EB-2016-0152

GEC COMPENDIUM PANELS 3a & 3b

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

ieso
Independent Electricity System Operator

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.

E-10 E-10

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Official Report of Debates (Hansard)

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Mercredi 26 octobre 2016

Standing Committee on Estimates

Comité permanent des budgets des dépenses

Ministry of Energy

Ministère de l'Énergie

Chair: Cheri DiNovo
Clerk: Eric Rennie

Présidente : Cheri DiNovo
Greffier : Eric Rennie

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

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

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

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

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

Can you tell me—

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

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

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

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

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

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

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

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

1510

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

Mr. John Yakabuski: Not exactly, but—

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

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

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

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

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

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

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

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

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

Hon. Glenn Thibeault: Good afternoon.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Mr. Serge Imbrogno: Okay.

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

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

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

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

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

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

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

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

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

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

Mr. Peter Tabuns: So are they doing it?

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

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

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

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

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

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

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

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

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

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

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

Mr. Serge Imbrogno: That's correct.

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

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

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

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

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

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

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

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

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

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

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

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

Mr. Serge Imbrogno: I'll just add—

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

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

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.

required to restore on-going operating and maintenance programs back to normal resource levels over the 2017-2020 period.

The 2021 normal operating costs are those required to maintain ongoing base operations, project and outage OM&A work as well as the capital projects necessary to continue the safe operation and maintenance of the plant. These costs also include funds for a scheduled Vacuum Building Outage in 2021.

3.4 The Benefits of Extending Pickering Operations

For the Ontario Electricity System, extending the operation of Pickering will mitigate capacity uncertainties during the refurbishments of the Darlington and Bruce stations. The overall system economic value is positive because having Pickering available reduces the need to operate more expensive gas-fired capacity and the costs associated with siting and building additional gas-fired generation, and possible carbon pricing costs. Extended Operations also reduces the need for imports and reduces CO_2 emissions by approximately 17 million tonnes over the 2021 to 2024 period.

The IESO completed an updated assessment of Extended Operations in October 2015 (see Attachment 1). This assessment shows a present value benefit ranging from $300M to $500M ($2015). The IESO's assessment closely corresponds to OPG's internal assessment, which shows benefits ranging from $500M to $600M, with the difference arising primarily because the IESO uses a lower real discount rate (4 per cent versus approximately 5 per cent used by OPG) and different system assumptions for items such as load growth and the price of gas-fired generation.

For electricity customers, the primary benefit is to moderate the rate impacts, prior to rate smoothing, which would otherwise occur during the height of the Darlington refurbishment following shutdown of the Pickering units (See Ex. A1-3-3). This is made possible by increased nuclear generation after 2020, which results in a larger OPG generation base over which to spread the impacts of the Darlington Refurbishment costs being placed into the rate base.

Board Staff Interrogatory #132

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 36

At the above reference it is stated that early shutdown of Pickering would present practical challenges related to the securing of replacement supplies within a span of three years. OEB staff notes that the plan for the closure of Pickering in 2020 has been known for some time. In light of this, please explain why the IESO believes that there is inadequate time to source replacement supplies.

Response

The following response has been prepared by the IESO:

The above reference is addressing the scenario where Pickering would be shutdown early (i.e. by 2018) and notes that it would be more challenging to arrange approximately 3,000 MW of replacement supply within three years (i.e. by 2018) than it would be to arrange it within five years (i.e. by 2020). As a generalization, the point speaks to the need to account for resource development lead-times when planning. Relevant lead-times include the length of time required to develop and conduct acquisition processes (e.g. procurements, negotiations and/or market-based mechanisms such as capacity auctions) as well as the length of time of any applicable approvals, construction and commissioning activities related to replacement resources and enabling elements such as transmission.

Many of the electricity resources anticipated to enter service over the next few years are already at some stage of development or commissioning. Implementing additional resources at an accelerated pace would not be impossible, but would likely require the launching of new rounds of resource acquisition and development.

2016 Long-Term Reliability Assessment

Narrative Guide

General Instructions

Please adhere to the following guidelines when addressing the narrative questions below. Some questions will require specific actionable items or studies:

- Provide complete and accurate information in response to each question.
- Provide links to any documentation (e.g. studies, assessments) that will help explain your answers. If the study is non-public, please provide directly to NERC staff.
- The narrative section at the end of this request should include information used to respond to each question as well as additional information regarding long-term resource adequacy and reliability.
- The last section requires Regional Entity only responses.
- Do not modify the questions, however there is space for Regions to ask specific Assessment Area questions within the Regional Section as well as the Regional Specific Review. It is NERC's expectation that Regional entities develop tailored questions that support the core assessment questions in this narrative guide.
- Please contact NERC staff with any questions regarding this request.

Assessment Area Dashboard

Please complete the dashboard below.

Assessment Area Overview

The Independent Electricity System Operator (IESO) is the balancing authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometres (415,000 square miles) and has a population of more than 13 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Summary of Methods and Assumptions

Reference Margin Level *- no change since last year*

Load Forecast Method*- no change since last year*

Peak Season*- no change since last year*
2015LTRA: Summer

Planning Considerations for Wind Resources*- no change since last year*

Planning Considerations for Solar Resources*- no change since last year*

Footprint Changes

Assessment Area Footprint

Provided by NERC Staff

Peak Season Demand, Resources, and Reserve Margins *– Will be filled in by NERC*

Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	22,680	22,519	22,357	22,192	22,479	22,255	22,190	22,194	22,326	22,265
Demand Response	680	641	601	601	601	601	804	1,007	1,210	1,210
Net Internal Demand	22,000	21,878	21,756	21,591	21,878	21,654	21,386	21,188	21,116	21,056
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	26,793	26,402	27,187	27,449	26,206	25,843	24,928	25,744	23,790	24,617
Prospective	26,793	26,402	27,187	27,449	26,261	25,971	25,056	25,872	23,918	24,808
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	21.79%	20.68%	24.97%	27.13%	19.78%	19.35%	16.56%	21.51%	12.66%	16.91%
..Prospective	21.79%	20.68%	24.97%	27.13%	20.03%	19.94%	17.16%	22.11%	13.27%	17.82%
Reference Margin Level	18.13%	17.31%	17.13%	17.67%	17.00%	17.00%	18.00%	18.00%	16.00%	16.00%
Excess/Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	804	736	1,704	2,043	609	508	(307)	743	(705)	192
Prospective	804	736	1,704	2,043	664	636	(179)	871	(577)	383

Planning Reserve Margins

1- What is the Reference Margin Level for the Assessment Area?
• How is the Reference Margin Level calculated (if different from NERC's Reference Margin Level of 15%)? • Discuss any planned changes or initiatives to establish or revise a Reference Margin Level in the Assessment Area. • Describe how changes to the resource mix and generator performance changes are being incorporated in establishing Reference Margin Levels for all years of the assessment. • Has there been any change to the Reference Margin Level since the 2015LTRA? If yes, explain this change.
The IESO calculates the Reference Margin Level on an annual basis. For the next ten years, the Reference Margin Level ranges from approximately 16% to 18%. The Reference Margin Levels are calculated to satisfy the Northeast Power Coordinating Council (NPCC) resource adequacy design criterion stated in NPCC Regional Reliability Reference Directory # 1: Design and Operation of the Bulk Power System. The IESO uses the General Electric Multi-Area Reliability Simulation (GE-MARS) program to derive the annual reserve margin requirements. The MARS model captures the availability of existing and planned resources; energy limitations of renewable resources; resource planned outages and equivalent forced outage rates; retirement and refurbishment schedules; interface limits between Ontario's ten transmission zones; and demand forecast values and associated uncertainty over the study horizon. The IESO calculates the Reference Margin Levels every year based on the latest available information. The 2016 LTRA Reference Margin Levels are slightly lower than 2015 LTRA Reference Margin Levels.

2- Do Anticipated Reserve Margins fall below the Reference Margin Level during the assessment period?	Yes ☒ No ☐
If yes, • Indicate how much additional capacity is needed to maintain the Reference Margin Level. • Describe any resource adequacy concerns and detail all actions that will be taken to address them. • Describe the changes in generation, capacity transfers, etc. since the release of the 2015LTRA.	
Anticipated Reserve Margins are below the Reference Reserve Margin for 2023 and 2025 by approximately 300 MW and 700 MW, respectively. In those same years, the Prospective Reserve Margins (which include Tier 2 resources) are also below the Reference Reserve Margin by approximately 180 MW and 580 MW, respectively. In Ontario, Tier 2 resources are mainly resources directed by the Government of Ontario to be procured in the future, but not yet contracted. Nuclear refurbishments and expiring generation contracts create some level of uncertainty and the IESO has conducted risk analyses to anticipate delays in refurbishment schedules, as well as uncertainties posed by an aging fleet as contracts expire. This analysis shows that the earliest a need for additional resources may arise is 2023, and that need is expected to be less than 1 GW . Based on this analysis, the IESO is confident that Ontario possesses a range of options to address these capacity needs, including the potential for more conservation and demand response, additional capacity imports such as the recent capacity swap signed with Hydro Quebec, and the ongoing development of a capacity market in Ontario. The Large Renewable Procurement (LRP) I contracts have been executed since the release of the 2015 LTRA. Contracted projects will be required to obtain all necessary licenses and approvals, such as a Renewable Energy Approval or conducting an Environmental Assessment, before they can be built and operated. The LRP II projects are now categorized in Tier 2 for the 2016 LTRA (instead of Tier 1), as the definitions for the tiers have been updated since the release of the 2015 LTRA.	

Demand

3- Provide a brief overview of the 10-year demand forecast.
• Describe any notable increases or decreases in the demand forecast since the prior year. • Describe the contributing factors associated with this change (e.g., footprint changes, economic outlook, long-term weather outlook, demand-side management, distributed resources, behind-the-meter generation, changes to the load forecasting method, etc.).
The average annual growth of the Ontario Total Internal demand forecast is -0.1% during the 10-year period, a decrease since the 2015 LTRA report, which forecasted 0.1% average annual growth. This change is due to a more modest expected economic expansion and slower industry recovery. Grid-demand growth rates are expected to continue to decline as distributed photovoltaic solar and other behind-the-meter resources increase.

4- Identify cases where projected demand growth in a localized area is significantly above or below the average for the whole Assessment Area.
• Explain the drivers and expected duration for the positive/negative load growth. • Detail all reliability impacts attributed to this positive/negative load growth.
On a zonal basis, Ontario's Northwest has the highest growth rate among the 10 zones for the next 10 years, primarily due to expected mining expansion in the area. The Bruce zone, which lies west of Greater Toronto Area (GTA), will see negative growth resulting from significant increases in distributed generation. Although there is variation in the growth rates across various IESO zones, those variations are not expected to impact reliability.

Demand-Side Management

5- Describe the projected impacts of Energy Efficiency and Conservation programs in the Assessment Area, including any resulting from policy changes.
As specified in the Ontario Ministry of Energy's 2013 Long Term Energy Plan, energy efficiency programs, together with codes and standards changes, are expected to deliver an annual saving of 12 TWh by 2026, incremental to forecasted savings in 2017. The incremental peak saving is about 2,200 MW over the same period. These savings have been reflected in the demand forecast.

6- Describe Demand Response programs in the Assessment Area.
• Describe all Demand Response programs that have been introduced since the prior year's LTRA. • Describe any significant changes to the amount of Demand Response.
Ontario has four main demand response (DR) programs: Peaksaver, Dispatchable Loads, Capacity-Based Demand Response (CBDR) and the capacity procured through an annual DR Auction. Peaksaver is a residential load program targeting air-conditioners, water heaters and pool pumps; Dispatchable Loads are loads that bid into the market and are dispatched economically like other resources. These are existing programs that have not changed. The IESO is transitioning the procurement of CBDR to a market-based approach, i.e. a demand response auction. The first demand response auction was held in December 2015, when nearly 400 MW were procured for May 2016 to April 2017 through a competitive auction process. Ontario currently has approximately 550 MW of CBDR and DR Auction capacity under contract, a similar level to that in last year's LTRA. At minimum, this level of capacity will be maintained through subsequent auctions with additional capacity-based demand response expected to be acquired between 2021 and 2025,

consistent with government targets, to a total of 1,200 MW by 2025. Ontario currently has over 1.1 GW of demand response supply. It is anticipated that demand response capacity will reach 1.8 GW by the end of the assessment period, consistent with government targets.
7- Describe any long-term reliability impacts (e.g., resource adequacy, planning or operational impacts, etc.) resulting from changes to Demand Response.
The IESO recently launched two demand response initiatives: a DR auction where demand side resources compete to obtain a capacity obligation and a DR pilot where the IESO will assess their ability to follow changes in electricity consumption and help balance supply and demand. The combined total from both initiatives is approximately 480 MW of demand response that is now participating directly in the Ontario energy market. Demand response is expected to continue to grow with the next DR auction in December 2016 and through the learnings of the DR pilot. The growth of DR in Ontario's market is expected to have a positive impact on reliability because DR increases capacity and adds diversity to the resource mix. The performance characteristics and system impacts of DR resources will be monitored.

