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 3A CROSS-EXAMINATION

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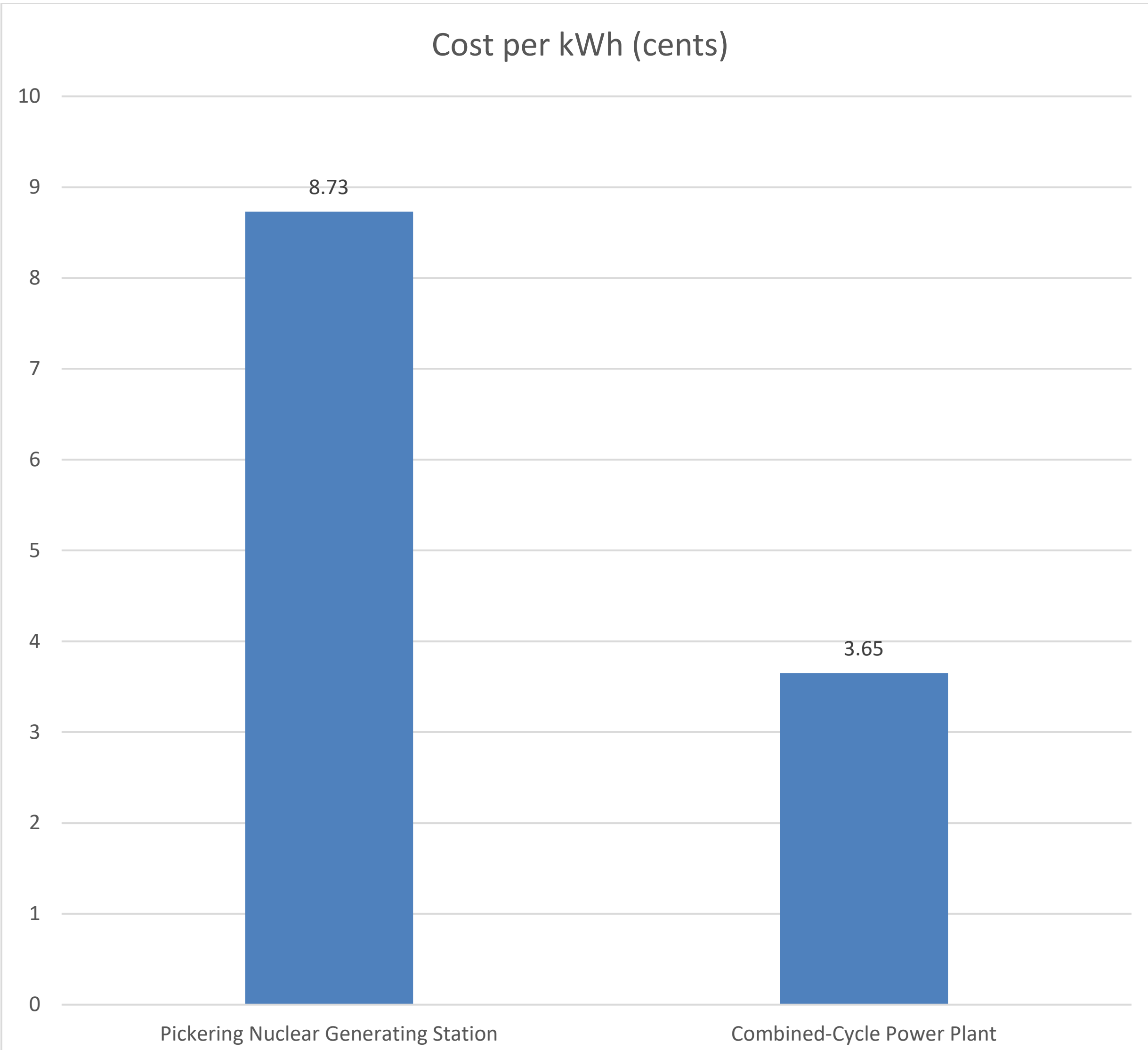
Note: The documents in tabs 6, 7, 12, 13, 17, 19, and 20 are excerpts of the relevant document.

Operating and Fuel Costs in 2017

Pickering Nuclear Station vs. Combined-Cycle Power Plant Assuming $20 per Tonne Price of Carbon

Pickering Nuclear Station: 8.73 cents per kWh[1]

Combined-Cycle Power Plant: 3.65 cents per kWh[2]



[1] Undertaking JT2.4.

[2] Assumptions: Gas cost of $3.85 per MMBtu (March 7, 2017 Henry Hub gas price of $2.87 per MMBTu and exchange rate of 0.7457 per the March 7, 2017 *Report on Business*); carbon tax of $20 per tonne, which is equivalent to $1 per MMBTu (see Ex. F2-2-3, Attachment 1, Page 64); combined-cycle plant heat rate of 6,800 Btu per kWh (Ex. L, Tab 6.5, Sch. 1 Staff-125, Page 2); combined-cycle power plant's variable operating and maintenance costs of 0.35 cents per kWh (F2-2-3, Attachment 1, Page 64).

**IESO Natural Gas Price Forecast vs. NYMEX Natural Gas Futures Prices
For December of Each Year at Henry Hub**

	2017	2018	2019	2020	2021	2022	2023	2024
IESO Forecast (2015 real U.S. $/MMBTU)[1]	5.45	5.45	5.44	5.44	5.43	5.43	5.43	5.43
IESO Forecast (nominal U.S. $/MMBTU)[2]	5.67	5.78	5.89	6.01	6.12	6.24	6.36	6.49
NYMEX Future Prices[3] ($/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

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**

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).

From: Trent Winstone [mailto:trent.winstone@navigant.com]
Sent: February-28-17 12:51 PM
To: jack@cleanairalliance.org
Cc: Todd Williams
Subject: FW: Dawn Natural Gas Price Differential Question

Hi Jack,
We apply the basis differential in $USD to the HH prices, and then convert to $CAD using an exchange rate forecast that varies from month to month. The source for the exchange rate is http://www.bmonesbittburns.com/economics/forecast/ca/cdamodel.pdf, and the rates used from Nov 2016 to Apr 2018 are provided below.

The change to a negative basis differential from HH to Dawn is relatively new trend that reflects the impact of shale gas.

Cheers,
Trent

Nov-16	1.369
Dec-16	1.369
Jan-17	1.342
Feb-17	1.342
Mar-17	1.342
Apr-17	1.329
May-17	1.329
Jun-17	1.329
Jul-17	1.317
Aug-17	1.317
Sep-17	1.317
Oct-17	1.304
Nov-17	1.304
Dec-17	1.304
Jan-18	1.303
Feb-18	1.302
Mar-18	1.301
Apr-18	1.3

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From: Todd Williams
Sent: Monday, February 27, 2017 3:18 PM
To: Trent Winstone <trent.winstone@navigant.com>
Subject: FW: Dawn Natural Gas Price Differential Question

Trent,

Could you please respond to Jack's question below.

Thanks,

Todd

TODD WILLIAMS | Managing Director
Energy | Navigant
Bay Adelaide Centre | 333 Bay Street, Suite 1250 | Toronto, ON M5H 2R2 | Canada
1.647.288.5204 Direct | 1.613.544.7941 Mobile | **twilliams@navigant.com**
Assistant: Colleen Martino | Direct: 1.416.956.5008 | **colleen.martino@navigant.com**
navigant.com

From: Jack Gibbons [mailto:jack@cleanairalliance.org]
Sent: Monday, February 27, 2017 2:30 PM
To: Todd Williams <twilliams@navigant.com>
Subject: Dawn Natural Gas Price Differential Question

Hi Todd,

I hope you are well.

I have been looking at your October 14, 2016 "Ontario Wholesale Electricity Market Price Forecast".

I have used your average exchange rate forecast of $1.376 CAD between Nov 2016 and April 2018 to calculate your basis differentials between Dawn and Henry Hub gas prices.   According to my calculations, you are forecasting that the Dawn price will always be lower than the Henry Hub price.   Specifically, the monthly differentials vary from -32 cents to -5 cents per MMBTu and have an average value of
-21 cents per MMBTu.

According to page 11 of your report, the "basis differential is based on Navigant's North American gas price forecast".   Does this forecast also assume an average exchange rate of $1.376 CAD?   Or do I need to know your month to month exchange rate forecasts to calculate your forecast monthly price differentials?

Thanks for your help.

Jack

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Market Price for Demand Response

Annualized cost of Summer 2017 Demand Response: $83/kW-year[1]

Annualized cost of Winter 2017/18 Demand Response: $75/kW-year

[1] The most recent DR Auction in December 2016 for the Summer 2017 (May-Oct) and Winter 2017/18 (Nov-Apr) commitment periods cleared at $331.33/MW-day and $299.48/MW-day, respectively. Annualized cost of Summer 2017 DR = $331.33/MW-day X 252 business days = $83,495.16/MW-year; Annualized cost of Winter 2017/18 DR = $299.48/MW-day X 252 business days = $75,468.96/MW-year. Information provided by the IESO.

NUG Framework Assessment

Opportunities for Non-Utility Generators to Compete in Meeting Anticipated System Needs - Analysis and Recommendations

Report to Minister of Energy

September 1, 2015

Independent Electricity System Operator

2.0 Scope and Principles

2.1 SCOPE

While this report considers a broader framework that includes other procurement initiatives, it is not intended to be used to evaluate these procurements going forward.

This report relates to the framework and assessment of contracting with NUG facilities that were identified in the November 23, 2010, directive that do not yet have a contract with the IESO. A complete list and location map of all eligible NUG facilities can be found in Appendix D.

Table 1 provides information regarding NUGs with contracts that expire up to the end of 2020 that are most likely to be impacted in the short term by the recommendations of this report.[13] Although negotiations were initiated with NUG facilities whose OEFC contract expired in May 2015 or earlier, not all resulted in agreements being reached. It should also be noted that the IESO understands that certain NUG contracts include provisions for possible extensions to their OEFC contract for a certain period, generally for 12-60 months, post the original expiry date. While the IESO has been informed that no extensions have been executed as of yet, the expiry dates set out below may change should the OEFC enter into extensions with specific NUG facilities.

Table 1: Summary of NUGs with OEFC Contracts Expiring Up to the End of 2020

Owner	Facility Name	Fuel	Capacity (MW)	Location	Expiry	Comments/ Considerations
HJ Heinz Canada	H.J. Heinz	Natural Gas	7	Leamington	1-Aug-2011	Host facility currently closed, connected behind the meter.
Brookfield	Lake Superior Power	Natural Gas	110	Sault St. Marie	1-May-2014	Facility is currently idled while Brookfield explores restart options.
Northland Power	Cochrane	Natural Gas	27	Cochrane	12-May-2015[14]	Northland issued termination notices to employees 60 days after contract expiry, believes facility can restart upon receipt of new contract[15]
		Wood Waste	11		12-May-2015	
Eastern Power	Keele Valley LFG	Landfill Gas (LFG)	30	Vaughan	1-Dec-2015	LFG fuel supply sufficient for <10 MW and falling annually. Option to co-fire with natural gas at very high heat rate.
Northland Power	Kingston (aka Destec) Cogen	Natural Gas	115	Bath	1-Feb-2017	Not currently operating as a cogen following the closure of thermal host (INVISTA)
Atlantic	North Bay Power Plant	Natural Gas	31	North Bay	31-Dec-2017	Compressor stations rarely used, therefore waste heat unlikely to be available for re-contracting
		Waste Heat	9			
Atlantic	Kapuskasing Power Plant	Natural Gas	30	Kapuskasing	31-Dec-2017	Compressor stations rarely used, therefore waste heat unlikely to be available for re-contracting
		Waste Heat	10			

13 Note – there are also three NUGs, representing about 270 MW of capacity, whose contracts will expire after the end of 2020

14 Cochrane's OEFC contract (both natural gas and wood waste) was originally set to expire on January 12, 2015, but was extended four months.

15 Northland Press Release – http://www.northlandpower.ca/Investor-Centre/News--Events/Recent_Press_Releases.aspx?MwID=1967791

Owner	Facility Name	Fuel	Capacity (MW)	Location	Expiry	Comments/ Considerations
TransAlta	Mississauga Cogen	Natural Gas	110	Mississauga	31-Dec-2018	No longer a cogen following closure of thermal host (McDonnell Douglas / Boeing)
Calpine Canada	Whitby Cogen	Natural Gas	50	Whitby	4-May-2019	Operates as a CHP plant with Atlantic Packaging as thermal host
Atlantic	Calstock Power	Wood waste	31	Hearst	17-Jun-2020	No steam host, purchases wood waste from local industry
		Total =	540			

2.2 PRINCIPLES

Consistent with the recontracting principles used to date and recent government statements (refer to Section 5.1.1 for further details), this assessment and the resulting recommendations were guided by the fundamental principle that:

The IESO seeks to ensure system reliability while minimizing ratepayer costs over the long term and meeting government policy objectives communicated through Ministerial direction

In applying this principle, this report took the following views on certain considerations:

Resource Equality – all resources (e.g., generation, transmission, conservation) available to address a given system need were treated without bias, and based solely on their specific cost and performance characteristics. NUGs need to compete against all resources going forward.

Environmental Impacts – differences in environmental impacts, either those deemed positive or negative, of various resources were not considered when making recommendations. It is expected that quantifiable financial impacts related to the environmental impacts of various resources will be priced in as necessary by generators when determining the price they are willing to accept in any future procurement.

Local Economic Impacts – the local economic impacts of any individual NUG were not considered in determining recommendations for the future framework for addressing NUGs.

Ontario Reserve Margin Requirements

2017 - 2021

December 30, 2016

Connecting Today. Powering Tomorrow.

2. Introduction

Through the annual release of the *Ontario Reserve Margin Requirements* (ORMR), the IESO reports the planning reserves ("reserve margins") required in Ontario over the succeeding five years to reliably supply Ontario's forecast demand. This report fulfills the requirements of Section 8.2 of the IESO's *Ontario Resource and Transmission Assessment Criteria*[1].

Reserve margin requirements are determined in accordance with the Northeast Power Coordinating Council (NPCC) resource adequacy design criterion stated in Regional Reliability Reference Directory # 1: *Design and Operation of the Bulk Power System*[2]. The criterion states as follows:

"Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year."

Directory #1 further states that in meeting this requirement, the Planning Coordinator or Resource Planner shall *"make due allowances for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."*

The LOLE represents the number of days per year on which supply is expected to be insufficient to meet demand.

The reserve margin requirement in any year is the amount of resources in excess of the annual peak demand needed to meet the reliability criterion of an annual LOLE of 0.1 days/year.

Currently, Ontario's reserve margin requirements are determined without reliance on emergency operating procedures or support from neighbouring Planning Coordinator Areas through non-firm imports. However, experience shows that Ontario's interconnections can be relied on during times of need and that occasional use of the interties to support Ontario's reliability is feasible. In light of this, the IESO is continuing to investigate the potential for considering non-firm imports to reduce future reserve margin requirements where the level of assumed interconnection support must reflect prevailing conditions, e.g. expected transfer capabilities between Ontario and neighbouring areas as well as declining trends in anticipated reserve margins across North America.

– End of Section –

[1] IMO_REQ_0041 "Ontario Resource and Transmission Assessment Criteria" can be found at www.ieso.ca
[2] NPCC Directory # 1: *Design and Operation of the Bulk Power System,* can be found at www.npcc.org

UNDERTAKING JT1.17
ATTACHMENT I

Undertaking

ED INTERROGATORY #34

1. With respect to the numbers in Section T4 for the years 2021 to 2024 inclusive: please provide for each year the IESO's estimate of: a) Pickering's installed capacity; and b) available capacity at the summer peak. Please describe the IESO's methodology and show its calculations for calculating the difference between installed and available capacity.

2. With respect to the load forecasts shown in Section T3: are any of them consistent with the IESO's MARS program? If no, please provide the MARS load forecasts for these years. [Note: The IESO uses General Electric's Multi-Area Reliability Simulation (MARS) program to derive its load forecast to estimate its reserve margin requirements. See IESO, *Ontario Reserve Margin Requirements 2016 – 2020: Issue 1.0* (December 21, 2015).]

3. Please provide a response to part (b). The IESO outlined a methodology but did not provide an answer.

Response

The following response has been prepared by the IESO. OPG has inserted the evidence reference in square brackets.

1. The following table summarizes Pickering's total installed capacity (MW) in different scenarios:

	Case with +65 TWh of Pickering Production, Pickering to 2020	Case with +65 TWh of Pickering Production, Pickering to 2022/2024	Case with +62 TWh of Pickering Production, Pickering to 2020	Case with +62 TWh of Pickering Production, Pickering to 2022/2024
2015	3094	3094	3094	3094
2016	3094	3094	3094	3094
2017	3094	3094	3094	3094
2018	3094	3094	3094	3094
2019	3094	3094	3094	3094
2020	3094	3094	3094	3094
2021	0	3094	0	3094
2022	0	3094	0	3094
2023	0	2064	0	2064
2024	0	2064	0	2064

As a starting point, the Pickering capacity that is available at the time of peak demand is assumed to be the installed capacity, provided that it is not on planned outage or forced outage or in a derated state. IESO's assessment of the overall performance of Pickering further units includes accounting for forced outage and planned outage rates and derates, which are considered in reserve margin calculations and power system production simulations.

2. Yes. The forecasts are consistent, but are not identical; this reflects different vintages of production. For example, the more recently produced demand outlooks contained in the Ontario Planning Outlook depict ranges rather than a single projection.

3. Per IR 34 [Ex. L-6.5-7 ED-34] response (b), the total amount of incremental firm capacity (MWs) that can be imported into Ontario is a function of: import capacity (the physical wires), real-time system constraints (physical constraints based on real-time internal and external supply/demand balances and transmission limitations) and economics (cost). The current physical import capacity is up to approximately 6,900 MW. This represents a theoretical level that could be achieved only with a substantial reduction in generation dispatch in the West and Niagara transmission zones. In practice, the generation dispatch required for high import levels would rarely, if ever, materialize. Therefore, at best, due to internal constraints in the Ontario transmission network in conjunction with external scheduling limitations, Ontario has an expected coincident import capability of approximately 5,200 MW.

GEC Interrogatory #56

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

Interrogatory

Reference:
Exhibit F2-2-3 Attachment 1, page 36 (IESO's presentation evaluating the economic case for extending Pickering's operations until 2024.)

(Note: On page 48 of OEB staff's interrogatories, OPG is asked to consult with the IESO as necessary to respond to interrogatories related to the IESO's analysis of the Pickering Extended Operations. GEC makes the same request here.)

a. IESO states that Pickering's closure would present challenges related to the deployment of replacement supply. However, the government's 2013 Long Term Energy Directive directed OPG to plan for Pickering's closure in 2020 and potentially as early as 2017. What planning and procurement did the IESO undertake in response to the 2013 LTEP directive in order to secure adequate replacement supply to replace Pickering in 2020?

b. What is the IESO's current plan to secure replacement supply if OPG doesn't gain approval from either the CNSC or the OEB to extend Pickering's operational life until 2024?

c. In light of the province's "Conservation First" policy, did the IESO's cost analysis of Pickering's extended operations consider the additional cost effective conservation potential outlined in its June 2016 "Achievable Potential Study: Short Term Analysis" and how cancellation of the continued operations could affect conservation potential? If so, please provide details.

Response

The following response has been prepared by the IESO:

a. The IESO has supported implementation of various aspects of the 2013 LTEP since its publication in 2013. Conservation, supply and transmission resources that were planned, acquired and/or brought online since then are identified in the IESO's 2016 Ontario Planning Outlook, which is available at: http://www.ieso.ca/Pages/Ontario's-Power-System/Ontario-Planning-Outlook/default.aspx.

Planning has taken into account the nuclear refurbishment principles laid out in the 2013 Long-Term Energy plan. For example, the Ontario Planning Outlook identifies a variety of implementation and performance risks that will have to be managed in coming years, including risks related to nuclear operations and refurbishment plans. Likewise, planning and contracting has helped provide for nuclear refurbishment off-ramps among some nuclear units planned for refurbishment in Ontario. In parallel, among other things, market renewal initiatives at the IESO are underway, including a capacity auction work stream which would continue to evolve the demand response auction in the province; facilitate short term capacity trade; and implement an incremental capacity auction.

b. Options for addressing resource requirements in the event that Pickering does not operate to 2024 include taking greater advantage of supply resources whose existing contracts expire in coming years, taking advantage of resource options via capacity auctions, and greater use of non-firm intertie transactions. The plan to address such needs should they arise is touched upon in the Ontario Planning Outlook at http://www.ieso.ca/Documents/OPO/MODULE-4-Supply-Outlook-20160901.pdf. Irrespective of the particular options to be selected, mitigating and managing risks in the years ahead will be supported by well understanding the risks and their drivers, assessing them systematically and in cooperation with others, identifying and communicating needs and having the appropriate mechanisms to address them.

c. No, the analysis of Pickering's extended operation was completed in 2015 while the Achievable Potential studies were finished in June 2016. However, the most recently identified achievable potentials are consistent with the conservation forecast used in Pickering analysis. The cancellation of the continued operations would have minimal impact on conservation potential.

UNDERTAKING JT1.17
ATTACHMENT H

Undertaking

ED INTERROGATORY #29

1. With respect to response (b), for each year please state how much of the difference in MWs between Pickering's "installed" and "available capacity" is due to expected forced outages.

2. Part (d) requested the avoided generation that the IESO estimates would be caused by Pickering operating to 2022/2024. The IESO stated as follows: "Not applicable, as the simulation run of Pickering operates to 2020 is not available." This response does not explain why a response could not be calculated or provided. Please provide a response to that part of the interrogatory.

3. Part (e) requested the IESO's *current* forecast of the Pickering forced outage rate from 2016 to 2024. The reference provided in response does not include that information. Please provide the requested information.

4. No response was provided to part (f). Please provide a response.

5. No response was provided to part (l). Please provide a response. This is relevant. If Ontario's incremental peaking requirements, assuming Pickering is not extended, have changed, then this will impact the economics of the proposed Pickering extension. Whether or not a Pickering simulation is available, the IESO will have up-to-date estimates of our incremental capacity requirements if Pickering is not extended.

6. No response was provided to part (m). Please provide a response. The IESO analysis has assumed that the cost of the replacement capacity is equal to the cost of building new gasfired peaker plants. But it is highly relevant to know if there are lower cost options to meet our capacity needs.

7. The last line of the interrogatory asked that the IESO "please state your methodology for calculating Pickering's available capacity (MW) at the time of Ontario's peak demand." No response was provided to this part of the interrogatory. Please provide a response.

Response

The following response has been prepared by the IESO. OPG has inserted evidence references in square brackets.

1. As indicated earlier in ED IR #28 [Ex. JT1.17(g)] part 1, the Pickering capacity that is available at the time of peak demand is assumed to be the installed capacity, provided that it is not on planned outage or forced outage or in a derated state. The forced outage rate is accounted for, however, and influences the size of the required

reserve margin. The forced outage rate is also accounted for in production simulation analysis.

2. The change in generation production as a result of Pickering Extended Operations is summarized in the tables below.

The following table summarizes the avoided generation (MWh) by fuel type as a result of Pickering's extended operation in the plus 65 TWh of Pickering Production case. Blue and positive numbers represent increase in production and red and negative numbers represent decrease in production as a result of Pickering's extended operation.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Gas	0	0	332,680	274,744	470,923	456,172	-6,756,544	-6,473,855	-4,730,629	-4,167,951
Hydroelectric	0	0	19,589	61,943	99,731	303,070	-373,796	-183,024	-106,101	-228,202
Wind	0	0	30,636	19,706	21,952	213,356	-42,286	0	0	-11,202

The following table summarizes the avoided generation (MWh) by fuel type as a result of Pickering's extended operation in the plus 62 TWh of Pickering Production case. Blue and positive numbers represent increase in production and red and negative numbers represent decrease in production as a result of Pickering's extended operation.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Gas	0	0	332,680	209,640	351,228	763,473	-6,424,056	-6,111,821	-4,473,760	-4,108,400
Hydroelectric	0	0	19,589	61,943	83,710	287,308	-357,001	-182,338	-99,313	-219,580
Wind	0	0	30,636	19,706	16,050	140,642	-28,515	0	0	-11,202

Please see response to ED IR #28 [Ex. JT1.17(g)] part 2 for the impact of Pickering extended operation on electricity imports and exports.

3. Forced outage and planned outage rates assumed in the IESO study are summarized in the response to ED IR #28 [Ex. JT1.17(g)] part 3.

4. See response to part 7 of this interrogatory [Ex. JT1.17(g)].

5. The replacement capacity assumed is assumed to be equivalent to the change in capacity requirements between Pickering operation to 2020 and 2022/2024. These are summarized in the table below.

	Increase in Capacity Requirements Pickering to 2020 relative to 2022/2024 (MW)
2015	0
2016	0
2017	0
2018	0
2019	0
2020	0
2021	2,316
2022	2,301
2023	2,064
2024	1,090

100% of this capacity was assumed to be replaced. This represents the capacity that would need to be replaced to meet NPCC resource adequacy criteria.

6. The cost of replacement capacity is benchmarked to be that of a new-build SCGT at $130/kW-yr. Gas is used as a proxy resource here. This would be the benchmark price for other resources such as demand response or firm capcity imports.

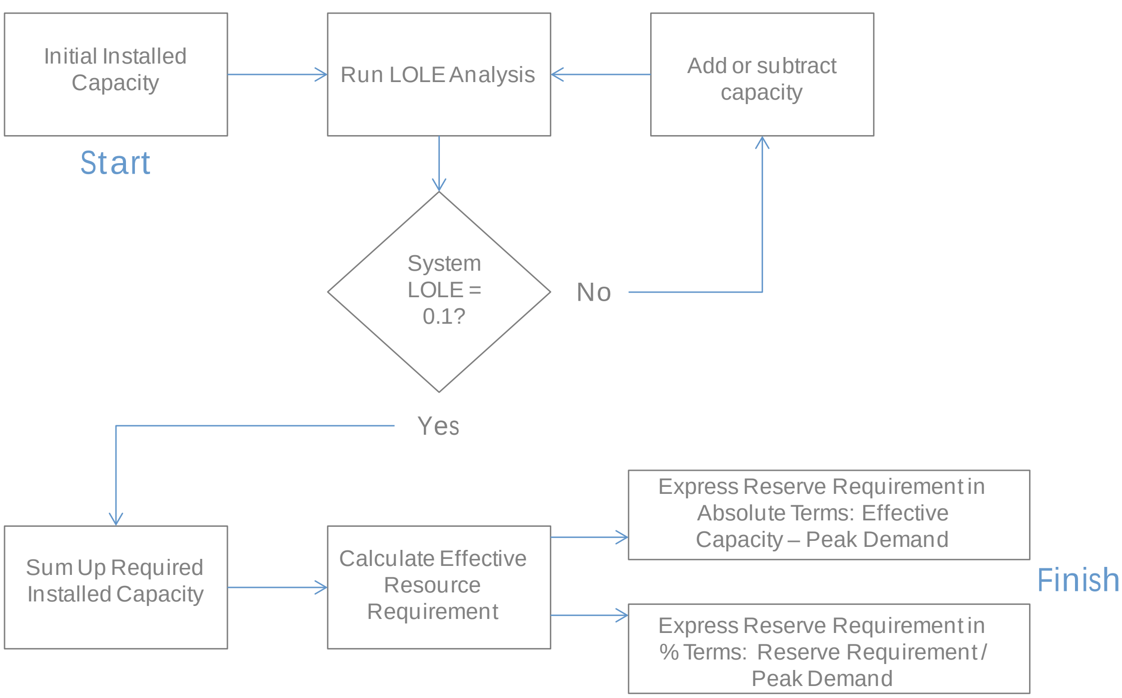
7. The "capacity contribution" or "effective capacity" of a supply resource is an approximation of its power output capability during peak demand periods and can be expressed as a percentage of a resource's installed capacity. Capacity contributions vary among resource types and can be estimated through a variety of methods.

   For planning purposes, the IESO estimates the capacity contributions through a variety of approaches, including by incorporating values submitted to the IESO by electricity generators, analyzing historical generator performance and using statistical methods to assess resource contributions during various percentiles of peak demand or other hours.

   Data and methods used to estimate capacity contributions evolve over time as more data is acquired and as methodological improvements are made. The following table provides indicative overall values, which in practice differ by generator, location and season. More information about these values is available at the Ontario Planning Outlook at http://www.ieso.ca/Pages/Ontario's-Power-System/Ontario-Planning-Outlook/default.aspx:

	Indicative Capacity Contribution (% of Installed Capacity Available at Time of Peak Demand)	
	At Summer Peak	At Winter Peak
Nuclear	99%	90%
Natural Gas	89%	95%
Waterpower	71%	75%
Bioenergy	89%	89%
Wind	11%	28%
Solar PV	33%	5%
Demand Response	83%	66%

Capacity contribution estimates are used in two main ways: they are part of the iterative loss of load expectation and resource requirement assessment process shown in the schematic below and they are used in a variety of supply-demand balance visualizations to allow for approximate but efficient portrayal.



News Release

Ontario and Québec Working Together to Drive Economic Growth

Partnerships Will Help Consumers and Create Conditions for Businesses to Thrive

October 21, 2016 2:50 P.M. | Office of the Premier

Ontario Premier Kathleen Wynne and Québec Premier Philippe Couillard today held a joint meeting of cabinet ministers in Toronto. Focused on innovation and the economy, the meeting generated seven agreements between the two governments.

A Historic Electricity Trade Agreement

To help make electricity more affordable and reliable, while continuing to reduce greenhouse gas (GHG) emissions, Ontario and Québec have finalized an agreement for trading electricity, energy capacity and energy storage.

Ontario and Québec have concluded a historic agreement that will limit GHG emissions by making Quebec's renewable energy supply available to Ontario, through their operators Hydro-Québec and Ontario's Independent Electricity System Operator (IESO). Under the agreement, IESO will purchase a total of 14 terawatt hours (TWh) from Hydro-Québec over a seven-year period, from 2017 to 2023.

Ontario will reduce electricity system costs for consumers by about $70 million from previous forecasts by importing up to 2 terawatt hours annually of clean hydro power from Québec at targeted times when natural gas would otherwise be used. This is enough electricity to power the city of Kitchener for a year and will reduce electricity sector GHG emissions by approximately 1 million tonnes per year. Ontario will also leverage Québec's energy storage capacities to make better use of its own clean energy resources. Ontario also will reserve 500 MW of capacity for Hydro-Québec to meet Québec's winter peak demand.

The agreement confirms the close cooperation that exists between Québec and Ontario with regard to energy and the fight against climate change. This agreement makes the best possible use of Ontario and Québec's existing electricity systems without additional costs to either province. Starting this December, and remaining in effect until 2023, the agreement is the culmination of a Memorandum of Understanding (MOU) signed at the 2015 joint cabinet meeting in Québec City.

Developing the 5G Network

While pursuing our efforts towards extending coverage and access to the internet for all citizens and to build the backbone of the next generation of digital infrastructure, Québec and Ontario are committed to driving innovation and enhancing partnerships among the provinces and business. The provinces signed a new MOU, which is also designed to help businesses and start-ups grow while attracting the highly skilled workforce to help the two provinces continue to thrive. Together, these activities will contribute to the creation of more high-quality jobs and economic growth in the two provinces.

Both provinces will help realize the vision of the 5G network by working with leading global information and communications technology (ICT) organizations. Creating an open innovation ecosystem, the approach would allow small and medium enterprises, government and academia access to pre-commercial and commercial technologies for the testing and validation of new technologies and products to help bridge the gap between research and commercialization. Moving towards the next-generation network will generate value for consumers and help the provinces' businesses stay at the cutting edge of technology.

Helping Consumers Transition to Electric Vehicles

To help ensure people and goods can continue to move confidently between the provinces, Ontario and Québec will cooperate on the creation of an electric vehicle (EV) charging corridor. More than 200 new high-speed charging stations will be installed by the end of March 2017, complementing Québec's network of 102 high-speed charging stations. EV charging stations will be conveniently located at locations immediately off the 401 corridor that connects the two provinces.

These moves will build on Québec's strong network of high-speed charging stations, improving EV drivers' confidence on long trips and giving more drivers the freedom to make the transition. Collaboration will also address issues such as signage and payment options between Ontario and Québec.

Infrastructure

The Premiers and cabinet ministers also discussed each province's commitment to investing in the infrastructure the more than 20 million people living in the provinces need. Both Ontario and Québec have made strong, long-term commitments to investing in the roads, transit, hospitals and schools to support people in Ontario and Québec now and into the future.

Ontario's $160 billion commitment over 12 years starting in 2014-15 and Québec's $89 billion commitment over 10 years starting in 2016 are now complemented by the federal commitment to $60 billion in new funding for all of Canada. Both governments strongly believe that the federal investment will need to support provinces' existing plans and priorities to have the best impact on their citizens' lives and their respective economies. Ontario and Québec call on Ottawa to work with them to that end.

Forestry and Softwood Lumber Agreement

Ontario and Québec will also partner on a number of targeted actions that address shared interests and challenges related but not limited to the Softwood Lumber Agreement, cross-border movement of wood, industry benchmarking and forest sector innovation, and market development.

Continuing to build strong relationships among Ontario and Québec's governments, businesses and academic sectors strengthens the economic centre of Canada. Creating the right conditions for innovation will help Ontario and Québec accelerate economic growth and increase partnerships among all sectors to deliver real results for people across both provinces.

Quick Facts

- This was the sixth Québec-Ontario joint meeting of cabinet ministers and third annual since 2014. The Premiers have committed to meeting again in Québec in 2017.
- Together, Ontario and Québec form Canada's largest economic region, accounting for about 56 per cent of GDP and 53 per cent of interprovincial trade.
- Ontario and Québec signed seven agreements at the close of the cabinet meeting regarding innovation, electricity trade, environment, northern development, culture, regulatory cooperation and forestry.

Background Information

- Outcomes of Québec-Ontario Joint Meeting of Cabinet Ministers
- Actions to Reduce Energy Costs
- Memorandum of Understanding Regarding a Common Engagement in Building the 5G-Next Generation Networks
- Agreement Concerning Electricity
- Memorandum of Understanding Concerning the Implementation of the Recommendations of the Ontario-Québec Chapter 3 Regulatory Cooperation Enhancements Working Group of September 2015
- Memorandum of Understanding Concerning Collaborative Actions on Forestry
- Agreement Concerning Environmental Cooperation 2016
- Memorandum of Understanding Concerning Economic and Social Development in the North
- Agreement Regarding Culture

Quotes

"Ontario and Québec share a commitment to growing our economies to positively affect the lives of the people who live in our provinces. We are increasing our engagement because we know we can achieve more by working together. Today, we achieved significant progress in fighting climate change, making electricity more affordable and reliable, and ensuring our two provinces are places where businesses thrive. We have also signed seven exciting new agreements and laid the groundwork for further partnerships. All of these actions help ensure our two provinces remain leaders, as Canada's largest, most dynamic and diversified economic region."

Kathleen Wynne
Premier of Ontario

"In many cases, the numerous challenges faced by Québec and Ontario call for common approaches. In terms of innovation, forestry, economic development, climate change, and energy, both Québec and Ontario benefit from working together. We have been successfully doing so for a long time. As there have been positive impacts, since 2014 we have been striving to intensify our efforts, which have notably resulted in the conclusion of nearly 15 agreements. Therefore, there is cause to celebrate the progress made, building on past successes, and the benefits that we will continue to reap in the future from this productive relationship, in which our respective economies and populations come out ahead. The work must continue to ensure that Québec and Ontario thrive and perform even better."

Philippe Couillard
Premier of Québec

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Hydro deal with Quebec to save Ontario electricity grid $70M

7-year agreement will help Ontario move away from natural gas, reduce greenhouse gases, sources says

By Keith Leslie, The Canadian Press Posted: Oct 21, 2016 5:50 AM ET Last Updated: Oct 21, 2016 10:06 PM ET

Ontario will import enough electricity from Quebec to power a city of more than 200,000 people under a seven-year agreement signed Friday, but the provinces won't say how much Ontario is paying Hydro Quebec.

Premiers Kathleen Wynne and Philippe Couillard signed the deal, which will see Ontario import up to two terawatt hours of electricity from Quebec annually, allowing the province to reduce its use of natural gas to generate power.

"We wanted to do this, but I said it would have to be a good deal for the people of Ontario," said Wynne. "And it is a good deal for Ontario, and for Quebec."

The agreement is expected to save Ontario's electricity system about $70 million in costs over the seven years, but the two government's cited "commercial sensitivities" for refusing to say how much Ontario will pay for the electricity.

However, Montreal newspaper *La Presse* reports the agreement is worth $1-billion, and calculates Ontario will pay five cents a kilowatt hour for the electricity.

The agreement will also allow Ontario to reduce its greenhouse gas emissions by one million tonnes a year by replacing gas-fired generation with clean power generated from Quebec's hydro dams.

"The reality about gas plants is that they are peaker, they often sit idle when that power is not needed," and are turned on when there's high demand, said Wynne. "The whole point of the gas plants is they are only used when that power is needed."

Wynne declined to say how much the $70 million in reduced costs would impact electricity bills in Ontario, if at all.

- Ontario Liberals rethink $1.9B cap-and-trade projection in uncertain market
- Environmentalists, automakers applaud Ontario's $8.3B climate change plan
- Ontarians see higher hydro bills as consumption comes down

NDP environment critic Peter Tabuns welcomed the import of more clean power from Quebec, but said the impact on consumers' electricity bills and the actual reduction in greenhouse gas emissions from the agreement will be minuscule.

"Scientists and economists will be able to detect it," said Tabuns, "but ordinary people will not be able to detect it."

Ontario plans to join the cap-and-trade market with Quebec and California next January, and Canada's two largest provinces have been finding more ways to work together on initiatives to combat climate change.

There has long been talk of an east-west power grid in Canada, and Couillard said it only makes sense to start with the two largest, neighbouring provinces.

"We always said when this question was mentioned that first and foremost the priority should be given to regional deals, and Quebec-Ontario is the most obvious example of that," said Couillard.

Environmentalists have long urged Ontario to import more clean power from Quebec's hydro-electric dams, but officials always said that would require huge and expensive upgrades to the transmission lines linking the two provinces.

However, the provinces say the existing transmission lines can support their new power agreement.

"The reality seems to be the transmission lines can handle a fair chunk of power and we should be looking at this as an option to deal with high hydro rates," said Tabuns.

Green Party of Ontario Leader Mike Schreiner called the Quebec deal a step in the right direction, but said the province should not extend the life of the Pickering nuclear station or rebuild the reactors at the Darlington station.

"The Liberals made the right decision to import low cost water power from Quebec," Schreiner said in a release. "Now they need to save billions by closing Pickering on schedule and cancelling the Darlington rebuild."

The new agreement will also allow Ontario to keep up to 500 gigawatt hours of power behind Quebec's dams in what is called a "pump storage" system, which will allow the province to reduce its surplus generation.

Wynne's Liberals face daily attacks from the opposition over soaring electricity prices, and the government is looking to do whatever it can to ease upward pressure on rates.

"This is one in the list of things that we are doing to remove costs from the system, whether it's the suspension of the long-term energy plan, whether it's renegotiating the Samsung (green energy) deal ... and removing the eight per cent provincial portion of the HST (from hydro bills) as of January," she said.

Ontario already has a surplus of power, and has signed 20-year contracts for electricity from two new natural-gas fired generating stations being built in Sarnia and Napanee.

Those gas-fired plants were originally going to be built in Mississauga and Oakville until the Liberals cancelled them days before the 2011 election, which the auditor general said would cost ratepayers up to $1.1 billion.

Canada March 8, 2017 9:08 pm

Ontario in talks to buy more power from Quebec

By Brian Hill Associate Producer Global News

Ontario Premier Kathleen Wynne says the province is currently in talks to purchase more hydro electricity from Quebec.

“Our officials are talking as we speak,” said Wynne during a conference call held late Wednesday to outline the province’s Fair Hydro Plan.

> “We’re buying power from Quebec and we’re trading power with Quebec. So I want to do more of that.”

READ MORE: Ontario to slash hydro bills by up to 25 per cent

Wynne did not provide any specifics about what a new agreement with Quebec might look like, but said the sale of electricity between the two provinces is a benefit to Ontarians and "makes sense."

"We've actually signed a couple of agreements with Quebec and both Premier Philippe Couillard and I have said to our officials: 'Continue to explore opportunities.' So that's happening."

WATCH: Premier Kathleen Wynne announces Fair Hydro Plan

Wynne gave no indication of when a new deal might be confirmed. She did, however, say purchasing power from Quebec is an important part of ensuring Ontarians continue to have access to a diversified supply of electricity.

"I can't tell you at this moment whether there's another agreement in the offering, but we certainly are interested in doing everything that we can with Quebec."

READ MORE: Ontario hydro crisis timeline: How did we get here and what comes next?

Asked if it made more sense to increase energy trade between the two provinces rather than spend billions on nuclear projects with a history of massive cost overruns, Wynne said that's one of the reasons why her government decided not to build new nuclear.

"We were on track to build $15 billion worth of new nuclear – we made a decision not to do that," said Wynne, adding it would be irresponsible to rely entirely upon Quebec for electricity.

