into account. If you were to do it the other way, you would add that back in. We've already taken it into account through all the measures that we've announced that the demand curve would be reduced by that amount. Then, the IESO does their analysis from that basis.

What I'm saying is that we've already taken into account all the conservation when you see the analysis that the IESO does in that piece.

Mr. Peter Tabuns: We had this discussion the other day. You're not planning at this point—we'll see what happens with your long-term energy plan—to take advantage of all the conservation opportunities that have been identified. There is a lot more conservation opportunity out there than is currently planned for. Why, when you say conservation is your first option, do you not compare it to life extension for Pickering? Why does it not even feature in the documentation that is put together?

Mr. Serge Imbrogno: I think our conservation targets are very aggressive. That's already incorporated. I think the study you're referring to talks about economic conservation if you have no budget constraint. I'm sure you could drive further conservation if there was no budget constraint. I think what we'd do is optimize through the IESO: Where's the best return for your investment? That's what we've built into the plan.

Going forward, as we electrify, for example, there'll be more opportunities for more conservation—more opportunity for different funding from the cap-and-trade proceeds, for example.

At this point, we believe we've captured all of the conservation that's appropriate. Going forward, there's opportunity to do more.

Mr. Peter Tabuns: I have to say, the way you appear to be using conservation is, if you need a filler in your graphs, you put it in as a filler. You never compare it to actual generation investments. So if you're making a generation investment here, in a province where people are hard-pressed with high hydro bills, you have an opportunity with conservation to provide electricity services at a much lower price than the extension of Pickering, yet you didn't do that.

Conservation is clearly not first in your assessment of options. Frankly, you could make an assessment of conservation compared to Pickering and, in five years or 10 years from now, as technologies develop, look at other conservation options to deal with the need for electricity services. Deputy Minister and Minister, conservation is not first. Conservation apparently, in your scheme, is a filler. It is not actually compared to generation.

Mr. Serge Imbrogno: I think it's the opposite, because when we do our forecasts of our supply need, we first start with conservation and reduce demand by that amount. Once we reduce demand, then we forecast what additional supply we need. So we actually do start with conservation, reduce the demand accordingly and then we fill in the supply, based on what's left. In doing that, we try and optimize how much conservation is achievable, and that's what the achievable potential study does, from the IESO. Once we've done that, then we fill in the difference with supply.

Mr. Peter Tabuns: Minister, if you were going to make the decision around the extension of Pickering—and I'll be interested to hear exactly what you're charging per kilowatt hour for power from that plant—and you have the opportunity to fill that gap with conservation today, why are you not putting conservation on one side of the balance and Pickering life extension on the other and looking to see which is most cost-effective?

Hon. Glenn Thibeault: Thanks for the question. To reiterate the piece—I am aware of the time, so I won't reiterate a lot of what the deputy minister was talking about. It is important for me to highlight that the framework specific to this is talking about—we're working on trying to achieve seven terawatts of savings to assist the province in achieving its long-term conservation target of 30 terawatts by 2032. When we're comparing those two, we're wanting to make sure, as the deputy minister said, that conservation does come in first, we reduce that demand and then we meet the needs in our capacity accordingly.

On the specifics of Pickering, I know, Deputy, that you can talk about those costs and those types of things.

Mr. Serge Imbrogno: I could provide more detail, if you want, on Pickering.

Mr. Peter Tabuns: I will ask specific questions about that.

Mr. Serge Imbrogno: Okay.

Mr. Peter Tabuns: Moving on to that, in the last long-term energy plan, your projection was closing Pickering by 2020. In fact, in the plan you say that there are opportunities to close it earlier. Why are you extending it to 2024 and why are you doing that without a public consultation on that?

Mr. Serge Imbrogno: The IESO is always looking for opportunities to find efficiencies. OPG is also looking for opportunities to run their existing plants more efficiently.

The opportunity exists to extend the life of Pickering. It's not a refurbishment. It's using the existing facility. It's doing more testing to determine if the life could be extended, which is part of the return to the CNSC.

For a marginal investment in extending the life of Pickering, we're able to continue with that zero-GHG-emission power. We'll save money, because it will be extended at the existing relatively low price for nuclear power. That saves us money, going forward. The IESO analysis says, on a system-cost basis only, that it's $600 million. That doesn't include the additional GHG reductions. It doesn't include extending the workers at Pickering as well. There are other economic benefits that we haven't incorporated into that $600 million. We think that for a modest increase in extending the life, we have a large benefit.