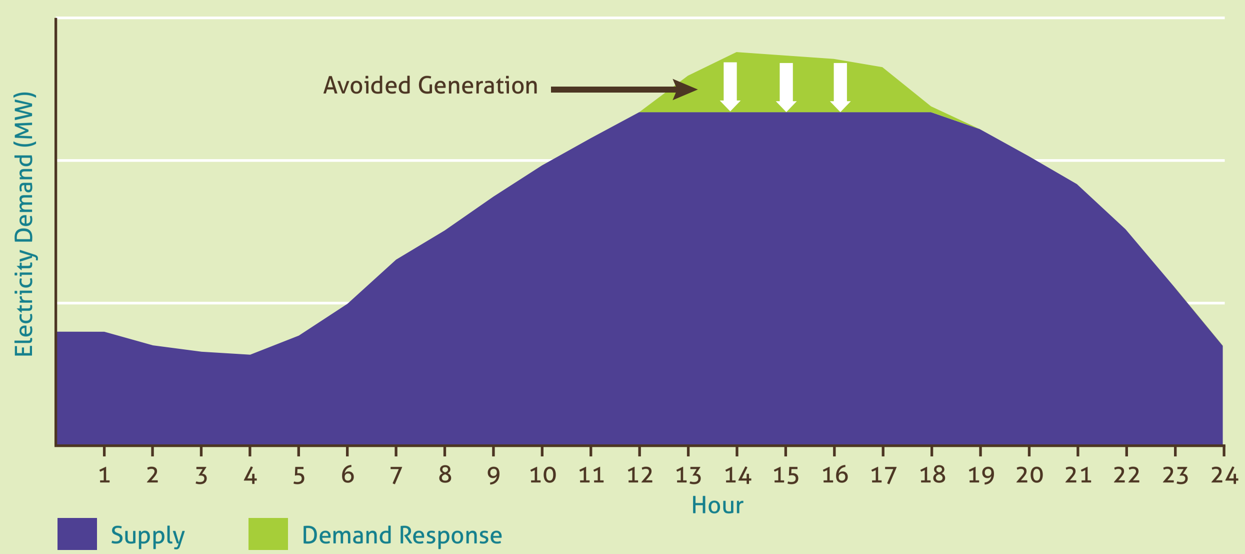
Generation

8- Summarize capacity additions in the Assessment Area since the prior LTRA, as well as those expected during the assessment period.
• Responses should be provided for notable Tier 1 and 2 capacity additions including the generation types (e.g. Coal, Petroleum, Natural Gas, and Nuclear). • Detail the expectation for returning any mothball generation to active status.
Since the prior assessment, Ontario added the following grid-connected installed capacity: - Six (6) solar facilities, totaling 240 MW (Grand Renewable Energy Park, Kingston Solar Project, and four Northland Power facilities: Empire, Abitibi, Long Lake, and Martin's Meadows); - Nine (9) wind facilities, totaling 898 MW (Adelaide Wind Energy Centre, Bornish, Jericho, K2, Goulais, Cedar Point Phase II, Armow, and Grand Valley). By the end of the assessment period, year-end 2026, Ontario expects the following Tier 1 grid-connected installed capacity additions, which have already been procured and are currently under development: - Three (3) natural gas facilities, totaling 1,189 MW - Nine (9) solar facilities, totaling 240 MW - Eighteen (18) hydroelectric facilities, totaling 134 MW* - Eleven (11) wind facilities, totaling 895 MW* Additionally, 1,043 MW of grid-connected supply procurements (Tier 2) have been directed by government (some of which are already underway) and are expected to come into service during the assessment period: - 250 MW of solar resources - 600 MW of wind resources - 30 MW of biomass resources - 89 MW of hydroelectric resources - 75 MW of energy-from-waste facilities *Based on procurement experience, a percentage of feed-in tariff facilities tend to not reach commercial operation for economic, construction-related, or regulatory reasons. The capacity values have been adjusted to reflect this experience.

From LTEP 2013 - Achieving the Balance

Figure 13: Demand Response

Demand Response programs can reduce the need to build costly peaking generation that would only be required during the highest demand hours of a hot summer day.



Note: For illustrative purposes only, not to scale.

2015, lasting for six years and replacing the one that is currently winding down. Subject to further discussion with our partners, the government intends to build the new Framework on the following principles:

- There will be long-term, stable funding for conservation so that customers and LDCs have the certainty they need to implement and deliver programs.
- Customers will be given more program choice along with streamlined oversight and administration.
- LDCs will have accountability for meeting their assigned conservation goals, and will be provided the authority and means for meeting them cost-effectively.
- The new Framework will encourage innovation and the adoption of new technologies.
- While there will be conservation programs available for all residential, commercial and industrial sectors, the value of conservation investments may be higher in some sectors than others.
- There will be renewed efforts to deepen consumer awareness of conservation, and more broadly, of the electricity system.
- Conservation programs for low-income residential customers will be improved.
- For Aboriginal communities, the role of LDCs in the delivery of conservation programs will be enhanced, particularly for on-reserve First Nation customers.
- Industrial and transmission-connected customers will continue to have access to the OPA's conservation programs, which will be expanded to facilitate broader program choice and financing flexibility.

To ensure value for ratepayers, the new Framework will continue to provide cost-effective conservation programs at less than the cost of new supply.

In Summary

- The Ministry of Energy will work with its agencies to ensure they put conservation first in their planning, approval and procurement processes. The ministry will also work with the Ontario Energy Board (OEB) to incorporate the policy of conservation first into distributor planning processes for both electricity and natural gas utilities.
- The province expects to offset almost all of the growth in electricity demand to 2032 by using programs and improved codes and standards. This will lessen the need for new supply. Our long-term conservation target of 30 terawatt-hours (TWh) in 2032 represents a 16% reduction in the gross demand for electricity, an improvement over the 2010 LTEP.
- Ontario is aiming to use Demand Response (DR) to meet 10% of peak demand by 2025, equivalent to approximately 2,400 megawatts (MW) under forecast conditions. To encourage further development of DR in Ontario, the Independent Electricity System Operator (IESO) will evolve existing DR programs and introduce new DR initiatives.
- The IESO will continue to examine and consult on the potential benefits and development of a capacity market, where different generation and demand resources compete to address capacity needs.
- The government is committed to promoting a co-ordinated approach to conservation and will encourage collaboration of conservation efforts among electricity and natural gas utilities.
- The government will work to make new financing tools available to consumers starting in 2015, including on-bill financing for energy efficiency retrofits.
- To help consumers choose the most efficient products for their homes and businesses, Ontario will provide information and incentives; it will also continue to show leadership in establishing minimum efficiency requirements for products such as water heaters, clothes dryers, televisions, fluorescent lamps, motors and boilers.
- The Green Button Initiative will give consumers access to their energy data and the ability to connect to mobile and web-based applications so they can analyze and manage their energy use.
- Social benchmarking can increase awareness of energy use and promote conservation. A social benchmarking pilot program is under way, led by the Ontario Power Authority (OPA) to test different approaches that enable consumers to compare their energy consumption with other similar consumers. Pending the success of the pilot program, the government will explore expanding social benchmarking and including other sectors.
- The government is also working with Ontario EcoSchools to bring more resources about energy conservation to the curriculum for students and teachers.

Page 16a

Table 2: Current Technology Characteristics

	Capacity	Energy	Operating Reserve	Load Following	Frequency Regulation	Capacity Factor	Contribution to Winter Peak	Contribution to Summer Peak	LUEC ($/MWh)
Conservation	Yes	Yes	No	No	No	Depends on Measure	Depends on Measure	Depends on Measure	$30-50
Demand Response	Yes	No	Yes	Yes	Limited	N/A	60%	85%	N/A
Solar PV	Limited	Yes	No	Limited	No	15%	5%	30%	$140-290
Wind	Limited	Yes	No	Limited	No	30%	30%	10%	$65-210
Bioenergy	Yes	Yes	Yes	Limited	No	40-80%	90%	90%	$160-260
Storage	Yes	No	Yes	Yes	Yes	Depends on technology/ application	Depends on technology/ application	Depends on technology/ application	Depends on technology/ application
Waterpower	Yes	Yes	Yes	Yes	Yes	30-70%	75%	71%	$120-240
Nuclear	Yes	Yes	No	Limited	No	85-95%	90-95%	95-99%	$120-290
Natural Gas	Yes	Yes	Yes	Yes	Yes	up to 65%	95%	89%	$80-310

Source: IESO. LUEC: Levelized Unit Energy Cost.

While higher demand could create a need for additional resources in the longer term, these needs are not projected to occur until the mid-2020s, with significant increases in resource requirements beyond 2030. Higher demands also provide greater potential for conservation. The value of conservation is greater in the higher demand outlooks as conservation can avoid the construction of new electricity infrastructure in these outlooks. This increased value of conservation could unlock conservation potential from existing end-uses that were otherwise uneconomic, supporting higher investment in more efficient technologies than under low demand outlooks.

3.3.4. Supply Resources

Ontario faces sizeable and increasing opportunities for further deployment of cleaner technologies including distributed energy resources to meet higher demand outlooks. These opportunities are being driven by technological advancements, evolutions in policy and market design and increasing customer engagement.

It is important to note that no single resource option can meet all customer needs at all times (Table 2). Some resources are baseload in nature; others are peaking. Some resources have higher operating costs but are dispatchable, while others have low operating costs but are highly variable. Electricity needs can relate to one or several types of products or services such as energy, capacity, regulation and ramping. Maintaining a diverse resource mix, where the different resources are complementary to each other, is an effective way to provide the various services necessary to support reliable and efficient operations.

The characteristics of each of these current technologies are discussed above.

Conservation: Conservation represents savings from energy efficiency programs and building codes and equipment standards. Conservation as a resource is described more fully in Section 3.2. Levelized unit energy cost (LUEC) values in Table 2 reflect the current range of costs to procure conservation.

Demand Response: Opportunities also exist for demand response (DR) resources. The 2013 LTEP included a DR goal of 10 percent by 2025 (approximately 2.5 GW). DR resources amounted to approximately 1.8 GW in 2015. The extent to which additional DR resources become available will depend on the demand outlook and the types of loads that can contribute in the event that Ontario becomes a winter-peaking system.

ED Interrogatory #39

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

Interrogatory

Reference:
Reference: Ex. F2-2-3, Attachment 1

The September 2016 Mandate Letter to the Minister of Energy asks that he "Continue to partner and collaborate with the Province of Québec on key energy issues, including … In co-operation with the IESO and Hydro-Québec, further the intention to explore an electricity trade agreement that would provide value to Ontario ratepayers."

(a) Please compare the net present value of the overall costs and benefits of following three scenarios:
   i. OPG's proposal to continue operating Pickering until 2022/2024;
   ii. Pickering shutdown in August 31, 2018, with replacement power to come from an electricity trade agreement with Quebec (to the extent that it is technically feasible, with any additional power that cannot be imported to be provided by the next least-cost alternative); and
   iii. Pickering shutdown in December 31, 2020, with replacement power to come from an electricity trade agreement with Quebec (to the extent that it is technically feasible, with any additional power that cannot be imported to be provided by the next least-cost alternative).

Please make best efforts to estimate the cost of replacement power from an electricity trade agreement with Quebec. Please include provisos is necessary. Please consider including a number of agreement scenarios or ranges to address uncertainty regarding the terms of such an agreement. Please indicate and state assumptions and calculations.

Response

The following response has been prepared by the IESO:

(a) Please refer to "Assessment of Pickering Life Extensions Options: October 2015 Update" October 30, 2015. This presentation presents a net present value analysis of OPG's proposal to continue operating Pickering A until 2022, and Pickering B until 2024. This analysis concludes that there is a net benefit to the proposed continued operation, relative to the least-cost alternative.