WATCH: Ontario signs deal to purchase two terawatt-hours of electricity a year from Quebec

In October, Wynne and Couillard announced plans for Ontario to purchase up to two terawatt-hours of electricity from Quebec each year for the next seven years. Worth roughly $1 billion annually, the deal will supply Ontario with enough hydro power to run 230,000 homes.

The deal will also reduce the amount of electricity Ontario generates with natural gas. In total, the government says the plan will save Ontario ratepayers $70 million and remove roughly one million tonnes of greenhouse gas emissions.

READ MORE: Ontario energy minister admits mistake with green energy program

Meanwhile, New York Governor Andrew Cuomo announced in January that his state is also seeking to purchase more electricity from Quebec. The announcement came following an agreement to shut down the state's Indian

Point nuclear facility, which provides roughly a quarter of New York City's electricity supply.

In his annual State of the State address in Manhattan, Cuomo called the Indian Point facility, which is roughly the same age as Ontario's Pickering plant, a "ticking time-bomb."

IESO Response to Questions from the Ontario Clean Air Alliance

1. How much energy (TWh) can Ontario currently import per year from Quebec using the existing interties and transmission system?

Ontario cannot rely on the energy from Quebec to meet the IESO's adequacy requirements without the enhancements to the transmission system that are described in the *Review of Ontario Interties* report. Without those enhancements Ontario would not be able to import the energy when it needs it the most (i.e. under low water conditions and peak load levels in Ontario). To plan the system in a manner capable of reliably delivering power to consumers, firm imports must meet adequacy planning criteria as set out by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC) and the IESO. These take into account variables such as operating characteristics, weather and extreme weather patterns, generator and transmission outages, transmission transfer capabilities, and availability of fuel. All of these variables factor into the analysis to determine the amount of *firm* energy that can be relied upon to serve Ontario consumers. Ontario's ability to import firm energy from Quebec is limited by transmission constraints in the Ottawa area, as noted in the Review of Ontario Interties.

Unlike Ontario's interties with other neighbours (e.g. New York); most of the interties with Quebec are radial interconnections that can only be used to deliver power from very specific generators in Quebec. Ontario has one non-radial intertie with Quebec (the "HVdc intertie"), which can be used to deliver power from any generator in Quebec. The IESO estimates that the non-radial HVdc intertie has the hypothetical capability of delivering between 8.7 and 9.8 TWh of energy from Quebec in 2015. Additionally if the radial interties with Quebec are considered, then this hypothetical range becomes 16.5 TWh to 18.5 TWh. Quebec's ability to export this hypothetical amount of energy is dependent on the availability of the specific generators in Quebec that could connect to the radial interties.

Although Ontario is able to hypothetically import between 16.5 and 18.5 TWh in a year from Quebec, Ontario typically imports 3 TWh of energy and exports 1.6 TWh of energy. This indicates that either energy is not available in Quebec to export to Ontario or it is not economical to export this energy to Ontario.

2. What is the breakdown of the $500 million transmission upgrade cost estimate for each of the three measures listed in Appendix F of *Review of Ontario Interties*?

Item	Cost
New 230 kV double circuit line between Cornwall and Ottawa	$300 M

New 230 kV circuit, approximately 8 km in length, to connect existing circuits in the west of Ottawa	$75 M
Additional voltage control equipment in the Ottawa area	$75 M
Other enhancements (e.g. converting circuit H9A to 230 kV operation)	$50 M

3. **What is the breakdown of the $1.4 billion transmission cost estimate for each of the measures listed in Appendix F and on Page 25 of the Review of Ontario Interties report?**

Item	Cost
New HVdc Interconnection	$1.1 B
New 500 kV double circuit line from Bowmanville to Cherrywood	$225 M
Replacement of existing phase-angle regulating transformers	$40 M

4. **What is the IESO's estimate of how many MW Ontario's firm import capability from Quebec will be increased for every 1 MW of incremental conservation and demand management (CDM) and/or distributed generation (DG) in the west end of Ottawa?**

Reducing the demand in the west end of Ottawa, either through CDM or DG, would increase Ontario capability to source firm capacity from Quebec. However, the precise ratio would depend on a number of variables that would require further clarification, including:

- future transmission system enhancements
- where the CDM and/or DG is located in the Ottawa area (on the 230 kV network or the 115 kV network)
- type of CDM and/or DG

These types of considerations would be part of the work conducted through an Integrated Regional Resource Plan process. For more information please visit: http://www.powerauthority.on.ca/power-planning/regional-planning/greater-ottawa/ottawa.

5. **If the IESO were to assume that imports from Quebec were used to replace the output of Bruce B, would that change the conclusions of the Review with respect to the transmission upgrades needed to accommodate firm water power imports from Quebec?**

   The upgrades identified in the *Review of Ontario Interties* would remain as described in the report. However, the loss of the Bruce B facilities and accompanying energy would necessitate further analysis and likely require transmission system changes to accommodate such a significant change to the overall Ontario electricity system.

THE GLOBE AND MAIL

<p>Hydro-Québec is counting on the adoption of a bill in Massachusetts that would make room for the importation of a huge chunk of hydro power from Canada, and Quebec in particular.</p>
Bloomberg

Hydro-Québec eyes new long-term power accords in U.S. Northeast

Frederic Tomesco And Jim Polson
Published Tuesday, Dec. 06, 2016 02:41PM EST
Last updated Wednesday, Dec. 07, 2016 04:53AM EST

Hydro-Québec, Canada's biggest electricity utility, wants to expand power sales to U.S. Northeast states hungry for green energy to meet climate change goals.

The power supplier can generate as many as 3,000 additional megawatts that could be shipped south of the border without having to build a new dam, Chief Executive Officer Eric Martel said in an interview at Bloomberg headquarters in New York. It has an annual generating capacity of about 37,000 megawatts.

"We can probably already commit to 3,000 megawatts without building anything other than the transmission line," Martel said Tuesday. "Today we are limited by the number of transmission lines."

Martel wants to double revenue by 2030, targeting takeovers in the Americas and Europe while increasing sales of hydro-generated power to the U.S. Hydro-Québec hopes to win long-term contracts from states like Massachusetts and New York that want to lower emissions of heat-trapping carbon dioxide.

“The states we are working with, mainly New England and New York, are really engaged in reducing emissions. They have their own targets.”

Power sales outside Quebec generated $1.7-billion ($1.3-billion U.S.) of revenue last year, representing about 13 per cent of the company’s sales. Three lines in the planning process– the Champlain Hudson Power Express, the New England Clean Power Link, and Northern Pass – could allow the provincially owned utility to boost exports south.

“Those three projects are about the same size, about 1,000 megawatts of power each, and we could participate in all three,” Martel said in the interview. “We would be comfortable doing that if we got a long-term commitment.”

With most exports currently sold at spot rates, Hydro-Québec would prefer to sign long-term, fixed-rate contracts for the additional power, Martel said. Agreements could last as long as 40 years, he added.

“There is interest on our side and from our customers to have longer-term contracts with stability on pricing,” he said. “That’s one thing that we are working on for the future.”

Hydro-Québec had net income of about $2.2-billion on revenue of about $9.9-billion in the first nine months of 2016. More than 99 per cent of the power that the provincial-owned utility generates comes from renewable sources, according to the company’s 2015 annual report.

By 2030, power exports and acquisitions could propel annual revenue to about $27-billion, with annual profit of about $5.2-billion, Martel said Tuesday.

Can water power from Quebec avoid the need for the Darlington Re-Build?

ONTARIO CLEAN AIR ALLIANCE RESEARCH | www.cleanairalliance.org APRIL 7, 2015

The Ontario Clean Air Alliance (OCAA) is recommending that Ontario sign a long-term electricity contract with Hydro Quebec to lower the province's electricity bills and permit the cancellation of the proposed Darlington Nuclear Station Re-Build Project.

According to our analysis, a long-term electricity supply contract with Hydro Quebec at a price of 6 cents per kWh would reduce our electricity costs by at least $14 billion over 20 years by permitting the cancellation of the higher cost Darlington Re-Build Project.[1]

In this context, it is important to note that in 2010 Hydro Quebec signed a 26-year electricity export deal with Vermont at a price of 5.8 cents per kWh.[2]

However, in its October 2014 report, *Review of Ontario Interties*, the Independent Electricity System Operator (IESO) has suggested that water power imports from Quebec may not be a viable option to replace Darlington's aging nuclear reactors since "Quebec has a winter peaking system and is currently capacity limited in the winter".[3]

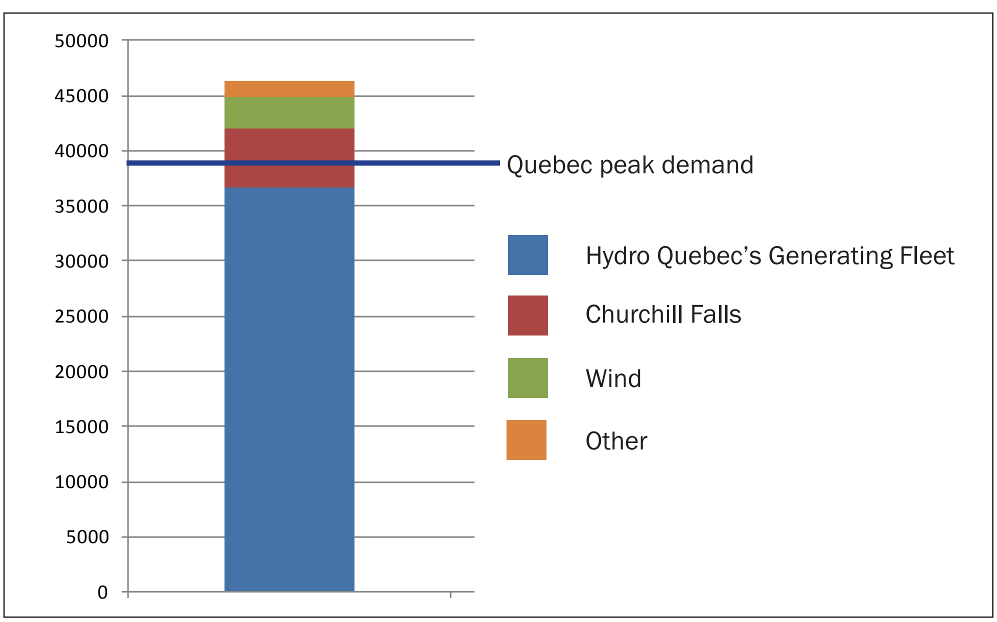
This concern was re-iterated by Kim Warren, Chief Operating Officer of the IESO, on the CBC Radio show, *Ontario Today*, on March 25, 2015.

Hydro Quebec's Capacity and Peak Winter Demand

As Figure 1 reveals, in 2014, Hydro Quebec's total generation capacity [46,314 megawatts (MW)] exceeded its winter peak day demand [38,743 MW] by 20%.[4]

Hydro Quebec's generation capacity includes its own generating fleet, which has a capacity of 36,643 MW, plus an additional 9,671 MW under contract to Hydro Quebec, including 5,428 MW from Churchill Falls.[5]

Figure 1: Hydro Quebec's Capacity and Demand, 2014

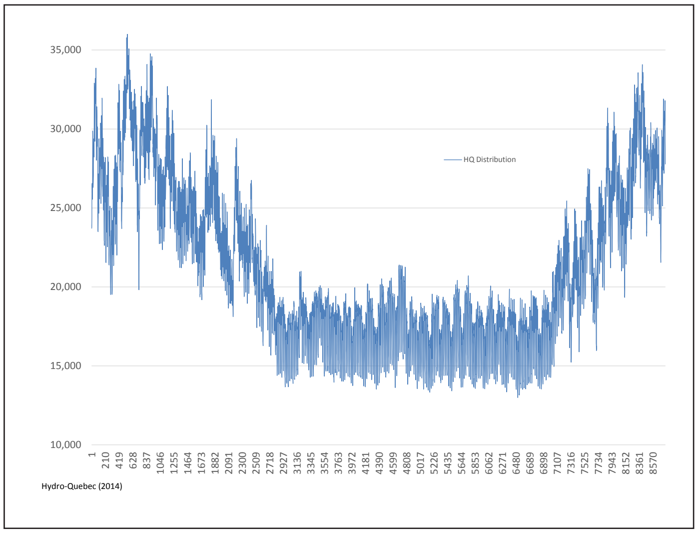


Hydro Quebec's Annual Hourly Demand Profile

Figure 2 plots Quebec's demand for electricity during each hour of 2013. It reveals three key facts.

- First, Quebec's demand for electricity spikes on cold winter days.
- Second, these spikes in demand are needle peaks which only last for brief periods.
- Third, Quebec's annual *peak* hour demand for electricity is more than 80% greater than its *average* annual hourly demand.[6]

Figure 2: Hydro Quebec's 2013 Hourly Demand for Electricity[7]



Analysis

While Quebec may not wish to export power to Ontario during some very cold winter days, a review of Figures 1 and 2 strongly suggests that Quebec has surplus generation capacity for at least 99% of the hours of the year. During the 1% of the year when Quebec water power may not be available, Ontario could meet its electricity needs by increasing the output of its natural gas-fired power plants. As the IESO has noted, "Ontario, by comparison, is a summer-peaking province, which means the province has spare capacity in the winter".[8]

In this context, it is important to remember that nuclear generating stations are also **not** available for 100% of the hours of the year. In fact, the Darlington Nuclear Station's average annual capacity factor since it commenced operation in the 1990s has been only 83%.[9]

In conclusion, Ontario's base-load electricity needs can be met at a lower economic and environmental cost by an integrated combination of water power from Quebec (99%) and natural gas-fired generation (1%) than by re-built nuclear reactors (83%) and natural gas-fired generation (17%).

Endnotes

1 Ontario Clean Air Alliance Research Inc., *Ontario's Long-Term Energy Plan: A One Year Review*, (November 2014).

2 Hydro Quebec, *Press Release*, "Vermont and Quebec reach new energy agreement", (August 12, 2010).

3 IESO, *Review of Ontario Interties*, (October, 2014), page 22.

4 Hydro Quebec's reported peak demand includes the demands of their "interruptible" customers which Hydro Quebec is not obliged to serve during peak demand periods. Hydro Quebec, *Annual Report 2014*, page 2.

5 Hydro Quebec, *Annual Report 2014*, page 2.

6 Hydro Quebec, *Annual Report 2014*, page 2.

7 Pierre-Olivier Pineau, Professor, HEC Montreal, "Can Ontario and Quebec benefit from more electricity market integration? A long-term perspective", Power Point Presentation for York University Conference, January 9, 2015.

8 IESO, *Review of Ontario Interties*, (October, 2014), page 22.

9 Ontario Energy Board Docket No. EB-2013-0321, Undertaking J14.3.

Thanks to the Echo Foundation and the Taylor Irwin Family Foundation for their support

ONTARIO CLEAN AIR ALLIANCE RESEARCH

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November 2015

ONTARIO POWER GENERATION

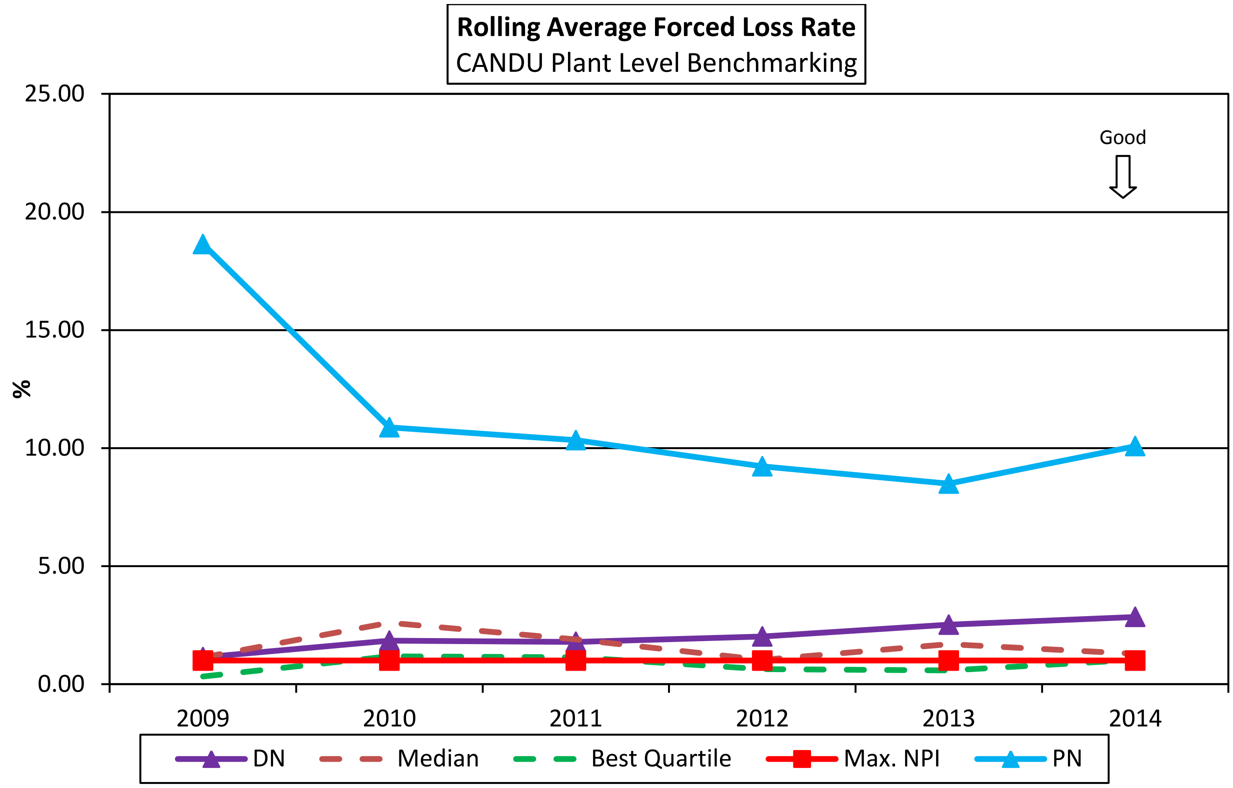



ONTARIO POWER GENERATION NUCLEAR

2015 NUCLEAR BENCHMARKING REPORT

Non-Confidential – For General Release

Nuclear Finance – Business Planning and Benchmarking


Rolling Average Forced Loss Rate
CANDU Plant Level Benchmarking
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Best Quartile
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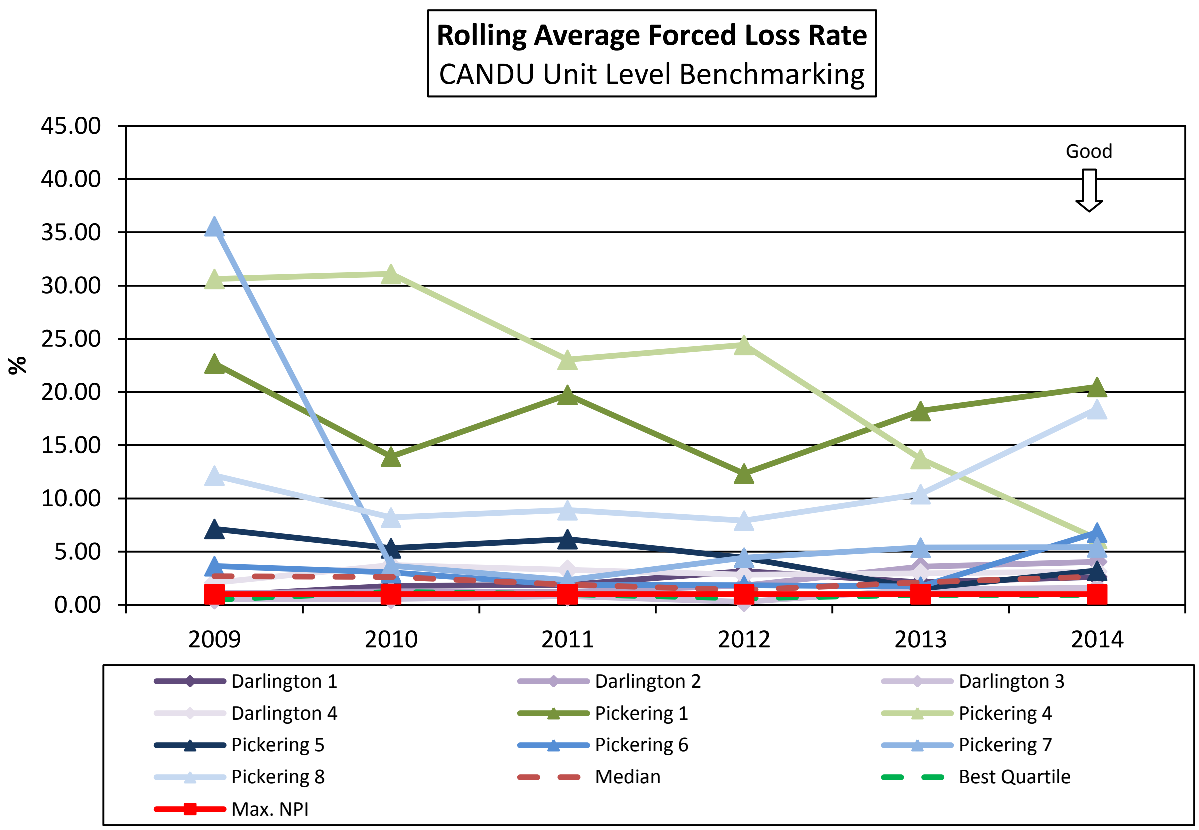
Rolling Average Forced Loss Rate
CANDU Unit Level Benchmarking
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Pickering 6
Pickering 7
Pickering 8
Median
Best Quartile
Max. NPI

3-Year Non-Fuel Operating Cost per MWh

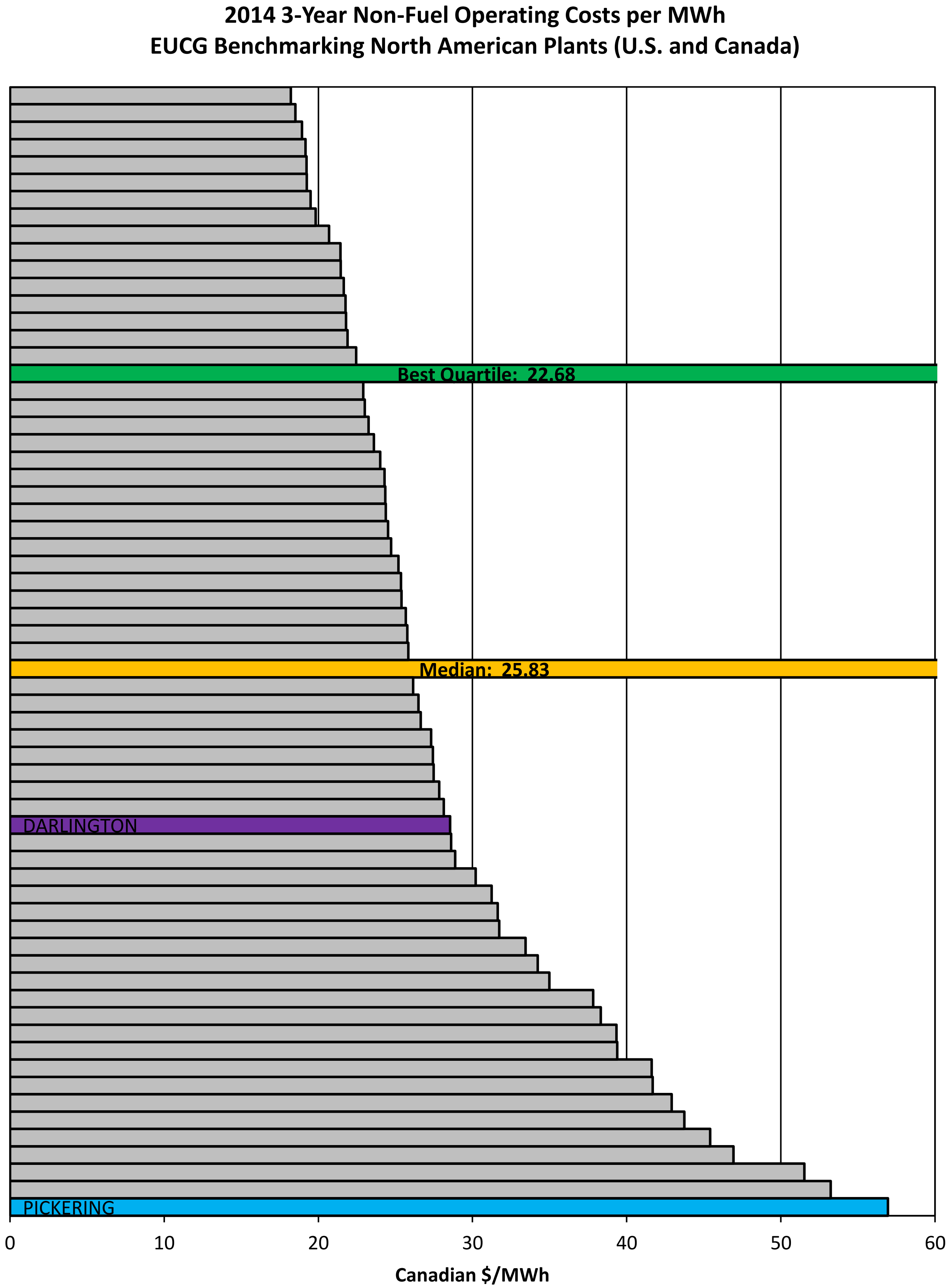

Table 13: NPI Plant Level Performance Summary (North American Panel)

Indicator	2014 Actuals				
	NPI Max	Best Quartile	Median	Pickering	Darlington
Rolling Average Industrial Safety Accident Rate (#/200k hours worked)	0.20	0.00	0.02	0.03	0.06
Rolling Average Collective Radiation Exposure (person-rem per unit)	80.00	31.30	43.30	82.24	69.06
Fuel Reliability Index (microcuries per gram)	0.000500	0.000001	0.000004	0.001580	0.000158
2-Year Reactor Trip Rate (# per 7,000 hours)	0.500	0.000	0.235	0.363	0.000
3-Year Auxiliary Feedwater System Unavailability (#)	0.0200	0.0029	0.0043	0.0181	0.0000
3-Year Emergency AC Power Unavailability (#)	0.0250	0.0098	0.0132	0.0000	0.0000
3-Year High Pressure Safety Injection Unavailability (#)	0.0200	0.0020	0.0033	0.0000	0.0000
Rolling Average Forced Loss Rate (%)	1.00	0.76	1.55	10.08	2.85
Rolling Average Unit Capability Factor (%)	92.0	93.2	90.4	74.5	89.4
Rolling Average Chemistry Performance Indicator (Index)	1.01	1.00	1.00	1.04	1.00
WANO NPI (Index)	Not Applicable	98.1	93.5	64.3	92.1

FACING CLIMATE CHANGE

Greenhouse Gas Progress Report 2016

Environmental Commissioner of Ontario

Chapter 4. Cap and Trade

4.1 Introduction

Ontario's new *Climate Change Mitigation and Low-carbon Economy Act, 2016* ("Climate Act") and its two regulations - a cap and trade regulation, *O. Reg. 144/16*[1], and a reporting regulation, *O. Reg. 143/16*[2] - set out the legal framework to reduce greenhouse gases (GHGs) in the province. The central feature is a cap and trade program for GHG emissions. The cap and trade program has already come into effect; the first four-year compliance period begins January 1, 2017.

A cap and trade program is an indirect way of putting a price on GHG emissions.

A cap and trade program is an indirect way of putting a price on GHG emissions (see text box 4.1.1). Covered emitters[3] must obtain, and subsequently remit to the government, an amount of allowances equal to their emissions over the term of the compliance period. Emitters can obtain allowances from government for free or at an auction, or by buying them from other companies (the trade).[4]

Allowances are effectively permits to emit GHG pollution. The government limits, and gradually cuts, the total number of allowances available, thereby driving down the amount of emissions that covered facilities (and fuel consumers) can lawfully release each year (this is the cap). As allowances become scarce, their cost should rise. The rising cost of the allowances, and the prospect of increasing scarcity, gives emitters (and fuel consumers) a predictable financial incentive to reduce their carbon pollution.

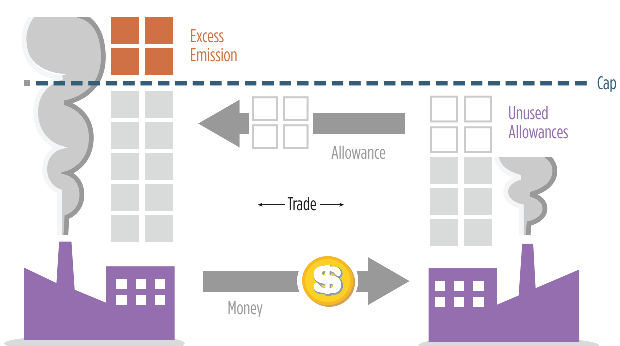

Figure 1: Schematic of how cap and trade works

Source: Adapted from Ontario's Climate Change Strategy (2015)

For an introduction to the basic functioning of a cap and trade program, see Appendix A (available online only at eco.on.ca), which draws on the excellent work of Quebec's Sustainable Development Commissioner.

4.1.1 Why Put a Price on Carbon?

The ECO, many major companies, and economists around the world have long supported carbon pricing, i.e., putting a price on GHG pollution. One of the major reasons for such a thick carbon blanket in Earth's atmosphere (see Chapter 1) is that polluting the atmosphere with greenhouse gases has long been free. In the Paris Agreement[5], governments around the world recognized the need for stronger efforts to fight carbon pollution. Putting a price on carbon pollution gives businesses and citizens an economic incentive to reduce their GHG emissions.

In 2016, about 40 countries and over 20 subnational governments – or about 13 per cent of the world's GHG emissions – had a carbon pricing initiatives in place.[6] Many more are planned for 2017, including the world's largest emitter, China. As carbon pricing policies become more widespread, they evolve and countries learn from each other.[7]

There are two main ways to put a price on carbon pollution: a direct carbon tax, and/or a cap and trade program. Each can work well, or badly, depending on design and implementation. A carbon tax and cap and trade can be used individually or together. British Columbia chose a carbon tax. Ontario and Quebec chose cap and trade. Most calculations show that the price of carbon has to be significantly higher than current levels in order to drive significant emission reductions.[8]

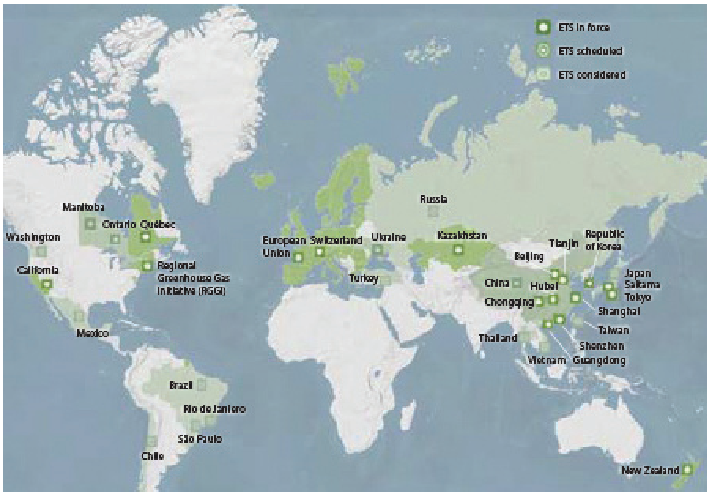

Figure 2: Cap and trade spreading around the world

Source: World Bank's PMR-ICAP Emissions Trading 2016 Handbook

The cap and trade program is just one element of Ontario's new GHG reduction strategy. Others include:

- **A policy framework:** a provincial climate change strategy,[9] 5-year action plan[10], a co-ordinated review of land-use planning, and the aforementioned *Climate Change Mitigation and Low-carbon Economy Act, 2016*. A second new law, the *Waste-Free Ontario Act, 2016* could play an important supporting role.
- **Partnerships:** Ontario signed a climate policy memorandum of understanding (MOU) with Quebec[12] and Manitoba,[13] a joint declaration with Quebec and Mexico,[14] hosted the first Climate Summit of the Americas,[15] and signed the Under 2 MOU, a voluntary commitment by subnational governments to reduce GHGs.[16] Ontario is working closely with California and Quebec to create a linked carbon market. Ontario is actively participating in various working groups to create a Pan-Canadian climate change framework with the federal government and other provinces and territories.
- **Use of proceeds:** In 2017-2020, the government expects to earn annual proceeds of $1.8-1.9 billion from the sale of GHG allowances, which it plans to spend through the Greenhouse Gas Reduction Account. For details on what the government proposes, and issues around transparency and accountability for the use of these funds, see *Chapter 5: Spending the money well*.

4.2 Key Design Issues for Policy Makers

All GHG cap and trade programs are complex. What key design choices did Ontario make? How will they affect the success of the program in reducing Ontario's GHG emissions? Did the chosen design anticipate and address the issues that have arisen in other jurisdictions with cap and trade programs? Will the program produce GHG reductions within Ontario? Will the reductions be at the lowest cost?

We address these questions in three main categories, based on the stakeholders for whom they are a primary concern: policymakers, capped emitters (emitters who must submit allowances) and the public. We begin here with the key design issues for policymakers.

All GHG cap and trade programs are complex.

4.2.1 The Emitters: Who Needs Allowances?

Who is part of the cap and trade program, i.e., required to surrender allowances equivalent to their GHG emissions? Using the National Inventory Report data (see Chapter 2), the Ministry of the Environment and Climate Change (MOECC) estimates that the cap and trade program will be mandatory for 82 per cent of Ontario's direct GHG emissions.[17] In 2017, Ontario's total GHG emissions are predicted to be 172.5 Mt.[18]

Entities engaged in the following economic activities require allowances for their own direct emissions and those of most[19] of their customers, and must buy the allowances:

- Importers of electricity;
- Generators of gas-fired electricity who are connected directly to international or inter-provincial pipelines;[20]

Cap and trade program will be mandatory for 82 per cent of Ontario's direct GHG emissions.

- Natural gas distributors; and,
- Wholesale vendors of transportation and other liquid fuels, including propane and fuel oil.

In 2017, these sectors are forecast to be responsible for roughly 100 Mt of GHG emissions.[21]

Entities engaged in the following economic activities require allowances for their own direct emissions, but will receive most of them free of charge for the 2017-2020 compliance period:

- large industrial and commercial operations (such as manufacturing, base metal processing, steel, pulp and paper, and food processing); and,
- institutions (e.g., universities).[22]

In 2017, these sectors are forecast to be responsible for roughly 40 Mt of GHG emissions.[23]

Ontario's remaining 2017 emissions are forecast to be roughly 31 Mt,[24] primarily from sectors such as agriculture, waste management and forestry. These sectors do not require allowances for their direct emissions in 2017 – 2020, although their suppliers of petroleum products, natural gas and electricity will have paid for allowances for their fossil fuel use. GHG reductions and co-benefits in these sectors are intended to be encouraged by a program of offset credits, and perhaps by regulations.[25]

4.2.2. Setting the Cap

The cap is the government-imposed limit on carbon allowances for all sectors covered by the regulation, which goes down over time. It is supposed to be initially set to match their collective projected carbon emissions for the first year. If set correctly, the cap should force emission reductions as the number of

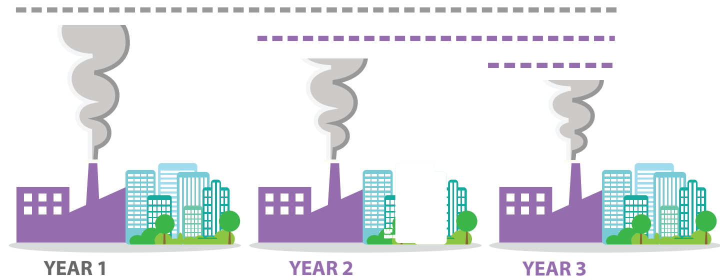

Figure 3: Cap declines over time

Source: Ontario's Climate Change Strategy (2015)

available allowances gradually declines and their price may increase.

An initial cap that is set too high may do little to reduce emissions, yet can be difficult to avoid. First, setting the cap is difficult because of the many unpredictable factors that influence future GHG emissions, including energy prices, industry output, new technology, fuel costs and economic growth rates. Second, there is a political incentive to set a fairly loose cap in the program's early years, to make it easy for companies to comply, and to help the program gain acceptance. Other programs, including those of the Regional Greenhouse Gas Initiative and the European Union, set high initial caps, resulting in limited emission reductions and low allowance prices. Third, linking to other jurisdictions who have surplus allowances can also loosen a cap; see Chapter 4.2.6.

Ontario set its 2017 cap by projecting emissions into the future based on current trends and the government's best estimates of factors such as economic growth. This is notoriously difficult to do accurately.[26] The cap decline rate[27] of just over 4 per cent per year to 2020[28] is quite aggressive, and is declining faster than the caps of our partner jurisdictions in their initial years.[29,30] Ontario's cap decline rates in later compliance periods (post-2020) are currently unknown, but will have to continue to be aggressive to meet the *Climate Act*'s GHG reduction target of 37 per cent below 1990 levels by 2030.

How many allowances will Ontario issue?

Allowances will be created under section 30 of the *Climate Act*. As per O. Reg. 144/16, section 54, the

ED Interrogatory #28

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

Interrogatory

Reference:
Reference: "Pickering extension to 2022/2024 yields a net benefit in the range of $0.3B-$0.6B…" Exhibit F2-2-3, Attachment 1, Page 6 of 116

With reference to the above captioned study, please provide its assumptions with respect to the following inputs for each year of its analysis:

(a) Pickering's total installed capacity (MW);

(b) Pickering's available capacity (MW) at the time of Ontario's peak annual demand;

(c) Pickering's generation (MWh);

(d) The avoided generation (MWh), by fuel type, as a result of Pickering's extended operation;

(e) Pickering's rolling average forced loss rate as defined by OPG's *2015 Nuclear Benchmarking Report;*

(f) The installed capacity (MW) of the replacement peaking generation capacity;

(g) The available capacity (MW) of the replacement peaking generation capacity at the time of Ontario's peak annual demand;

(h) Pickering's fuel and operating cost per kWh;

(i) Pickering's incremental capital expenditures to permit its extension to 2022/24;

(j) The natural gas price at Henry Hub;

(k) Ontario's carbon price;

(l) Ontario's incremental peaking requirements (MW) to meet the NPCC resource adequacy criterion if Pickering is not extended to 2022/24; and

(m) Ontario's cost per MW of incremental peaking requirements to meet the NPCC resource adequacy criterion if Pickering is not extended to 2022/24.

Response

The following response has been prepared by the IESO, except for part (e), which has been provided by OPG:

(a) The following table summarizes Pickering's total installed capacity (MW) in different scenarios:

	Case with +65 TWh of Pickering Production, Pickering to 2020	Case with +65 TWh of Pickering Production, Pickering to 2022/2024	Case with +62 TWh of Pickering Production, Pickering to 2020	Case with +62 TWh of Pickering Production, Pickering to 2022/2024
2015	3094	3094	3094	3094
2016	3094	3094	3094	3094
2017	3094	3094	3094	3094
2018	3094	3094	3094	3094
2019	3094	3094	3094	3094
2020	3094	3094	3094	3094
2021	0	3094	0	3094
2022	0	3094	0	3094
2023	0	2064	0	2064
2024	0	2064	0	2064

(b) The following table summarizes Pickering's estimated available capacity (MW) at the time of Ontario's peak annual demand. The available capacity is lower than the installed capacity shown in part (a) because of forced and planned outages among Pickering units.