Mr. Peter Tabuns: Just to be clear, you have not yet made a final decision to extend to 2024. Is that correct?

Mr. Serge Imbrogno: That's correct. We've given OPG the authority to go forward, to go through the OEB, and also to the CNSC for regulatory approvals, and then to return, closer to 2017, I believe, for a final decision.

Mr. Peter Tabuns: That will be a decision made at the cabinet level?

Mr. Serge Imbrogno: It will be made by the minister and, I would suggest, at the cabinet level as well.

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Mr. Peter Tabuns: Are you currently in the process of putting in place plans should the CNSC or the OEB give you a red light on this?

Mr. Serge Imbrogno: That's the job of the IESO. They would take into account all of the different options and be ready in case we go one way or the other. That's something that the IESO does. It's part of their job.

Mr. Peter Tabuns: So are they doing it?

Mr. Serge Imbrogno: Yes, that's what they do.

Mr. Peter Tabuns: They do all kinds of things. Sometimes, they may miss something. Can you tell us that they are currently planning for contingencies in case they don't proceed with the Pickering extension?

Mr. Serge Imbrogno: The IESO is planning for contingencies in all events in Pickering's service life. Whether it's shorter or longer would be one of the contingencies that they would take into account.

Mr. Peter Tabuns: And do you know what the contingencies are—what they are currently planning as the alternatives to the life extension?

Mr. Serge Imbrogno: I don't know. There are contracts that are coming due that they could extend. There are other measures that they could take. I don't know the specifics.

I guess that an obvious one would be to continue to run the gas plants that are currently running, which we were going to get the GHG reductions from. That's always an option for the IESO, but one that we're trying to reduce in order to reduce the GHG footprint.

Mr. Peter Tabuns: What is the cost per kilowatt hour of power from the Pickering reactors? I gather that four of them are at one cost and two are at a different cost. What is the cost?

Mr. Serge Imbrogno: It's estimated in the $65-per-megawatt-hour range.

Mr. Peter Tabuns: That's the average between all six of them?

Mr. Serge Imbrogno: When we extend the life of Pickering, that's what we're forecasting for the cost of the production.

Mr. Peter Tabuns: So $65 per megawatt hour for production as a whole?

Mr. Serge Imbrogno: That's correct.

Mr. Peter Tabuns: And there's no differentiation between the reactors?

Mr. Serge Imbrogno: They would just get the price that the OEB provides—the nuclear rate.

Mr. Peter Tabuns: I've seen in the past a price of nine cents per kilowatt hour for power from two of the reactors at Pickering. You're telling me that that's not the case?

Mr. Serge Imbrogno: I don't know where that number comes from. I think that Pickering's performance has improved dramatically, so you may be referring to an older number.

Mr. Peter Tabuns: So you're currently saying $65 per megawatt hour?

Mr. Serge Imbrogno: That's the forecast of what the price would be for the extended terawatt hours that we'll be receiving.

Mr. Peter Tabuns: Is the government of Ontario currently seeking to negotiate an electricity supply contract with Hydro-Québec which would permit Ontario to close Pickering earlier?

You were able to get something like five cents a kilowatt hour in the most recent deal, according to La Presse. This is six and half cents a kilowatt hour. Are you looking at a deal to give us lower-priced power, as opposed to that extension?

Hon. Glenn Thibeault: I think that, when it comes to the deal that we announced with Quebec last week, we were pretty excited at the deal that we were able to get. The two terawatts that we are getting now, we're going to target, as mentioned, to our natural gas utilities during peak times. We're helping them, doing the 500-gigawatt swap in their peaking hours, and then we're going to do the storage component as well.

I think that it's important for us to say that we're always going to look at opportunities that present themselves with Quebec in relation to where that goes. We just finished a three-year deal. I think that we're all taking a breath right now. But it's important for us to—

Mr. Peter Tabuns: Minister, I think that you're getting off-track from my question. Are you looking now, given that you were able to get a good price from Quebec, at a cheaper price than the one that the deputy minister just cited for the Pickering plant?

Hon. Glenn Thibeault: I was going to say, in answer to your question, the importance for us to continue working with Quebec on all aspects—I don't think that any door is shut. I think that this three-year agreement that we've been able to come forward with is exciting news for Ontario because it just shows that we can continue to have negotiations with Quebec. But any of those specifics, Deputy?

Mr. Serge Imbrogno: I'll just add—

Mr. Peter Tabuns: No, I would like to go back to the minister, sorry.

I'm not talking about doors open or closed. Are you negotiating with Quebec right now to follow up on that