To replace the power from Pickering with a firm agreement with Québec, the agreement would need to include both capacity and energy. Québec has an abundance of energy, but currently has a capacity shortfall during their winter peak. Their need for winter capacity continues until the 2024 time period. Please refer to Tableau 4-2 of "État d'avancement 2015 du Plan d'approvisionnement 2014-2023" http://www.regie-energie.qc.ca/audiences/Suivis/SuiviD-2014-205_PlanAppro2014-2023/HQD_EtatAvancement2015_30oct2015.pdf

The capacity needs in Québec indicate that they would not be able to reliably provide firm, year-round capacity to Ontario during the 2018-2024 time-frames. Therefore all additional power would need to be supplied by the next least-cost alternative. The analysis presented in the aforementioned deck from October 30, 2015 assesses the net present value of operating Pickering until 2022/2024 against additional power being supplied by the next least-cost alternative.

GEC Interrogatory #43

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

Interrogatory

Reference:

In EB-2013-0321 F2-2-3, Attachment 2 OPG filed the Ontario Power Authority's assessment of the prudency of operating Pickering until 2020. It stated: "On balance, the OPA's assessment of system cost impacts suggests an expected cost advantage to Pickering continued operation (in the order of approximately $100 Million). This advantage predominately reflects expected costs savings from reduced natural gas-fired energy production and lower replacement capacity requirements. Based on evaluation to date of the broader uncertainties, the OPA estimates a range of up to approximately $1.3 billion in potential net-benefit from Pickering continued operation to $0.76 billion in potential net-cost (dis-benefit). These estimates represent illustrative bookends and explore combinations of factors that together would increase or decrease the cost impacts of Pickering continued operations."

In EB-2013-0321, F2-2-3, Schedule 3, OPG's 2012 assessment of the Pickering continued operation estimates the net present value to be "approximately $520 million (2012 PV dollars)."

In contrast, EB-2010-0008, Exhibit F2-2-3, Attachment 2 states: "Depending on the amount of gas-fired generation or similarly-priced imports replaced by Pickering NGS generation, the overall system benefit could be up to 1.6 B$ (104 TWH multiplied by 15 $/MWh) due to the reduction of system costs."

a. Please provide a table comparing the demand forecasts used in the OPA's reviews of operating Pickering until 2020 filed in the past cases against actual demand and current forecasts.

b. Based on actual demand and current demand forecasts until 2020, is the continued operation of Pickering until 2020 a net system benefit or dis-benefit according to the OPA's earlier assessments?

c. Please define "system benefit" as used in these assessments. In answering this question please describe any differences between OPG and the OPA/IESO's definition of system benefit and explain if and how OPG and/or the OPA/IESO's definitions of "system benefit" have changed since the earlier assessments.

Response

The following response has been prepared by the IESO:

a.

i) EB-2010-0008 – To our best recollection, the following forecasts were used in EB-2010-0008, Exhibit F2-2-3

Net Peak (MW)	2011	2012	2013	2014	2015	2016	2017	2018
Reference	24,842	24,576	24,265	24,054	24,005	24,010	24,020	24,037
IPSP 1	24,714	24,606	24,500	24,396	24,294	24,436	24,535	24,634

Net Peak (MW)	2019	2020	2021	2022	2023	2024	2025
Reference	24,087	24,168	24,303	24,459	24,622	24,823	24,996
IPSP 1	24,794	24,969	25,314	25,669	26,036	26,407	26,802

Net Energy (TWh)	2011	2012	2013	2014	2015	2016	2017	2018
Reference	148	148	147	147	146	146	146	147
IPSP 1	149	149	148	147	146	148	148	149

Net Energy (TWh)	2019	2020	2021	2022	2023	2024	2025
Reference	147	148	150	151	153	155	157
IPSP 1	150	152	153	155	157	159	161

ii) EB-2013-0321 – The following forecasts were used in EB-2013-0321, F2-2-3

Net Peak (MW)	2011	2012	2013	2014	2015	2016	2017	2018
Low	24,155	23,887	23,590	23,317	23,164	23,069	22,997	22,883
Medium	24,351	24,304	24,036	23,853	23,824	23,747	23,718	23,798
High	24,425	24,344	24,230	24,213	24,277	24,300	24,335	24,377

Net Peak (MW)	2019	2020	2021	2022	2023	2024	2025
Low	22,883	22,816	22,837	22,813	22,896	22,999	23,093
Medium	23,797	23,833	23,948	24,121	24,302	24,571	24,836
High	24,418	24,831	25,682	26,643	27,628	28,696	29,794

Net Energy (TWh)	2011	2012	2013	2014	2015	2016	2017	2018
Low	142	141	140	139	138	138	138	138
Medium	143	144	145	145	146	146	146	147
High	144	145	146	147	149	150	151	153

Net Energy (TWh)	2019	2020	2021	2022	2023	2024	2025
Low	138	139	139	139	140	142	143
Medium	147	148	150	151	153	155	157
High	154	158	161	165	169	173	177

iii) Historical Actual Demand- The actual weather corrected demand for the province of Ontario from 2011- 2015 is shown in the table below.

Net, Weather Corrected	2015	2014	2013	2012	2011
Energy (TWh)	142.5	144.0	144.8	145.2	144.1
Summer Peak (MW)	23,965	22,659	24,804	24,256	23,949

iv) Ontario Planning Outlook (OPO)

The following forecasts were used in the published Ontario Planning Outlook (OPO). The OPO documents can be found here

Net Summer Peak (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
A	23,965	23,971	23,900	23,705	23,465	23,216	23,029	22,879	22,777	22,628	22,568
B	23,965	24,046	24,083	24,041	23,993	23,916	23,889	23,881	23,890	23,868	23,918
C	23,965	24,048	24,088	24,108	24,124	24,112	24,152	24,216	24,298	24,353	24,486
D	23,965	24,048	24,088	24,166	24,242	24,291	24,393	24,520	24,667	24,788	24,987

Net Winter Peak (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
A	22,159	22,093	22,020	21,825	21,574	21,338	21,143	20,976	20,864	20,694	20,602
B	22,159	22,140	22,143	22,072	21,985	21,898	21,841	21,799	21,778	21,718	21,718
C	22,159	22,190	22,251	22,315	22,395	22,501	22,661	22,863	23,105	23,326	23,626
D	22,159	22,190	22,251	22,385	22,560	22,783	23,083	23,442	23,862	24,273	24,779

Net Energy (TWh)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
A	143	143	142	141	139	138	136	135	134	133	133
B	143	143	143	143	142	142	142	142	142	142	142
C	143	144	143	144	144	145	146	147	148	149	150
D	143	144	143	144	145	147	148	150	152	154	157

b. The IESO's most recent outlooks for long-term electricity demand are described in the Ontario Planning Outlook at http://www.ieso.ca/Pages/Ontario's-Power-System/Ontario-Planning-Outlook/default.aspx and are summarized in the tables immediately above (in response "b.iv."). The IESO has not updated its assessment of Pickering continued operations to reflect these updated electricity demand outlooks or other recent developments such as the cancellation of the Large Renewables Procurement II Request for Qualifications process, introduction of the Climate Action Plan, etc.

c. Exhibit F2/T2/S3/Attachment 1, Page 58 of 116 describes the approach taken by the IESO in its economic evaluation of Pickering extended operation options and provides context for the expression “system benefit”. In brief, the cost of extending Pickering life was compared to the savings resulting from reduced electricity system replacement energy and capacity costs relative to a base case where Pickering operated until 2020. If the estimated cost of Pickering extended operation was less than the estimated cost of replacement energy and capacity, a net benefit was the result. Conversely, if the estimated cost of Pickering extended operation was more than the estimated cost of replacement energy and capacity, a net cost or ‘dis-benefit” was the result. The expression “system benefit” in this context refers to any cost savings that might result from extended Pickering operation. System benefits can be compared against system costs to derive an estimate of net system benefits or dis-benefits. Other types of system benefits were also identified, but were not economically quantified. These include carbon emission reductions and some coverage during a period of supply system change and risk.

To the IESO’s knowledge, OPA/IESO’s current approach for assessing benefits of extended Pickering operations is consistent with the approach take in earlier assessments. Also to the IESO’s knowledge, there are differences of detail between the IESO and OPG’s assessments. Items of difference include discount rate assumptions, supply/demand outlooks and natural gas price assumptions (for example, as indicated at F2/T2/S3/Attachment 2, Page 18 of 22).

Ontario Planning Outlook

A technical report on the electricity system prepared by the IESO

SEPTEMBER 1, 2016

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Connecting Today.
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Figure 3: Historical Ontario Energy Demand[3]

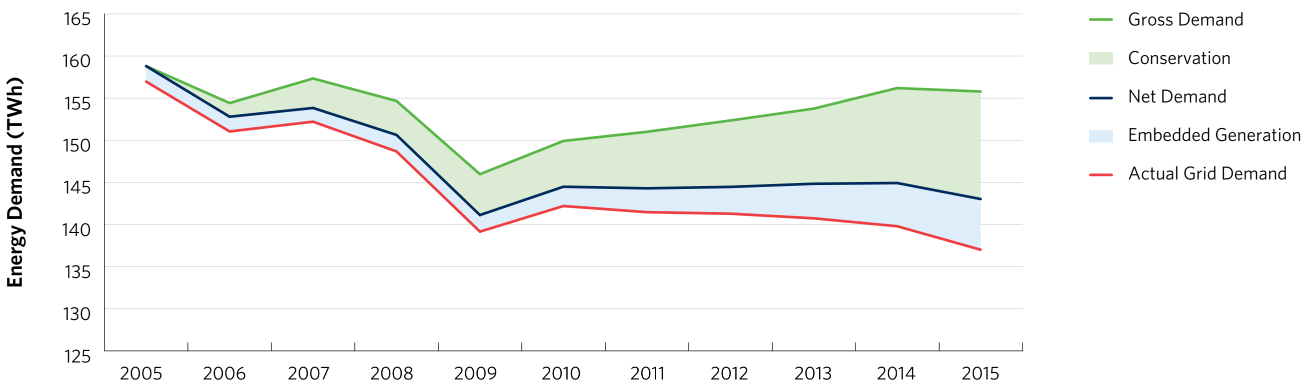


Figure 4: Conservation Savings in 2015

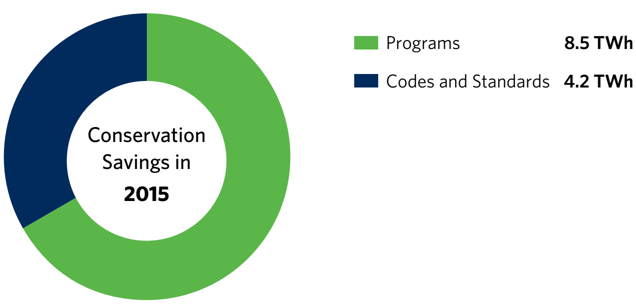
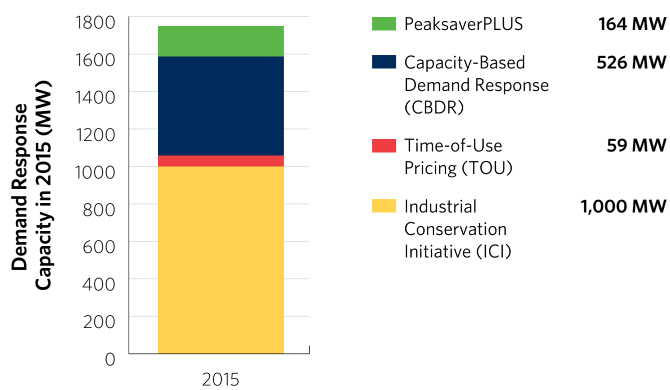


Figure 5: Demand Response Capacity in 2015



137 TWh in 2015. As a result of the additional supply and reduction in demand, there has been a sizeable appreciation of Ontario's capacity margins, and the capacity deficits that existed in the early 2000s have been eliminated.

Conservation and demand management played an increasing role in reducing both energy and peak demands over the 2006-2015 period, with the province achieving 12.7 TWh of electricity savings through conservation programs and changes to codes and standards (Figure 4).[4]

Demand response initiatives have combined to reduce peak demand on summer days. The grid peak demand of 27,005 MW on August 1, 2006 continues to be the all-time highest provincial grid peak demand. By comparison, the grid peak demand in 2015 was 22,516 MW.[5] The IESO has introduced demand response into the market where it can be called upon like other resources to meet provincial needs. The first capacity-based demand response auction conducted in December 2015 is contributing 391.5 MW for the 2016 summer season and 403.7 MW for the 2016-17 winter season. Demand response resources together amounted to approximately 1.8 GW in 2015 (Figure 5).