	Case with +65 TWh of Pickering Production, Pickering to 2020	Case with +65 TWh of Pickering Production, Pickering to 2022/2024	Case with +62 TWh of Pickering Production, Pickering to 2020	Case with +62 TWh of Pickering Production, Pickering to 2022/2024
2015	2579	2579	2579	2579
2016	2578	2578	2578	2578
2017	2579	2063	2063	1547
2018	2064	2063	2064	2063
2019	2579	2063	2064	2063
2020	3094	3094	3094	2579
2021	0	3094	0	3094
2022	0	3094	0	3094
2023	0	2064	0	2064
2024	0	2064	0	2064

(c) The following table summarizes Pickering's generation (MWh) in different scenarios:

	Case with +65 TWh of Pickering Production, Pickering to 2020	Case with +65 TWh of Pickering Production, Pickering to 2022/2024	Case with +62 TWh of Pickering Production, Pickering to 2020	Case with +62 TWh of Pickering Production, Pickering to 2022/2024
2015	23,887,836	23,887,836	23,887,836	23,887,836
2016	21,269,076	21,269,076	21,269,076	21,269,076
2017	20,130,936	19,240,032	20,130,936	19,240,032
2018	20,585,928	19,300,818	20,585,928	19,424,418
2019	21,442,720	19,593,600	20,651,680	19,049,760
2020	24,289,248	20,884,154	23,930,808	19,902,158
2021	-	19,730,040	-	18,963,000
2022	-	21,301,800	-	20,312,064
2023	-	14,836,032	-	13,956,768
2024	-	16,716,336	-	16,295,280

(d) The following tables summarize the avoided generation (MWh) by fuel type as a result of Pickering's extended operation in the plus 65 TWh of Pickering Production case. Blue and positive numbers represent increase in production and red and negative numbers represent decrease in production as a result of Pickering's extended operation. Please note that besides Ontario resources, Pickering's extended operation also has impact on the transactions of interconnections.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Gas	0	0	**332,680**	**274,744**	**470,923**	**456,172**	**-6,756,544**	**-6,473,855**	**-4,730,629**	**-4,167,951**
Hydroelectric	0	0	**19,589**	**61,943**	**99,731**	**303,070**	**-373,796**	**-183,024**	**-106,101**	**-228,202**
Wind	0	0	**30,636**	**19,706**	**21,952**	**213,356**	**-42,286**	0	0	**-11,202**

The following tables summarize the avoided generation (MWh) by fuel type as a result of Pickering's extended operation in the plus 62 TWh of Pickering Production case. Blue and positive numbers represent increase in production and red and negative numbers represent decrease in production as a result of Pickering's extended operation. Please note that besides Ontario resources, Pickering's extended operation also has impact on the transactions of interconnections.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Gas	0	0	**332,680**	**209,640**	**351,228**	**763,473**	**-6,424,056**	**-6,111,821**	**-4,473,760**	**-4,108,400**
Hydroelectric	0	0	**19,589**	**61,943**	**83,710**	**287,308**	**-357,001**	**-182,338**	**-99,313**	**-219,580**
Wind	0	0	**30,636**	**19,706**	**16,050**	**140,642**	**-28,515**	0	0	**-11,202**

(e) Pickering's rolling average forced loss rate in 2014 as defined by OPG's 2015 Nuclear Benchmarking Report was 10.08% (see Ex. F2-1-1 Attachment 1, p. 51).

(f) The following table summarizes the installed capacity (MW) of the replacement generation capacity.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Capacity Deficit of the case of Pickering to 2020	0	0	0	0	0	0	2,316	2,301	2,931	1,090
Capacity Deficit of the case of Pickering to 2022/2024	0	0	0	0	0	0	0	0	867	0
Installed capacity (MW) of replacement peaking generation capacity	0	0	0	0	0	0	2,316	2,301	2,064	1,090

(g) The answer is the same as part (f). For simplicity, it is assumed that 100% of replacement peaking generation capacity is available at the time of Ontario's peak annual demand.

(h) The following table summarizes Pickering's fuel cost per KWh (2015 real cents per KWh). The OM&A expenditures is included in the answer of part (i). These values were provided to the IESO by OPG.

	Case with +65 TWh of Pickering Production, Pickering to 2020	Case with +65 TWh of Pickering Production, Pickering to 2022/2024	Case with +62 TWh of Pickering Production, Pickering to 2020	Case with +62 TWh of Pickering Production, Pickering to 2022/2024
2016	0.58	0.58	0.58	0.58
2017	0.57	0.57	0.57	0.57
2018	0.54	0.54	0.54	0.54
2019	0.53	0.53	0.53	0.53
2020	0.53	0.53	0.53	0.53
2021		0.53		0.53
2022		0.53		0.53
2023		0.54		0.54
2024		0.54		0.54

(i) The following table summarizes Pickering's incremental capital and total OM&A expenditures (2015 real $M) to permit its extension to 2022/24. These values were provided to the IESO by OPG.

2016	2017	2018	2019	2020	2021	2022	2023	2024
$7	$35	$79	$145	$218	$987	$902	$631	$494

(j) The following table summarizes the projected natural gas price at Henry Hub (2015 real US$/MMBTU). Sensitivity cases were also considered.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015	4.38	4.36	4.27	3.95	3.95	3.97	3.99	3.99	4.00	4.01	4.04	4.19
2016	4.99	4.96	4.87	4.52	4.52	4.54	4.57	4.57	4.58	4.60	4.69	4.87
2017	5.54	5.50	5.40	5.04	5.05	5.07	5.10	5.10	5.11	5.13	5.24	5.45
2018	5.53	5.50	5.40	5.04	5.04	5.06	5.10	5.10	5.10	5.12	5.24	5.45
2019	5.53	5.50	5.39	5.04	5.04	5.06	5.09	5.10	5.10	5.12	5.23	5.44
2020	5.53	5.49	5.39	5.03	5.04	5.06	5.09	5.09	5.10	5.12	5.23	5.44
2021	5.52	5.49	5.39	5.03	5.03	5.05	5.09	5.09	5.09	5.11	5.23	5.43
2022	5.52	5.49	5.38	5.03	5.03	5.05	5.08	5.09	5.09	5.11	5.22	5.43
2023	5.52	5.49	5.38	5.03	5.03	5.05	5.08	5.09	5.09	5.11	5.22	5.43
2024	5.52	5.49	5.38	5.03	5.03	5.05	5.08	5.09	5.09	5.11	5.22	5.43
2025	5.52	5.49	5.38	5.03	5.03	5.05	5.08	5.09	5.09	5.11	5.22	5.43
2026	5.52	5.49	5.38	5.03	5.03	5.05	5.08	5.09	5.09	5.11	5.22	5.43
2027	5.52	5.49	5.38	5.03	5.03	5.05	5.08	5.09	5.09	5.11	5.22	5.43
2028	5.52	5.49	5.38	5.03	5.03	5.05	5.08	5.09	5.09	5.11	5.22	5.43
2029	5.52	5.49	5.38	5.03	5.03	5.05	5.08	5.09	5.09	5.11	5.22	5.43
2030	5.52	5.49	5.38	5.03	5.03	5.05	5.08	5.09	5.09	5.11	5.22	5.43
2031	5.52	5.49	5.38	5.03	5.03	5.05	5.08	5.09	5.09	5.11	5.22	5.43
2032	5.52	5.49	5.38	5.03	5.03	5.05	5.08	5.09	5.09	5.11	5.22	5.43

(k) Ontario’s carbon price is zero in all scenarios.

(l) The assessment of replacement peaking generation capacity in part (f) accounts for the NPCC resource adequacy criterion.

(m) As shown in EB-2016-0152 Exhibit F2-2-3 Attachment 1 Page 93 of 116, additional peaking requirements are assumed to be met by new unspecified capacity based resources priced at SCGT (represents the least-cost supply resource), which is $130/KW-year from a ratepayer perspective based on York Region SCGT. DR, NUG contract renewals, coal conversions, or firm imports can also provide capacity if similarly prices.

ED Interrogatory #29

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

Interrogatory

Reference:

Reference: "Pickering extension to 2022/2024 yields a net benefit in the range of $0.3B-$0.6B…" Exhibit F2-2-3, Attachment 1, Page 6 of 116

For each year of the Pickering extension to 2022/2024 analysis, please provide the IESO's *best current estimate* of:

a) Pickering's total installed capacity (MW);

b) Pickering's available capacity (MW) at the time of Ontario's peak annual demand;

c) Pickering's generation (MWh);

d) The avoided generation (MWh), by fuel type, as a result of Pickering's extended operation;

e) Pickering's rolling average forced loss rate as defined by OPG's *2015 Nuclear Benchmarking Report*;

f) The available capacity at the time of Ontario's peak annual demand of new gas-fired peaking capacity as a percent of its installed capacity;

g) Pickering's fuel and operating cost per kWh;

h) Pickering's incremental capital expenditures to permit its extension to 2022/24;

i) Natural gas prices at Henry Hub;

j) The NYMEX natural gas futures prices at Henry Hub;

k) Ontario's carbon prices;

l) Ontario's incremental peaking requirements (MW) to meet the NPCC resource adequacy criterion if Pickering is not extended to 2022/24;

m) Ontario's cost, per MW, of meeting the NPCC resource adequacy criterion if Pickering is not extended to 2022/24 by: a) domestic supply resources; b) demand response resources; c) energy efficiency resources; and c) electricity imports from neighbouring jurisdictions.

Please fully justify all your responses. In particular, please state your methodology and assumptions for calculating Pickering's available capacity (MW) at the time of Ontario's peak annual demand.

Response

The following response has been prepared by the IESO, except for part (e), which has been provided by OPG:

(a) The following table summarizes Pickering's total installed capacity (MW) as shown in 2016 Ontario Planning Outlook.

2016	3094
2017	3094
2018	3094
2019	3094
2020	3094
2021	3094
2022	3094
2023	2064
2024	2064

(b) The following table summarizes Pickering's available capacity (MW) at the time of Ontario's peak annual demand as shown in 2016 Ontario Planning Outlook.

2016	2578
2017	2579
2018	2063
2019	2063
2020	3094
2021	2579
2022	3094
2023	2064
2024	2064

(c) The following table summarizes Pickering's generation (MWh) as shown in 2016 Ontario Planning Outlook.

2016	21,177,276
2017	19,351,248
2018	19,411,674
2019	19,602,972
2020	20,007,314
2021	18,972,174
2022	20,528,508
2023	13,913,424
2024	16,332,432

(d) Not applicable, as the simulation run of Pickering operates to 2020 is not available.

(e) Please see Ex. L-6.5-7 ED-28 part (e).

(f) Not applicable, as the simulation run of Pickering operates to 2020 is not available.

(g) The IESO has not analyzed any updates to Pickering's fuel and operating cost per KWh since the analysis of November 2015, which is available at EB-2016-0152 Exhibit F2-2-3 Attachment 1 Page 1 to Page 10.

(h) The IESO has not analyzed any updates to Pickering's incremental capital expenditures to permit its extension to 2022/24 since the analysis of November 2015, which is available at EB-2016-0152 Exhibit F2-2-3 Attachment 1 Page 1 to Page 10.

(i) The following table summarizes the natural gas price at Henry Hub (2016 real US$/MMBTU) as shown in 2016 Ontario Planning Outlook.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	2.39	2.38	2.33	2.13	2.13	2.15	2.18	2.20	2.19	2.22	2.28	2.40
2017	3.14	3.13	3.07	2.80	2.80	2.83	2.87	2.89	2.88	2.91	2.99	3.16
2018	3.61	3.60	3.53	3.22	3.22	3.25	3.30	3.32	3.31	3.35	3.44	3.63
2019	4.06	4.05	3.97	3.63	3.62	3.66	3.71	3.74	3.73	3.77	3.87	4.09
2020	4.25	4.24	4.16	3.80	3.79	3.83	3.88	3.91	3.91	3.95	4.06	4.28
2021	4.25	4.24	4.16	3.80	3.79	3.83	3.88	3.91	3.91	3.95	4.06	4.28
2022	4.25	4.24	4.16	3.80	3.79	3.83	3.88	3.91	3.91	3.95	4.06	4.28
2023	4.25	4.24	4.16	3.80	3.79	3.83	3.88	3.91	3.91	3.95	4.06	4.28
2024	4.25	4.24	4.16	3.80	3.79	3.83	3.88	3.91	3.91	3.95	4.06	4.28
2025	4.25	4.24	4.16	3.80	3.79	3.83	3.88	3.91	3.91	3.95	4.06	4.28
2026	4.25	4.24	4.16	3.80	3.79	3.83	3.88	3.91	3.91	3.95	4.06	4.28
2027	4.25	4.24	4.16	3.80	3.79	3.83	3.88	3.91	3.91	3.95	4.06	4.28
2028	4.25	4.24	4.16	3.80	3.79	3.83	3.88	3.91	3.91	3.95	4.06	4.28
2029	4.25	4.24	4.16	3.80	3.79	3.83	3.88	3.91	3.91	3.95	4.06	4.28
2030	4.25	4.24	4.16	3.80	3.79	3.83	3.88	3.91	3.91	3.95	4.06	4.28
2031	4.25	4.24	4.16	3.80	3.79	3.83	3.88	3.91	3.91	3.95	4.06	4.28
2032	4.25	4.24	4.16	3.80	3.79	3.83	3.88	3.91	3.91	3.95	4.06	4.28
2033	4.25	4.24	4.16	3.80	3.79	3.83	3.88	3.91	3.91	3.95	4.06	4.28
2034	4.25	4.24	4.16	3.80	3.79	3.83	3.88	3.91	3.91	3.95	4.06	4.28
2035	4.25	4.24	4.16	3.80	3.79	3.83	3.88	3.91	3.91	3.95	4.06	4.28

(j) The NYMEX natural gas future prices at Henry Hub can be found at this link:

http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html

(k) The following table summarizes Ontario's carbon price (2016 real US$/kg CO2) as shown in 2016 Ontario Planning Outlook.

2016	0
2017	0.013391
2018	0.014074
2019	0.014763
2020	0.015487
2021	0.016246
2022	0.017043
2023	0.017878
2024	0.018754
2025	0.019674
2026	0.020638
2027	0.02165
2028	0.022711
2029	0.023824
2030	0.024992
2031	0.026217
2032	0.027503
2033	0.028851
2034	0.030265
2035	0.031749

(l) Not applicable, as the simulation run of Pickering operates to 2020 is not available.

(m) Not applicable, as the simulation run of Pickering operates to 2020 is not available.

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

Line No.	Constant 2015 M$	2016 (a)	2017 (b)	2018 (c)	2019 (d)	2020 (e)	2021 (f)	Source (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.


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)

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**

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.

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Standing Committee on Estimates

Ministry of Energy

Chair: Cheri DiNovo
Clerk: Eric Rennie

Assemblée législative
de l'Ontario

Deuxième session, 41e législature

Journal des débats (Hansard)

Mercredi 26 octobre 2016

Comité permanent des budgets des dépenses

Ministère de l'Énergie

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.

1520

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 five cents a kilowatt hour—which is cheaper than Pickering—to see if you can replace power from Pickering that we will be paying a lot more for until 2024?

Hon. Glenn Thibeault: As I was saying, the agreement that we had over the last three years was a landmark deal. We're excited to have the opportunity to have this deal with Quebec. The IESO and Hydro-Québec were the two entities that sat down and had that conversation. I know the IESO is always in negotiations and always looking for ways to benefit the province. But when it comes to those specifics, I do believe that the deputy would have more details for you.

Mr. Peter Tabuns: Are they negotiating a deal to replace the power from Pickering?

Mr. Serge Imbrogno: I would just add that the power from Pickering is different in the sense that—it's baseload power, but it's 24/7/365 and an 80%-plus capacity factor. So this is our baseload power. The negotiations with Quebec were really at the margins to try to reduce our gas burn, so it's not throughout the year. It's a different type of negotiation. That's why Pickering provides us with such an important part of extending that life, because of the type of power we get and when we get it.

Mr. Peter Tabuns: So you're not negotiating with them.

Mr. Serge Imbrogno: I think we always have discussions between the IESO and Hydro-Québec—

Mr. Peter Tabuns: But you're not negotiating with them right now to see if you can replace some or all of the power from Pickering with lower-cost power from Quebec. Is that correct?

Mr. Serge Imbrogno: I wouldn't frame it that way. I would just say that—

Mr. Peter Tabuns: Well, you can say no.

Mr. Serge Imbrogno: The other thing, the minister and I haven't confirmed that it's five cents, just to make that clear.

Mr. Peter Tabuns: No, I understand. It was La Presse who did the calculation: the number of years, the total amount of power, the total price. You do the math; you do the division.

If you have a different price, I'm quite happy to have you put it on the table today.

Mr. Serge Imbrogno: No, I just didn't want to give the impression that we were confirming it was five cents or not. We'll leave it to—it was in La Presse.

The Chair (Ms. Cheri DiNovo): Mr. Tabuns, you have about four minutes.

Mr. Peter Tabuns: Thank you.

So you're not negotiating with Quebec to try to replace some or any of the power from the Pickering life extension.

On another matter related to Pickering, the International Atomic Energy Agency, when talking about decommissioning of facilities, says that best practices call for immediate dismantling of a plant that has been shut down on the basis that there's no safety advantage in waiting decades to start the process. Are you planning to tell OPG, when Pickering is shut down, to start dismantling it so it's in line with the International Atomic Energy Agency's standard recommendations?

Mr. Serge Imbrogno: The plan right now for Pickering, like all the other nuclear facilities—the CNSC reviews those plans and approves those plans and the OPG sets aside funds for decommissioning and for used fuel disposal. The CNSC has approved a 30-year safe storage period. That allows the facility to sit for 30 years and then we begin the decommissioning. So that's approved by the CNSC, and OPG funds according to that plan.

Mr. Peter Tabuns: Do you have the funds now to decommission or do you have to wait 30 years for interest to accumulate to be able to decommission?

Mr. Serge Imbrogno: There are two parts of the funds that have been established. There are the funds for decommissioning and there are funds for the used fuel disposal. The Ministry of Finance through the OFA manages those funds, along with OPG. There's full disclosure. I believe the decommissioning funds are fully funded and then the used-fuel funds, over time, will be invested and contributed to in order to be fully funded. But that information is available.

Mr. Peter Tabuns: So the funding is available for doing a decommissioning consistent with international best practices. That's what you're telling me.

Mr. Serge Imbrogno: Consistent with what the regulator requires.

Mr. Peter Tabuns: I'm sure the regulator doesn't see a big problem giving you a 30-year pass, but I'm sure the regulator may also be totally open to having you do it very quickly, because there's a job creation opportunity here in Pickering that would put an awful lot of people to work. Is there a reason that you're not going to do it now, in 2024 or earlier, which would put a lot of people to work?

I'm glad to hear that there's money in the kitty so that we actually could do it now, if we wanted. That's great.

Mr. Serge Imbrogno: Every five years, the liability estimate is updated and OPG goes before the regulator. I guess there will be opportunity for the regulator to determine a different course, but OPG would provide its evidence and best advice on how to move forward with decommissioning. I don't think there are any plans to change that from a 30-year safe storage to a prompt decommissioning.

1530

Mr. Peter Tabuns: Is there a reason you wouldn't take advantage of this job creation opportunity?

Mr. Serge Imbrogno: I think there are pros and cons. We leave it up to the regulator to provide whatever they believe is the best course. I think the longer you have the safe storage, the longer you can accumulate the funds and invest them and have that money available for decommissioning.

Mr. Peter Tabuns: But I gather it's fully funded now, correct?

Mr. Serge Imbrogno: Well, there are assumptions about when you do the decommissioning and what you're going to get when you invest those funds over the next 30 years. All of those things are factored in.

Mr. Peter Tabuns: So it's not fully funded now. It's fully funded if we have 30 years of interest accumulation on it.

Mr. Serge Imbrogno: Well, we would classify it as fully funded.

Mr. Peter Tabuns: And that means the money could be used to decommission within the next five years, within the next eight years.

Mr. Serge Imbrogno: No, they would be fully funded according to the plan that you have in place, that they would be available 30 years from when you start.

The Chair (Ms. Cheri DiNovo): I'm afraid your time is up now, Mr. Tabuns. We move to the government side: Mr. Dong.

Mr. Han Dong: Good afternoon, Deputy. Good afternoon, Minister. I want to talk about the Green Energy Act, because it actually made Ontario a leader in clean energy. From my experience travelling, I've seen emerging economies and jurisdictions that, although they're doing well in terms of GDP, do pay a hefty environmental cost, and health care costs as well. I think that as globalization deepens, entrepreneurs and innovative minds will pick and choose where they want their families to reside. That's why Ontario and Canada keep being, perhaps, some of the most popular destinations for immigration. Just thinking on the reverse side of that, there are countries that are losing talent and entrepreneurs, and it partly has to do with the quality of air and water and all of these basic necessities to provide for their families.

I'm very pleased that the Green Energy Act has actually made us a leader in clean energy. I wanted to ask the minister for your thoughts on how Ontario has benefited from integrating these renewable energies into our system, and whether or not other jurisdictions are following our path to achieve cleaner energy systems, if you can give us some explanation.

Hon. Glenn Thibeault: Sure. Thanks for the question. I think it's important to talk about our commitment to renewable energy. We currently have 18,000 megawatts of power contracted or online. That's very, very important to say because we've seen significant reductions in GHGs that relate to that.

Another important thing in relation to your question is how we eliminated our coal-fired plants. When we stopped polluting our air, the benefits that we're seeing in health care—we're talking about $4.3 billion in savings in health care. The Toronto's Vital Signs Report talked about how we've seen a 41% reduction in air pollution deaths. That's significant and something that we should all be proud of in relation to our investments that we've made when it comes to green energy and the importance of having a clean, reliable system. Some of the specifics on what we've done since 2003, even—I know, Deputy, that you can get into some of those details.

Mr. Serge Imbrogno: Yes, thank you. I was going to ask Kaili Sermat-Harding, our ADM who works in the renewables division, to come up and say a few words, but I would just say, as the minister said, we have 18,000 megawatts of solar and wind energy, bioenergy and hydroelectric energy.

In terms of other jurisdictions, our Independent Electricity System Operator has been able to integrate renewables into our grid. I think we're looked upon as a leading jurisdiction for that. One part of the piece that some people forget is how the IESO has been able to integrate wind and solar into our system.

But I'll let Kaili walk you through the investments we've made over time and how they've contributed to our greenhouse gas reduction.

Ms. Kaili Sermat-Harding: Thank you, Deputy. My name is Kaili Sermat-Harding. I'm the assistant deputy minister of the conservation and renewable energy division at the Ministry of Energy. I appreciate the opportunity to dive into some of the details around the initiatives that Ontario has been pursuing, as well as to put it into a bit of global context and outline some of the very tangible benefits that have come about as a result of our series of initiatives.

In 2013, wind and solar power represented 8% of Ontario's energy supply mix. Today they comprise approximately 17%, and are expected to rise to approximately 23% by 2025. To date, as the minister mentioned, Ontario has over 18,000 megawatts of wind, solar, bioenergy and hydroelectric generation contracted or online. Of the almost 16,000 megawatts of renewable energy that is online, that includes 4,500 megawatts of wind power, roughly 2,200 megawatts of solar PV, approximately 8,800 megawatts of hydroelectric capacity and roughly 500 megawatts of bioenergy.

The province is home to five of the 10 largest wind projects in Canada as of the end of the 2015 calendar year, more than 99% of all installed solar PV capacity in the country, and the largest 100% biomass facility in North America at the Atikokan Generating Station.

Ontario has established itself as a leader in renewable energy through a variety of initiatives, including the Green Energy Investment Agreement, the feed-in tariff and microFIT programs, the large renewable procurement program and net metering.

With respect to the Green Energy Investment Agreement, Ontario's partnership with Samsung through the agreement, referred to as the GEIA, has supported the creation of a strong and thriving clean energy industry in the province. The agreement set a framework to build renewable energy projects and manufacturing plants in Ontario. It was signed in 2010 between Ontario and Samsung, with amendments negotiated in 2011 and 2013.

In June 2013, the ministry worked collaboratively with Samsung to update and revise the agreement, and this resulted in reducing contract costs by $3.7 billion. The revised agreement includes protecting the original agreement's job commitments and adding a commitment to solar manufacturing jobs in 2016, reducing the agreement's total commitment for renewable energy projects from 2,500 megawatts to 1,369 megawatts and requiring

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

Overview

- In March 2015, upon Ministry of Energy request, the IESO provided an independent assessment of the integrated power system impacts of various Pickering life extension scenarios between 2018 and 2024 (see Appendix 2)
  - Technical and economic information concerning Pickering was provided to the IESO by OPG between December 2014 and January 2015 for each scenario assessed

- IESO's March 2015 assessment concluded that, while not without its potential pitfalls, extended Pickering operation holds potential benefit and merits further exploration. In particular, the scenario of Pickering operation to 2022/2024 appeared most promising among the extension options assessed.
  - Feasibility of Pickering extension beyond 2020 from a regulatory perspective has yet to be shown

- In April 2015, the Ministry of Energy, OPG, and IESO developed a joint work plan identifying activities to increase the economic, technical, and regulatory confidence with respect to Pickering life extension (see Appendix 3), including providing an update on the economic merits of life extension in Q4 2015.

- In October 2015, the IESO updated its evaluation of the merits of Pickering extension, with focus on the extension to 2022/2024 option in particular, in light of updated technical and economic information from OPG and changes to the electricity planning context since the March study.

- The IESO's updated assessment is presented in the following slides.

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.

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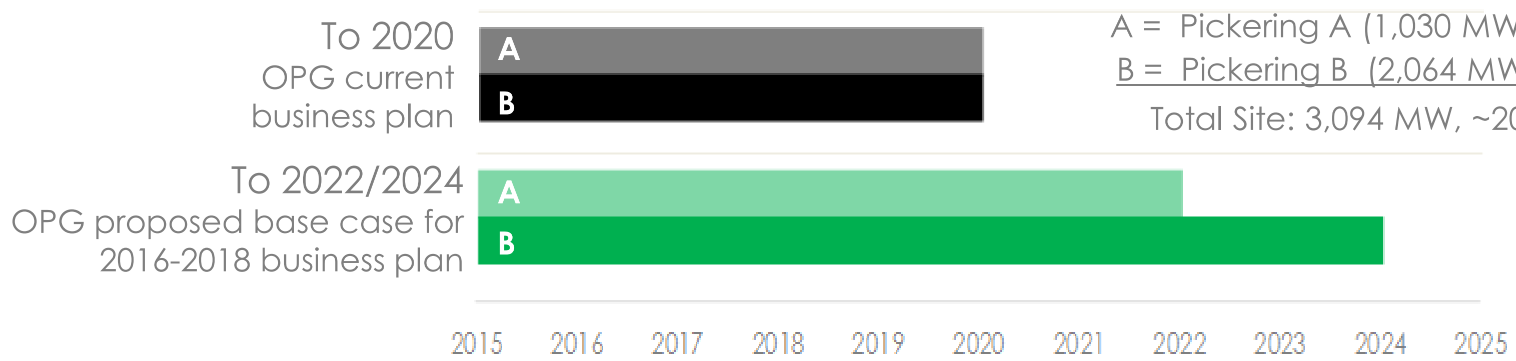
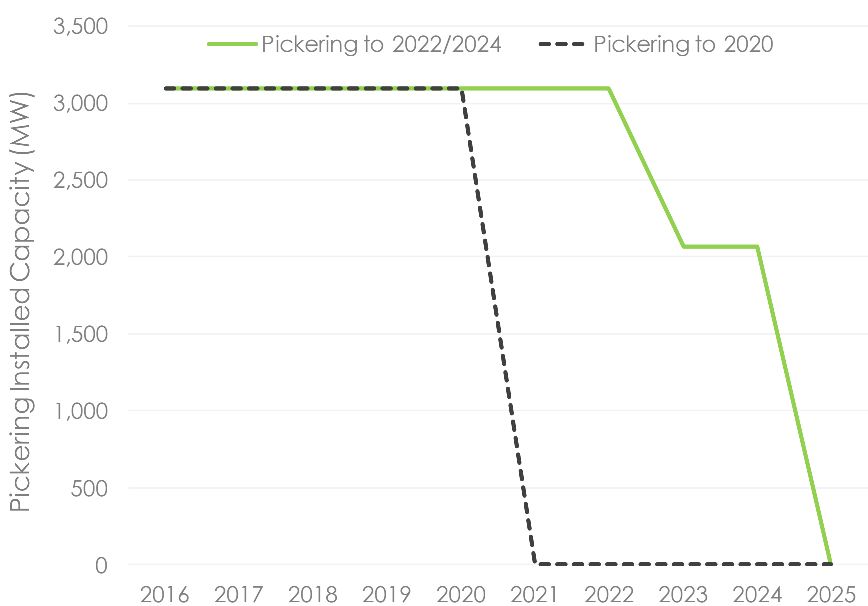
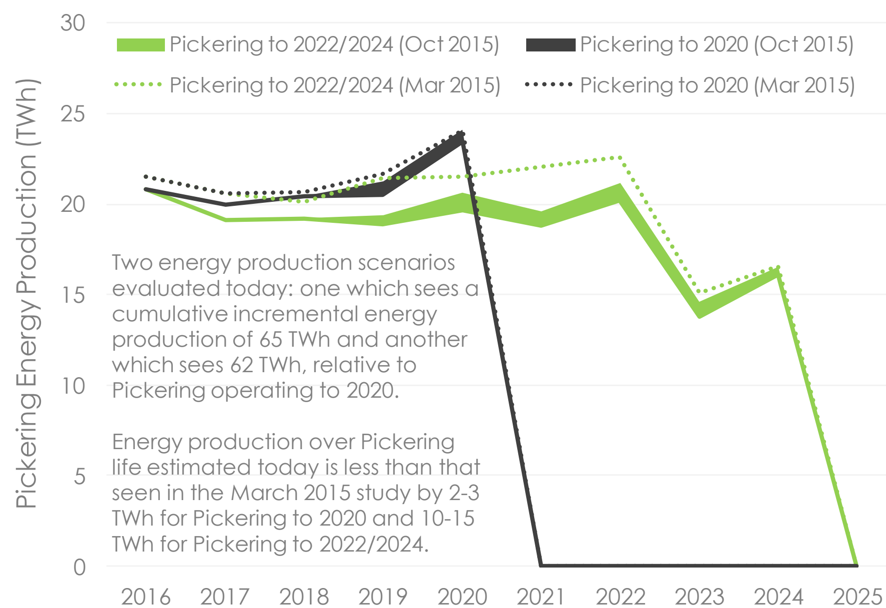
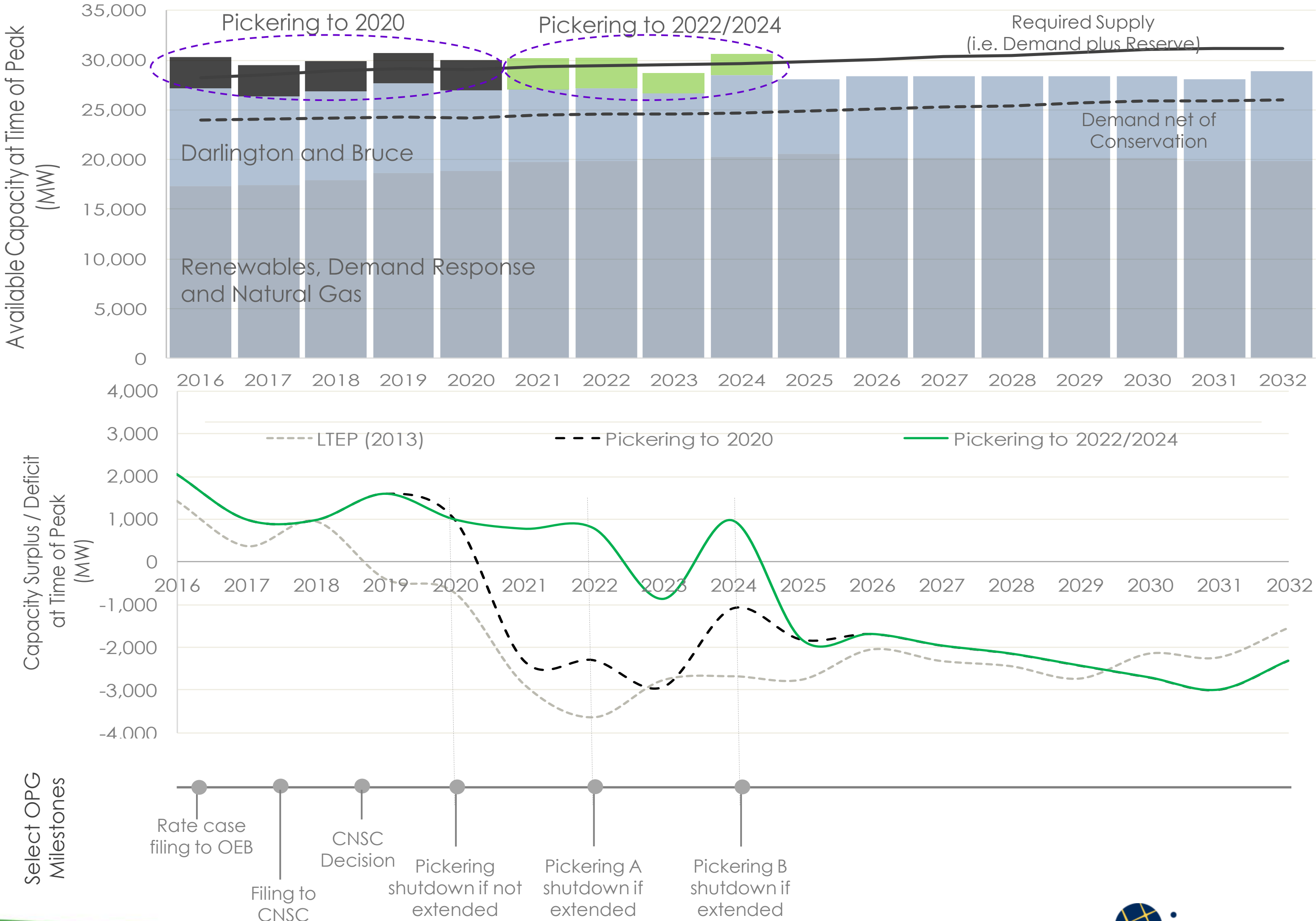
Two Pickering scenarios assessed: one features Pickering operations to end of 2020 per OPG's more recent business plan, the other features additional years of operation to 2022/2024. Approximately 3,100 MW and 20 TWh is provided by Pickering for each year of operation.



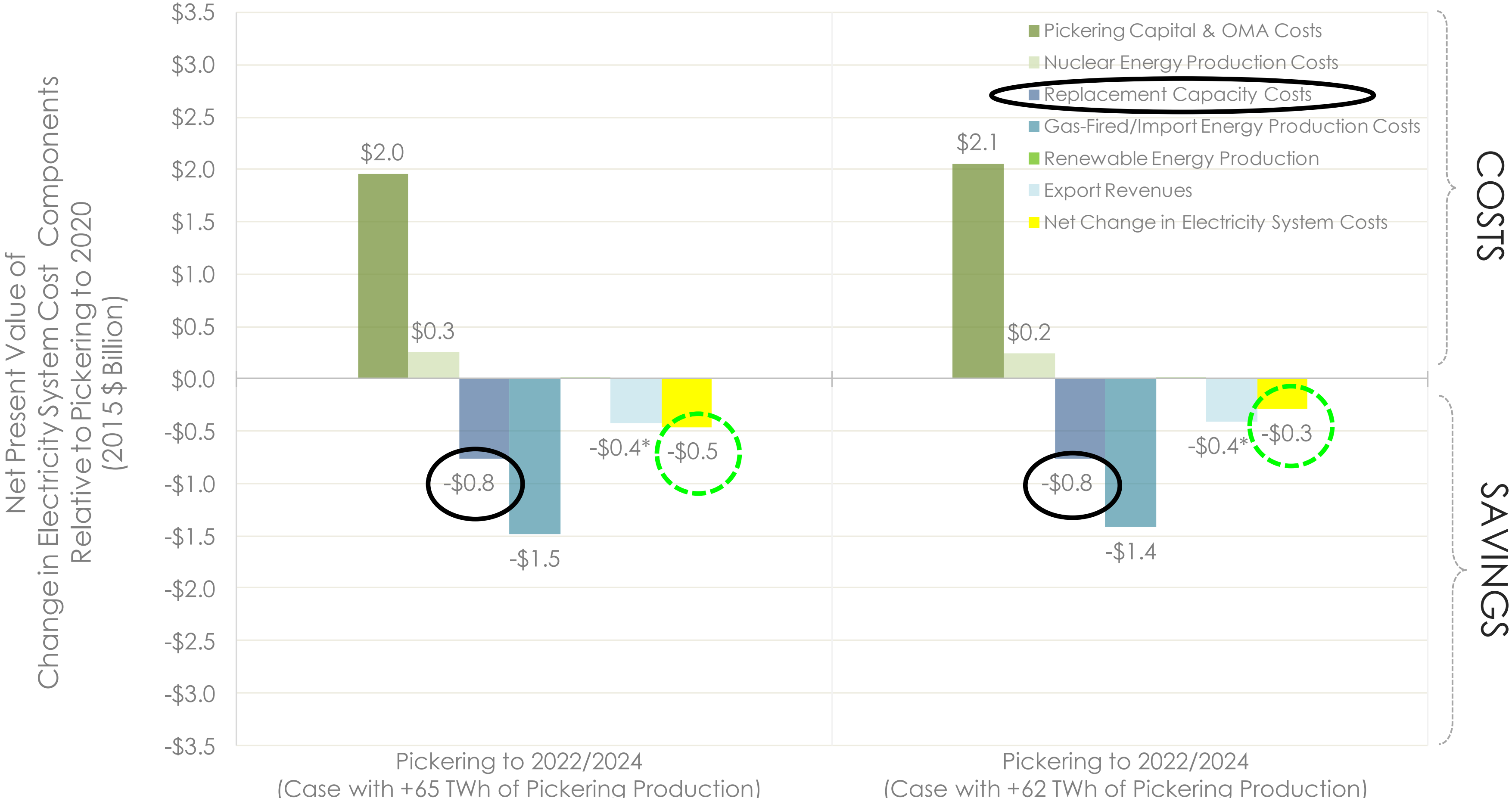




Ontario's existing, committed and directed resources will provide adequate supply for the next few years, after which time additional resources will be required. With Pickering operating to 2020, capacity needs begin to emerge in about 2021 and are on the order or 2,000 MW to 3,000 MW. Extended operation at Pickering to 2022/2024 would defer this need for additional supply by a few years. Although life extension defers procurement decisions, confirmation of its viability arrives late and on the cusp of possible transition from surplus to deficit.



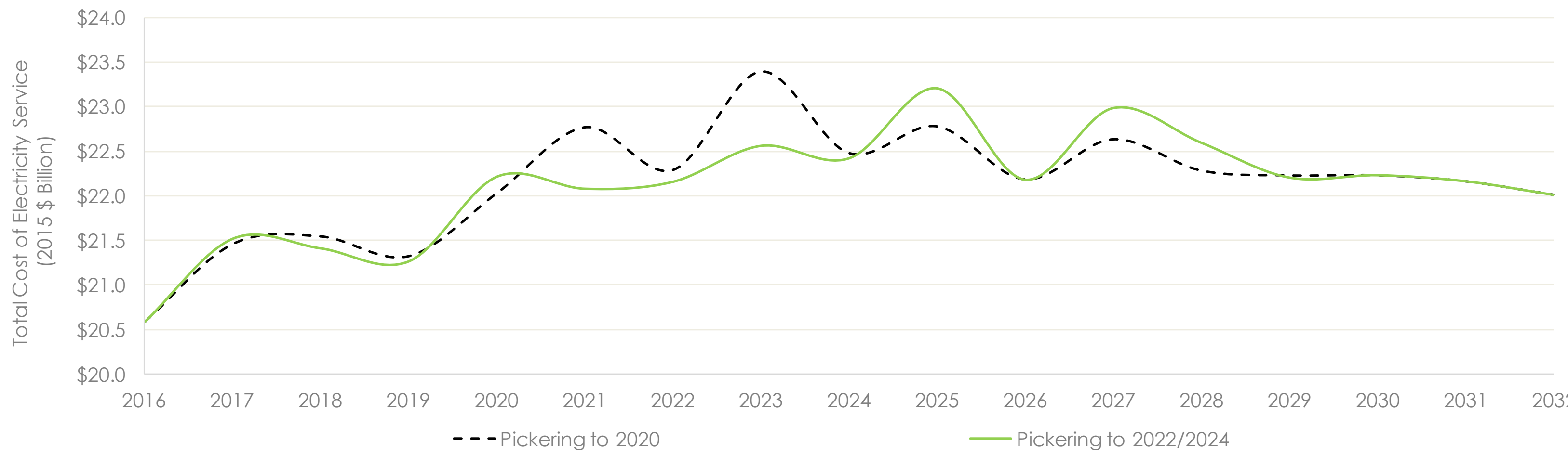
Pickering extension to 2022/2024 yields a net benefit in the range of $0.3B-$0.5B vs $0.6B in the previous study (NPV from 2016-2032 in 2015 $, includes impact of Pickering severance costs, excludes benefit associated with deferring decommissioning liabilities and transmission investments). Cost savings from extending Pickering operations are driven by reductions in replacement capacity and energy costs from gas-fired resources and energy imports. These savings offset Pickering capital and operating costs, which comprise the largest cost components of Pickering extension. Value of extension could be lower if Pickering's production or availability at time of peak demand decreases, if Pickering's operating costs increase, or if natural gas/carbon prices decrease (see Appendix 1 for further details).