The operability of the system has also evolved over the past decade. In response to surplus baseload generation conditions, the IESO has enhanced its processes to maintain supply-demand balance through dispatching down grid-connected wind and solar facilities and manoeuvering nuclear units. The IESO's Renewable Integration Initiative (RII) introduced centralized resource forecasting to help

[3] "Grid demand" is delivered on the bulk system to wholesale customers and local distribution customers. "Net demand" is the grid demand plus output from embedded resources on the distribution system. "Gross demand" is the need for electricity prior to the effects of conservation and reflects net demand with conservation savings added back to it.

[4] 2015 conservation results have not yet been verified.

[5] Weather-corrected net peak demand in 2006 was 25,162 MW and in 2015 was 23,965 MW. All demand outlooks presented in this report refer to weather-corrected net peak demand unless described otherwise.

Figure 8: Ontario Net Energy Demand across Demand Outlooks

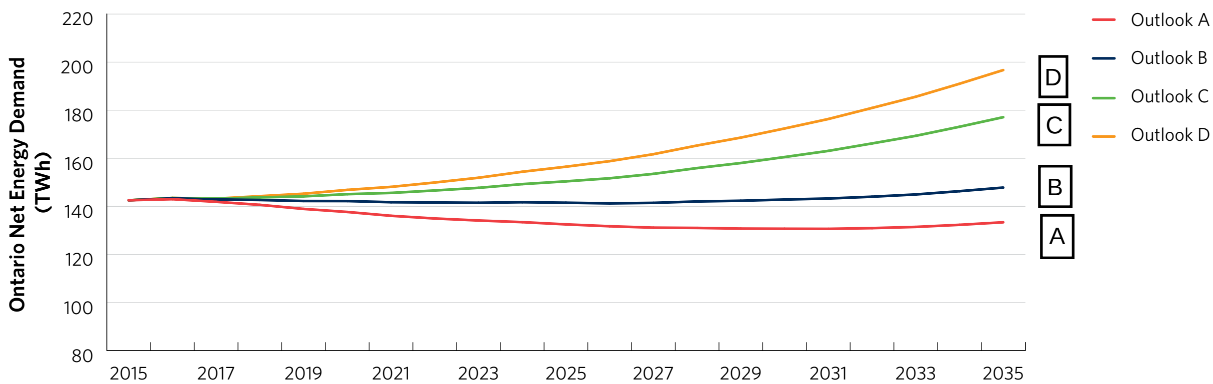


Figure 9: Ontario Net Summer Peak Demand across Demand Outlooks

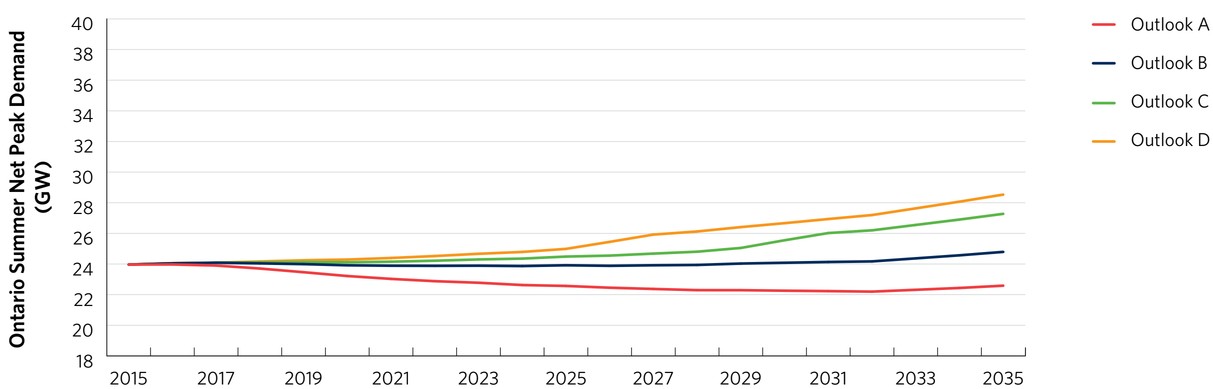
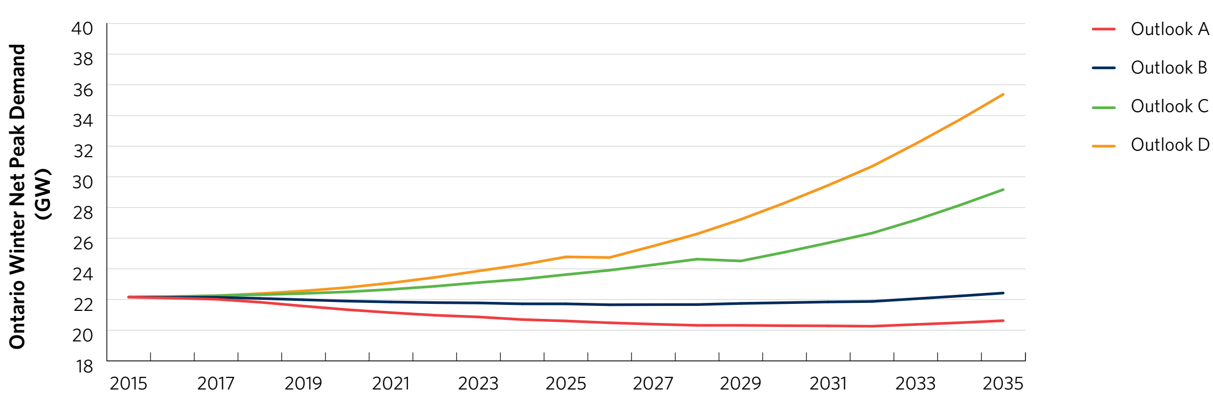


Figure 10: Ontario Net Winter Peak Demand across Demand Outlooks



DEMAND - SEASONAL	Year(s)	Unit	2015 (S)	2016 (S)	2017 (S)	2018 (S)	2019 (S)	2020 (S)
Peak Hour Demand - Year 2-10 Forecast	2018-2026	MW	[redacted]			22,518.8	22,357.3	22,192.5

2020 (S)	2021 (S)	2022 (S)	2023 (S)	2024 (S)	2025 (S)	2026 (S)
22,192.5	22,479.0	22,255.3	22,189.8	22,194.4	22,326.0	22,265.5

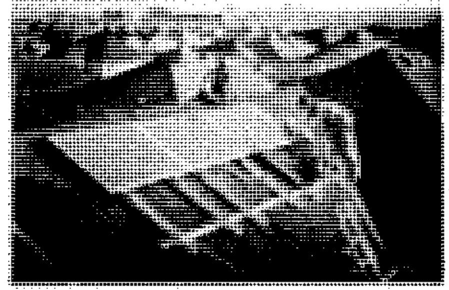
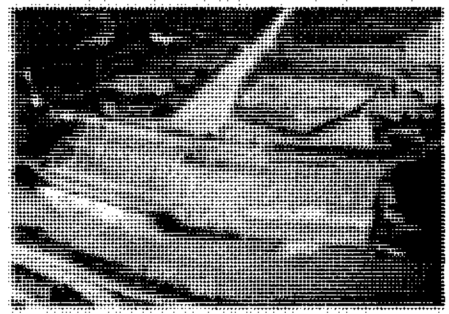
Peak Demand, MW	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
March 2015	23,471	23438	23,520	23,631	23,773	23,679	23,945	24,006	24,103	24,148	24,375	24,537
October 2015	23,947	23,959	24,048	24,158	24,300	24,230	24,498	24,498	24,636	24,682	24,912	25,076
Net Change	476	521	528	527	527	551	553	553	533			
September 2016 – NERC Season Peak	Not available	Not Available	Not Available	22,518	22,357	22,192	22,479	22,255	22,189	22,194	22,326	22,265

Note:
The first four rows are take from EB-2016-0152, Exhibit L, Tab 6.5, Schedule 1 Staff-130,.
The last row is take from IESO's 2016 submission to the North American Electric Reliability Corp (NERC)

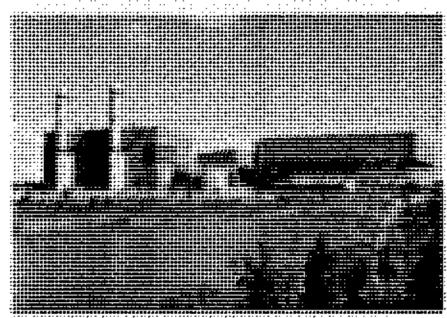
Exhibit A to the Affidavit of Shawn-Patrick Stensil dated
29, May, 2014
a commissioner etc.

CONFIDENTIAL

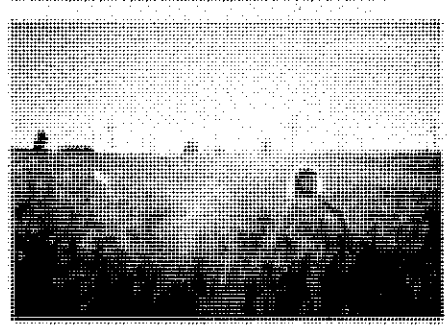
PRELIMINARY DRAFT PREPARED IN CONTEMPLATION OF LITIGATION

Report on the Integrated Power System Planning Impacts of Pickering NGS Continued Operation

April 16, 2012



ONTARIO POWER AUTHORITY

CONFIDENTIAL - PRELIMINARY DRAFT PREPARED IN CONTEMPLATION OF LITIGATION

REPORT ON THE INTEGRATED POWER SYSTEM PLANNING IMPACTS OF PICKERING NGS CONTINUED OPERATION

EXECUTIVE SUMMARY

This report provides an assessment of the integrated power system planning impacts of Ontario Power Generation's (OPG) proposal for continued operation of the Pickering Nuclear Generation Station ("Pickering NGS") between approximately 2015 and 2020.

The Ontario Power Authority's (OPA) assessment indicates that the net system benefit of Pickering NGS continued operation is expected to be $182 million, but could range from -$0.76 billion to $1.33 billion depending on a number of factors. These include higher or lower than forecast natural gas prices; implementation of carbon prices; a shorter continued operation period; higher or lower capital and fixed operating costs; and/or higher or lower production at Pickering NGS during the continued operation period.

There are several potential benefits to Pickering NGS continued operation. These include:

- A reduction in the need for replacement capacity and energy during the nuclear refurbishment period (2016 to 2024) and associated acquisition costs;
- A hedge against factors including increased demand, delay in achieving conservation targets, higher natural gas or carbon prices, nuclear refurbishment delays, or delays in the in-service of directed resources;
- Compliance with the Ontario government Supply Mix policy direction of 50% nuclear energy;
- A reduction in Ontario CO_2 emissions; and
- Deferral of transmission enhancements needed to maintain reliable load supply to customers in the east GTA upon retirement of Pickering NGS.

The OPA therefore considers it prudent, on balance, to spend funds in 2013 and 2014 for Pickering NGS continued operation should it prove to be technically feasible.

The technical feasibility of continued operation is expected to be known in 2012. A study is currently being conducted under the auspices of the CANDU Owner's Group to establish the technical feasibility of extending by approximately four years the operating life of each of the generating units that are in current operation. If feasible, it would provide the option to continue to operate the units at Pickering NGS through to approximately 2020. In the absence of continued operation, the six generating units that are currently in operation at Pickering NGS are expected to cease operation by approximately 2015.

From 2013 to 2014, it will be necessary for OPG to incur $190 million in additional capital and operating related costs associated with Pickering NGS. Of this, $85 million is associated with preserving the option of continued operation through additional inspection and maintenance work. It will be necessary for OPG to increase the number of generating unit planned outage hours at Pickering NGS during the 2013 to 2014 period to perform this

Figure 18: Net Benefit–Cost of Pickering Continued Operation for a Range of System Conditions 2013 – 2020

Source: OPA

The last 5 sensitivity scenarios relate to the performance of Pickering NGS. Three factors were explored in this regard: annual energy output of Pickering NGS under continued operation, duration of the continued operation period, and the capital and fixed operating costs associated with continued operation.

Reducing the annual capacity factor (a measure of plant energy production) to 64% increased the net system cost to $0.55 billion. This is due to reduced opportunities for gas displacement while fixed costs of operating Pickering NGS remain unchanged. An increase in the annual energy production from Pickering NGS to an 85% annual capacity factor resulted in a $0.27 billion net system benefit.

Reducing the duration of continued operation by 50% increased the net system cost to $0.46 billion. This is as a result of most of the additional energy production from Pickering NGS occurring during periods of significant surplus energy, thereby reducing opportunities to displace gas-fired generation.

A 10% decrease in capital and fixed operating costs translated to a $0.53 billion increase in net system benefit whereas a 20% increase in capital and fixed operating costs resulted in a $0.52 billion increase in net system costs.

Drivers of costs and benefits of continued operation under sensitivity conditions considered were found to have similar relative impact as under the reference scenario. For example, cost savings associated with reduced natural gas-fired production and imports in Ontario

DRAFT

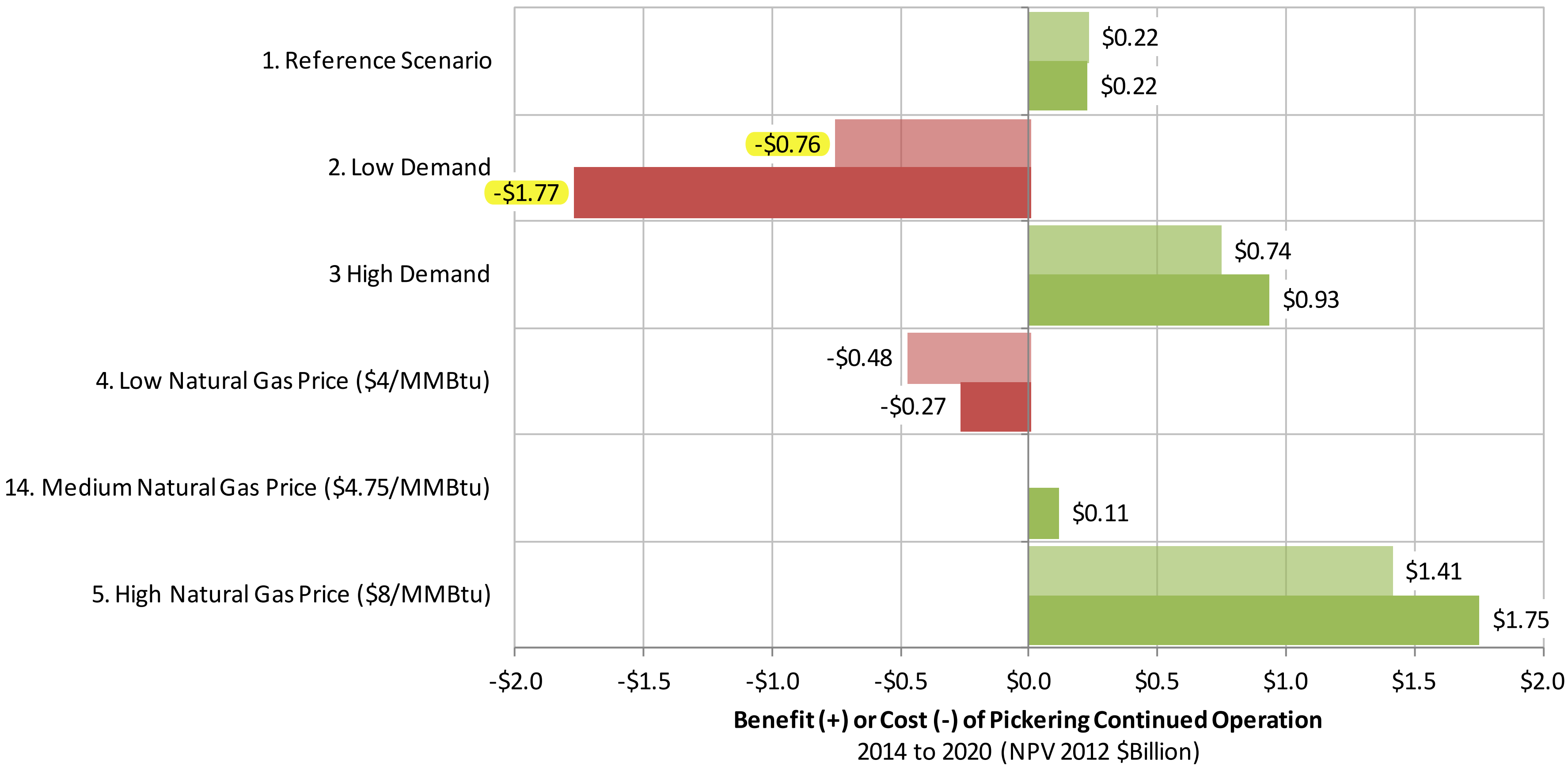
Feb 13th 2014

PICKERING CONTINUED OPERATIONS ANALYSIS

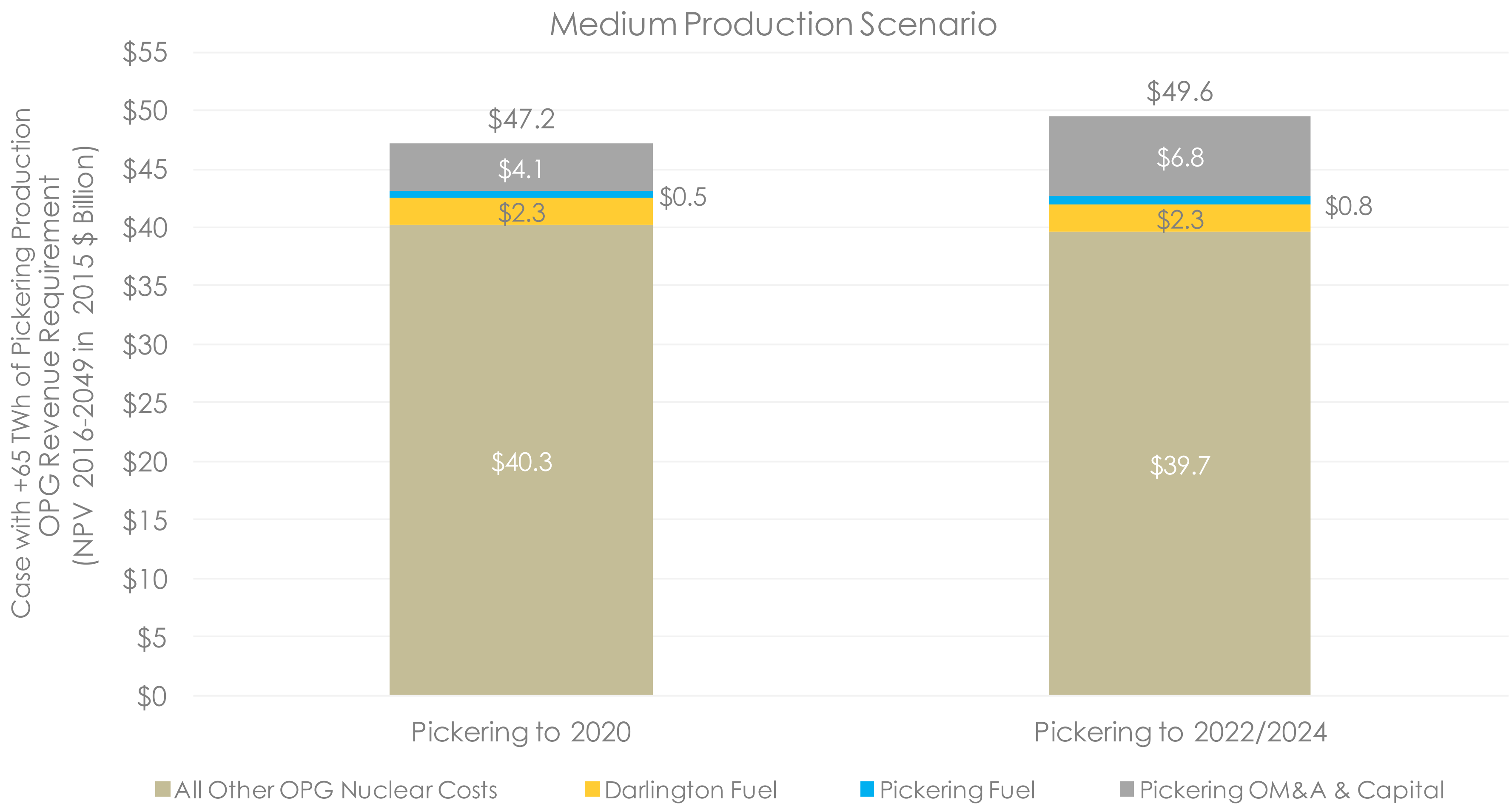
ONTARIO POWER AUTHORITY

Results Summary & Comparison to 2012 Study

- Results are directionally consistent with the previous study



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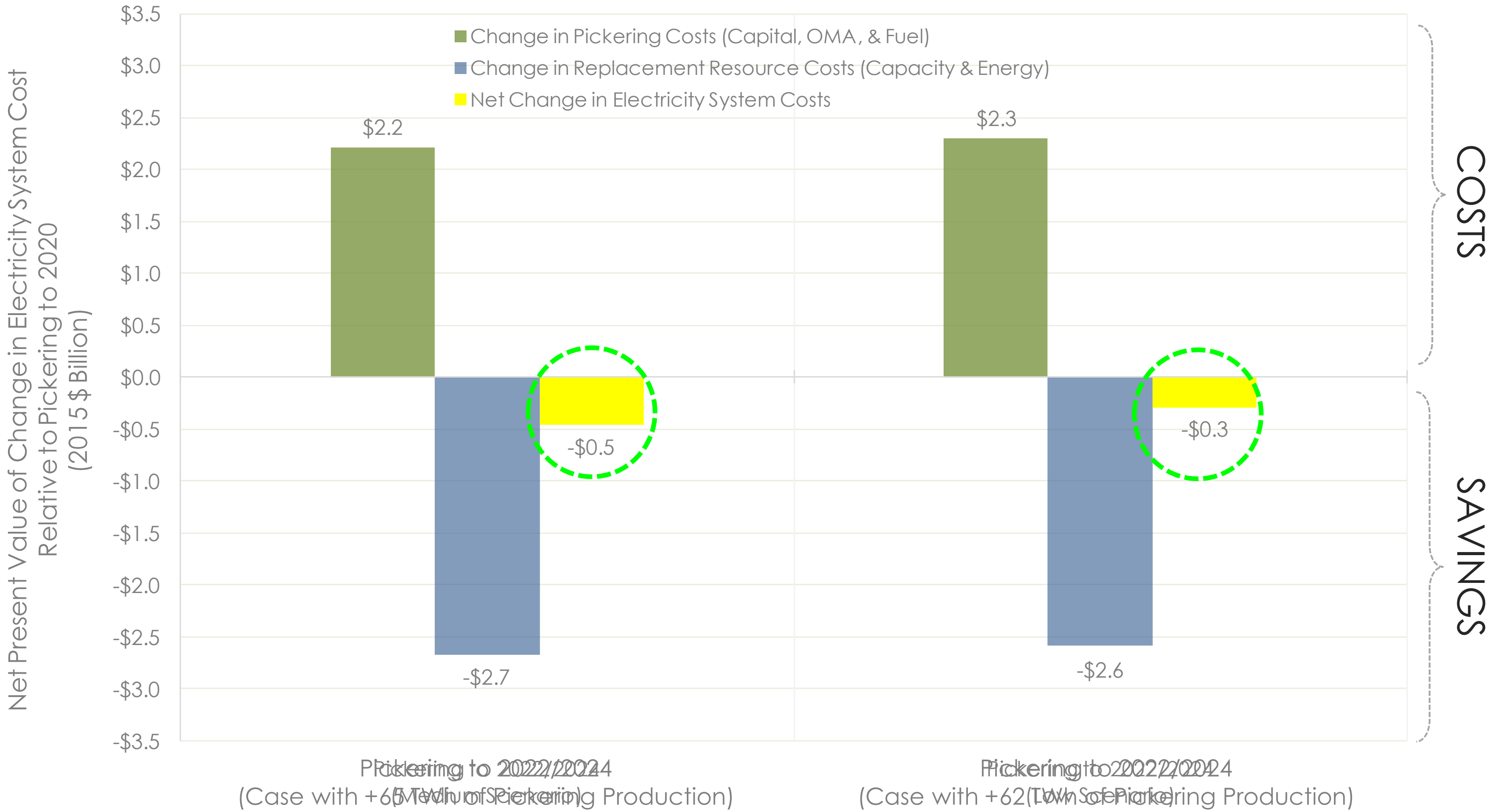
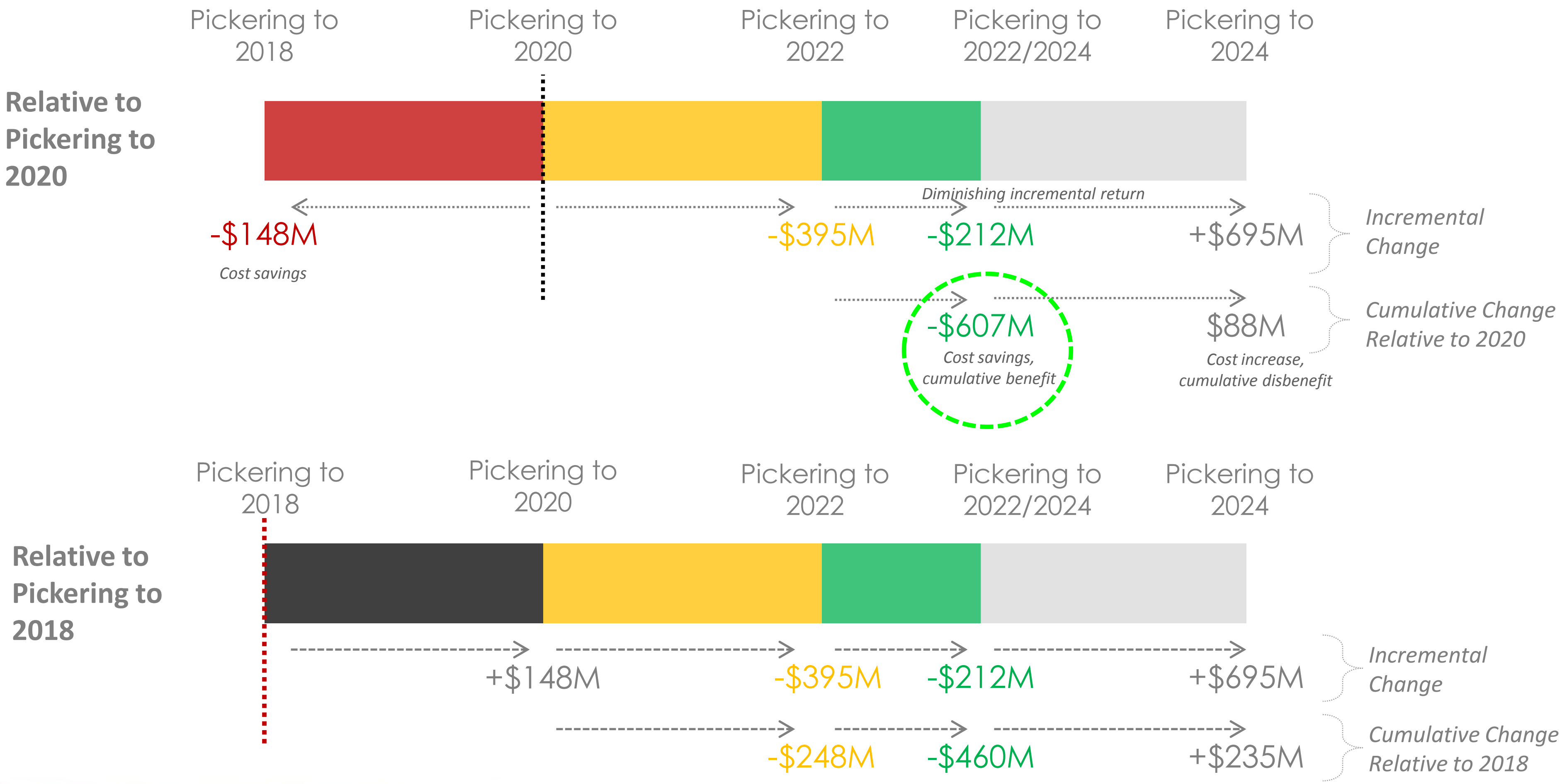
Pickering extension to 2022/2024 yields a net benefit in the range of $0.3B (in the case which sees a cumulative increase in Pickering production by 62 TWh) to $0.5B (in the case which sees a cumulative increase in Pickering production by 65 TWh) (NPV 2016-2032 in 2015 $). This is a reduction relative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