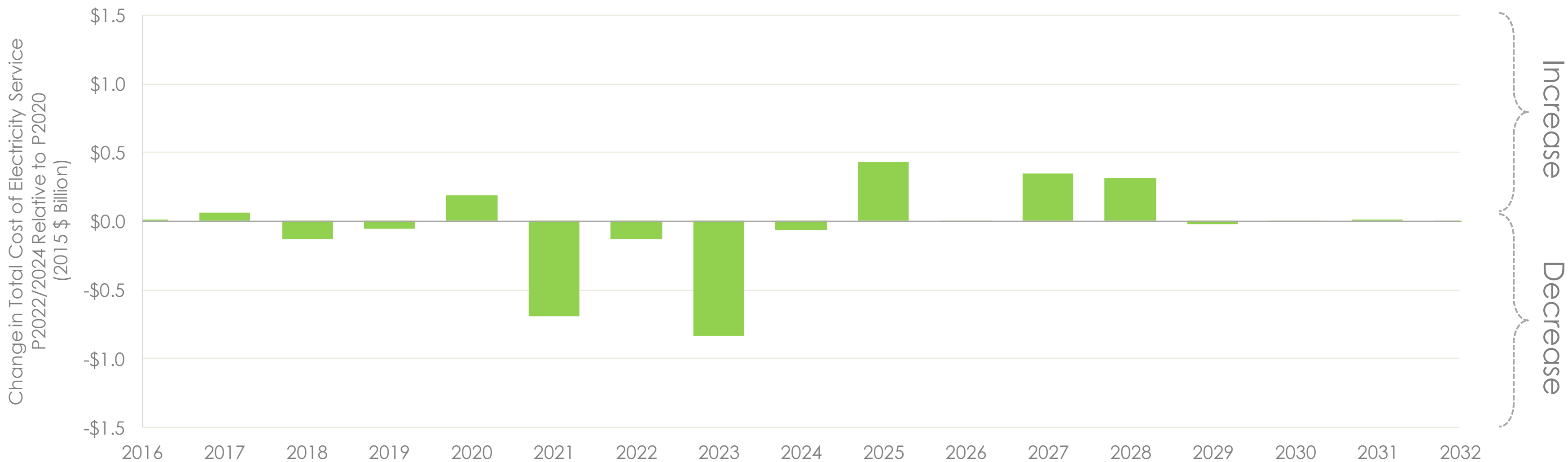


*Export revenues increase.
NPV evaluated at a 4% real discount rate. Excludes transmission and decommissioning advancement/deferral value.

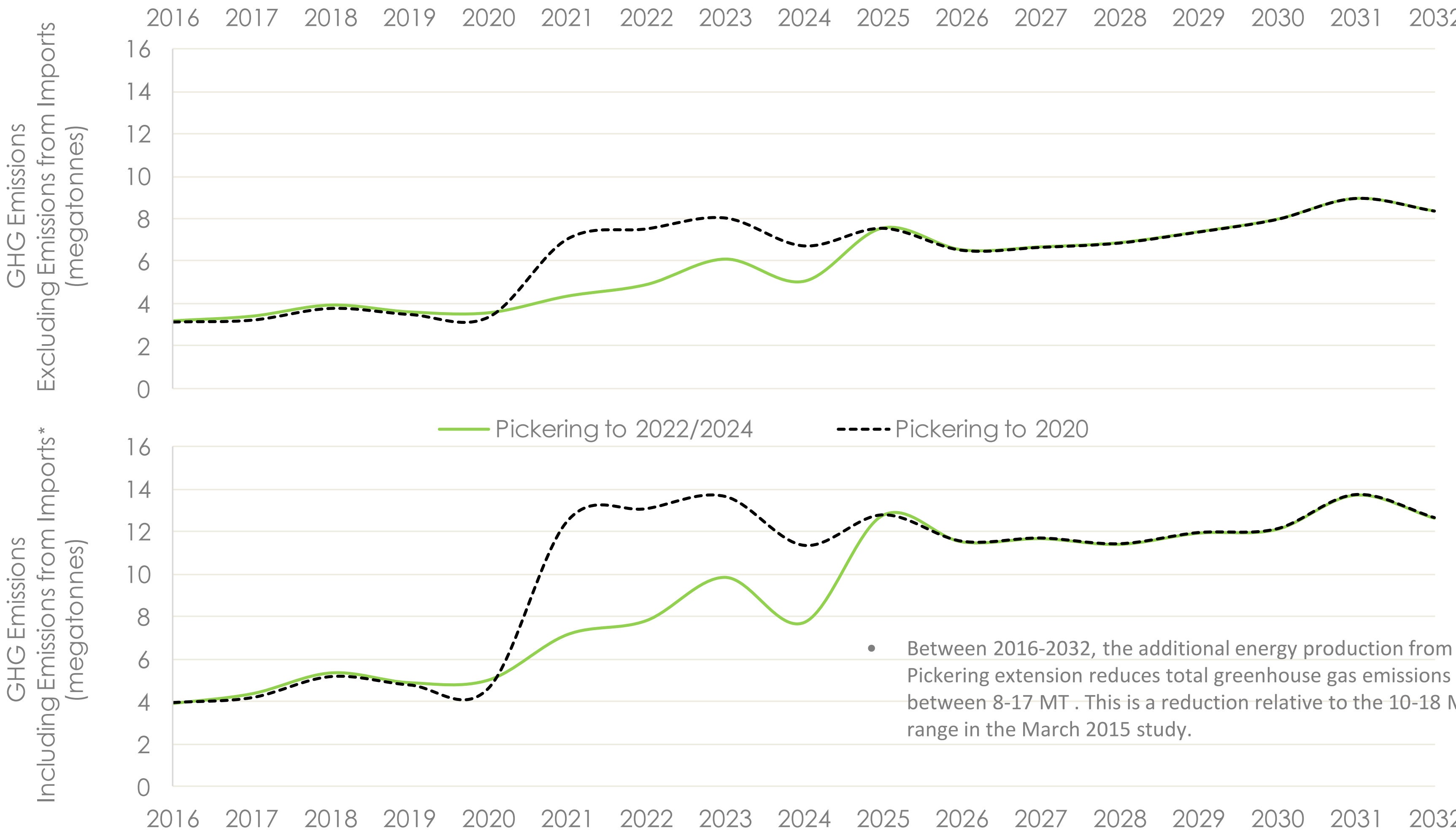
Independent Electricity System Operator

Extending Pickering operation beyond 2020 defers the increase in the total cost of electricity service that eventually takes place. Relative to Pickering operating to 2020, extending Pickering life to 2022/2024 generally leads to a lower cost of electricity service in the period prior to 2024 and generally a higher cost of electricity service for a few years post 2025.





Over the planning period, the additional energy production from Pickering operation to 2022/2024 also reduces total greenhouse gas emissions by between 8 megatonnes (excluding emissions from imports) and 17 megatonnes (including emissions from imports)



- Between 2016-2032, the additional energy production from Pickering extension reduces total greenhouse gas emissions by between 8-17 MT . This is a reduction relative to the 10-18 MT range in the March 2015 study.

*CCGT emission rates used for import emissions rates as a proxy.

Looking ahead

- While Pickering is currently scheduled to shut down in 2020, the IESO's updated assessment indicates, on balance, Pickering extension to 2022/2024 is an option worth continuing to explore on the basis of:
  - Defers timing of need and the supply/transmission investments that would otherwise be required
  - Defers procurement decisions with respect to new resources, providing more time in exercising options while reducing risk of over investment during a period of supply/demand uncertainty
  - Provides insurance supply in some years in case of nuclear refurbishment delays
  - Defers Pickering decommissioning and severance costs
  - Offsets production from natural gas-fired resources
  - Increases export revenues and reduces carbon emissions

- Over the next few years, OPG will seek to demonstrate the technical feasibility of extended Pickering operation to 2022/2024, develop the business case, and pursue regulatory approvals at the Ontario Energy Board and Canadian Nuclear Safety Commission (CNSC).
  - Discussions between OPG and the CNSC would begin prior to OPG's CNSC filing to determine regulatory requirements for extending operation beyond 2020. Additional work will follow for inclusion in OPG's submission.
  - OPG's filing to the CNSC would take place in 2017. CNSC decision would be received by late 2018.

- The timing and extent for additional resources is a moving target and will be influenced by factors such as electricity demand, refurbishment progress, conservation achievement, performance of existing fleet, and others. Prospect of Pickering extended operation introduces another moving piece and confirmation of its viability arrives late and on the cusp of possible transition from surplus to deficit.

Next steps

- The IESO re-emphasizes the importance of achieving the milestones laid out in the April 2015 work plan in a timely manner given the tightness of the overall discovery and decision timeline – in light of the current supply/demand outlook and implications on the need to develop/initiate alternative resource solutions

- In the meantime, in the event the Pickering extension option does not materialize, preparations must be made in a manner that preserves the ability to take advantage of the extension opportunity should it prove viable while not being caught short should it not:
  - Preserving ability to take advantage of the extension opportunity includes not over-committing, in the meantime, to other supply sources that would become redundant/stranded should the extension opportunity prove viable (i.e. feasible and cost-effective) and/or that would erode the economic value otherwise offered by Pickering extension
  - Not being caught short includes achieving timely decisions and maintaining the ability to implement resources in the quantities, capabilities and timelines required in the event, by 2017/2018, the extension option is proven unviable

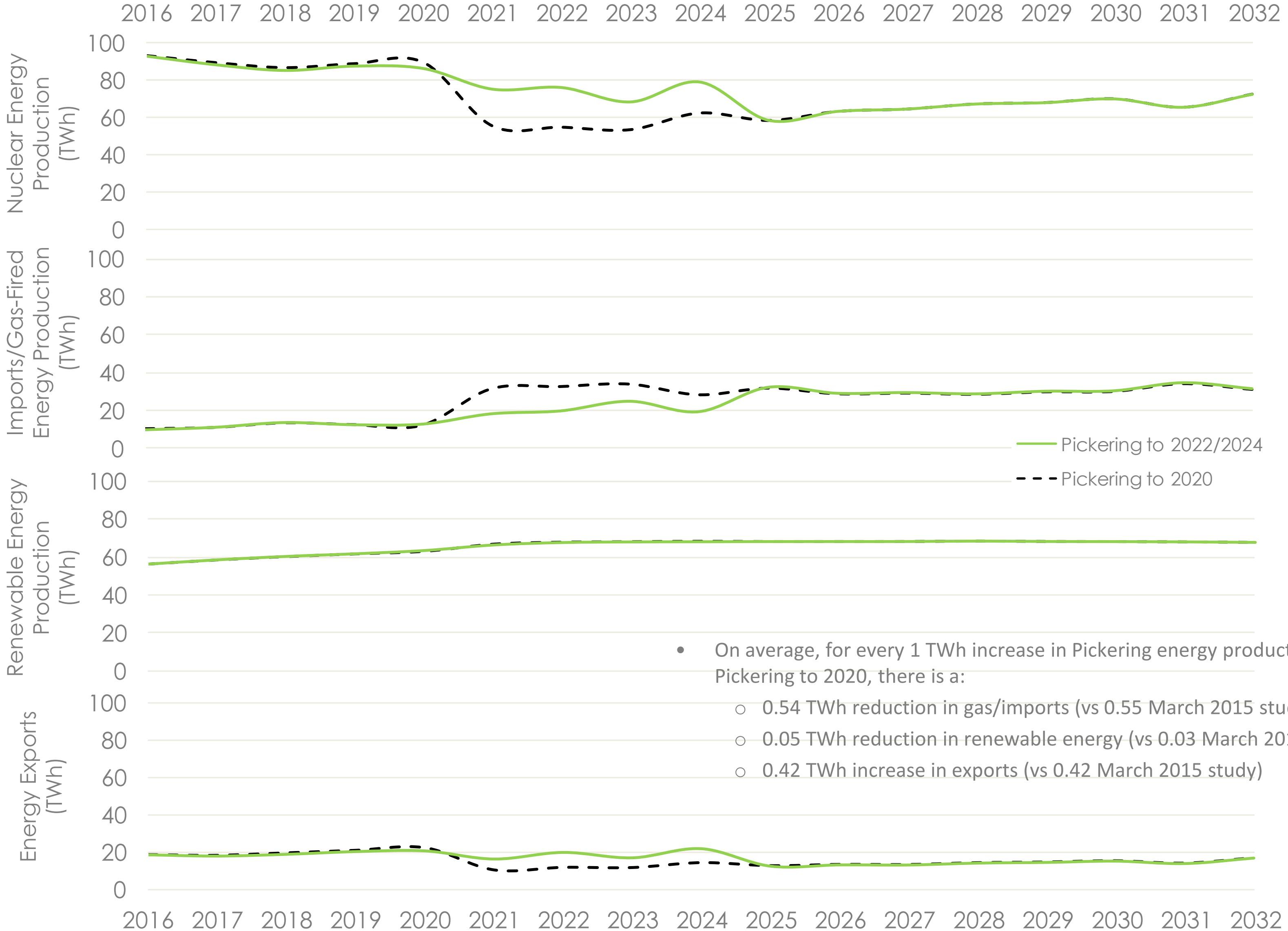
- Elements of our approach within this context include:
  - Frequent monitoring of progress on Pickering extension development work and approvals
  - Ongoing assessment of Pickering extended operations
  - Ongoing assessment of alternatives to Pickering extension and their implementation requirements
  - Routine updates to the Ontario supply/demand outlook
  - Ongoing contingency planning in case Pickering extended operations does not proceed
  - Continued development of mechanisms to secure supply and demand-side resources

- Work on these and other fronts is underway as part of a broader integrated planning initiative. Updates on progress will be brought forward as applicable.

APPENDIX 1:

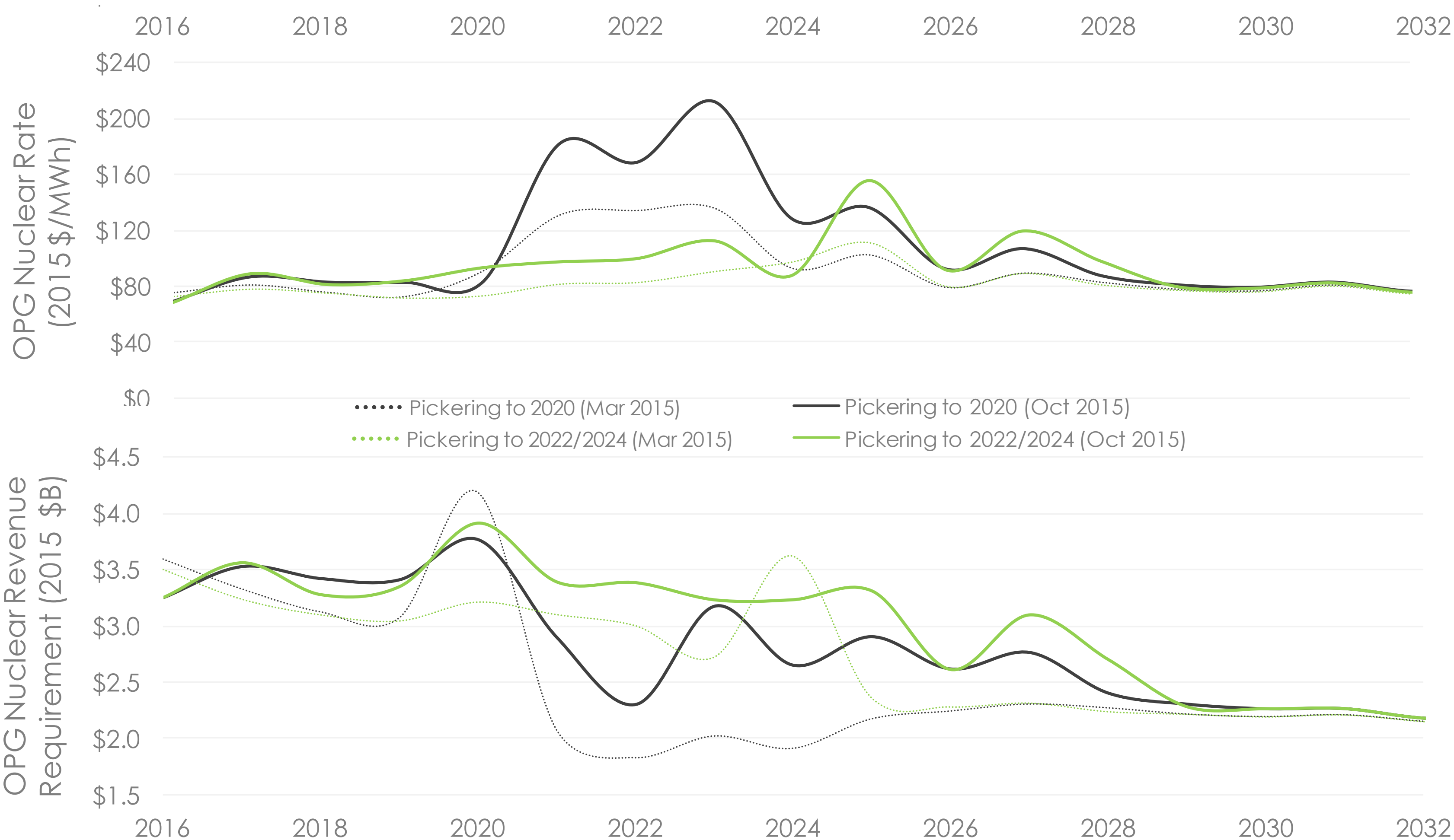
Additional details of IESO's October 2015 Updated Assessment of Pickering Life Extension Options

Energy production from Pickering extension displaces production from gas-fired resources, reduces energy imports, and increases energy exports in the period between 2021 and 2024 (i.e. the life extension period)

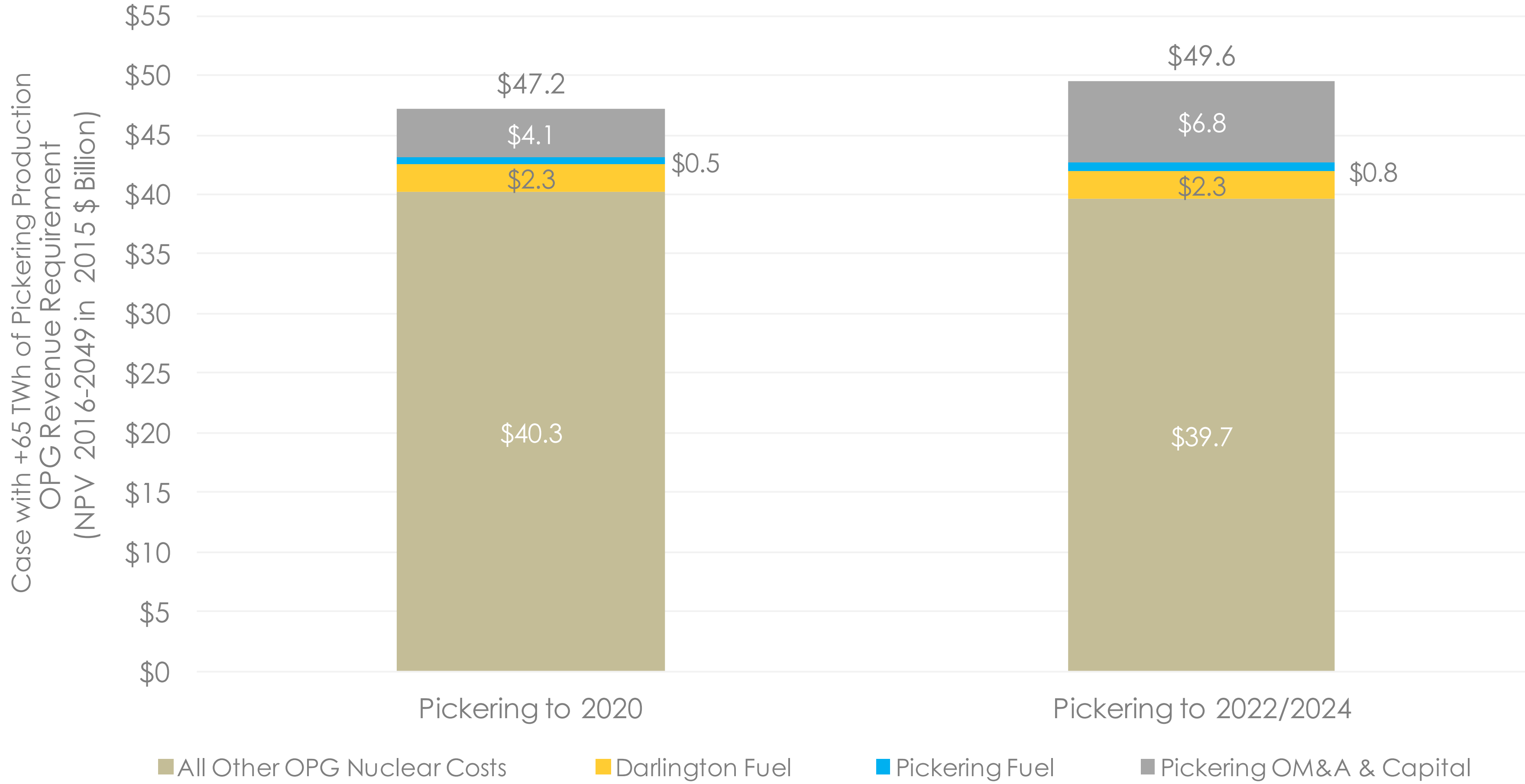


- On average, for every 1 TWh increase in Pickering energy production, relative to Pickering to 2020, there is a:
  - 0.54 TWh reduction in gas/imports (vs 0.55 March 2015 study)
  - 0.05 TWh reduction in renewable energy (vs 0.03 March 2015 study)
  - 0.42 TWh increase in exports (vs 0.42 March 2015 study)

OPG's total nuclear rate will increase as OPG nuclear production decreases. Life extension at Pickering increases OPG's annual nuclear production and tends to reduce OPG nuclear rates to 2024. OPG's nuclear program will cost between $2.2 billion and $3.9 billion (2015 $) per year between now and 2032.



Pickering extension sees OPG's total nuclear revenue requirement increase by $2.3B (NPV in 2015 $).



NPV evaluated at a 4% real discount rate.

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Pickering extension to 2022/2024 yields a net benefit in the range of $0.3B (in the case which sees a cumulative increase in Pickering production by 62 TWh) to $0.5B (in the case which sees a cumulative increase in Pickering production by 65 TWh) (NPV 2016-2032 in 2015 $). This is a reduction relative to the March 2015 study which saw a net benefit of about $0.6B (for a cumulative increase in Pickering production by 73 TWh).

NPV evaluated at a 4% real discount rate. Excludes transmission and decommissioning advancement/deferral value.

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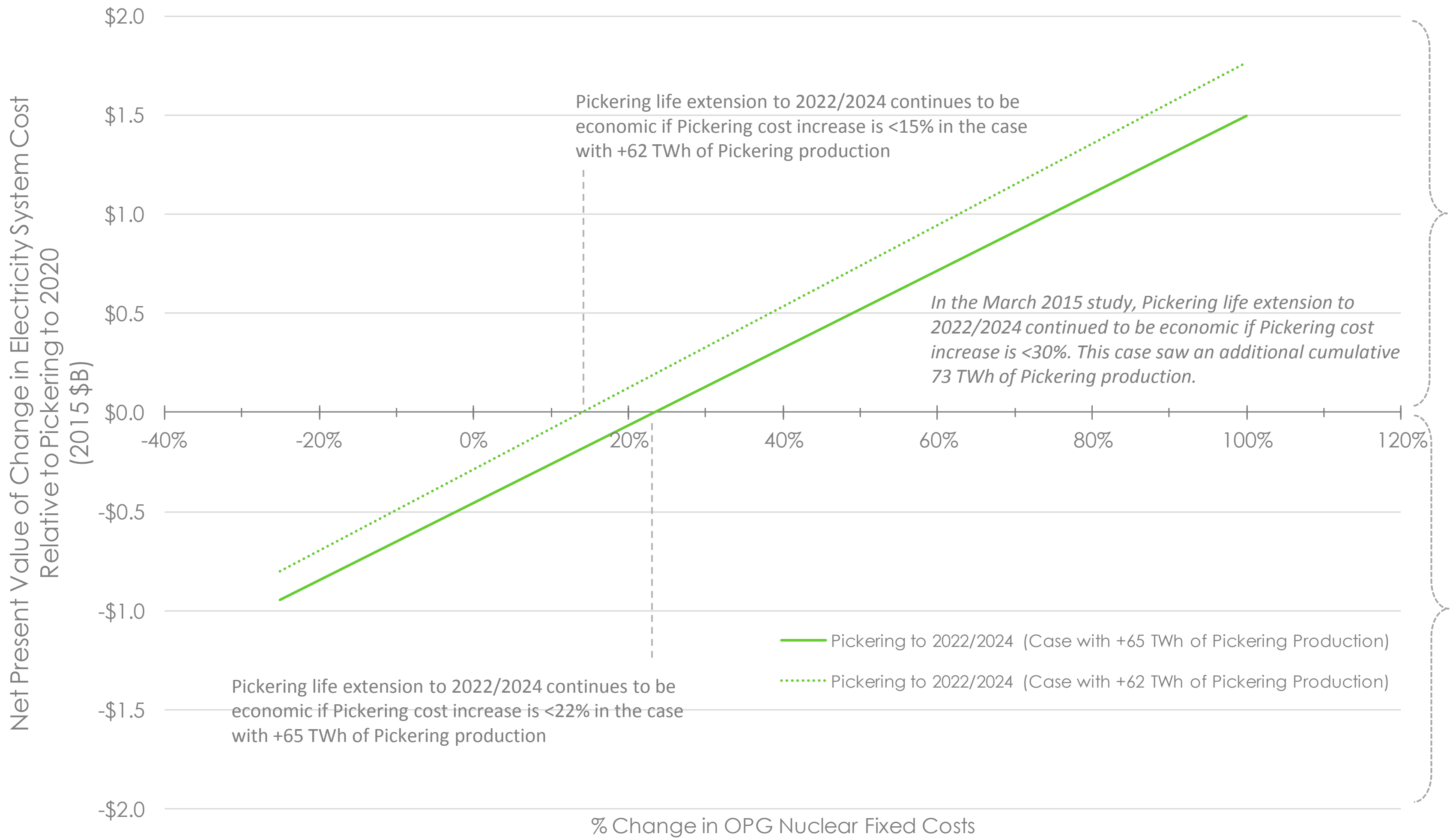
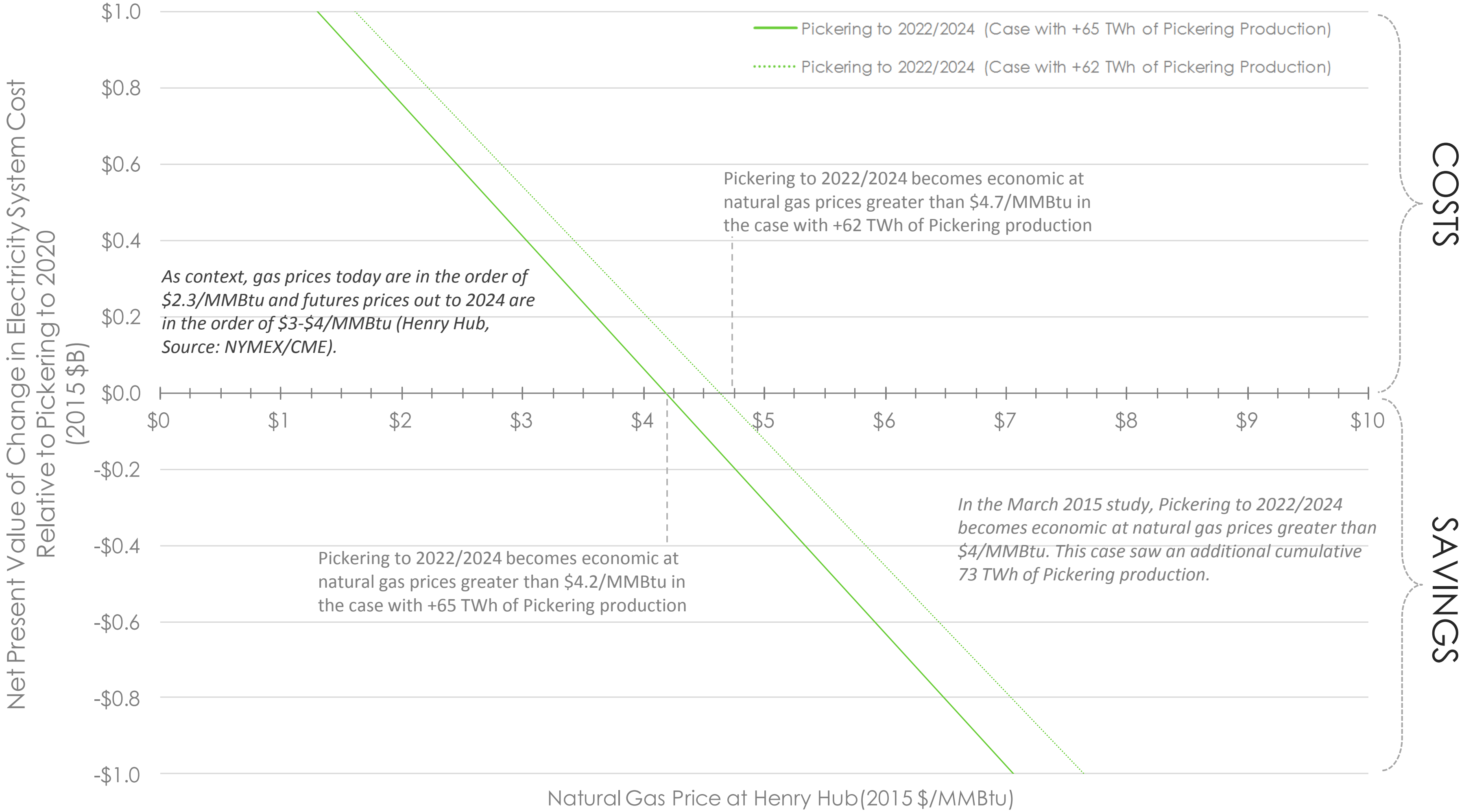
The economic proposition of Pickering extended operations to 2022/2024 is sensitive to Pickering capital and operating costs. As these costs increase, the value of extending Pickering life to 2022/2024 decreases. As production from Pickering decreases, the ability to tolerate cost increases also decreases.



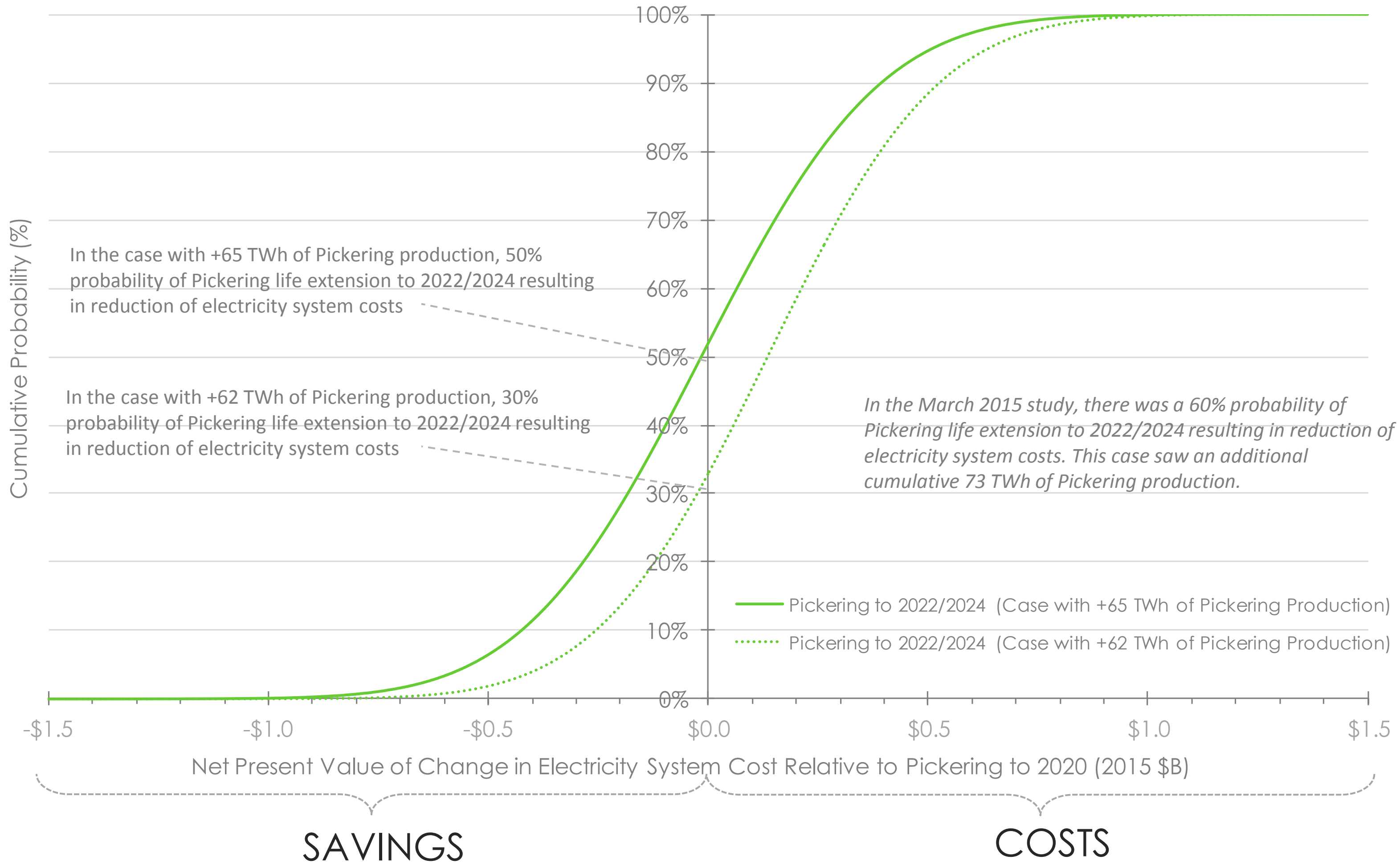
NPV evaluated at a 4% real discount rate. Excludes transmission and decommissioning advancement/deferral value.

Benefits of extended Pickering operations are also sensitive to natural gas prices. Higher natural gas prices (or combined natural gas/carbon prices) result in greater value from extended operations. Lower prices result in lower value. As production from Pickering decreases, the natural gas price at which Pickering life extension becomes economic also increases.



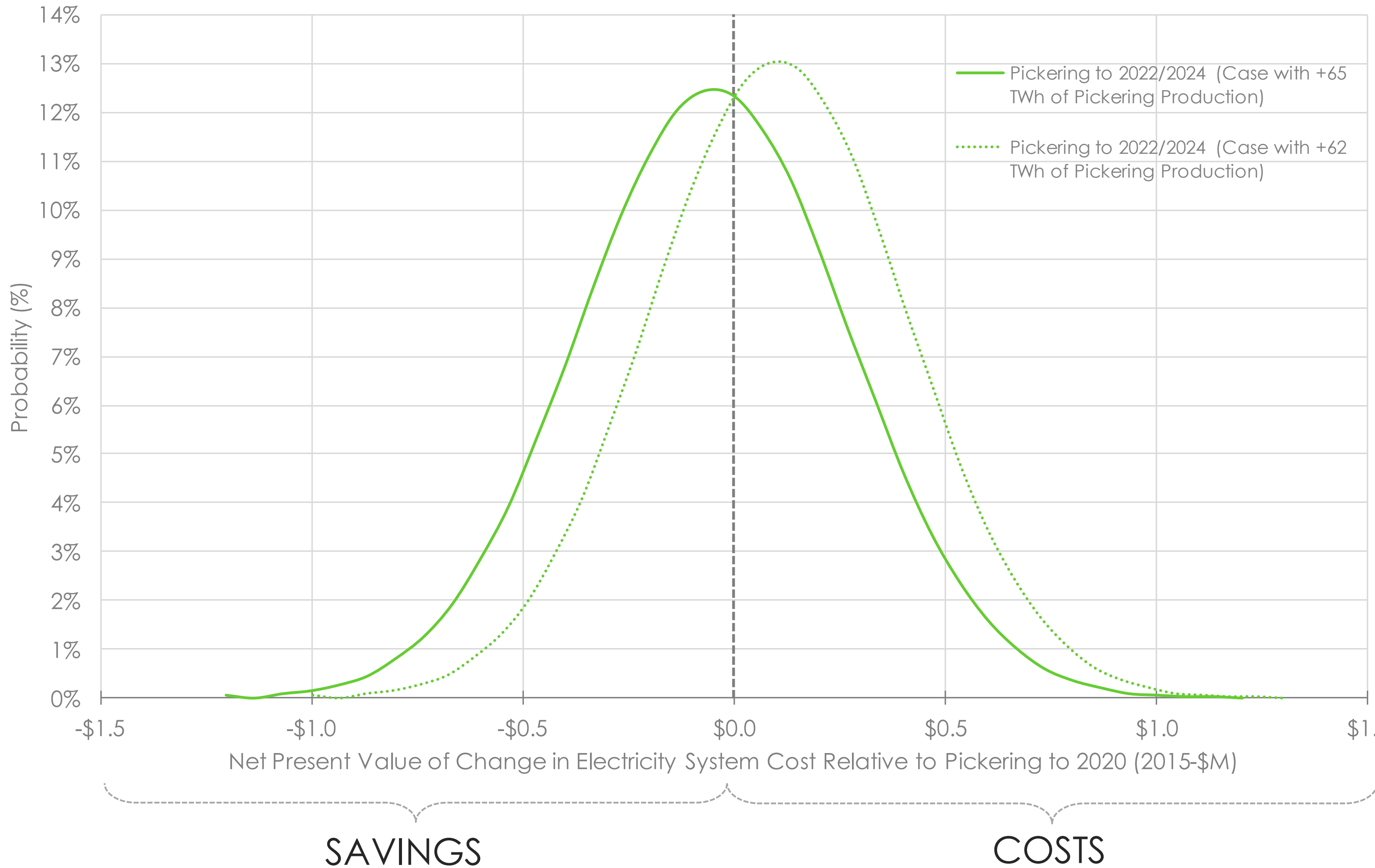
NPV evaluated at a 4% real discount rate. Excludes transmission and decommissioning advancement/deferral value.

Consideration of the historical gas price distribution between 2010 and 2015 adds insight into the cumulative probability of change in electricity system cost as a function of natural gas price under various Pickering extension scenarios. Pickering life extension to 2022/2024 offers moderate probabilities for savings. As production from Pickering decreases, the likelihood of achieving savings also decreases.



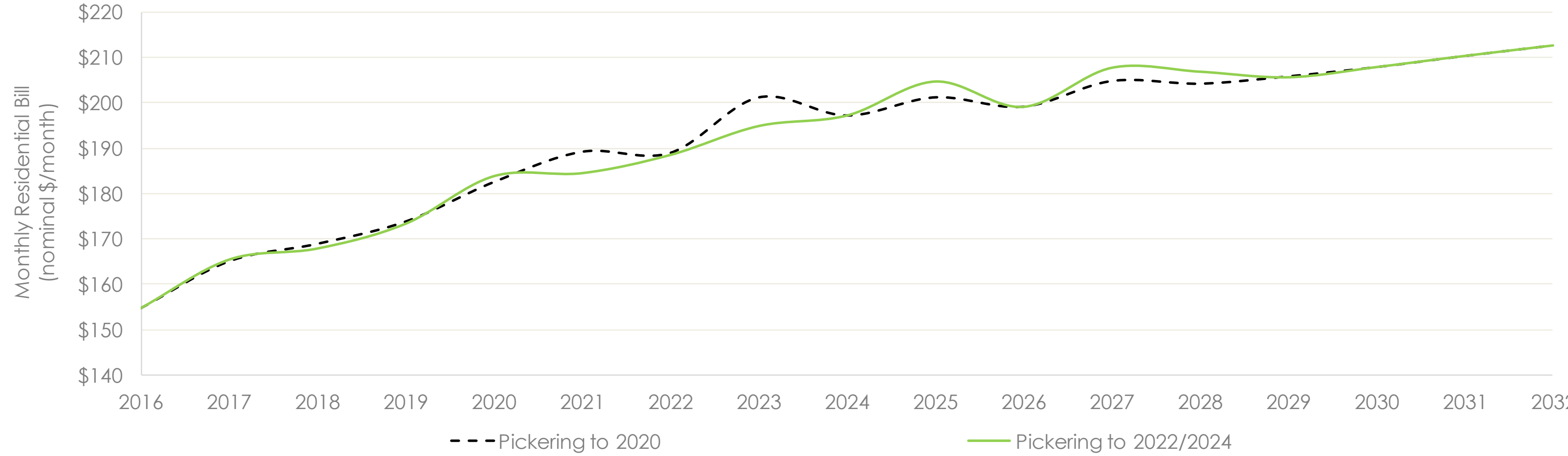
NPV evaluated at a 4% real discount rate. Excludes transmission and decommissioning advancement/deferral value.

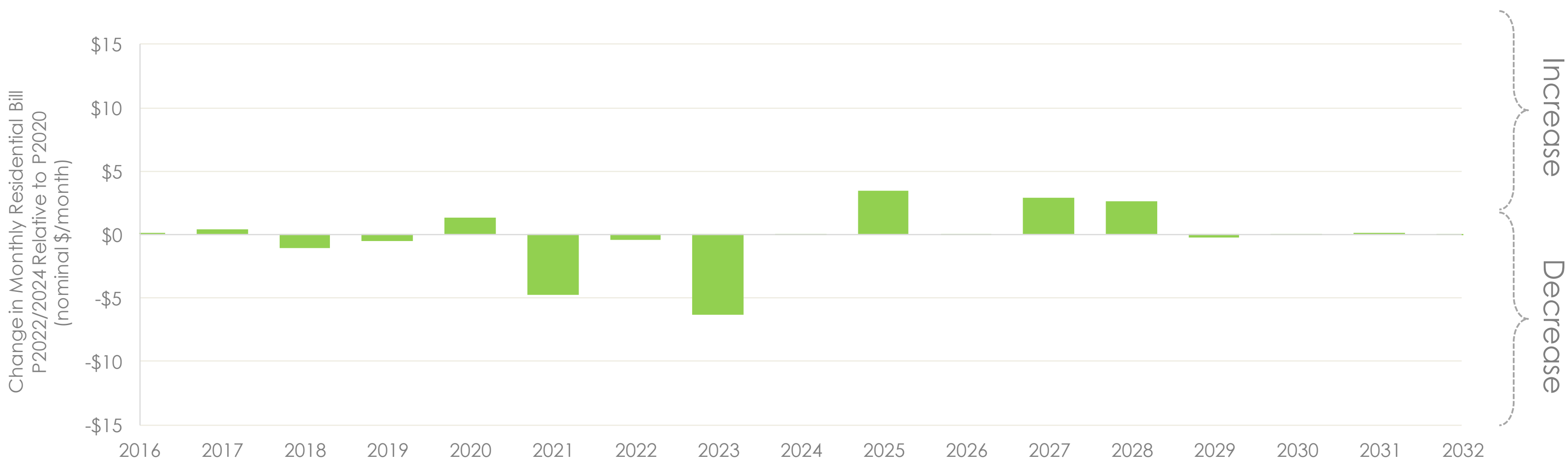
Viewing the same results as a set of NPV distributions illustrates the overlap of possibilities among the Pickering production scenarios as well as the variability within each distribution. As the additional production form Pickering life extension decreases, the NPV distribution shifts further towards life extension being a net cost.



NPV evaluated at a 4% real discount rate. Excludes transmission and decommissioning advancement/deferral value.

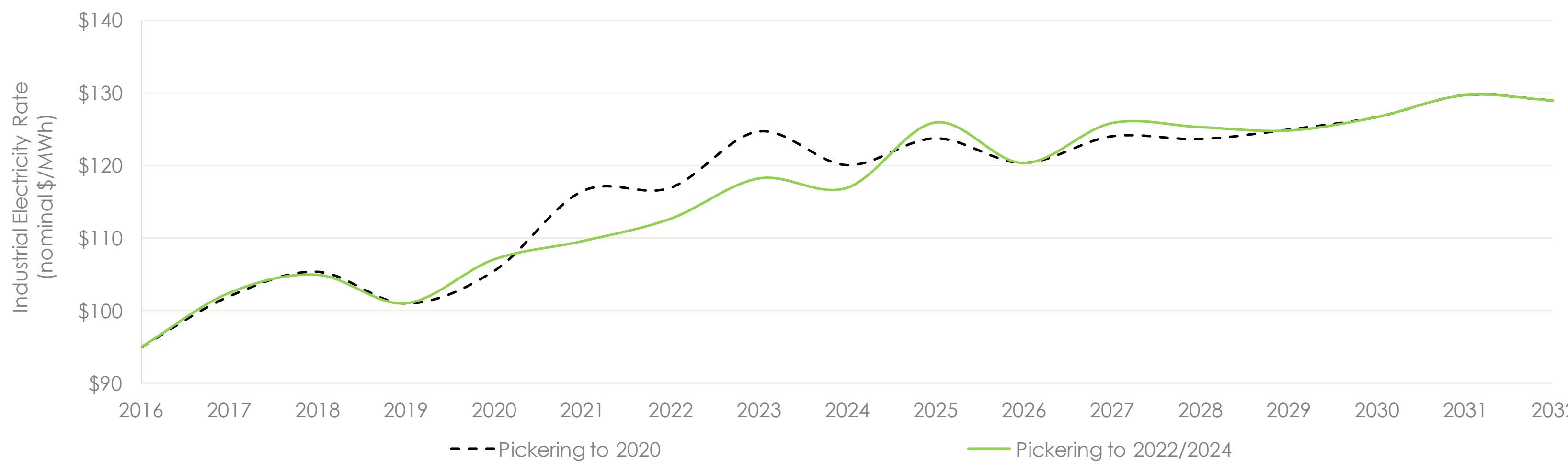
Extending Pickering operation to 2022/2024 generally leads to a reduction in residential electricity bills between 2016 and 2024 compared to Pickering operating to 2020. Residential electricity bills increase for a few years thereafter.

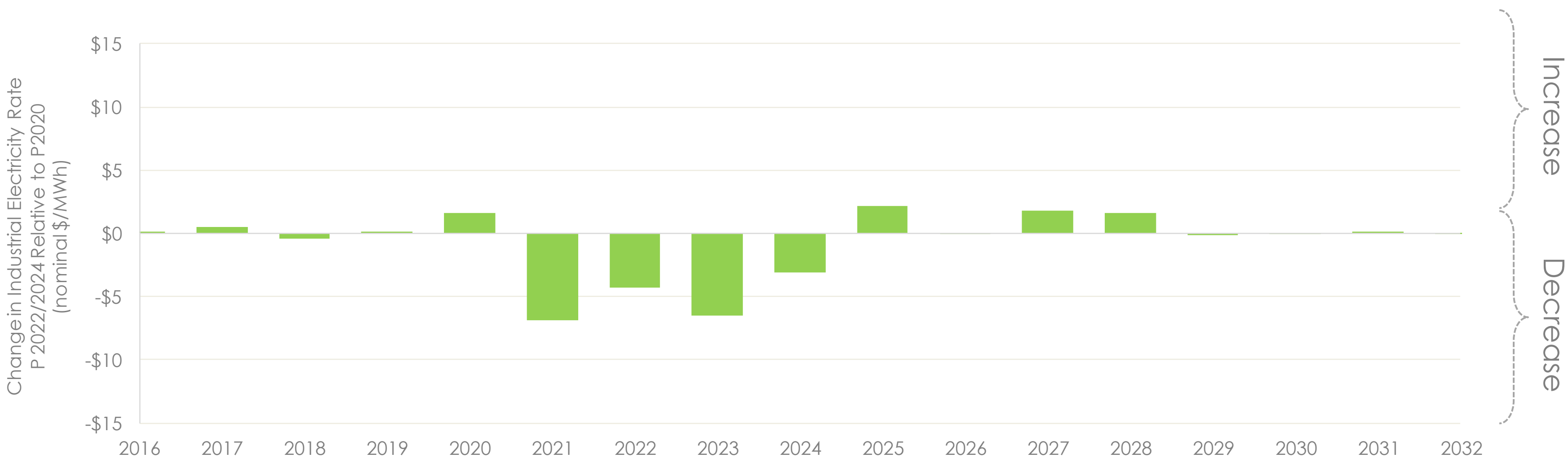




Residential electricity bill illustrated assumes a typical residential consumption of 800 kWh/month.

Similarly, extending Pickering operation to 2022/2024 generally leads to a reduction in industrial electricity rates between 2016 and 2024 compared to Pickering operating to 2020. Industrial electricity rates increase for a few years thereafter.





Industrial electricity rates illustrated assumes a typical large industrial customer with a demand of 5MW and a 75% capacity factor.

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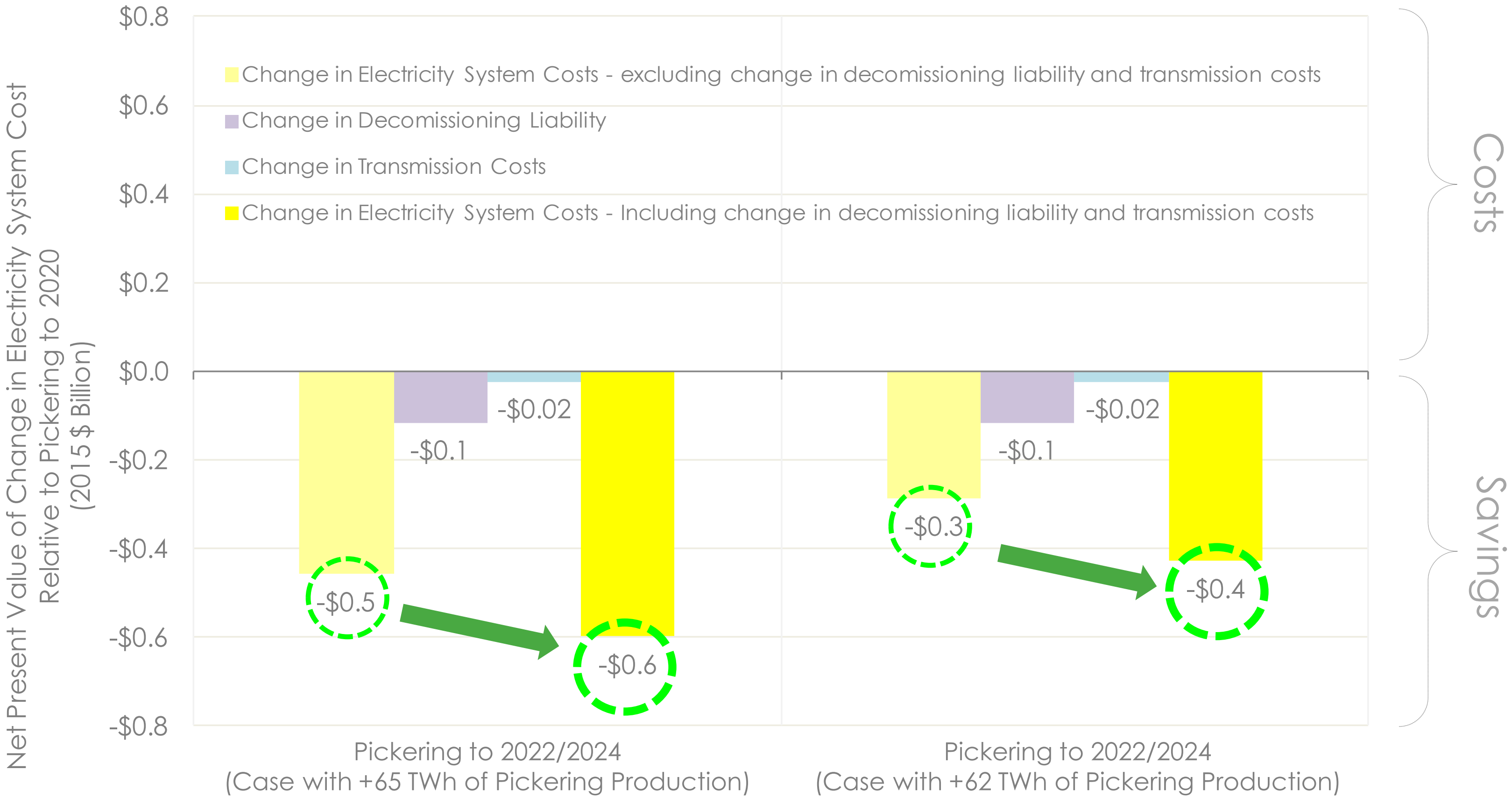
There are other benefits resulting from Pickering life extension. As Pickering life is extended, decommissioning expenditures are deferred. Extended Pickering operations could also defer the need for transmission reinforcements in the GTA region. Deferral of related expenditures results in a time value savings. After factoring in the time value effects of deferring decommissioning and transmission expenditures, the benefit of extending Pickering operations marginally increases.



NPV evaluated at a 4% real discount rate. Excludes transmission and decommissioning advancement/deferral value.

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APPENDIX 2:

IESO's Assessment of Pickering Life Extension Options, Delivered to Ministry of Energy in March 2015

Assessment of Pickering Life Extension Options: Executive Summary

Presentation to Ministry of Energy

March 9, 2015

Note: The appendix accompanying this presentation, which contains the detailed assessment, is excluded for brevity.

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Purpose

- IESO to present the assessment of Pickering life extension options to the Ministry of Energy

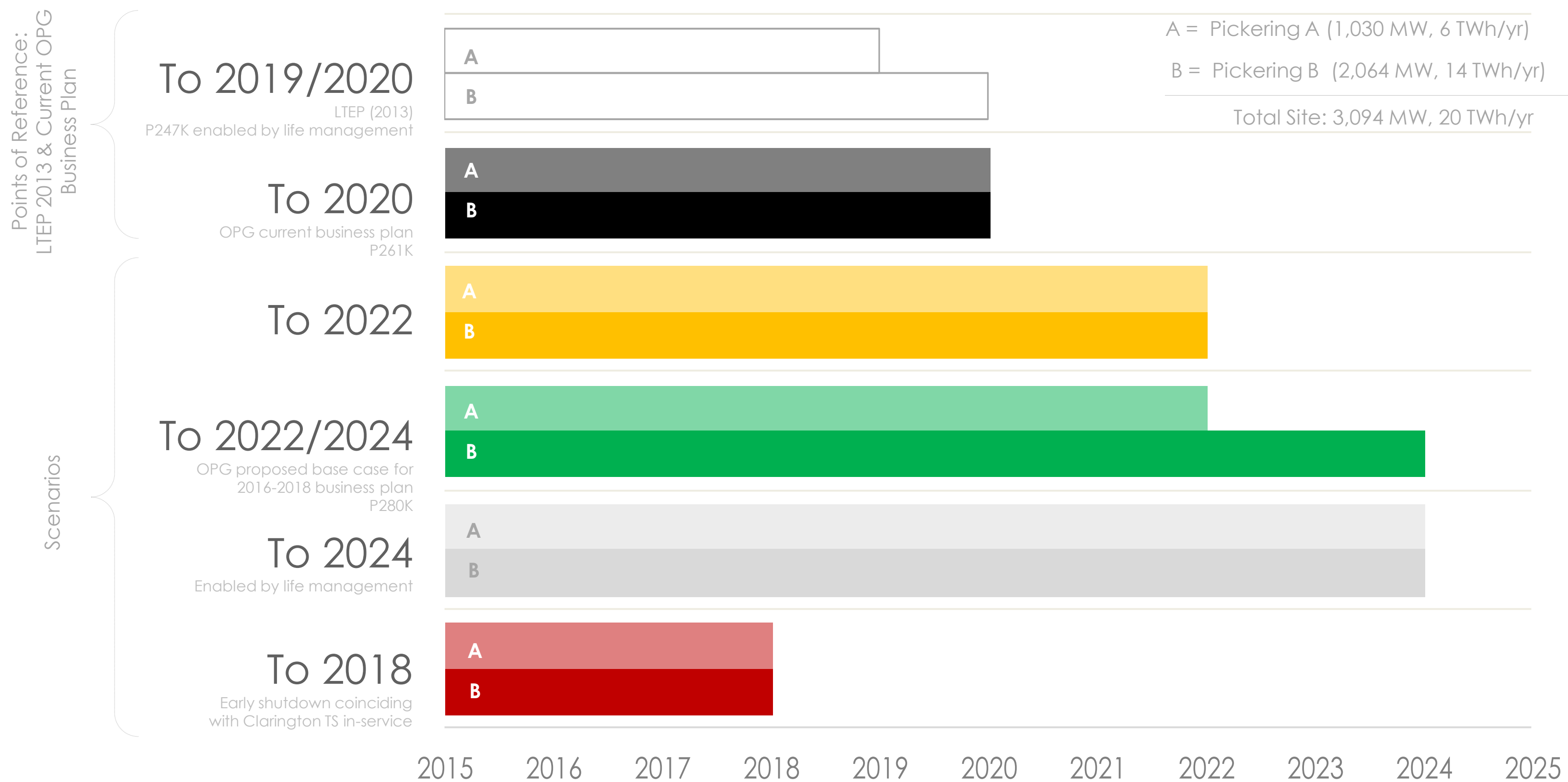
Overview

- The IESO has conducted an independent assessment of the long-term integrated power system impacts of various Pickering life extension scenarios between 2018 and 2024
- Pickering extension scenarios are considered against three Darlington refurbishment sequences
  - Analysis updates and builds on previous Pickering life extension studies conducted by the IESO
  - Technical and economic information concerning the Pickering and Darlington stations was provided by OPG between December 2014 and January 2015 for each scenario assessed
  - The scenarios have not been discussed publicly nor have they received necessary CNSC approvals
- Implications of the Pickering scenarios are assessed from a variety of perspectives, including:
  - Capacity needs and timing
  - Energy production from existing and contemplated resources
  - Greenhouse gas emissions
  - Surplus energy
  - Total cost of electricity service
  - Ratepayer costs
- A summary of this assessment is provided in the following slides. The IESO's full assessment is provided in the Appendix.

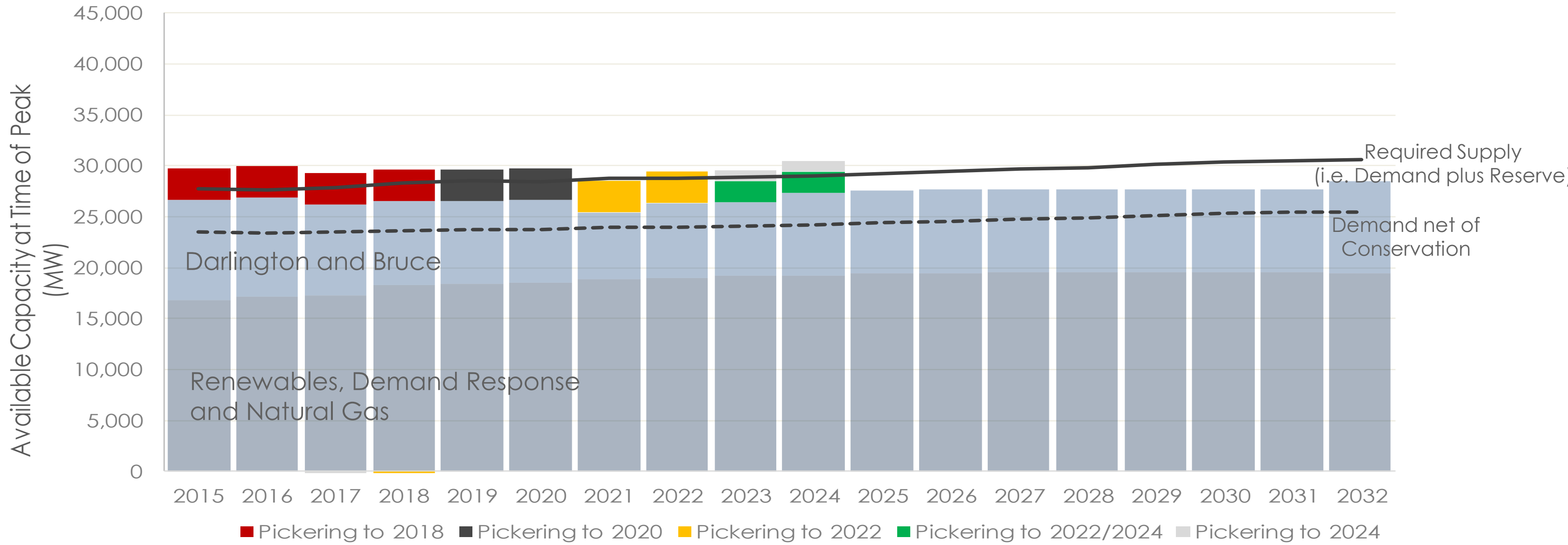
Summary of findings

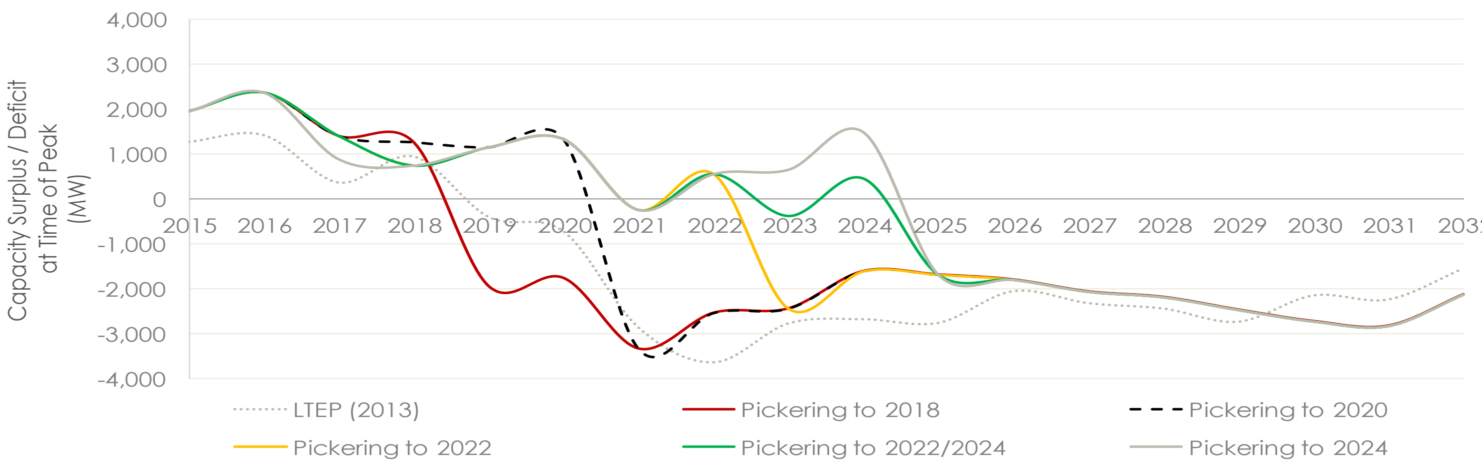
- On balance, the option of extended Pickering operations merits further exploration:
  - Pickering operation to 2022/2024 appears to be the most promising candidate among extension options assessed, as it provides the most savings and is among options with the lowest emissions
  - Extended operation to 2022 or shutdown in 2018 also holds potential for benefit, but less so than operation to 2022/2024
- In light of the impact that Pickering capital and operating costs have on the value proposition of extended Pickering operations, it may be worth exploring options for cost control
  - If OPG's actual capital and operating costs exceed estimates, then the cost savings resulting from Pickering life extension could be reduced or eliminated
- Unlapping of Darlington refurbishment outages generally reduces the value of Pickering extension
- It is worth exploring Pickering extension options involving fewer Pickering units (e.g. four to five units rather than six) to reduce its contribution to surplus baseload generation
- The IESO should be routinely updated by OPG on the status and substance of Pickering extension exploration efforts and related regulatory developments given the implications on need for additional supply and transmission investment

Pickering scenarios assessed



Resource requirements under Pickering scenarios





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Summary of changes in costs

Pickering Scenarios	Darlington Scenarios: Lapped	Darlington Scenarios: Unlapped Yes Idle Time	Darlington Scenarios: Unlapped No Idle Time
2018	-$0.1	+$0.3	-$0.2
2020	BASE	+$0.4	-$0.1
2022	-$0.4	Not Assessed	
2022/2024	**-$0.6**	+$0.1	-$0.3
2024	+$0.1	Not Assessed	

= Net Cost

= Net Benefit

Table shows NPV from 2015-2032 in billions of 2014 dollars compared to the base case

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Summary of changes in emissions

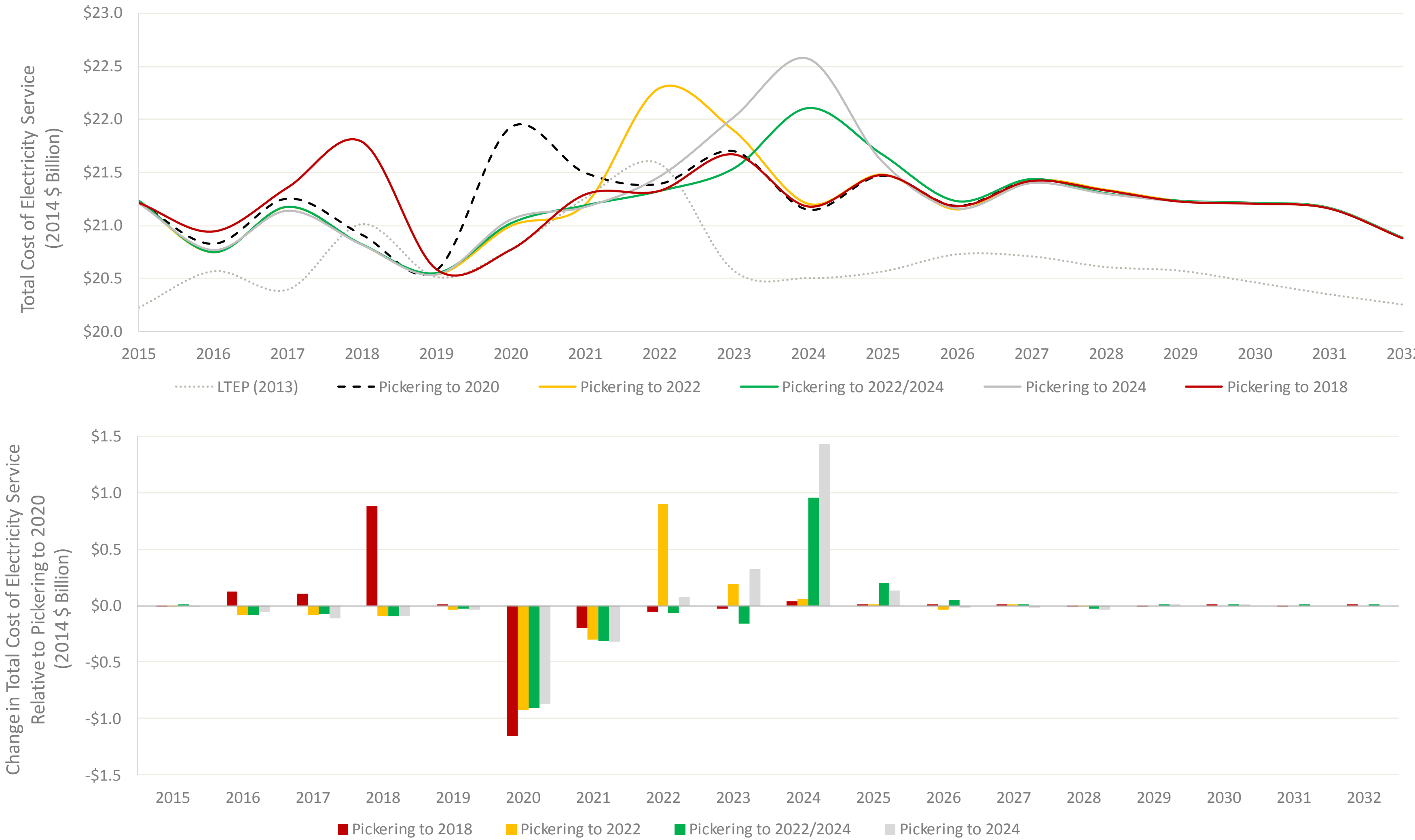
Pickering Scenarios	Darlington Scenarios: Lapped	Darlington Scenarios: Unlapped Yes Idle Time	Darlington Scenarios: Unlapped No Idle Time
2018	+4.8MT	+6.6MT	+4.5MT
2020	BASE	+1.7MT	-0.3MT
2022	-5.8MT	Not Assessed	
2022/2024	**-9.3MT**	-7.2MT	-8.9MT
2024	**-9.9MT**	Not Assessed	

= Net Cost

= Net Benefit

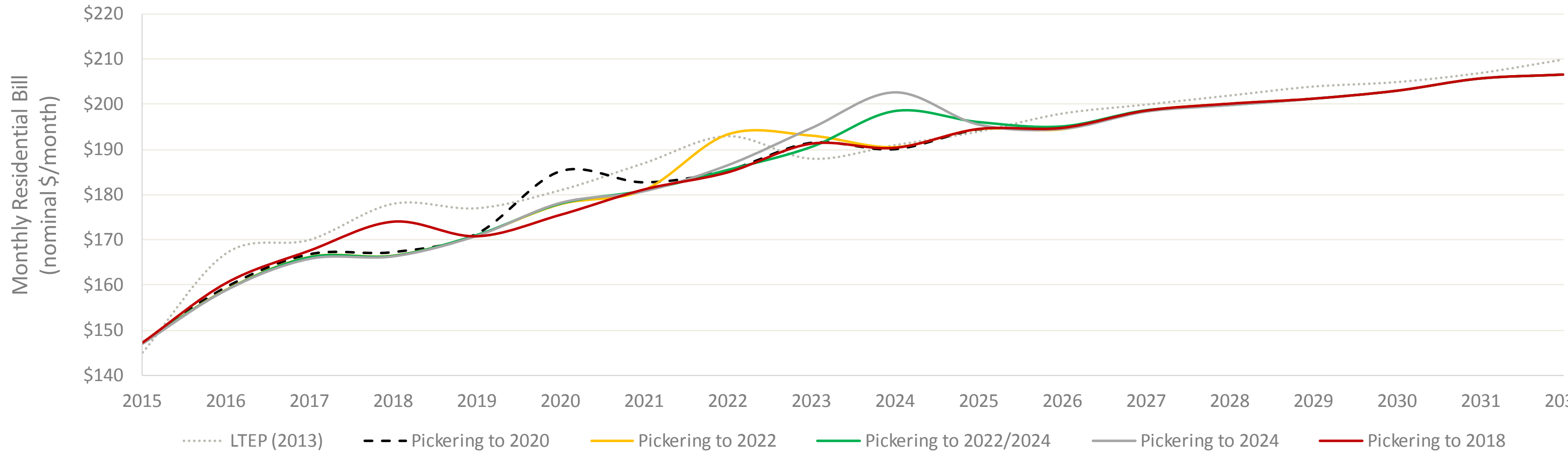
Table shows total change in CO_2 emissions between 2015-2032 in megatonnes (MT) compared to the base case

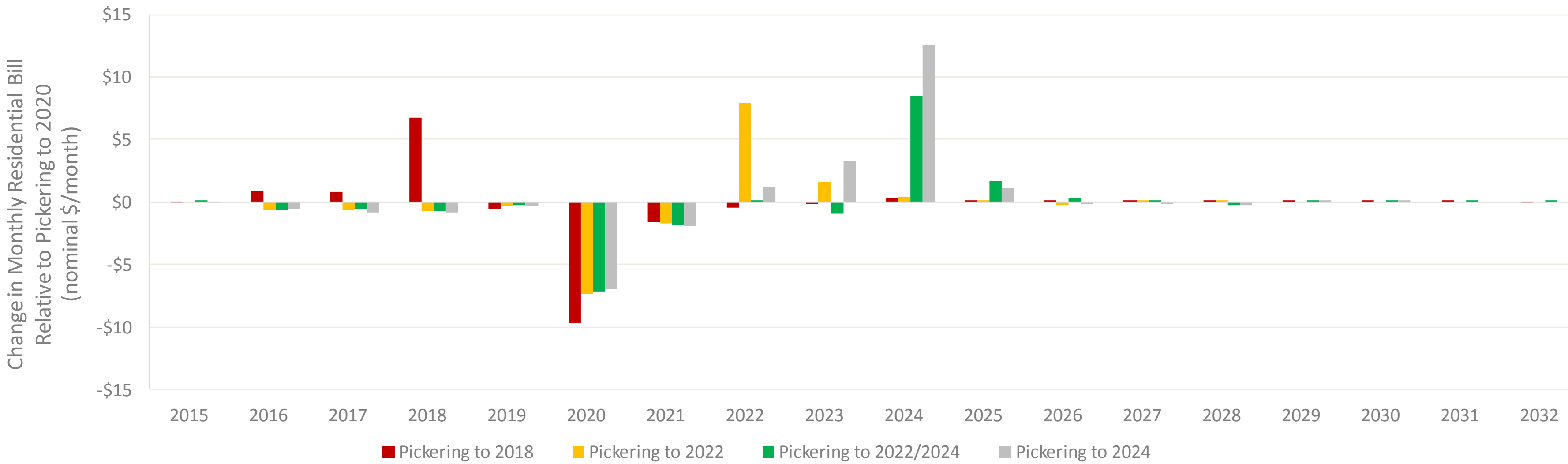
Total cost of electricity service



Excludes transmission and decommissioning advancement/deferral costs.

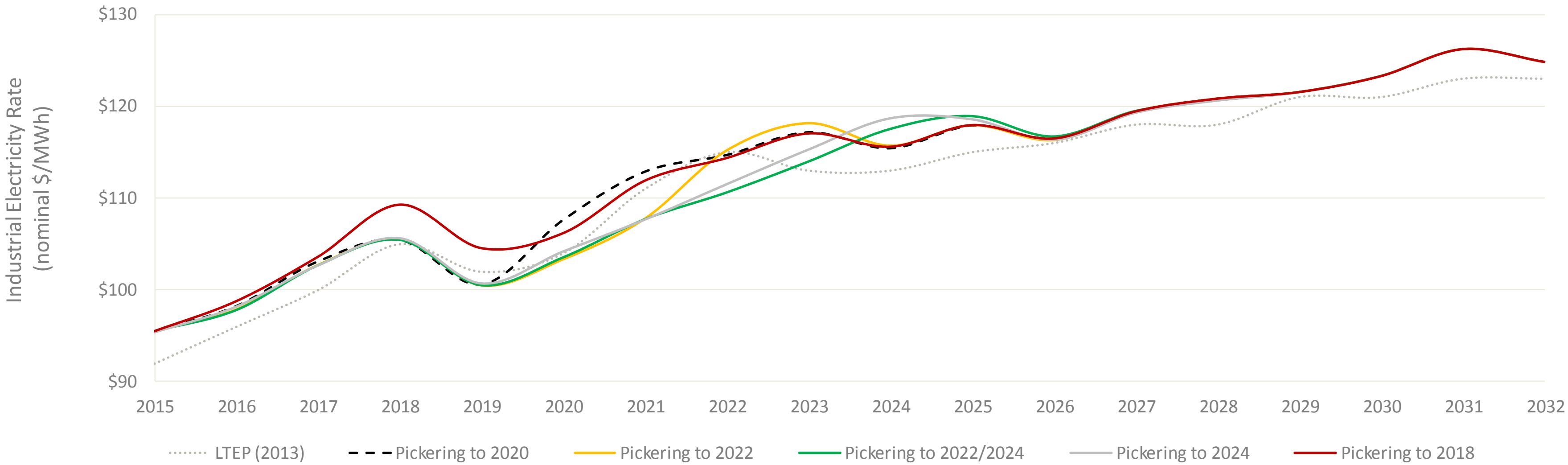
Residential electricity bills

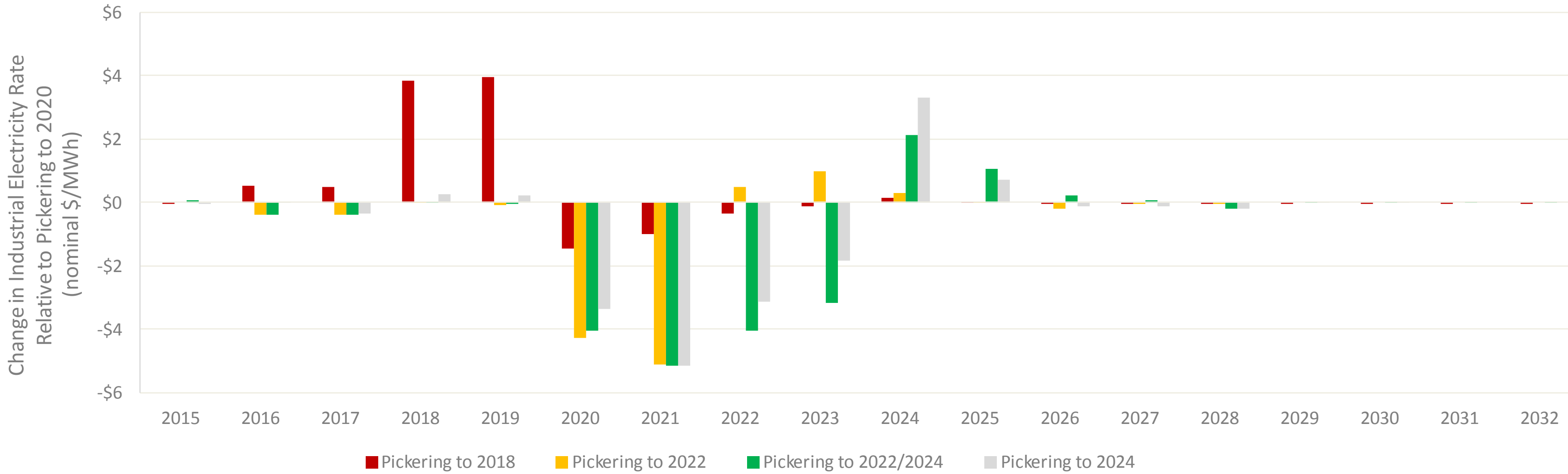




Assumes a typical residential consumption of 800 kWh/month. Excludes transmission and decommissioning advancement/deferral costs.

Industrial electricity rates





Assumes a typical large industrial customer with a demand of 5MW and a 75% capacity factor. Excludes transmission and decommissioning advancement/deferral costs.

Extending Pickering operations beyond 2020

- There is value in Pickering life extension. Extending operation beyond 2020:
  - Defers timing of need and the supply/transmission investments that would otherwise be required
  - Defers procurement decisions with respect to new resources, providing more time in exercising options while reducing risk of over investment during a period of supply/demand uncertainty
  - Defers decommissioning and severance costs
  - Offsets production from natural gas-fired resources and imports
  - Increases export revenues and reduces carbon emissions
  - But also increases potential surplus energy
- Extension of Pickering A units to 2022 and B units to 2024:
  - Shows the greatest net benefit among Pickering scenarios assessed
  - Minimizes increases to OPG nuclear rates to 2024
  - Defers the increase in the total cost of electricity service that eventually takes place under each of the scenarios considered and minimizes the magnitude of the total cost increase
- The value of extending Pickering operation to 2022/2024 is tied to the price of natural gas and carbon prices and to Pickering capital and operating costs
  - Value seen when natural gas or combined natural gas and carbon prices are above $4/MMBtu
- However, extension beyond 2022/2024 shows decreasing utility and results in a cumulative disbenefit
- Removing overlap among Darlington refurbishment outages (a.k.a. “unlapping”) generally reduces the value of extended Pickering operations

Early Pickering shutdown

- Early Pickering shutdown could lead to cost savings, but less savings than extended operations under the reference conditions assessed
  - Also results in less potential surplus energy and more carbon emissions
- The cost savings of early Pickering shutdown are less vulnerable to natural gas price/carbon risk than observed in Pickering extension scenarios
- All else being equal, cost savings from early Pickering shutdown would be negated if:
  - Pickering capital and operating costs declined by 10% from current projections; or,
  - If natural gas/carbon prices exceeded approximately $6/MMBtu
- Early shutdown would present practical challenges related to securing replacement supplies within the span of three years and within a context of significant transition in the Ontario electricity system
- Early shutdown would also present practical challenges related to labour and community impacts
- Early shutdown would advance increases to OPG nuclear rates as well as increases in the total cost of electricity service that eventually takes place under each of the scenarios considered

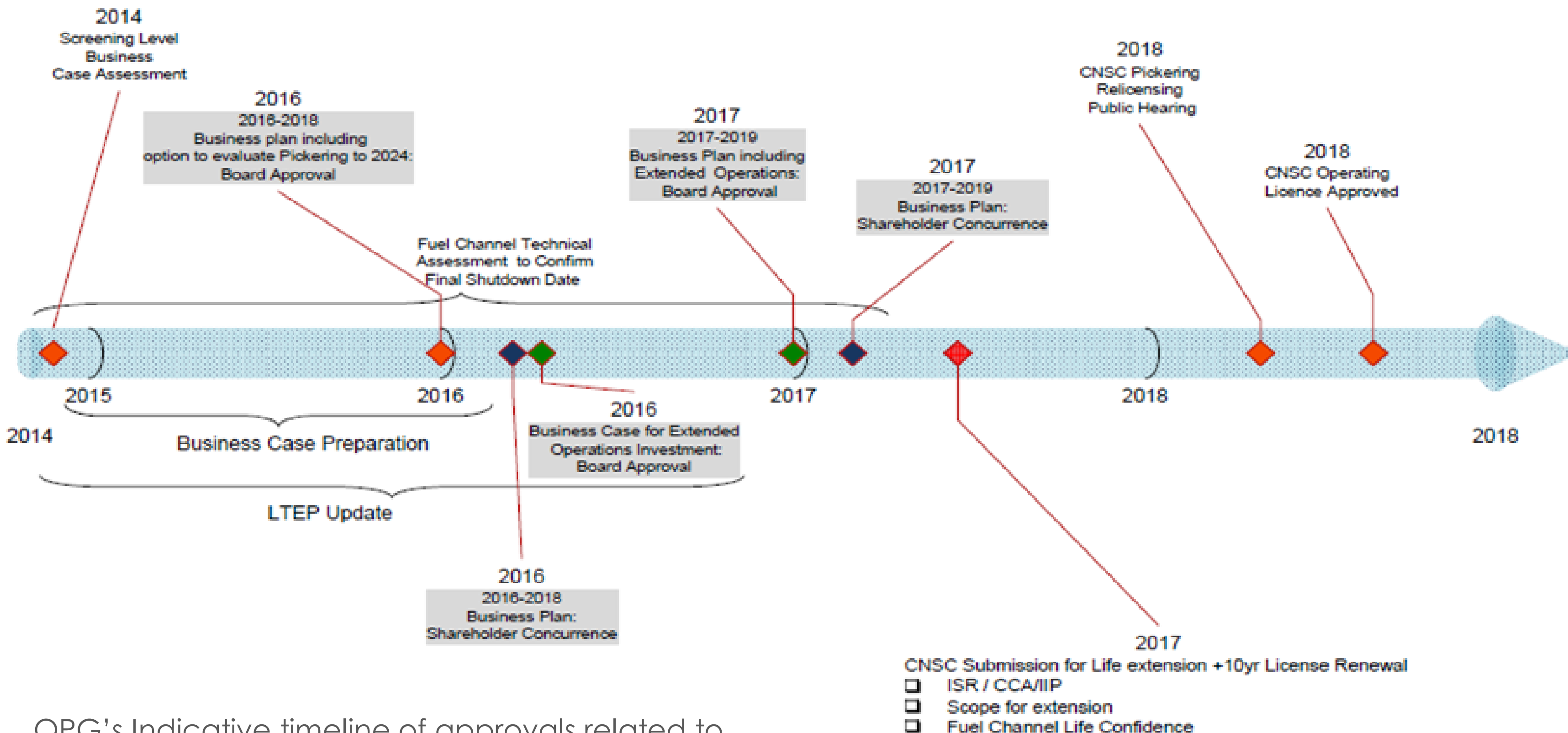
Next Steps

- Explore extension options involving fewer Pickering units to reduce contribution to surplus baseload generation
- Consider cost control mechanisms to ensure Pickering life extension continues to provide value
- IESO should be routinely updated on the status and substance of Pickering extension exploration efforts and related regulatory developments given the implications on need for additional supply and transmission investment

APPENDIX 3:

Additional Detail on Elements of a "Work Plan" in progress developed by Ministry of Energy, OPG, and IESO

Over the next few years, OPG will seek to demonstrate the technical feasibility of extended Pickering operation, develop the business case and pursue regulatory approvals at the OEB and CNSC. OPG's filing to the CNSC would take place in 2017 and a CNSC decision would be received by late 2018.