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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GEC Interrogatory #20

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

Interrogatory

Reference:
Exhibit F2-2-3, Attachment 2

What gas price forecast underlies OPG's cost-effectiveness analysis? Please compare the gas price forecast used to the corresponding current Henry Hub futures prices.

Response

The gas price forecast used in OPG's analysis and current Henry Hub future prices are provided in the Chart 1 below.

Chart 1

Description	Unit	2016	2017	2018	2019	2020	2021	2022	2023	2024
Henry Hub Gas Forecast - 2015 System Economic Values	$/MMBtu	$3.42	$3.34	$3.46	$3.58	$3.92	$4.21	$4.40	$4.61	$4.82
5-Oct-16 NYMEX Henry Hub Futures Prices (annual averages)	$/MMBtu	$3.11	$3.20	$2.98	$2.86	$2.87	$2.96	$3.11	$3.25	$3.40

All values are in U.S. dollars

Average 2018 to 2024 = $3.06

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

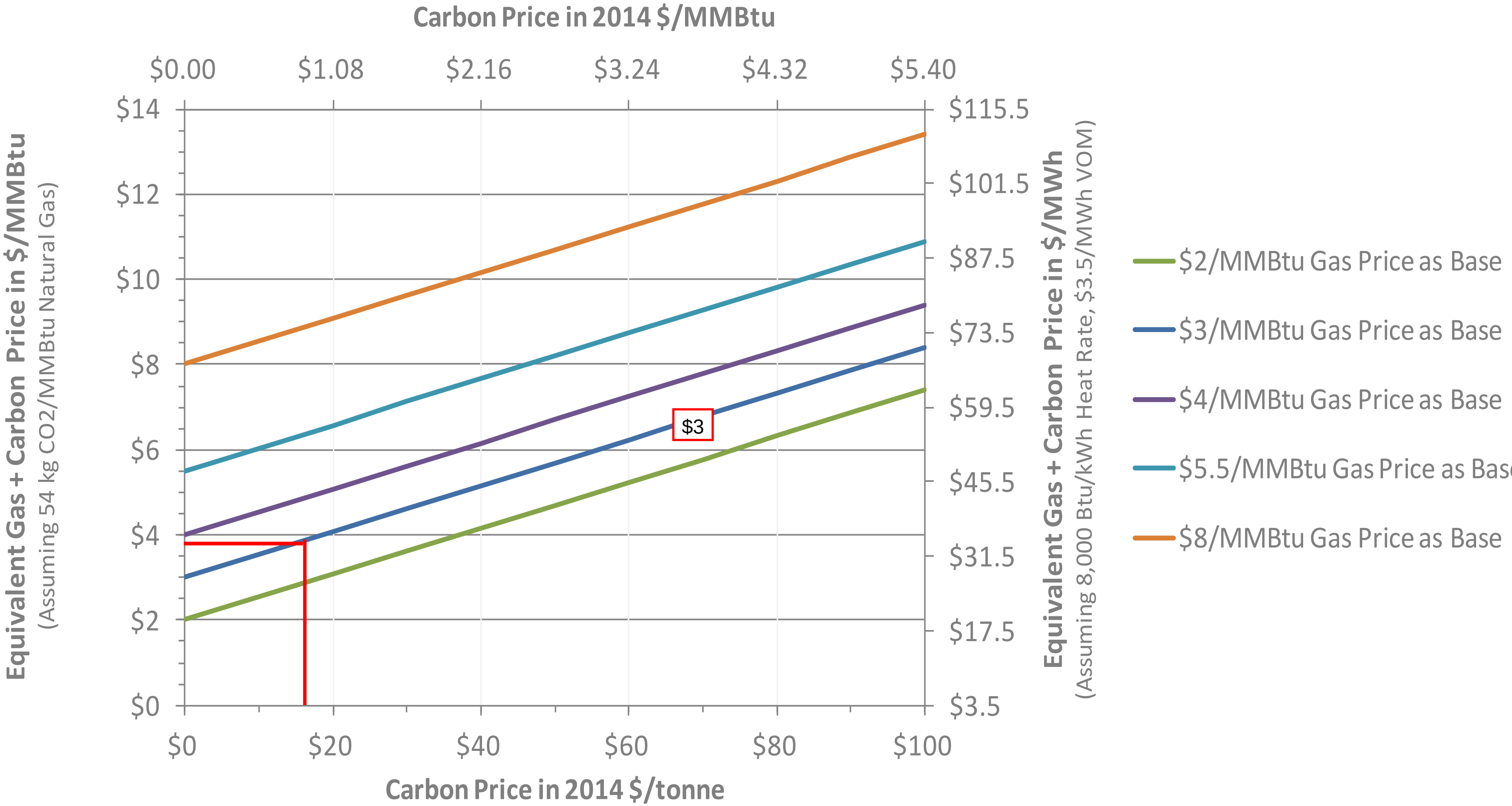
2016	0
2017	0.013391
2018	0.014074
2019	0.014763
2020	0.015487
2021	0.016246
2022	0.017043
2023	0.017878
2024	0.018754
2025	0.019674
2026	0.020638
2027	0.02165
2028	0.022711
2029	0.023824
2030	0.024992
2031	0.026217
2032	0.027503
2033	0.028851
2034	0.030265
2035	0.031749

Average 2018 to 2024 = 0.0163 or US$16.30/tonne

(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.

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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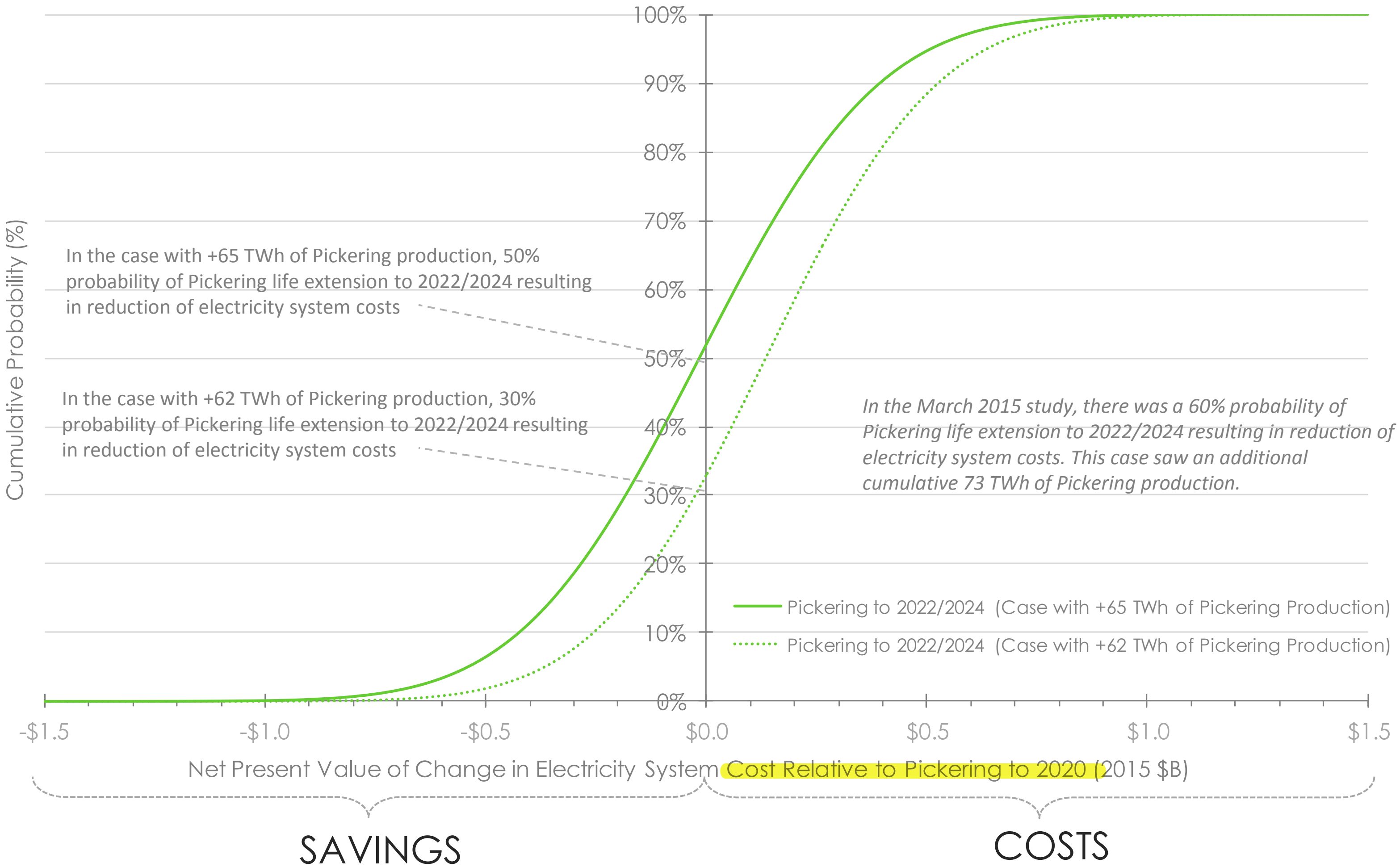
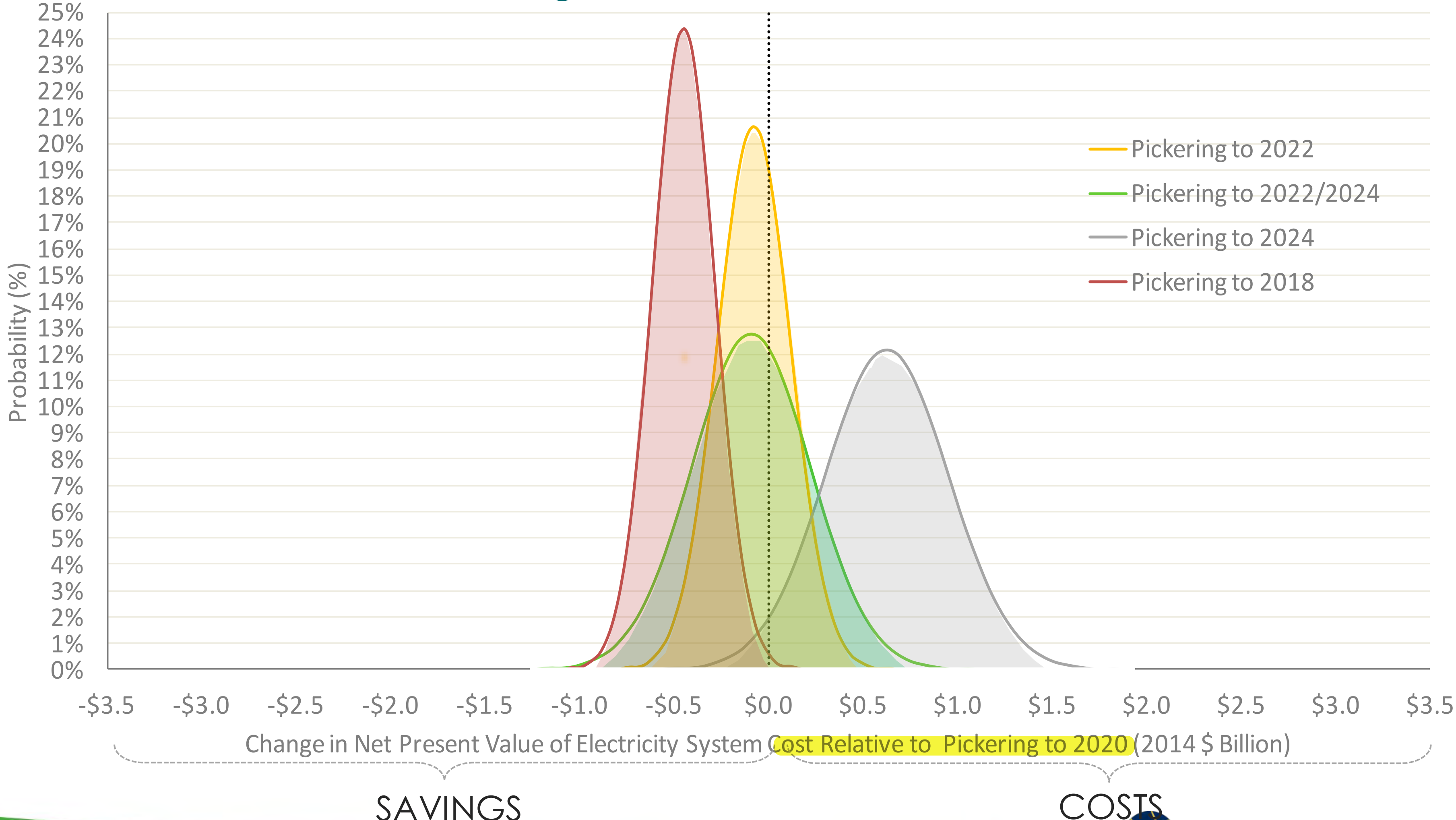
Consideration of the historical gas price distribution between 2010 and 2015 adds insight into the cumulative probability of change in electricity system cost as a function of natural gas price under various Pickering extension scenarios. Pickering life extension to 2022/2024 offers moderate probabilities 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.

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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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.

2016 IESO Operability Assessment - Summary

Review of the Operability of the IESO-Controlled Grid to 2020

Leonard Kula P.Eng.

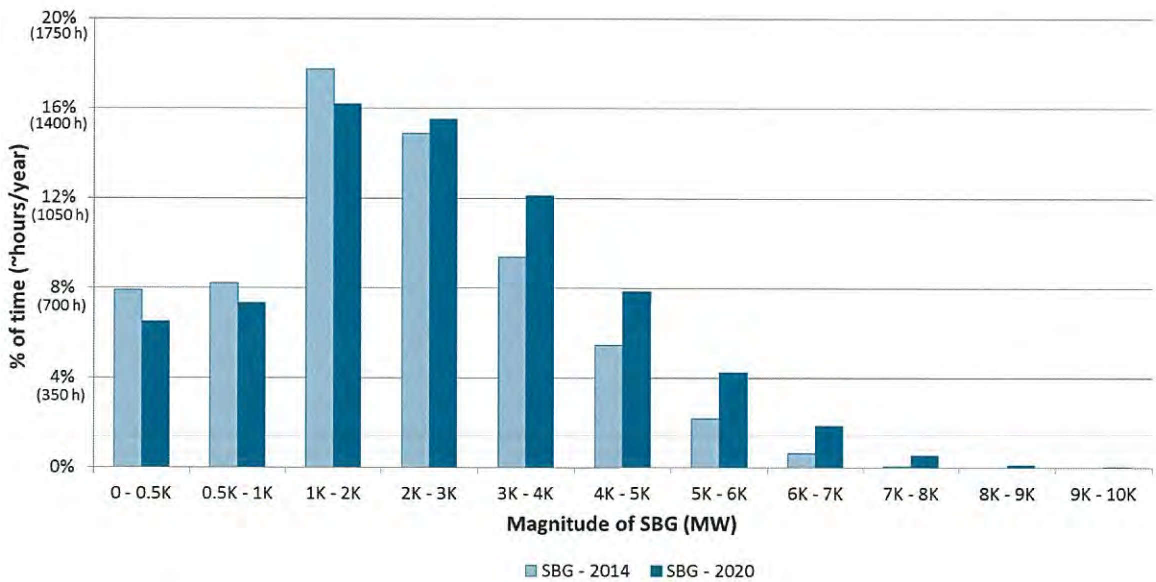
Director – Power System Assessments

March 2016

Connecting Today.
Powering Tomorrow.

Surplus Baseload Generation (SBG)

Chart 5: 2014 SBG vs 2020 SBG



What is it? Chart 5 shows the magnitude of surplus baseload generation in the year 2014 in comparison to the results of our simulation for the year 2020.

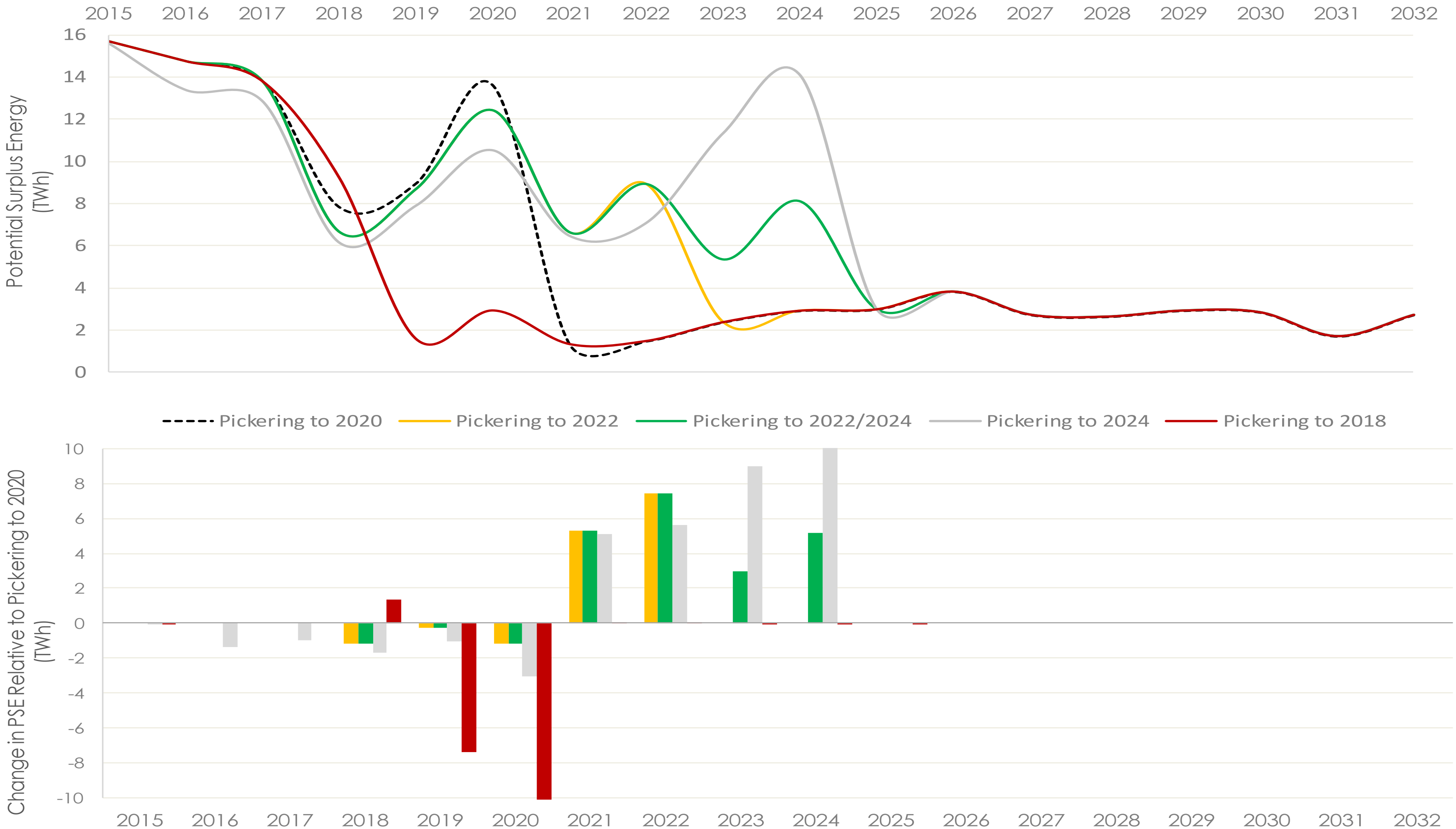
Why do we need to know? To ensure that our current SBG mitigating measures are sufficient in 2020.

What is it telling me? SBG conditions in 2020 are expected to be comparable in magnitude and frequency to those experienced in 2014. Ontario experienced SBG conditions ~66% of the time in 2014. This is expected to increase to ~72% of the time by 2020.

Operability considerations? Our current SBG mitigating measures are expected to be sufficient to manage SBG in 2020. These mitigating measures include: hydroelectric spill, economic exports, variable generation dispatch and nuclear manoeuvers/shutdowns.

Recommendations? None. We do not anticipate requiring significant changes to our processes to mitigate SBG, as the current measures are expected to be sufficient.

Energy production from Pickering increases potential surplus energy



	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.