OPG's Indicative timeline of approvals related to the operation of Pickering NGS beyond 2020

Elements of a work plan in progress
(source: Ministry of Energy, April 28 2015)

Organization	Activity to Increase the Economic, Technical and Regulatory Confidence	Completion Date
IESO	Update supply/demand outlook, ongoing assessment of Pickering extended operations and alternatives, ongoing contingency planning in case Pickering extended operations does not proceed	Ongoing
OPG	Economic evaluation of incremental investment and benefits of operation of Pickering units past 2020 • Ministry briefing	Q2 2015
OPG	2016-2018 Business Plan submission with operation to 2020 and evaluation of option for Pickering extension to 2024	Q4 2015
ENERGY	Cabinet submission on Pickering extension	Q4 2015
OPG	Technical assessment of fuel channels: • measurements to confirm rate of aging mechanisms • completion of research program on fuel channel aging and related safety analysis	Q2 2016
OPG Board	Approved business case for life management measures and their costs	Q2/3 2016
ENERGY	Consultations for 2017 LTEP	Q3 2016

Elements of a work plan in progress (continued)

(source: Ministry of Energy, April 28 2015)

Organization	Activity to Increase the Economic, Technical and Regulatory Confidence	Completion Date
OPG ENERGY	OPG Board approved business plan for extended operations of the Pickering units submitted to Energy	Q4 2016
ENERGY IESO	Decision to make Pickering extension preferred supply option	Q4 2016

ENERGY	Release 2017 LTEP including Pickering extension	Q1 2017
OPG	OPG's determination of end of life dates for Pickering and regulatory submission requesting approval of extended operations of Pickering units	Q2 2017
CNSC	Approval of Pickering extended operations operating license	Q3 2018

ENERGY	Release 2017 LTEP including alternative supply options	Q1 2017
IESO	Implement alternatives as required	By 2020

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Assessment of Pickering Life Extension Options

Prepared for discussion with Ministry of Energy

Power System Planning

March 9, 2015

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Overview

- Upon Ministry of Energy request, the IESO has conducted an independent assessment of the long-term integrated power system impacts of various Pickering life extension scenarios. Pickering extension scenarios are considered against three Darlington refurbishment sequences.
  - This report updates and builds upon previous Pickering life extension studies conducted by the former OPA
  - Technical and economic information concerning the Pickering and Darlington stations was provided to the IESO by OPG between December 2014 and January 2015 for each scenario assessed
  - The scenarios have not been discussed publicly nor have they received necessary CNSC approvals

- Implications of the Pickering scenarios are assessed from a variety of perspectives, including:
  - Capacity needs and timing
  - Energy production from existing and contemplated resources
  - Greenhouse gas emissions
  - Surplus energy
  - Total cost of electricity service
  - Ratepayer costs

- Results of the IESO's assessment are presented in the following slides, additional details are available in the Appendix

Summary of results

- Extending Pickering operation beyond 2020 defers some supply and transmission investments that would otherwise be required, defers decommissioning and severance costs, offsets production from natural gas-fired resources and imports, increases export revenues and reduces carbon emissions
- Extending Pickering operations beyond 2020 also increases potential surplus energy
- Extension of Pickering A units to 2022 and B units to 2024 shows the greatest net benefit among Pickering scenarios assessed, minimizes increases to OPG nuclear rates to 2024, defers the increase in the total cost of electricity service that eventually takes place under each of the scenarios considered and minimizes the magnitude of the total cost increase
- The value of extending Pickering operation to 2022/2024 is sensitive to natural gas and carbon prices: it shows value when natural gas or combined natural gas and carbon prices are above $4/MMBtu
- The value of extending Pickering operation to 2022/2024 is also sensitive to Pickering capital operating costs, but less sensitive than to natural gas/carbon price
- Extension beyond 2022/2024 shows decreasing utility and results in a cumulative disbenefit
- Removing overlap among Darlington refurbishment outages (a.k.a. “unlapping”) generally reduces the value of extended Pickering operations

Summary of results (continued)

- Early Pickering shutdown could lead to cost savings, but less savings than extended operations under the reference conditions assessed
- Early Pickering shutdown results in less potential surplus energy and more carbon emissions
- The cost savings of early Pickering shutdown are less vulnerable to natural gas price/carbon risk than observed in Pickering extension scenarios. All else being equal, cost savings from early Pickering shutdown would be negated if Pickering capital and operating costs declined by 10% from current projections or if natural gas/carbon prices exceeded approximately $6/MMBtu
- Early shutdown would present practical challenges related to securing replacement supplies within the span of three years and within a context of significant transition in the Ontario electricity system
- Early shutdown would also present practical challenges related to labour and community impacts
- Early shutdown would advance increases to OPG nuclear rates as well as increases in the total cost of electricity service that eventually takes place under each of the scenarios considered

Looking ahead

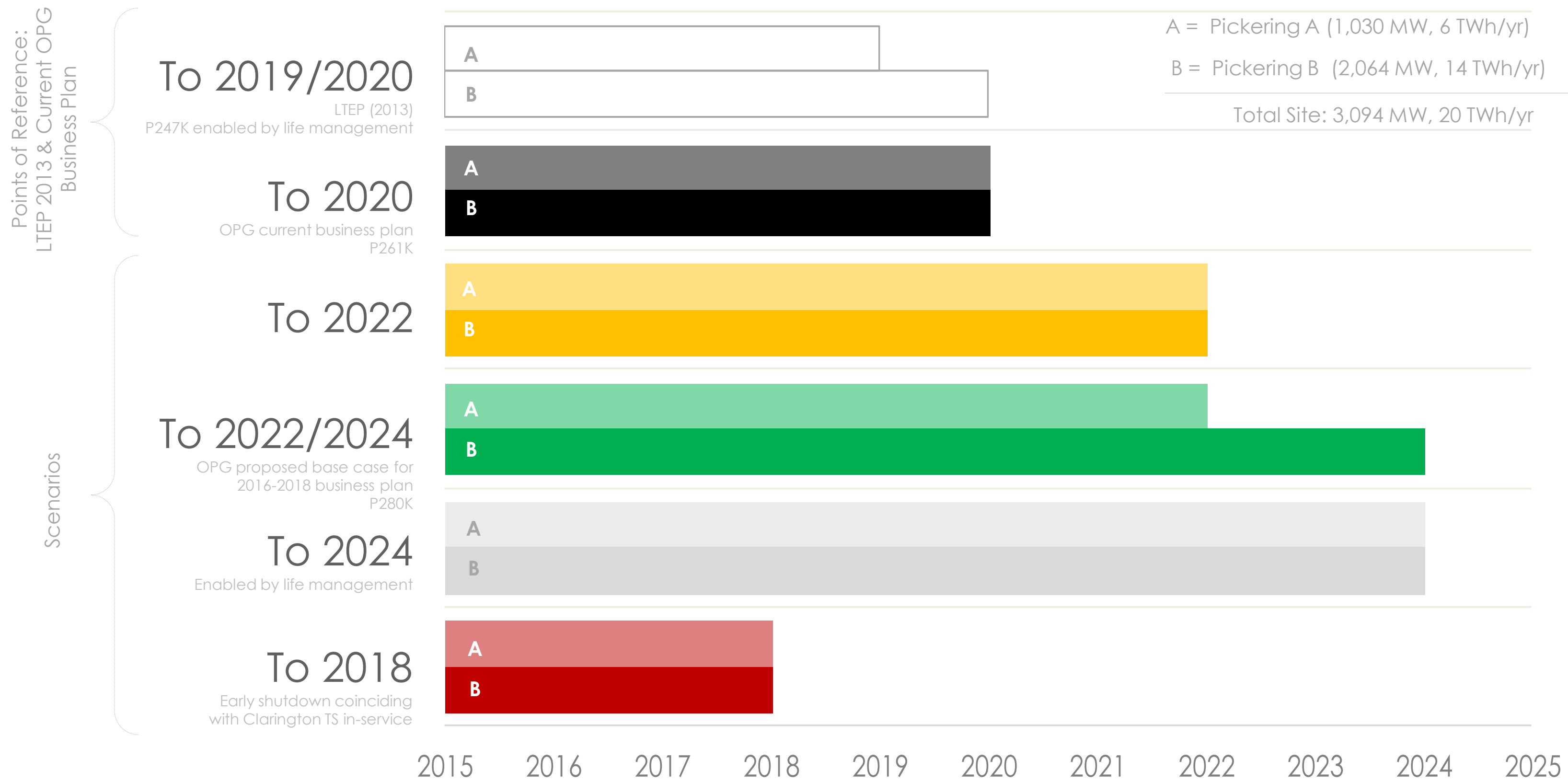
- On balance, the option of extended Pickering operations merits further exploration. The scenario of Pickering operation to 2022/2024 appears to be the most promising candidate among extension options assessed. Extended operation to 2022 also holds potential for benefit, but less so than operation to 2022/2024.

- In light of the impact of Pickering extended operations on potential surplus energy, it may be worth exploring Pickering extension options involving fewer Pickering units (e.g. four to five units rather than six)

- In light of the impact of Pickering capital and operating costs on the value proposition of extended Pickering operations, it may be worth exploring options for cost control

- In light of implications of Pickering shutdown timing on the need for additional supply and transmission investment, IESO should be routinely updated by OPG on the status and substance of Pickering extension exploration efforts and related regulatory developments

Four Pickering scenarios are assessed: three feature longer Pickering operation than in LTEP 2013 or in OPG's more recent business plan, one features earlier shutdown



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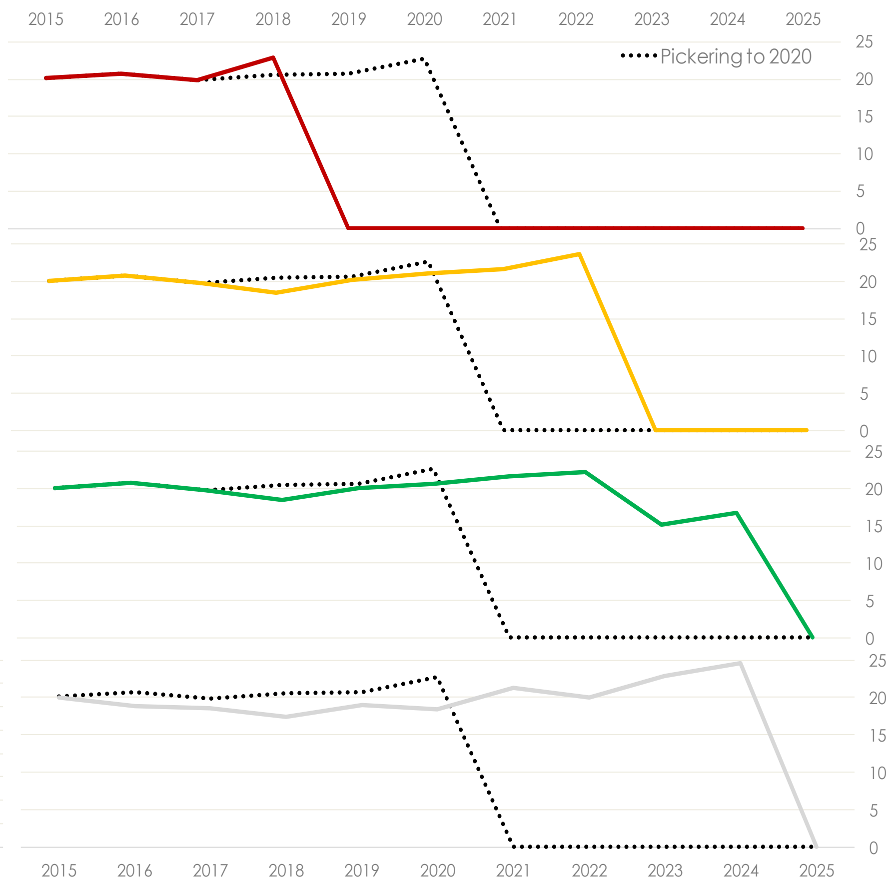
Approximately 3,100 MW and 20 TWh is provided by Pickering for each year of operation. Operation beyond 2020 is enabled by additional outages prior to 2020. These outages result in lower availability and output in some years prior to 2020.

Pickering Installed Capacity (MW)

Pickering Energy Production (TWh)



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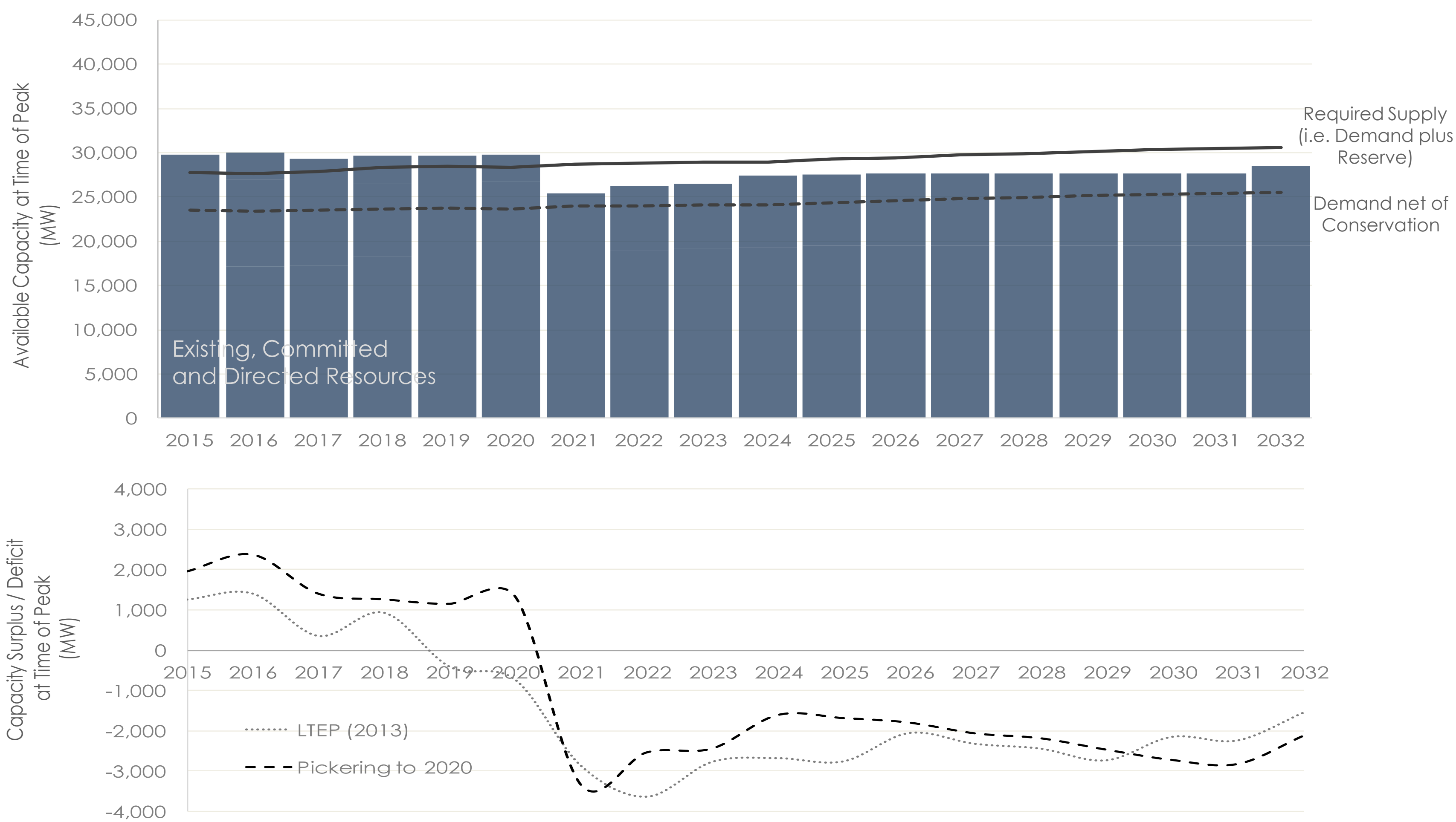
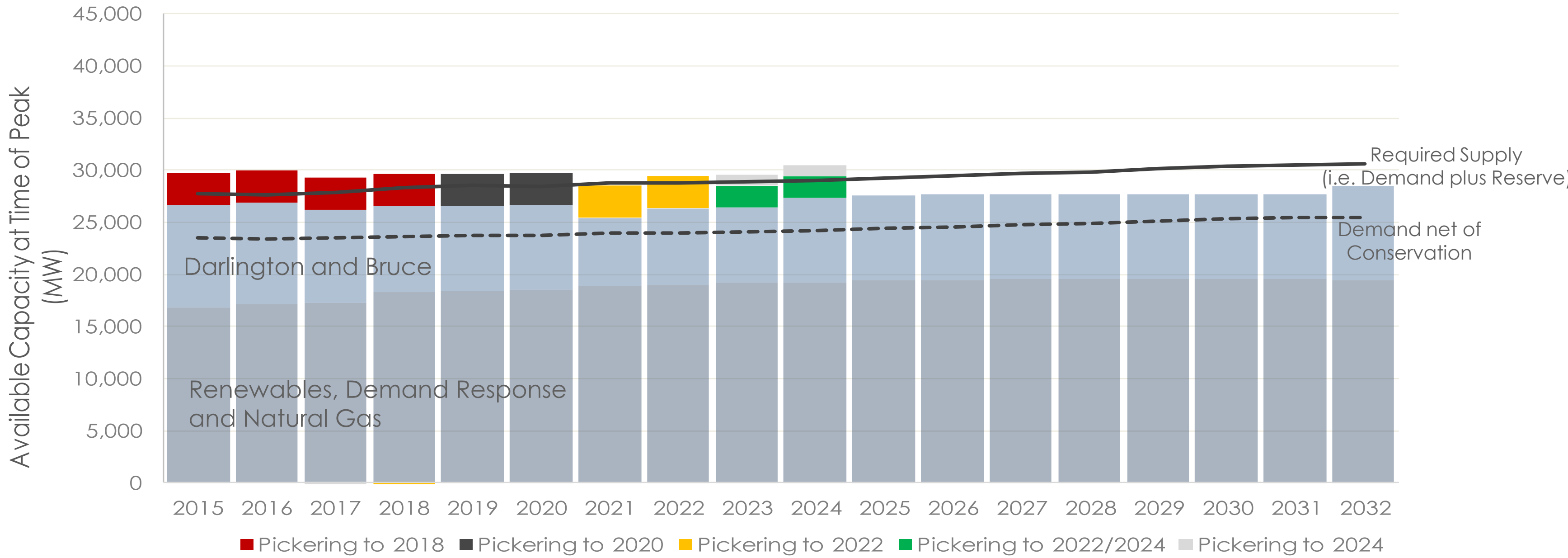
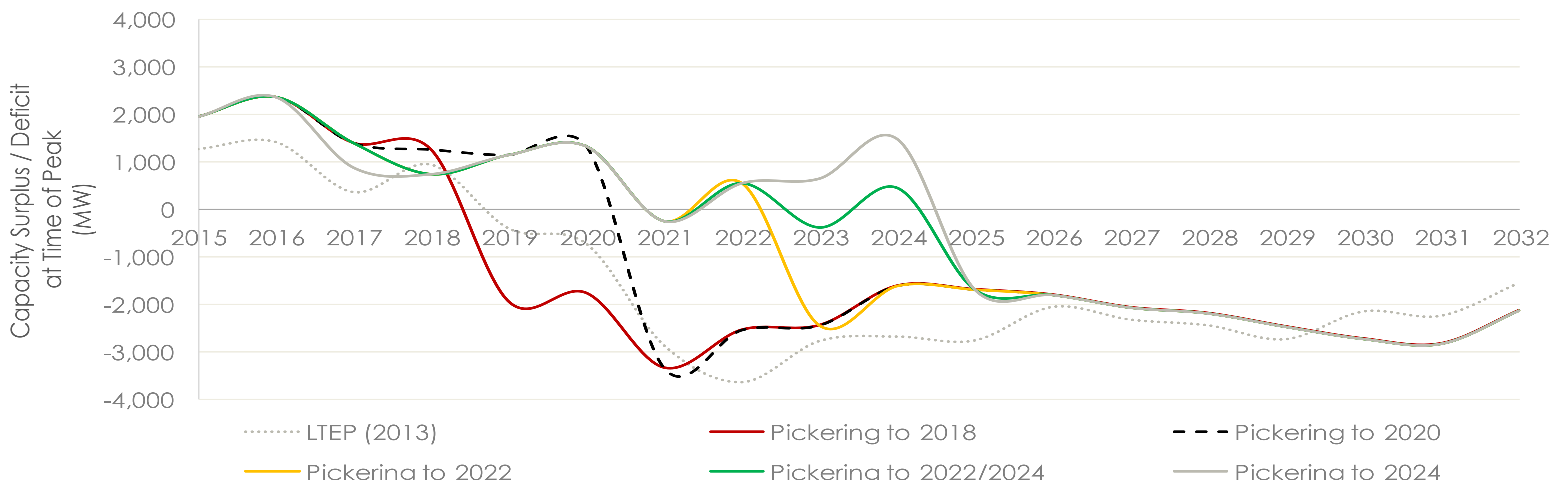
Existing, committed and directed resources will provide adequate supply for the next few years, after which time additional resources will be required. LTEP 2013 saw needs emerge in 2018/2019. Needs arise by 2020 in the current outlook.



Extended operation at Pickering beyond 2020 would defer the need for additional supply, earlier shutdown would advance the need





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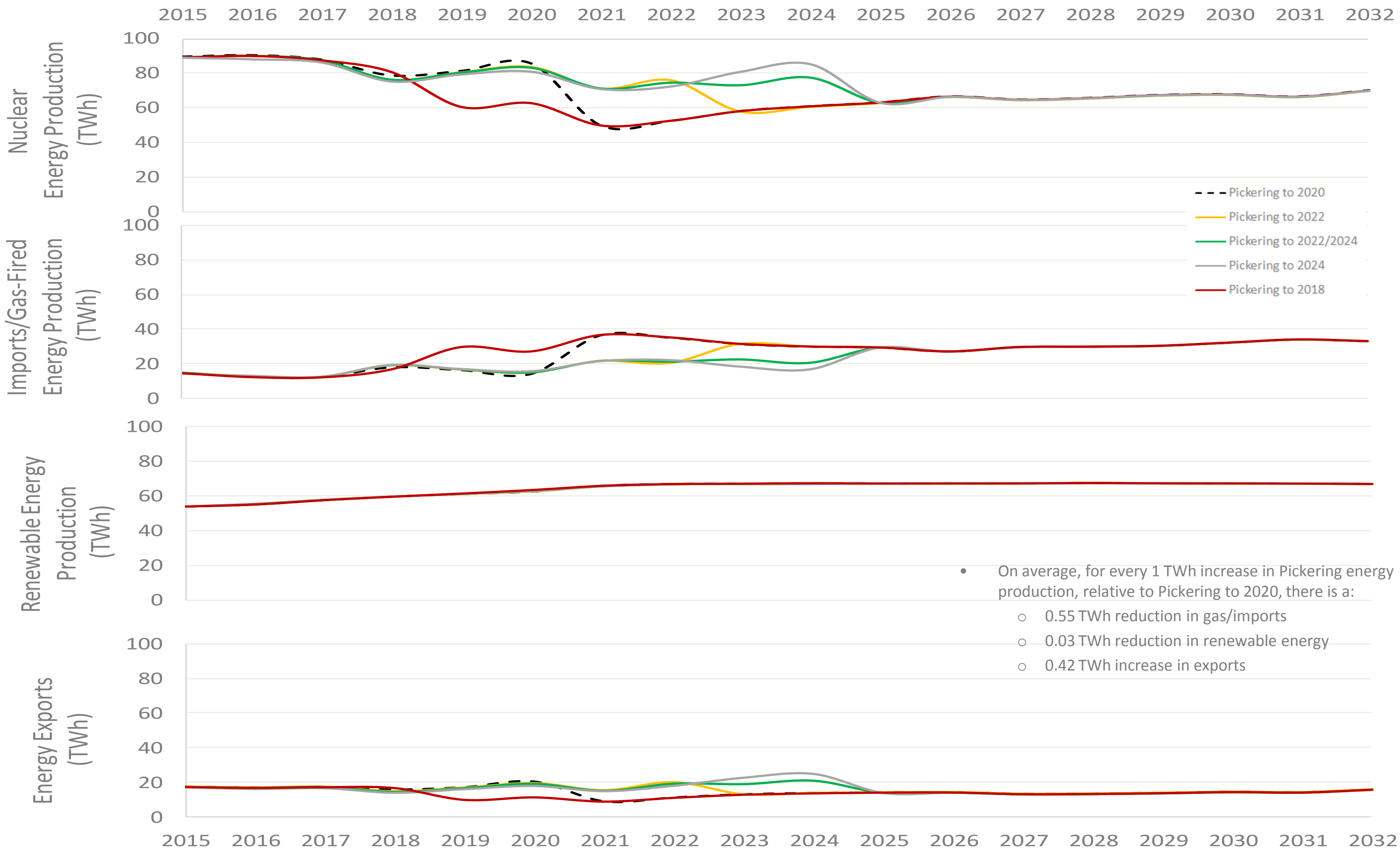
Energy production from Pickering displaces production from gas-fired resources, reduces energy imports and increases energy exports



- On average, for every 1 TWh increase in Pickering energy production, relative to Pickering to 2020, there is a:
  - 0.55 TWh reduction in gas/imports
  - 0.03 TWh reduction in renewable energy
  - 0.42 TWh increase in exports

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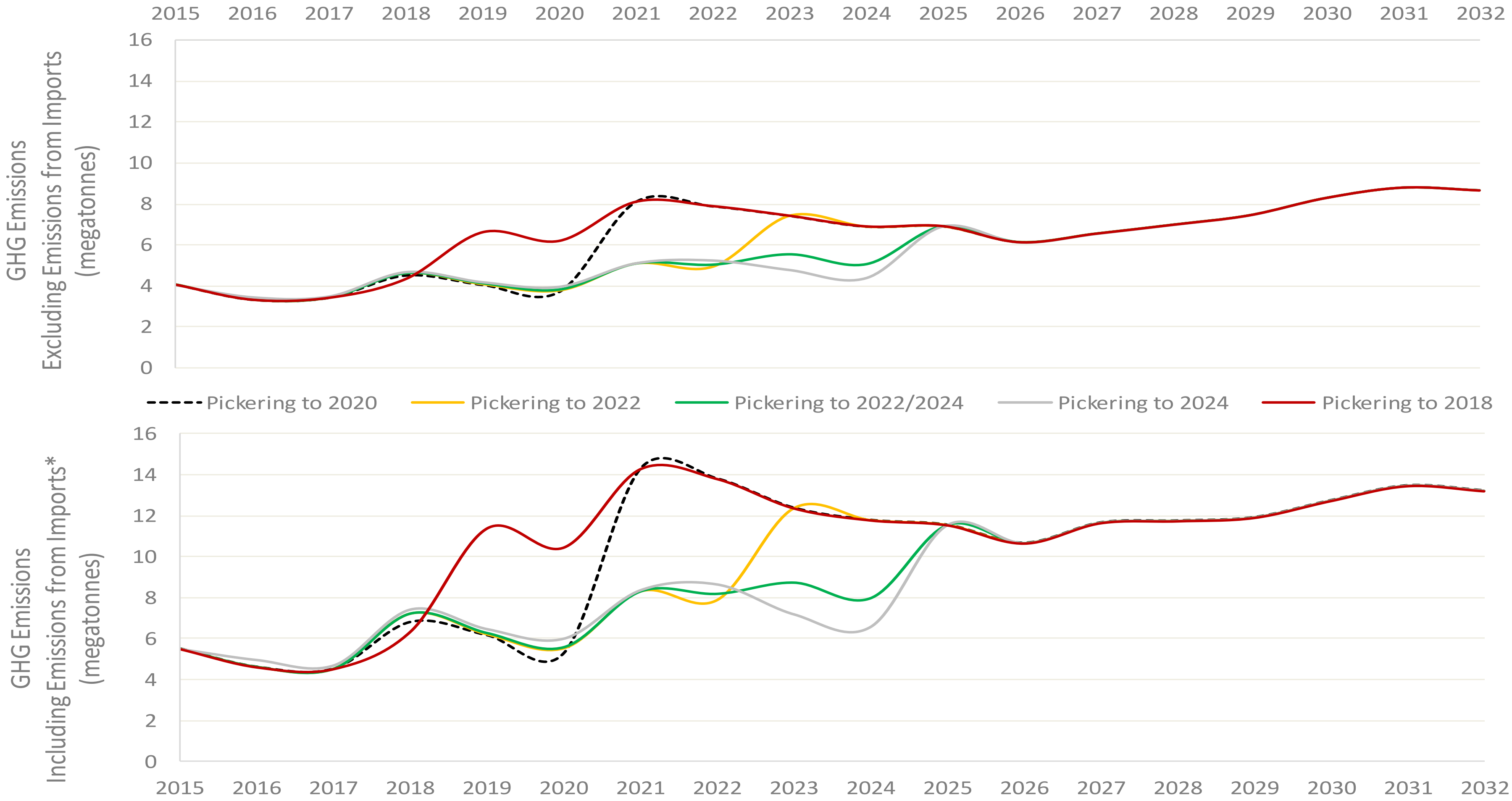
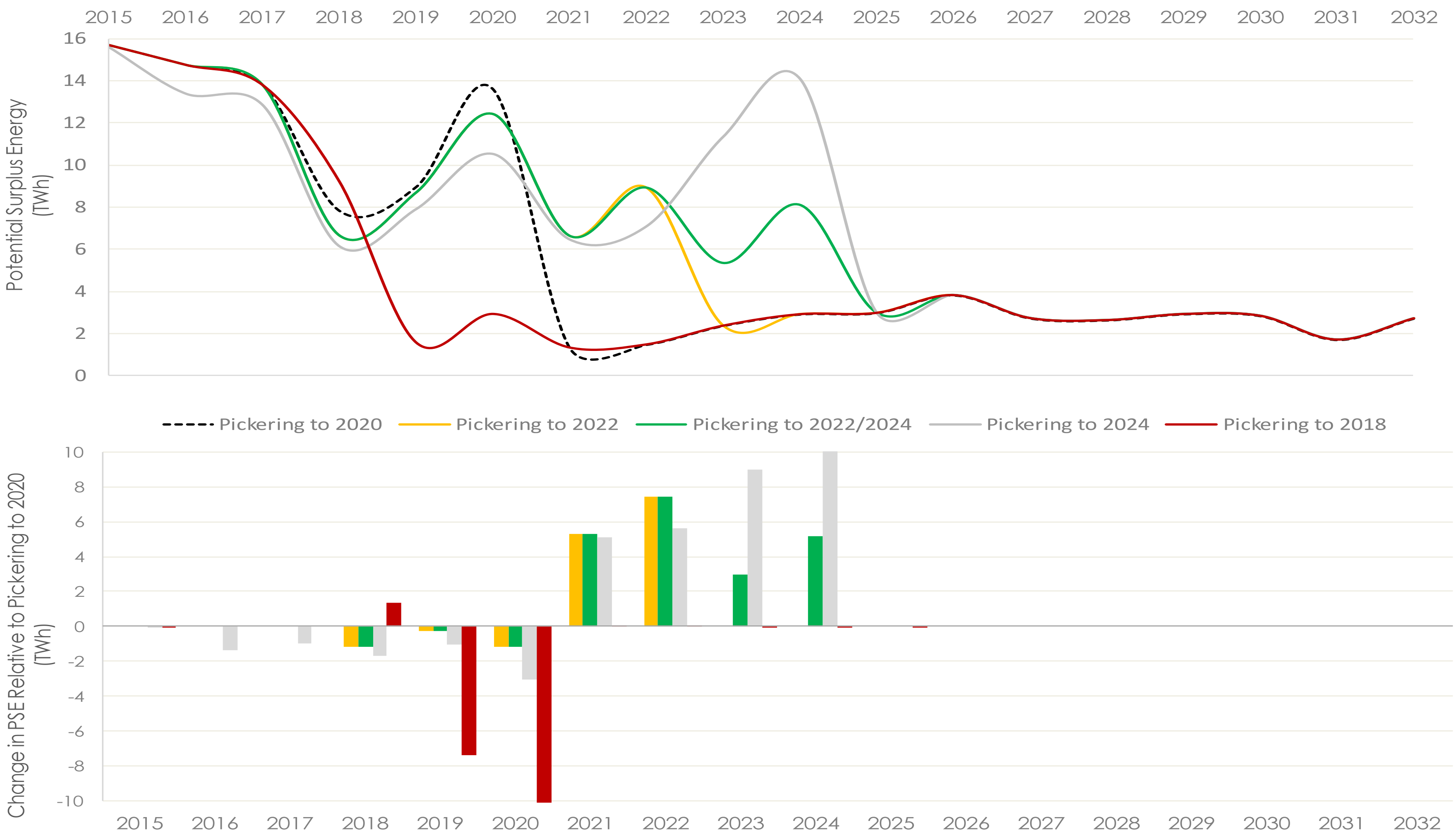
Energy production from Pickering reduces greenhouse gas emissions



*CCGT emission rates used for import emissions rates as a proxy

Energy production from Pickering increases potential surplus energy



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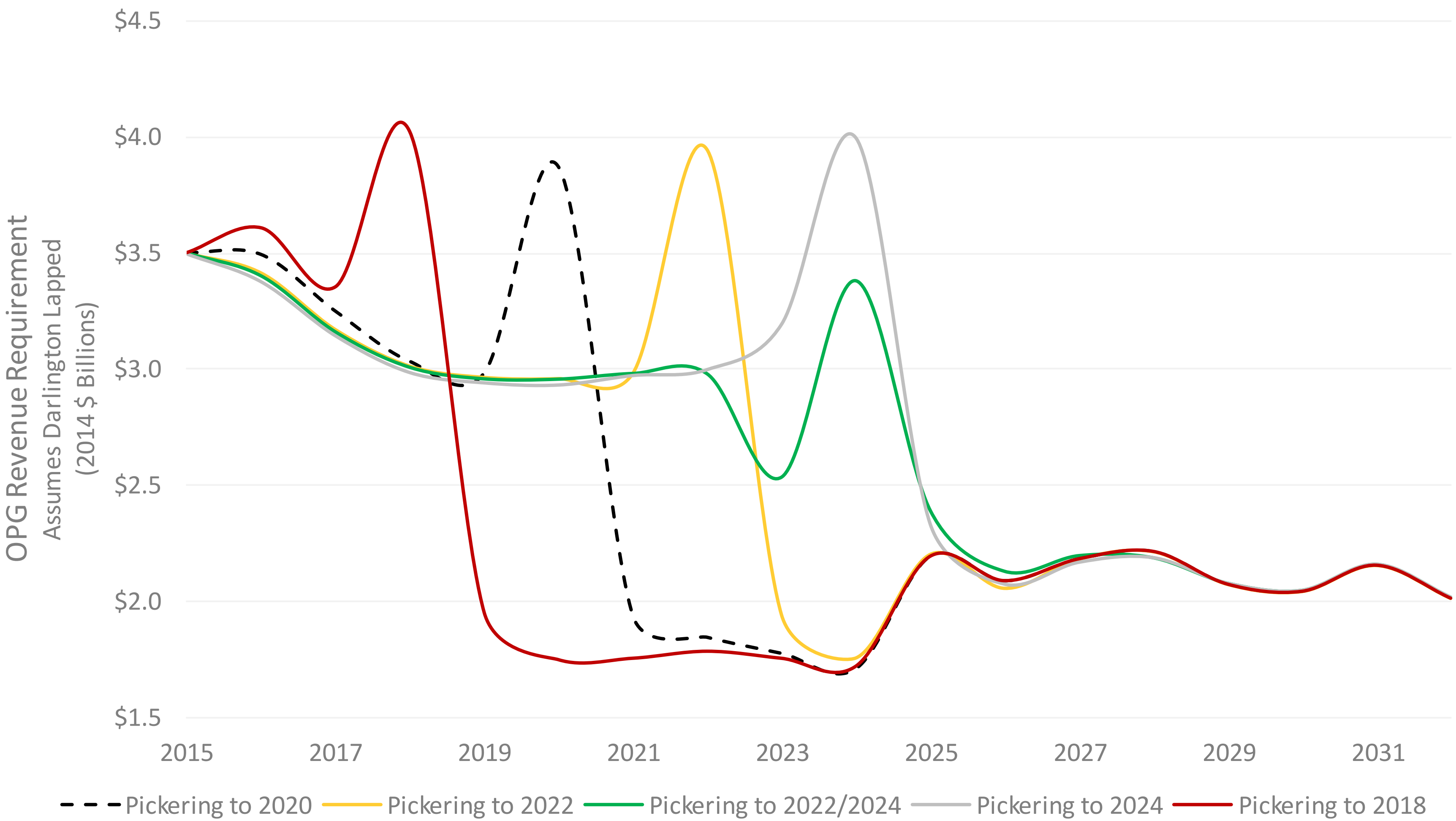
OPG's nuclear program will cost between $1.7 billion and $4.0 billion per year between now and 2032, depending on the Pickering extension and Darlington refurbishment sequence scenario



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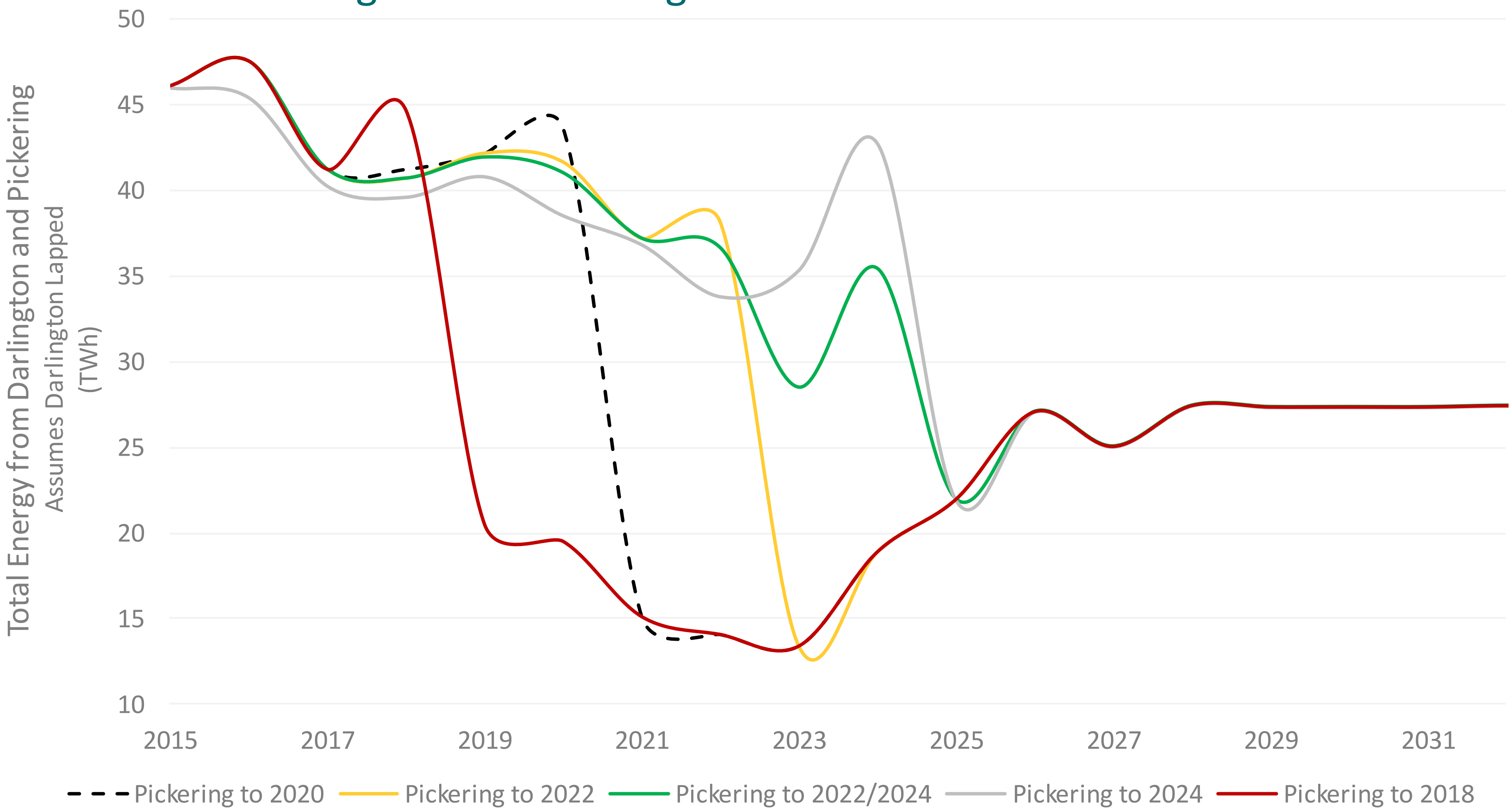
The costs of OPG's nuclear program will be recovered against the energy quantities generated by OPG nuclear stations. Annual quantities will vary depending on the scenario. Energy quantities decline as Pickering units are shut down and as Darlington units undergo refurbishment.