	Pickering Costs							
($M, unless otherwise stated)	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Total Operating Costs - Initial	**1,319.4**	**1,347.2**	**1,364.0**	**1,351.4**	**1,351.4**	**1,391.7**	**1,337.9**	**1394.5**
Add								
Inventory Obsolescence[1]	0.0	0.0	12.4	12.4	12.4	12.4	12.4	12.4
Pickering portion of Tritium Removal Facility[1]	0.0	0.0	10.4	11.2	11.6	10.9	12.2	12.8
Fuel Costs	113.5	120.4	120.2	114.4	115.5	116.5	120.5	117.9
Subtotal	**1,432.9**	**1,467.6**	**1,507.0**	**1,489.4**	**1,490.9**	**1,531.5**	**1,483.0**	**1537.6**
Less								
Capital	119.5	90.9	124.3	85.2	29.8	28.0	23.2	23.1
Subtotal	**1,313.4**	**1,376.7**	**1,382.7**	**1,404.2**	**1,461.1**	**1,503.5**	**1,459.8**	**1514.5**
Add								
OPEB and Pension excluded from Centrally Held Costs	10.7	45.8	48.5	62.7	39.2	25.5	15.7	10.0
IESO Non energy Charges[2]	32.2	51.5	27.6	30.6	28.2	25.7	28.7	22.3
Other[1]	0.0	0.0	-3.7	-68.6	-37.3	-25.8	-30.6	-22.7
Subtotal	**1,356.3**	**1,474.0**	**1,455.1**	**1,428.8**	**1,491.2**	**1,529.0**	**1,473.5**	**1,524.2**
Add								
Depreciation and Amortization _Pickering[2]	140.9	147.3	165.7	199.9	223.2	226.7	233.3	53.1
Depreciation and Amortization- Pickering Generic[2]	44.2	53.5	34.2	38.6	37.1	34.9	36.7	20.4
Income Tax - Pickering[2]	-25.7	-15.2	-8.3	-9.2	-9.2	-9.1	26.9	27.5
Property Tax- Pickering	4.9	4.9	5.0	5.4	5.5	5.7	5.8	6.3
Total								
Planned Operating Costs	**1,520.5**	**1,664.5**	**1,651.7**	**1,663.6**	**1,747.9**	**1,787.2**	**1,776.2**	**1631.4**
Pickering Generation - TWh	**20.1**	**21.2**	**20.8**	**19.1**	**19.2**	**19.4**	**19.6**	**18.8**
Planned Operating Costs- $/MWh	**75.7**	**78.4**	**79.5**	**87.3**	**91.1**	**92.3**	**90.5**	**86.7**

[1] Included in Total Operating Costs- Initial in 2014 actual and 2015 actual

[2] Allocation based on Pickering % of generation

GEC Interrogatory #34

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

Interrogatory

Reference:
In Table 3 of Attachment 2 to Exhibit F2-2-2, OPG lists "level of concern" for confidence in operation to 2022 to 2024.

Please provide a likelihood range for the levels of concern marked low, medium and high.

Response

The correct reference is Ex. F2-2-3 Attachment 2, Table 3.

The likelihood ranges for the confidence levels in Ex. F2-2-3 Attachment 2, Table 3 are provided below.

Low: <30% likelihood
Med: 30-70% likelihood
High: >70% likelihood

Based on technical work completed to date, Engineering has improved the confidence level associated with Units 1 and 6 from Low, as shown in Ex. F2-2-3 Attachment 2, Table 3, to Medium . All other confidence levels remain the same.

Technical assessment work on the fuel channels' fitness-for-service will continue through the Fuel Channel Life Assurance Project with the aim of completing a high confidence prediction of fuel channel fitness-for-service on all units by the end of 2017.

The technical fitness for service of other major components such as the Steam Generators, is not considered life limiting; however, additional inspection and maintenance scope is required to assure fitness-for-service to the dates in the Preferred Alternative. This additional work has been identified; impacts on the generation plan developed and the costs are included in the forecasts.

Fuel Channels:

The technical assessment has identified that the major concern is axial elongation of the pressure tubes. A number of channels are expected to reach the limits of available bearing travel (i.e. when the leading pressure tubes will no longer be supported on their bearings), with Units 1 and 6 being of greatest concern.

Table 3 summarizes the current confidence level for operation to 2024 for all units.

Table 3: Current Level of Confidence in Operation to 2022/2024 – All Units

Unit	Current Confidence for Operation to 2022/2024	Comments
Unit 1	Low	Current projections indicate potential for channels off-bearing by 3rd Quarter 2021
Unit 4	High	Operation to 2024 is possible technically based on pressure tube degradation mechanisms
Unit 5	Medium	Current projections indicate potential for channels off-bearing by late 2022/early 2023
Unit 6	Low	Current projections indicate potential for channels off-bearing by mid-2022
Unit 7	Medium	Current projections indicate potential for channels off-bearing by late 2022/early 2023
Unit 8	High	No channels projected off bearing to end of 2024

Several mitigation measures are available for pressure tube elongation. These include physical modifications as well as more detailed technical evaluations to refine assessments of the timing and number of channels which would approach limits of bearing travel on each unit. Some of the physical modifications which are available would be costly to implement and some of the technical solutions are complex and/or would require increasing the complexity of operational procedures. Therefore, the preliminary plans to enable the Preferred Alternative include only the less costly physical modifications and less complex technical evaluations. However, the remaining mitigation options have not been ruled out and will be assessed as part of the Fuel Channel Life Assurance Project. The costs of the Fuel Channel Life Assurance Project are covered in the partial release requested in this Business Case.

Currently, pending more detailed review and development of mitigation plans, Units 1 and 6 would be challenged to meet the end dates in the Preferred Extended Operations Alternative. Two other units, Units 4 and 8, are assessed to be able to surpass the planned end of operation dates, if necessary

Unit 1 is challenged by available bearing travel in order to achieve the end of 2022 in the Preferred Alternative. However, with expected mitigation, operation of Unit 1 into mid-to-late 2022 is likely. Further mitigation would be required to enable Unit 1 to operate to the end of 2022. A final

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Table E3 summarizes the generation forecasts developed for the extended operations Preferred Alternative.

Table E3: Estimated Generation Impacts of the Preferred Alternative

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

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

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

The "medium" to "high" risks associated with the Preferred Alternative are summarized below:

1. Reputational Risk (High): e.g. the risk that interest groups that are opposed to nuclear power will contest Extended Operations, particularly during the next license renewal process, and thereby cause increased community concern and potential earlier shutdown than planned. *Mitigating Actions:* Ongoing demonstration of the value and safety of Pickering through external communications, hearings and stakeholder relations.
2. Regulatory Risks (Medium): e.g. the risk that the proposed disposition for one or more known issues is not accepted by the CNSC. *Mitigating Actions:* Completion of the PSR and a pro-active approach with the CNSC to demonstrate technical fitness-for-service and maintenance of high safety standards.
3. Technical/Fitness-for-Service Risks (Medium): e.g. the risk that a major component, e.g. fuel channels, does not continue to meet fitness-for-service requirements. *Mitigating Actions:* On-going comprehensive inspection and maintenance programs are included in the work program; life cycle management program of major components adjusted based on the extended end-of-life dates.
4. System Value Assessment (Medium) – changes to Ontario system parameters such as flat or declining load growth, reduction in the cost of competing generation or changes to baseload supply (e.g. refurbishment schedules changes) could impact the overall economic system value negatively. *Mitigating Actions:* None that OPG can implement directly. Robust analysis across a range of scenarios and OPG ensuring that costs and generation forecasts are achieved.

Management assesses the risks associated with the extended operations Preferred Alternative to be manageable.

Management recommends that funding of $52M be released in order to complete the Periodic Safety Review, the Fuel Channel Life Assurance Project and to execute incremental outages and inspections in 2016 and 2017. Management will seek a full release following confirmation of the fuel channel life of the units and completion of the Periodic Safety Review.

SIGNATURES

Recommended by:

11 Nov 2015

Glenn Jager Date
President OPG Nuclear & Chief Nuclear Officer

Finance Approval:

Nov 11 2015

Beth Summers Date
Chief Financial Officer

Line Approval per OAR Element 1.3:

Nov 12, 2015

Jeff Lyash Date
President & Chief Executive Officer

Table 4: Fuel Channel Risks Associated with Operation of P1&4 to 2022 and P5-8 to 2024

Mechanism	Concerns	Level of Concern	Potential Mitigation
Pressure Tube (PT) Elongation	**P1** Up to 43 channels off-bearing by end 2022 if no add'l mitigation	**High**	• **Physical**: Reconfigure and Shift fuel channels • **Analytical:** Evaluations to disposition operation with a limited number of channels off-bearing
	P6 Up to 78 channels off-bearing by end 2024 if no add'l mitigation	**High**	
Calandria Tube (CT) Sag P1/4 **CT to LISS[(1)] Nozzle contact P5-8**	**P1 & 4** – potential for PT to CT contact given detensioning of tight fitting spacers. CTs were not replaced during retube, and modeling is not currently possible	**Medium**	• **Inspection**: Additional measurements and sampling to demonstrate low probability of PT to CT contact and hydrogen concentration below specified levels. • **Analytical**: Disposition likelihood of channels exceeding operational limits
	P5-6: Potential for ~10 channels to contact with LISS nozzles by end 2024	**Medium**	• **Inspection:** Repeat measurements could yield increased margins • **Physical:** Potential need to replace individual fuel channels
Pressure Tube Fracture Toughness	Potential to exceed fracture toughness thresholds	**Low**	• **Analytical:** Work underway to develop updated fracture toughness curves for P1& 4 & P5-8 – small potential for station modifications

(1) LISS – Liquid Injection Shutdown System – these nozzles extend horizontally into the reactor core and could come into contact with calandria tubes late in life on certain units, resulting in concerns regarding calandria tube integrity.

Steam Generators and Feeders:

Preliminary assessments indicate that steam generators and feeders do not present a significant hurdle for proving fitness-for-service of the units. Steam generators are not expected to show any significant degradation in performance provided that maintenance (water-lancing) and inspection campaigns are extended appropriately for each of the extended life scenarios. Similarly, a limited number of feeder replacements are required on Units 5-8 in order to operate to 2024.

Balance of Plant:

Balance of plant components, including the turbine-generator sets, the condensers, heat exchangers and major motors have also been assessed based on current system health reports and previous condition assessments, and no significant issues have been found which would preclude operation to 2024. Normal maintenance activities would continue in the Extended Operations period. Condition assessments are being updated based on a 2024 end-of-life date. The cost of this work is included in the Partial Release requested in the Business Case.

REGULATORY APPROVALS

In addition to component fitness-for-service uncertainties, the Preferred Alternative of extending operations will require concurrence by the CNSC. The current power reactor operating licence for Pickering was issued in September 2013 for a 5 year term (expiring in 2018). The license included a requirement that OPG confirm, in writing, by June 30, 2017 the planned end-of-life date for Pickering. OPG expects to provide that confirmation with the licence application for the next

GEC Interrogatory #51

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

Interrogatory

Reference:
The OPG cost benefit analysis presented in *P-REP-09013-0002, Pickering NGS – Beyond Design Basis Containment Integrity*, which dates from January 2014, recommended not installing a Containment Filtered Venting System (CFVS) in part due to the "the short remaining operating life of the station." OPG, however, has committed to install a CFVS at Darlington.

a. Has the decision not to install a CFVS been revisited, and if so changed, in light of OPG's decision to extend Pickering's operational life again to 2024?

b. If not, how long would OPG need to continue operating Pickering for the CFVS to be viewed as a reasonable upgrade?

c. Has the CNSC accepted OPG's decision not to install a CFVS in light of its request to operate the station until 2024?

d. Please provide a list of other safety enhancements or upgrades that OPG decided against installing prior to the 2013 relicensing hearings due to the plan to operate Pickering to only 2020.

Response

OPG declines to provide the requested information on the basis of relevance. This interrogatory seeks information on matters that are within the CNSC's regulatory jurisdiction (being technical information related to approval of the operation of Pickering) and that are not relevant to deciding any issue on the approved Issues List in OPG's application to set payment amounts.

Board Staff Interrogatory #121

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

Interrogatory

Reference:
Ref: Exh D2-1-3 Table 5b
In Table 5b at Exh D2-1-3, OPG has provided a listing of 19 projects that are to be funded through the test year Unallocated Capital.

a) It is not clear to OEB staff which of these projects is specifically related to ensuring the operation of Pickering beyond 2020. Please expand Table 5b by adding additional columns to include the following information: Identify the project driver for each project in the table as "PEO" or "PCO" or "other"; identify the planned in-service date for each project; total estimated capital expenditure for each project and in- service date.

b) Please confirm that the projects listed in Table 5a, relate exclusively to the DRP and are not intended to enable Pickering Extended Operations. If that is not true, please identify the projects in Table 5a that are intended to enable Pickering Extended Operations.

Response

a) None of the projects listed in Ex. D2-1-3 Table 5b are required to ensure operation of the Pickering station beyond 2020. The projects listed in Ex. D2-1-3 Table 5b have been identified to maintain safe and reliable operations to 2020 and are proposed projects to be started in the years listed. At this time, there has not been sufficient engineering, planning or estimating completed to provide estimates and in-service dates as requested.

   Any potential projects that may be required to ensure operations beyond 2020 will be identified following the completion of the Periodic Safety Review and other technical assessments that are currently in progress.

b) OPG does not confirm that the projects listed in Ex. D2-1-3 Table 5a relate exclusively to the Darlington Refurbishment Program. Rather, the projects listed in Ex. D2-1-3 Table 5a are modifications planned for the Darlington station. None of the projects in Ex. D2-1-3 Table 5a are intended to enable Pickering Extended Operations.