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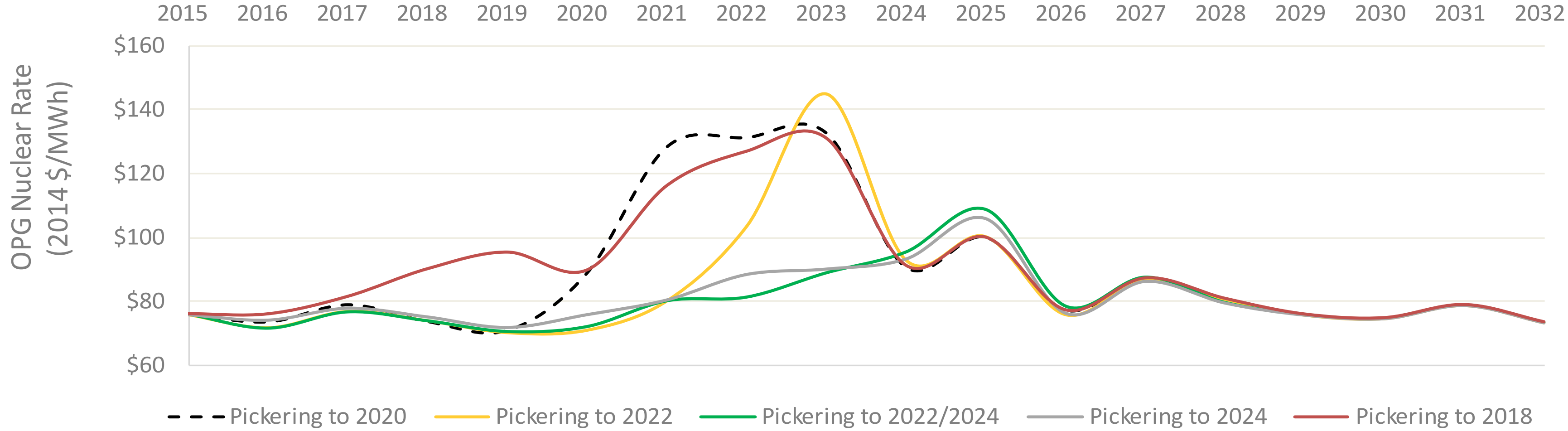
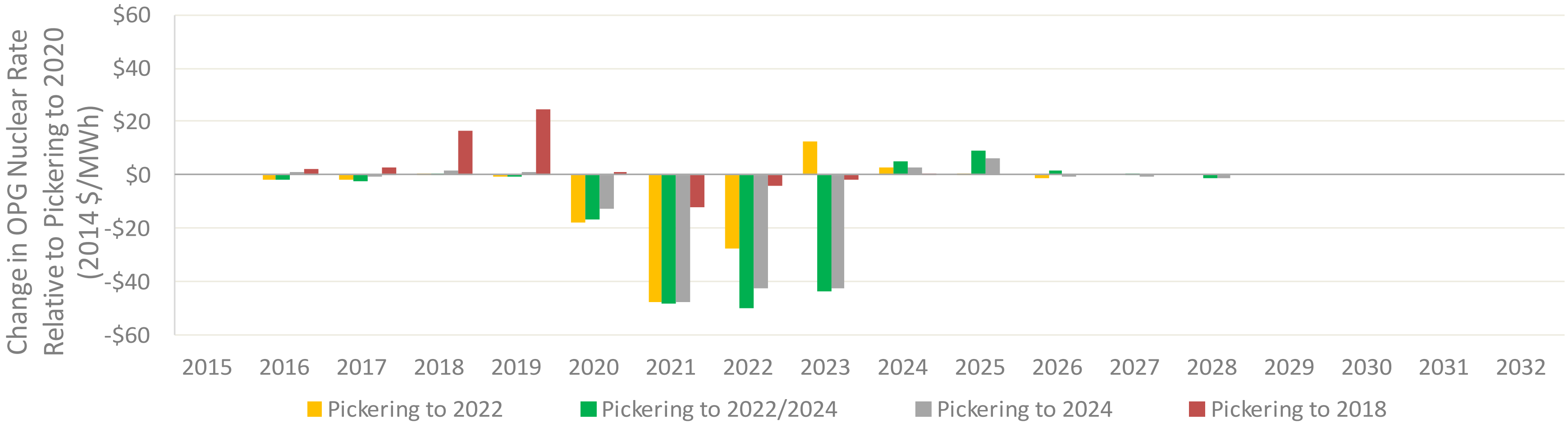
OPG's total nuclear rate will increase as OPG nuclear production decreases. Life extension at Pickering increases OPG's annual nuclear production and tends to reduce OPG nuclear rates to 2024.





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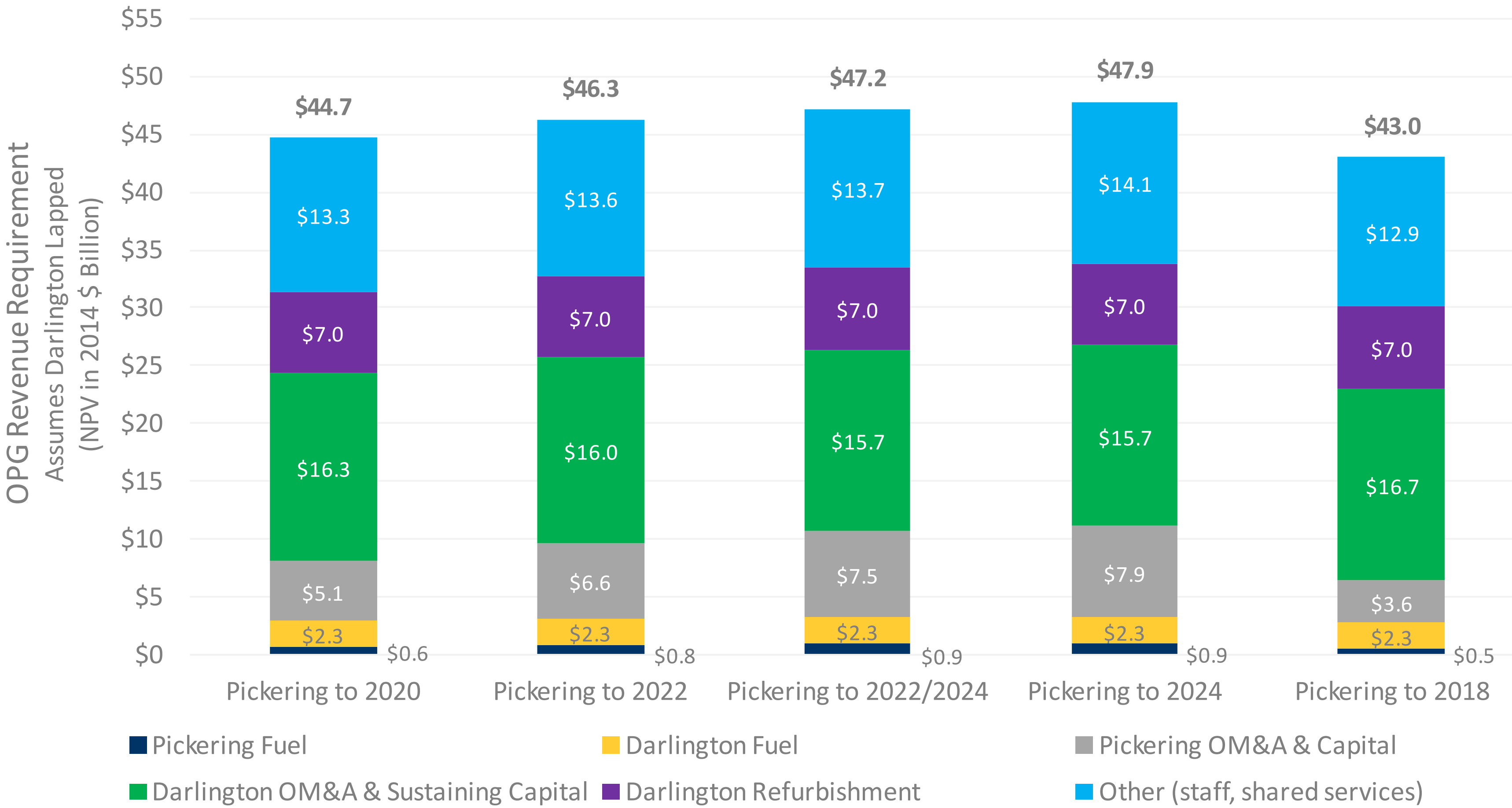
Rates reflect Pickering scenario stated and Darlington lapped (per LTEP (2013))

The present value of OPG nuclear costs will range between $43 billion and $48 billion, depending on the scenario. Pickering will account for between $4 billion and $9 billion of this total. Capital and non-fuel OM&A will comprise approximately 90% of Pickering costs.



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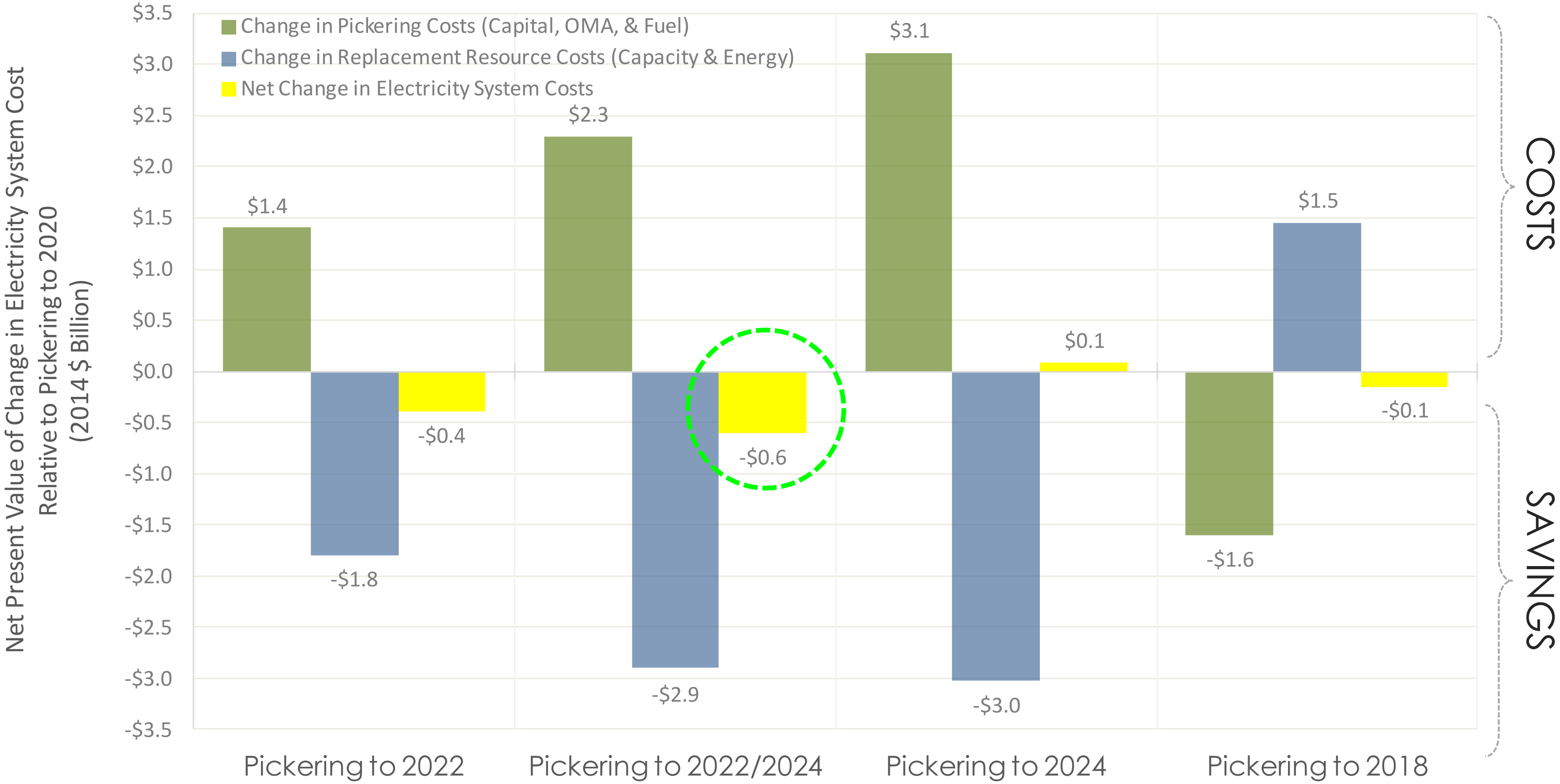
Economic evaluation: overview of approach

- The cost of extending Pickering life is compared to the savings resulting from reduced electricity system replacement energy and capacity costs, all relative to Pickering to 2020 (the current base case)
  - If the cost of Pickering life extension is less than the cost of replacement energy and capacity, there is a net benefit and overall electricity system costs decrease
  - Conversely, if the cost of Pickering life extension is greater than the cost of replacement energy and capacity, there is a net cost and overall electricity system costs increase.
- The current base case, Pickering to 2020, reflects recent updates to the supply mix and various policy initiatives since LTEP (2013) (see Appendix for list of updates)
  - Changes in Pickering life are compared to this base case
- In the absence of Pickering life extension:
  - Capacity needs are assumed to be met by an unspecified capacity resource with performance and cost characteristics equivalent to a simple-cycle gas turbine
  - Replacement energy is provided by existing generation resources
- Scenarios are evaluated under reference gas price assumptions of $5.25/MMBtu at Henry Hub
  - This is equivalent to gas at $4/MMBtu plus carbon priced at $23/tonne
- Sensitivity analysis is performed to evaluate the impact changes in Pickering capital cost and gas price have on system costs
- System costs analysis is performed in 2014 dollars. The change in net present value (NPV) of system cost of each Pickering life extension scenario relative to Pickering to 2020 is presented, 4% real discount rate is assumed
- Impacts on the annual cost of electricity service, residential bills, and industrial rates are also presented
  - Analysis reflects OPG nuclear rates developed by OPG for each individual scenario assessed
- Impacts on the cost of transmission are treated separately

Pickering extension to 2022/2024 yields the greatest net present value among the scenarios considered under the conditions assessed (i.e. results in the greatest cost savings)



Ontario electricity system costs decrease by extending Pickering to 2022 or 2022/2024 or shutting down early in 2018, relative to the Pickering to 2020 case. Costs marginally increase by extending to 2024.

NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

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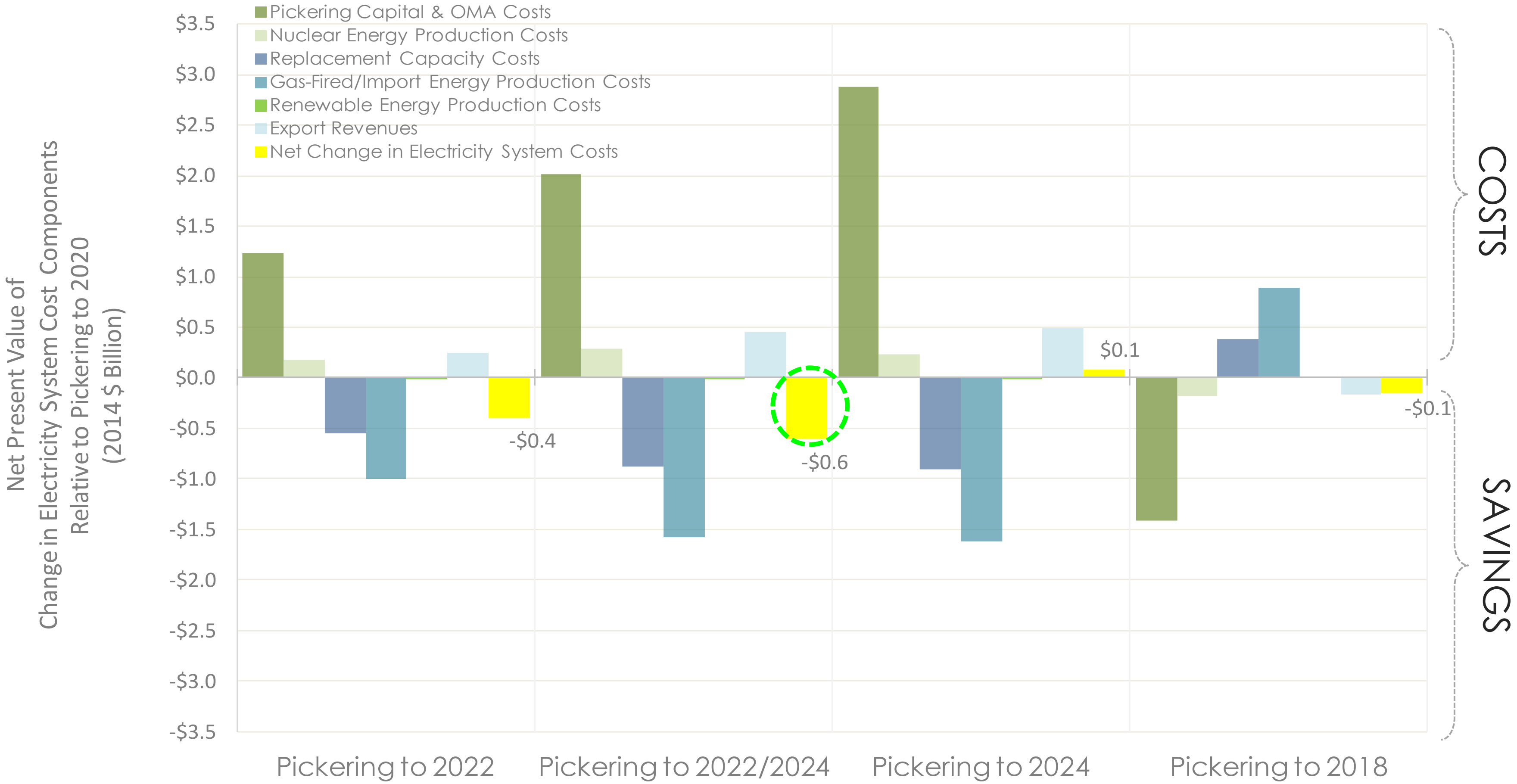
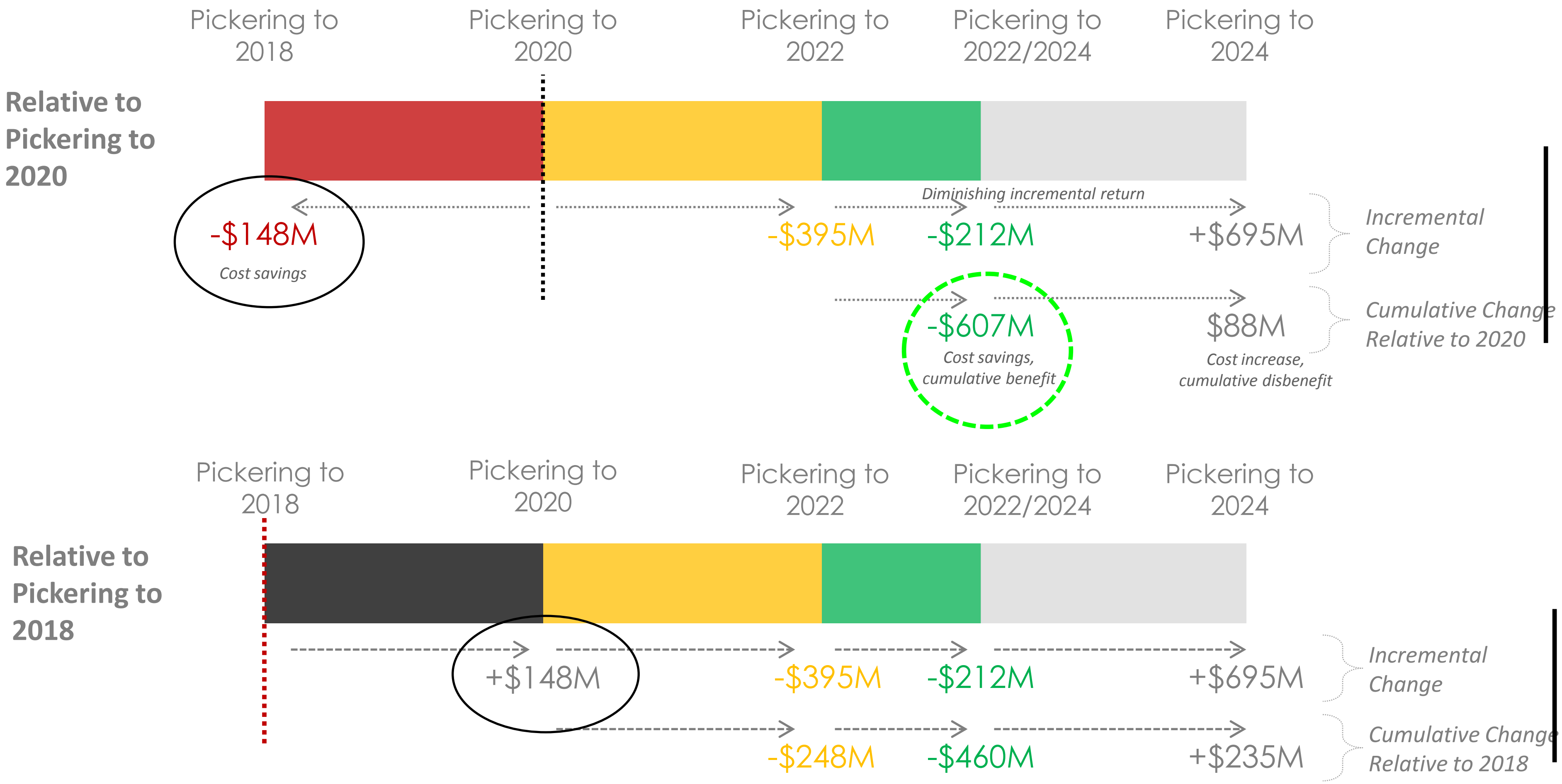
Cost savings from extending Pickering operations derive from reductions in replacement capacity costs and reductions in replacement energy costs from gas-fired resources and energy imports. These savings offset Pickering capital and operating costs, which comprise the largest cost components of Pickering extension.



NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

Pickering extension beyond 2020 results in cost savings, but at a diminishing incremental return beyond 2022. Beyond 2022/2024, diminishing returns result in a cumulative disbenefit.



Positive sign (+) indicates system cost increase , negative sign (-) indicates cost decrease. NPV evaluated at a 4% real discount rate. Excludes transmission and decommissioning advancement/deferral costs.

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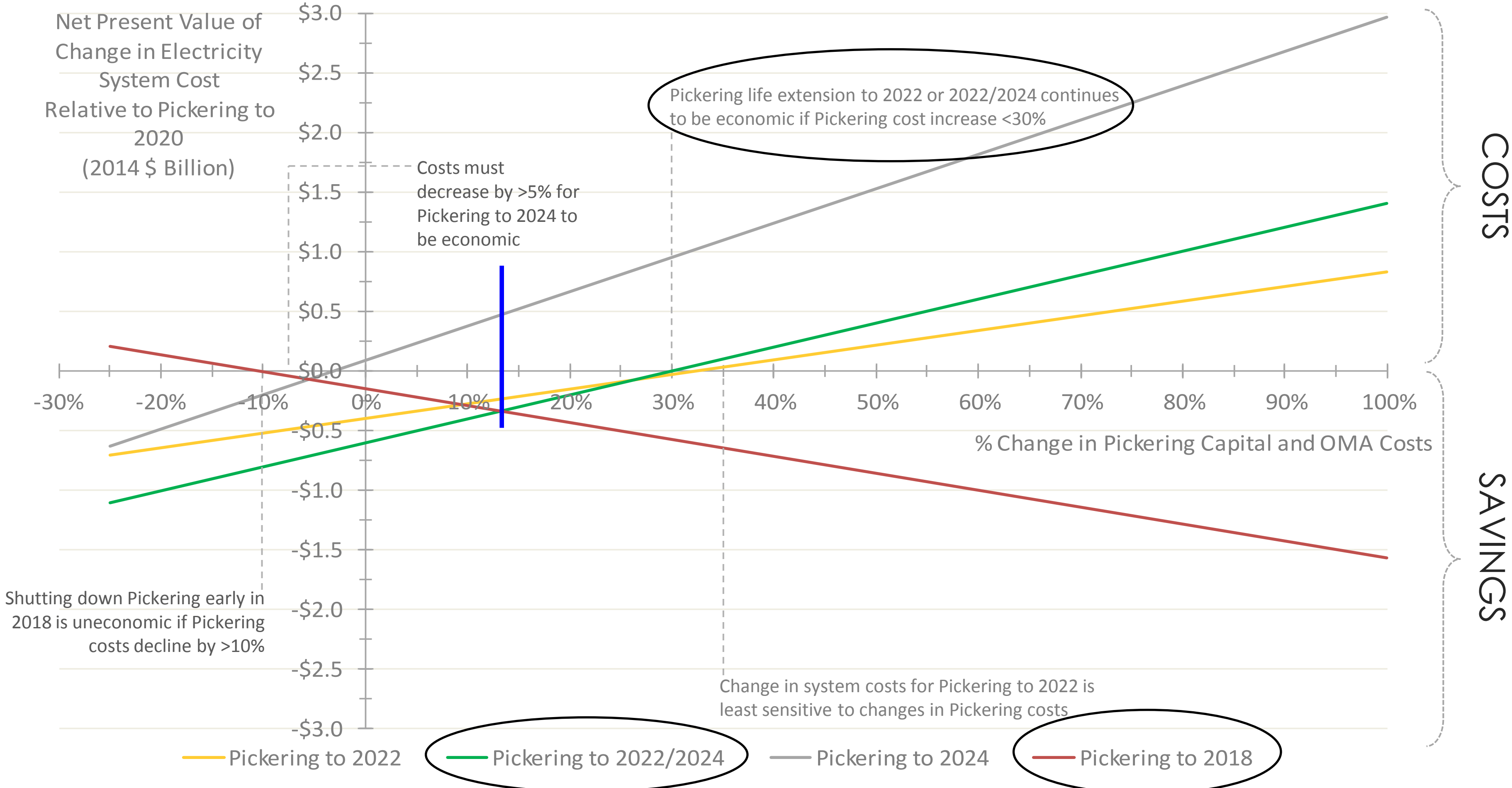
The economic proposition of extended Pickering operations is sensitive to Pickering capital and operating costs. As these costs increase, the value of extending Pickering beyond 2020 decreases, while the value of earlier shut down increases



System Cost Increase (+) / Decrease (-). NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

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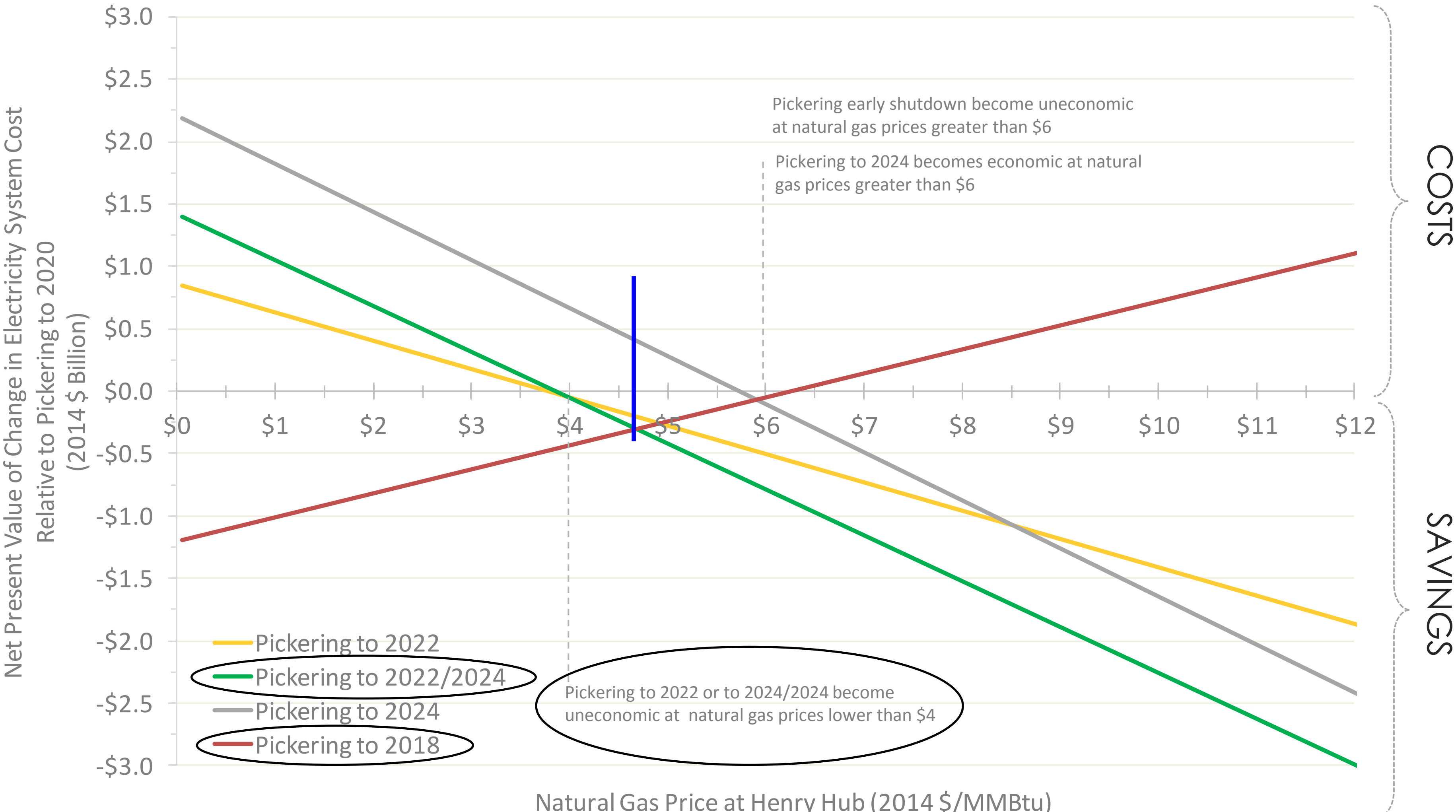
Benefits of extended Pickering operations are also sensitive to natural gas prices. Higher natural gas prices result in greater value from extended operations. Lower prices result in lower value.



System Cost Increase (+) / Decrease (-). NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

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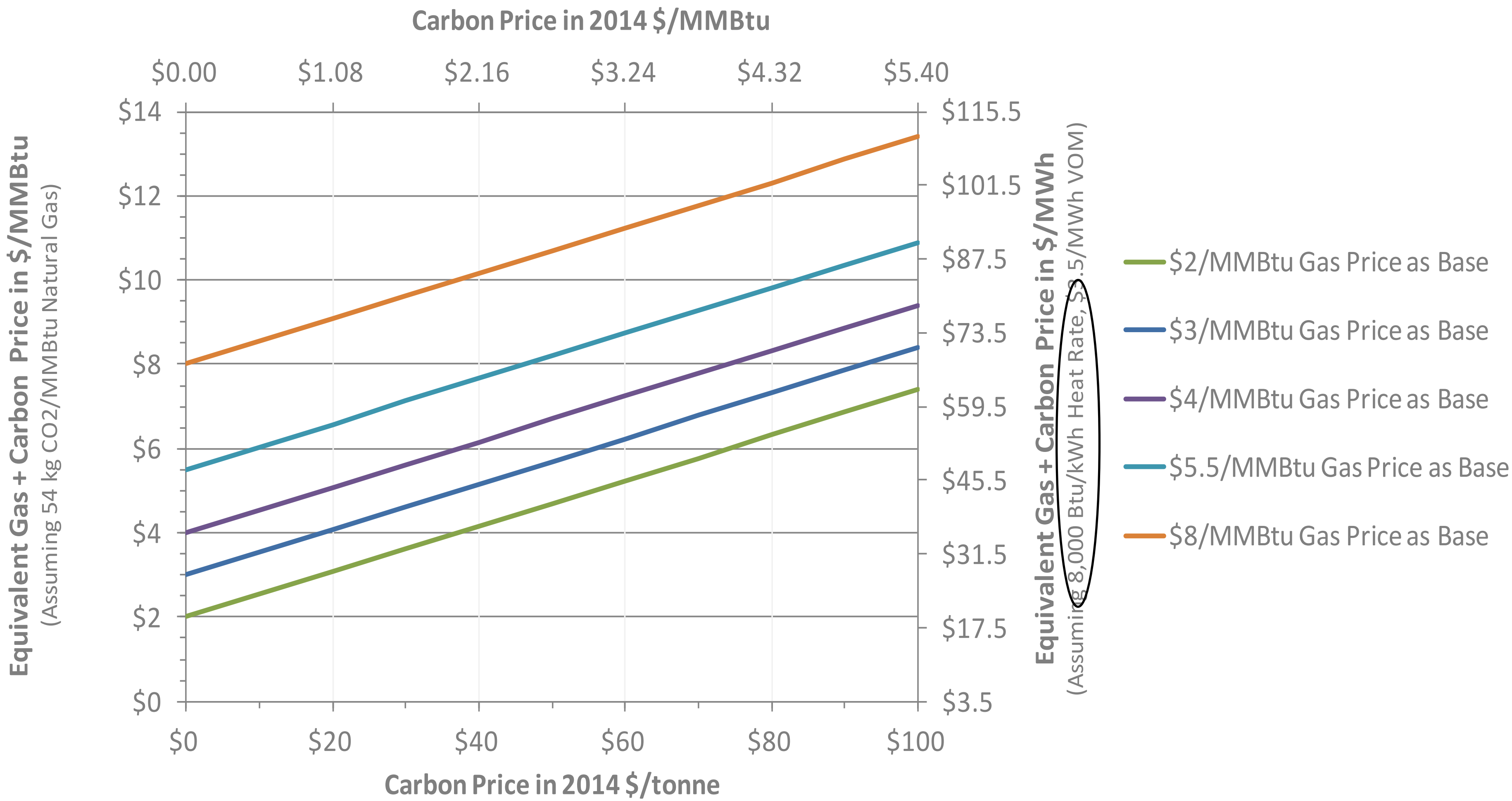
Carbon costs increase the effective cost of natural gas and can therefore impact the economic value of Pickering extended operations



- Example A: Gas at $5.25/MMBtu is equivalent to:
  - Gas at $3/MMBtu plus $42/tonne carbon
  - Gas at $4/MMBtu plus $23/tonne carbon
- Example B: Gas at $4.00/MMBtu is equivalent to:
  - Gas at $3/MMBtu plus ~$20/tonne carbon
  - Gas at $2/MMBtu plus ~$40/tonne carbon

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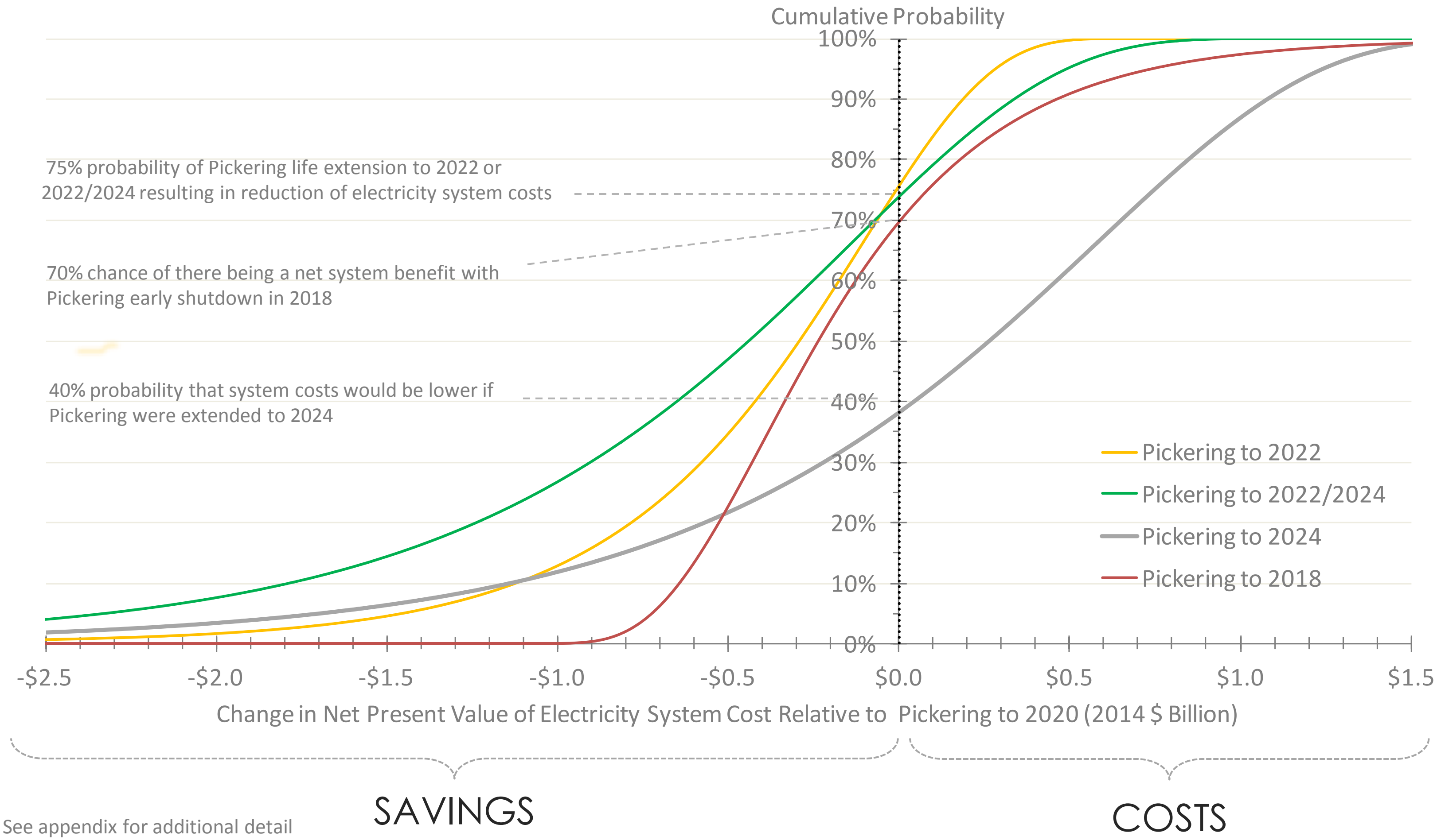
Consideration of the historical gas price distribution between 1997 and 2014 adds insight into the cumulative probability of change in electricity system cost as a function of natural gas price under various Pickering extension scenarios



See appendix for additional detail

System Cost Increase (+) / Decrease (-).
NPV evaluated at a 4% real discount rate.

Excludes transmission and decommissioning advancement/deferral costs.

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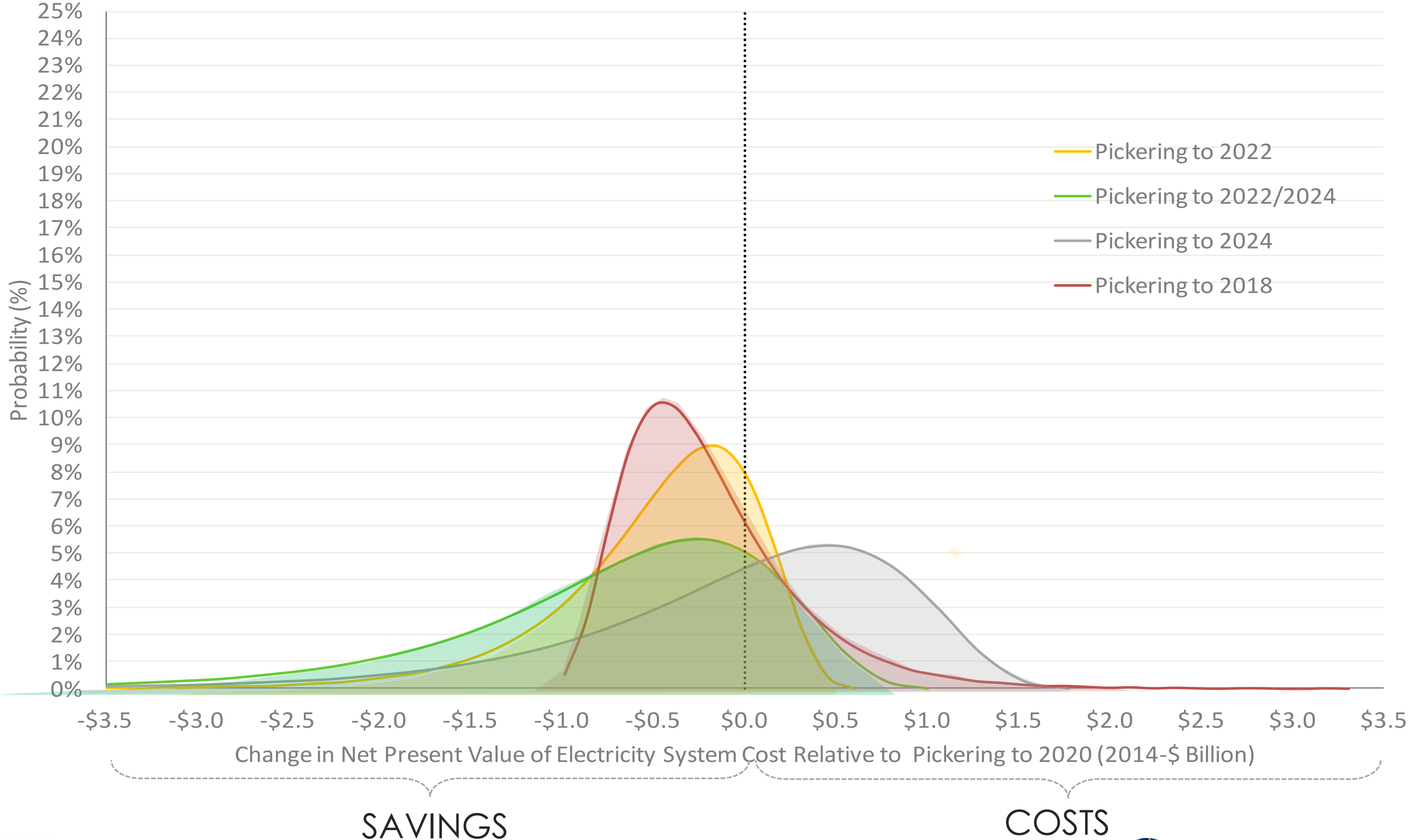
Viewing the same results as a set of NPV distributions illustrates the considerable overlap of possibilities among the scenarios as well as the variability within each distribution



System Cost Increase (+) / Decrease (-).
NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

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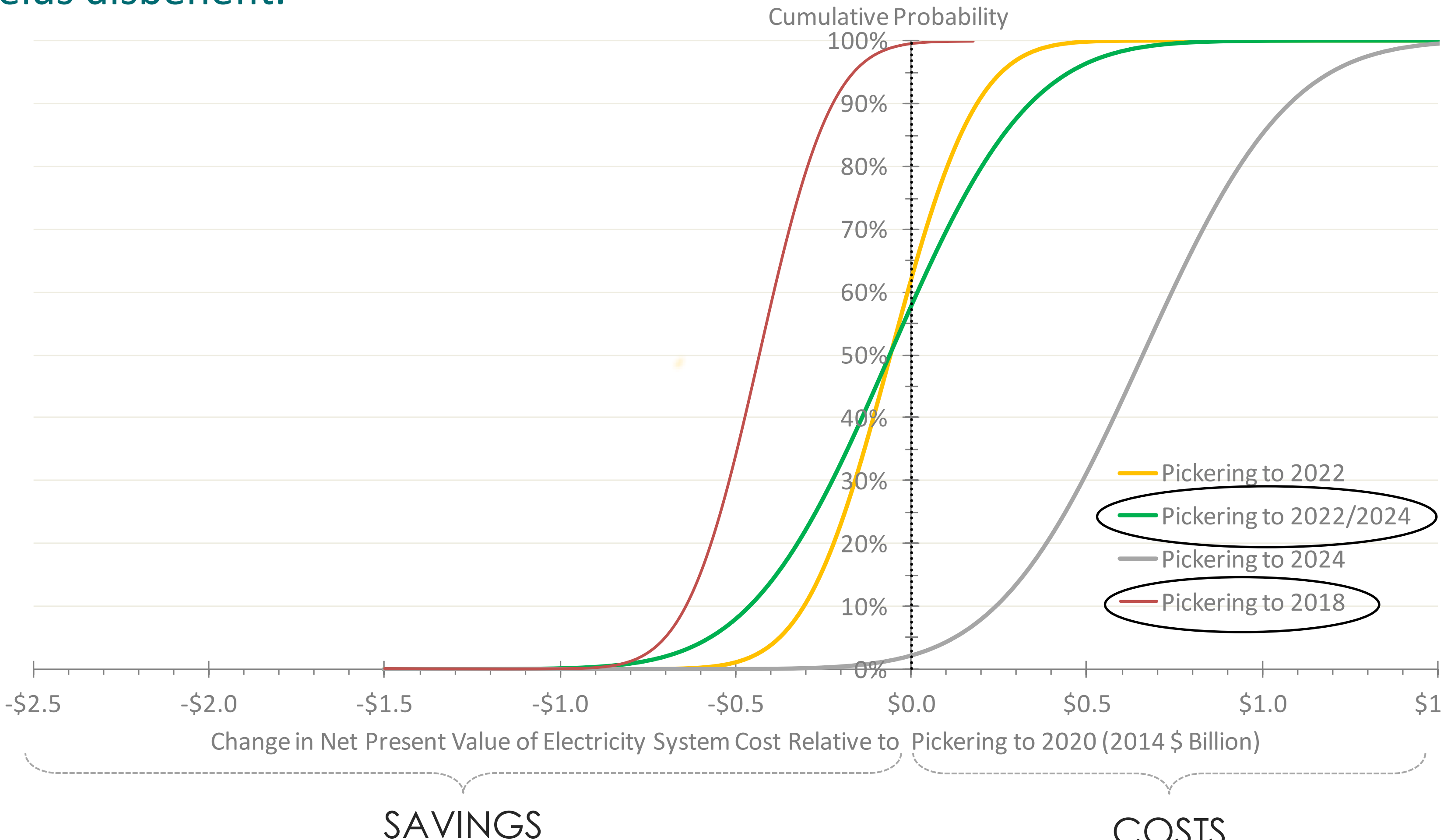
When only the distribution of natural gas prices in more recent years is considered (between 2010 and 2014), early shutdown poses the greatest probability for net cost reduction. Among the other scenarios, Pickering to 2022 and 2022/2024 continue to offer moderate probabilities for savings, while Pickering to 2024 largely yields disbenefit.



System Cost Increase (+) / Decrease (-).
NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

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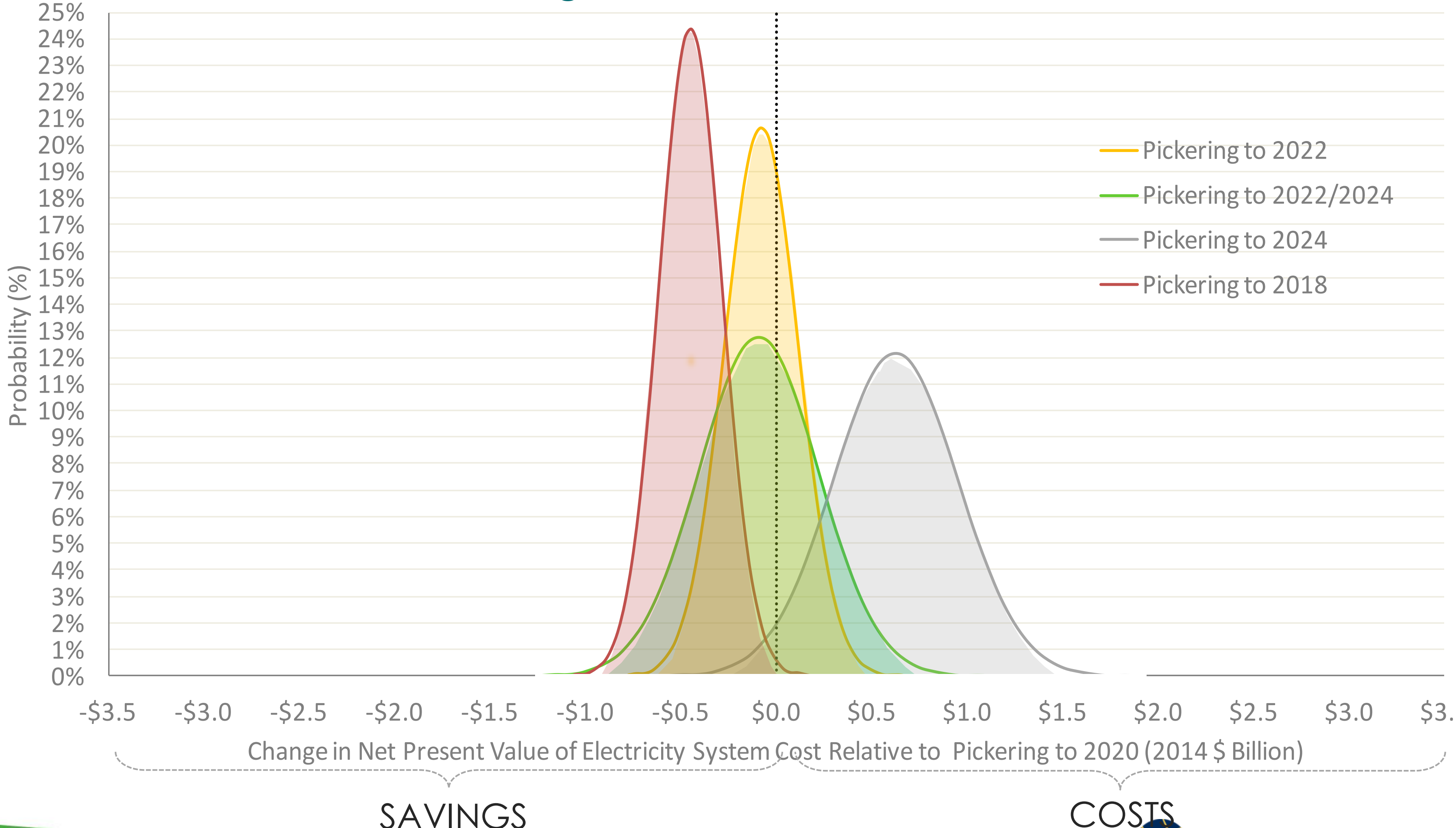
The mean natural gas price between 2010-2014 was lower than the mean between 1997 and 2014 and its distribution was more narrow. Considering this recent trend within the current analysis results in less overlap among scenario outcomes and a narrower range of likelihoods within each scenario.



System Cost Increase (+) / Decrease (-).
NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

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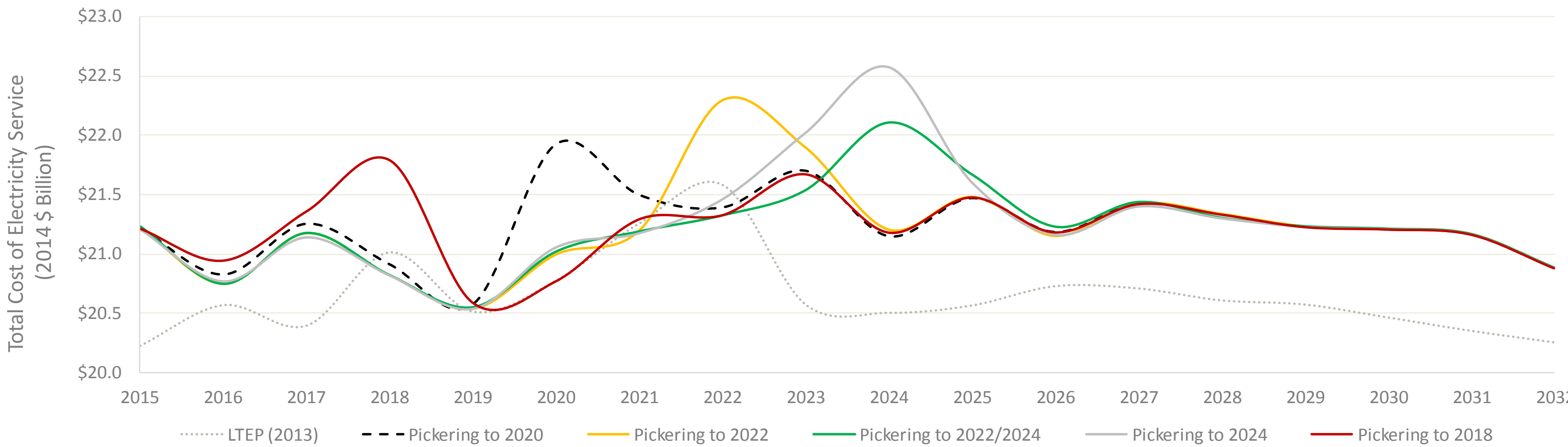
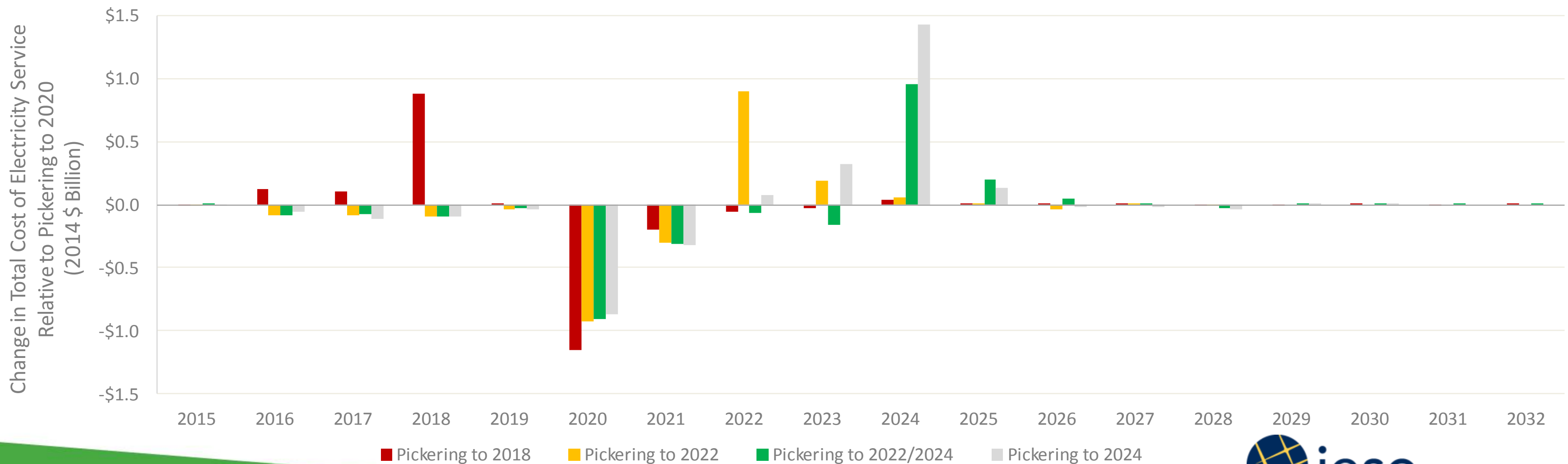
Extending Pickering operations beyond 2020 defers the increase in the total cost of electricity service that eventually takes place under each of the scenarios considered. Extending Pickering to 2022/2024 also minimizes the magnitude of the total cost increase.





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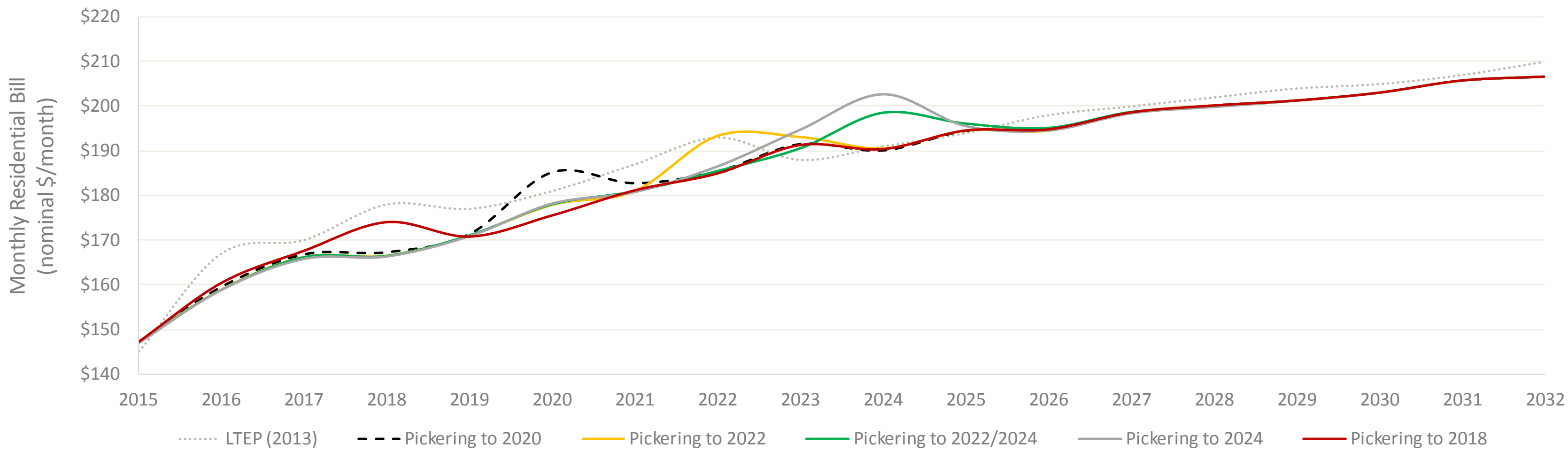
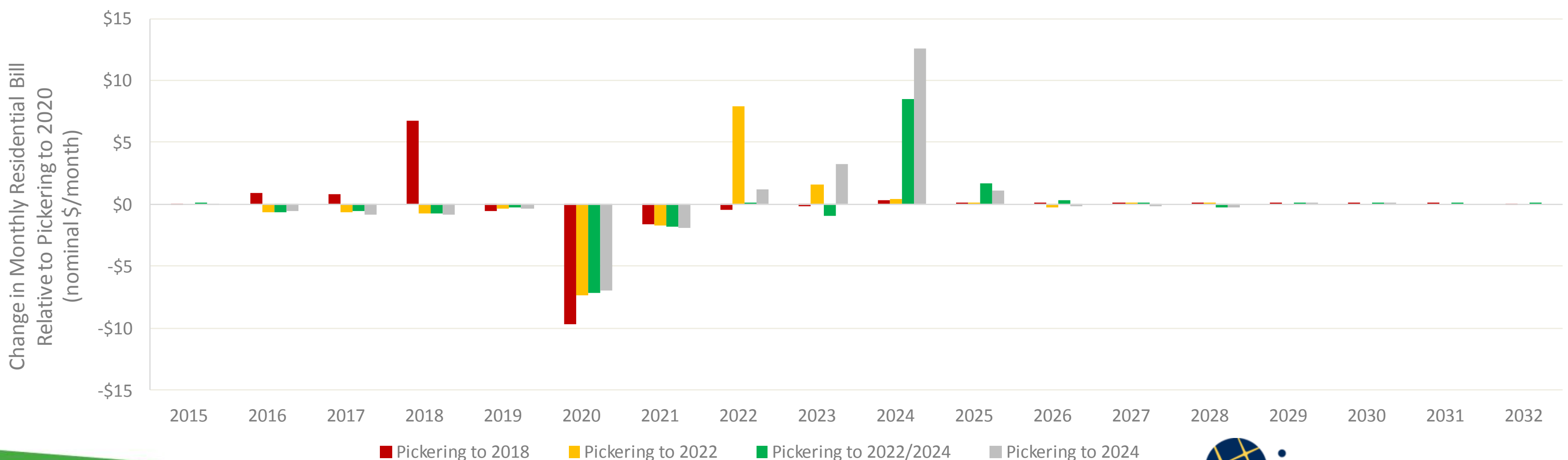
Excludes transmission and decommissioning advancement/deferral costs.

Extending Pickering operation beyond 2020 results in a reduction in residential electricity bills between 2016 and 2021 compared to the base case. Bills increase thereafter, the extent and timing of which varies with Pickering shut down timing. Early Pickering shutdown results in an increase in residential bills prior to 2020.





Assumes a typical residential consumption of 800 kWh/month. Excludes transmission and decommissioning advancement/deferral costs.

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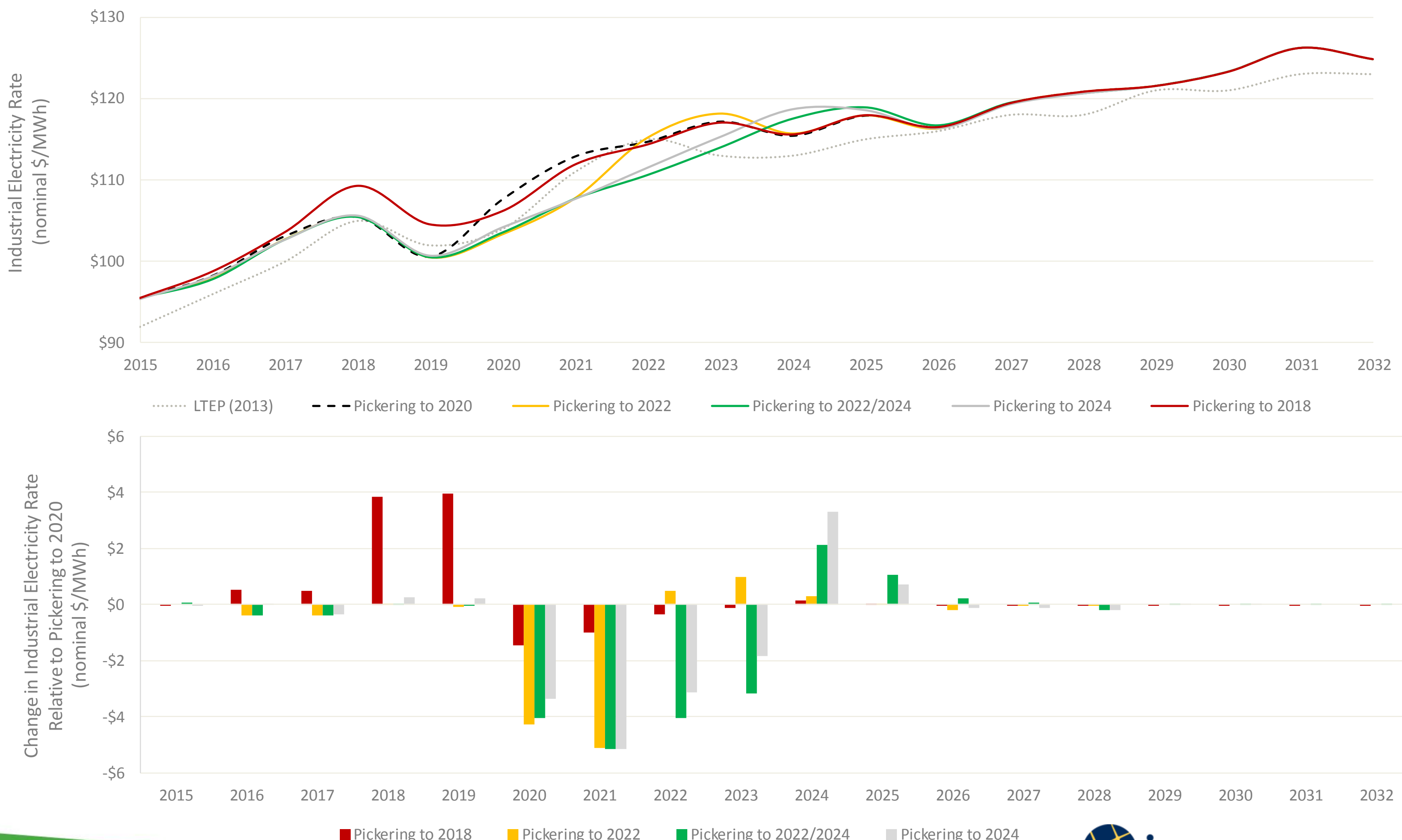
Similarly, extending Pickering life beyond 2020 results in a reduction in industrial electricity rates between 2016-2023. Early shutdown increases industrial rates prior to 2020, but decreases rates thereafter.



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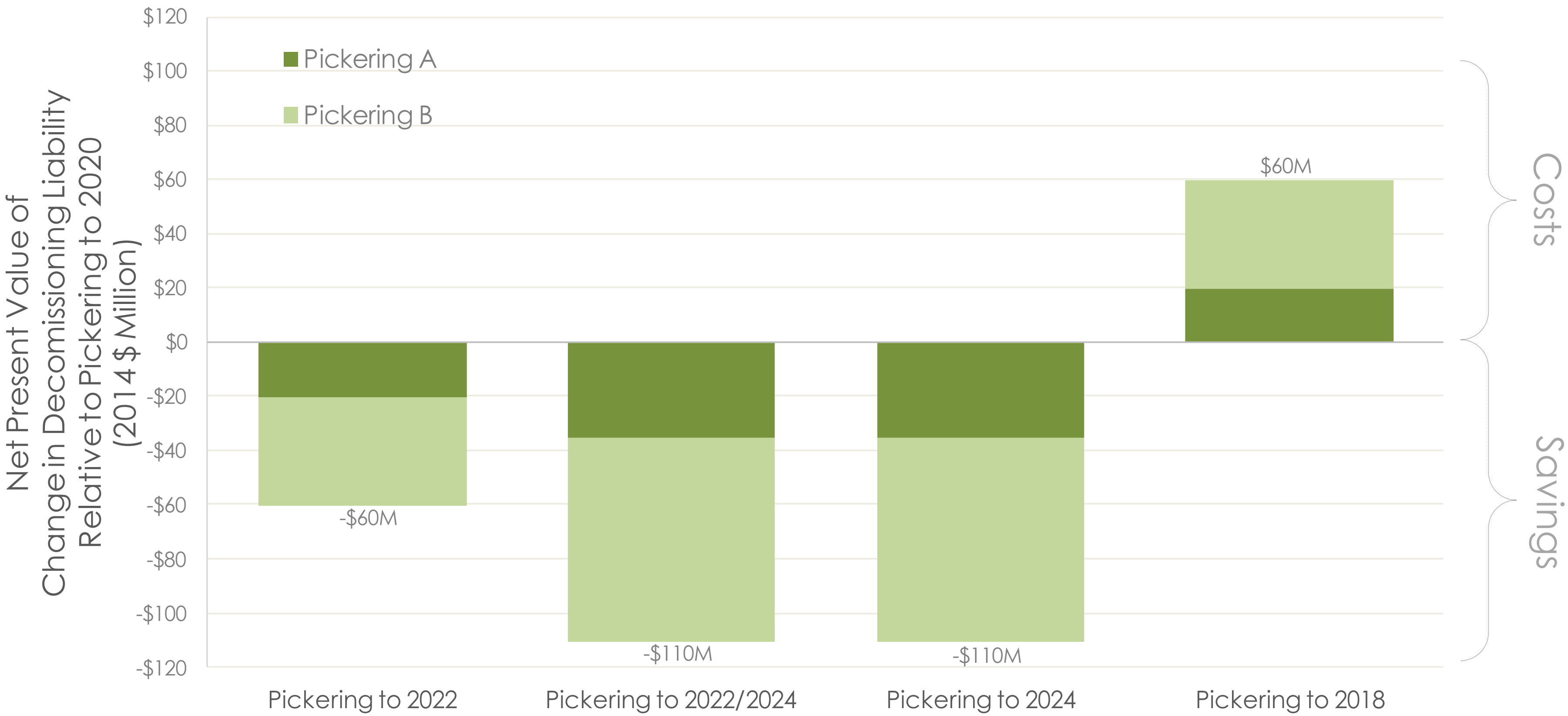
Assumes a typical large industrial customer with a demand of 5MW and a 75% capacity factor. Excludes transmission and decommissioning advancement/deferral costs.

Other cost considerations: Pickering decommissioning liability is affected by shutdown timing. As Pickering life is extended, decommissioning expenditures are deferred. Deferral results in a time value savings in decommissioning liability.



NPV evaluated at a 4% real discount rate.

Transmission considerations: extended Pickering operations could defer the timing of transmission needs and lead to deferral-related cost savings

- The availability of Pickering has an impact on transmission flows into and out of the GTA
- The transmission plan for East GTA includes the construction of a new 500/230 kV transformer station in Clarington to maintain supply reliability to Durham Region following Pickering shutdown and to provide a secure electricity supply in this high growth area
  - Hydro One is currently constructing the new transformer station (“Clarington TS”) and remains on schedule for an in-service of 2018
  - The IESO (former OPA) identified the need for the project in 2005 and requested the transmitter to initiate the project in 2011, with required approvals support
- In evaluating the various Pickering scenarios, it is assumed the in-service of Clarington TS remains unchanged and that the station would be in-service under the scenario of early Pickering shutdown (Pickering to end of 2018)
- The IESO has also identified a need for additional bulk transmission reinforcement in West GTA, following the shutdown of Pickering
  - The project includes construction of a new 500/230 kV autotransformer in the Milton area. The transmitter has provided a planning level capital cost estimate of $200M for the facility. The project would be sited within an existing switchyard. The IESO is currently targeting an in-service of 2020, coinciding with the current plan for Pickering shutdown in 2020
  - Advancing the in-service of this station to coincide with a Pickering shutdown at the end of 2018 could cost an additional $13M. However, deferring the in-service to 2022 through 2024 could result in $12-$23M in time value savings (cost expressed as NPV in 2014 $)
  - In addition, given the 3-year lead time required for in-service of the new station, there is both regulatory and construction risk that could potentially delay the in-service of the new TS (by an order of 1-2 years) thus requiring the inclusion of some interim solutions, such as forced operation of peaking gas generation, for a short period of time preceding station in-service

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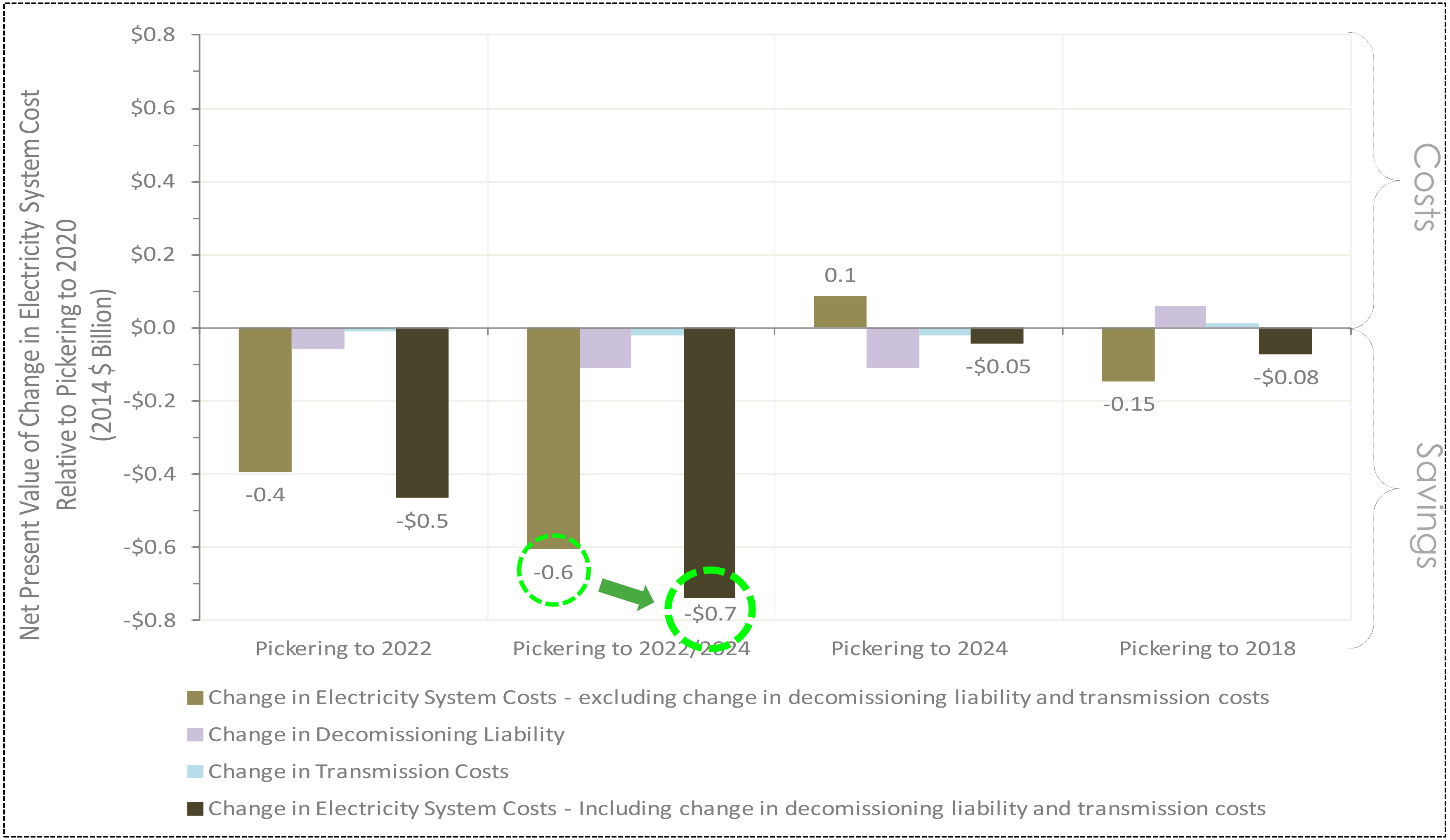
After factoring in time value effects of deferring or advancing decommissioning and transmission, the benefit of extending Pickering operations marginally increases



System Cost Increase (+) / Decrease (-). NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

APPENDIX

- Overview of methodology
- Assumptions
- Data tables

Overview of approach and of reference supply mix assumptions

- Between December 2014 and January 2015, OPG provided the IESO with technical and economic information on various Pickering life extension scenarios and Darlington refurbishment sequences

- The IESO has evaluated the impact Pickering extension scenarios from a number of perspectives, including capacity needs and timing, energy production, emissions, surplus energy, total cost of electricity service and ratepayer costs

- Each Pickering life extension scenario is compared to a “reference case”. This reference case is an updated version of the LTEP (2013), reflecting the following recent changes:
  - Pickering units operate to the end of 2020 per OPG’s current business plan
  - Bruce refurbishment per July/August 2014 schedule from Bruce Power (note Darlington unchanged)
  - Expanded ICI (includes customer 3-5 MW are part of high 5)
  - Ontario Electricity Support Program (effective 2016 – an additional $170M/y $2012) which will only be paid out to low income residential customers after Ontario Clean Energy Benefit expires)
  - IEI Stream 3 (expansion – also assumed to allow Stream 2 customers to carry on with is program until 2024)
  - Early Removal of DRC for residential customers (no DRC for residential bills after 2015)
  - Update of Thunder Bay
  - Included cost impact of Storage (2017 to 2019)
  - Updated CHPSOP 2.0
  - Updated NUGs recontracted
  - Updated OPG rates as per December 3, 2014

- The reference case demand, supply, and cost assumptions are consistent with the Ministry Scenario 2A (per Ministry 2014 LTEP scenario request)

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Cost assumptions

- Additional peaking requirements are assumed to be met by new unspecified capacity based resources priced at a SCGT (represents the least-cost supply resource)
  - $130/kW-yr from a ratepayer perspective based on York Region SCGT
  - DR, NUG contract renewals, coal conversions, or firm imports can also provide capacity if similarly prices

- Additional energy requirements met by existing, committed, and directed resources
  - Current gas-fired fleet relatively underutilized so limited need to build additional supply for energy. As gas-fired production increases, opportunities for lower cost resources to displace this production

- Long-run average gas price assumed to be $5.25/MMBtu at Henry Hub for Reference Case and no explicit cost for carbon
  - Based on Sproule
  - Alternatively, this can be looked at as a combined gas and carbon price
    - For example, gas at $5.25/MMBtu is equivalent to gas at $4/MMBtu plus carbon priced at $23/tonne (for context, BC carbon tax is currently $30/tonne, AB ~$15/tonne, RGGI ~$3/tonne)

- NPV evaluated with a 4% real social discount rate and all costs expressed in 2014 dollars

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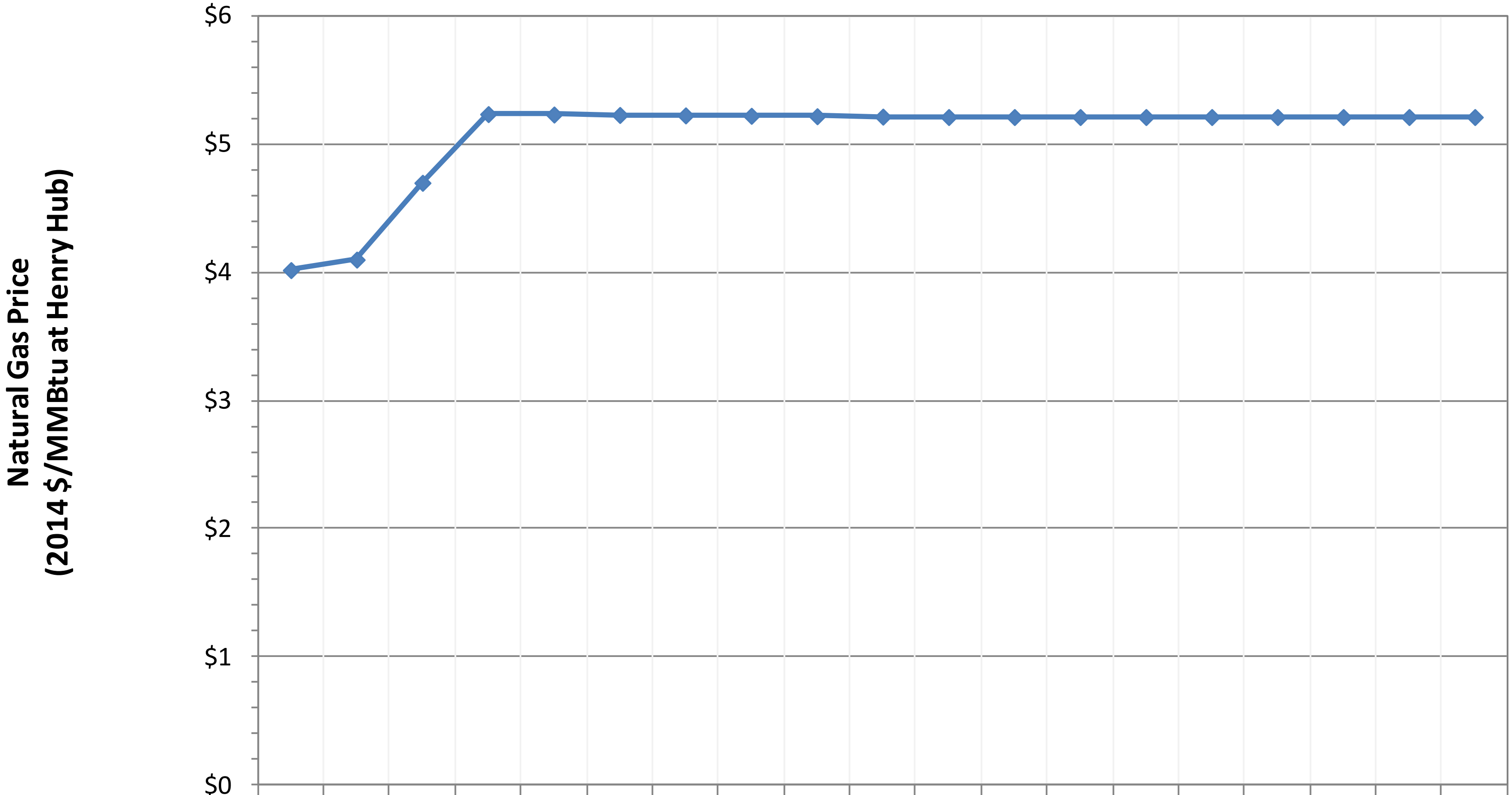
Reference natural gas price



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Reference Natural Gas Price	$4.0	$4.1	$4.7	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2

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