EB-2013-0321

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

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the Ontario Energy Board Act, 1998 for an order or orders determining payment amounts for the output of certain of its generating facilities.

GEC CROSS EXAMINATION MATERIALS

EB-2013-0321

GEC Cross Exhibit on Pickering costs

Industry median non-fuel O&M cost:

Industry **median** 3 year non-fuel oper. cost per MWh[1]: $24.40 (2011)
(adjusted for inflation @ 2%/a: 2014: 25.89, 2015: 26.41)

Impact of targeted Pickering O&M cost vs. industry median

A	B	C	D	E	F	G	H
Year	Pick. target TWh[2]	Pickering Non-Fuel Operating $/MWh[3]	Darl. target TWh[4]	Darlington Non-Fuel Operating $/MWh[5]	Total TWh (C+D)	Combined non-fuel O&M (BxC)+(DxE)	Combined non-fuel O&M with Pickering at industry median (B x 25.89 or 26.41) + (D x E)
2014	21.3	55.71	28.4	27.21	49.7	1959.39	1324.22
2015	21.9	53.34	26.1	32.82	48.0	2024.75	1434.98
2014-15	43.2		54.5		97.7	3984.14	2759.2

Pickering operated at industry median O&M level: total 2014-15 nuclear non-fuel O&M revenue requirement would fall approximately $1.225 billion

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Pickering vs. Darlington adjusting for unit size (3 year non-fuel)[6]

	Pickering	**Darlington**
3 Year non-fuel O&M $/MWh	56.54	26.42
Unit size MW	500	881
Non-fuel O&M adj. for unit size[7]	56.54	46.55
Difference vs adj. Darl. Cost	+17.6%	

Combined targeted non-fuel O&M if Pickering at Darlington levels[8] would fall from 3984.14 to 3661.72 saving $322.42 million

---

1 F2/T1/S1/p.5 (Benchmarking data)
2 F2-1-1 att 2 p. 7
3 F2-1-1 p. 15
4 F2-1-1 att 2 p. 7
5 F2-1-1 p. 15
6 F2/T1/S1/p.5 (Benchmarking data)
7 881/500 X 26.42 = 46.55 Does not account for offsetting economy of scale of 6 versus 4 unit station
8 [(BxC)/1.176]+(DxE)=3661.72

Comparison of 2011 OPG Nuclear Performance to Industry Benchmarks

		2011 Actuals			
Metric	**NPI Max**	**Best Quartile**	**Median**	**Pickering**	**Darlington**
Safety					
All Injury Rate (#/200k hours worked)				0.31	0.18
Rolling Average Industrial Safety Accident Rate (#/200k hours worked)	0.20	0.00	0.06	0.04	0.09
Rolling Average Collective Radiation Exposure (Person-rem per unit)	80.00	59.90	110.07	110.07 ⇧	71.12
Airborne Tritium Emissions (Curies) per Unit[1]		969	3,366	2,565	969
Fuel Reliability Index (microcuries per gram)	0.000500	0.000015	0.000154	0.000175 ⇧	0.001133 ⇩
2-Year Reactor Trip Rate (# per 7,000 hours)	0.50	0.00	0.10	0.60 ⇩	0.21
3-Year Auxiliary Feedwater System Unavailability (#)	0.0200	0.0000	0.0026	0.0044	0.0000
3-Year Emergency AC Power Unavailability (#)	0.0250	0.0005	0.0067	0.0107	0.0067
3-Year High Pressure Safety Injection Unavailability (#)	0.0200	0.0000	0.0001	0.0001	0.0000
Reliability					
WANO NPI (Index)		91.4	84.6	66.1	92.8
Rolling Average Forced Loss Rate (%)	1.00	1.14	1.90	10.34	1.80
Rolling Average Unit Capability Factor (%)	92.0	90.5	85.6	72.5	89.6
Rolling Average Chemistry Performance Indicator (Index)	1.01	1.00	1.01	1.10	1.03
1-Year On-line Deficient Maintenance Backlog (work orders per unit)[2]		260	378	301	266
1-Year On-line Corrective Maintenance Backlog (work orders per unit)[2]		33	52	160	121
Value for Money					
3-Year Total Generating Cost per MWh ($ per Net MWh)		34.21	41.28	65.86	33.05 ⇧
3-Year Non-Fuel Operating Cost per MWh ($ per Net MWh)		20.78	24.40	56.54	26.42
3-Year Fuel Cost per MWh ($ per Net MWh)		6.50	7.20	4.27	4.24
3-Year Capital Cost per MW DER (k$ per MW)		48.39	72.19	32.54	18.54
Human Performance					
18-Month Human Performance Error Rate (# per 10k ISAR hours)		0.00500	0.00700	0.00669 ⇧	0.00567 ⇩

Notes

1. 2010 data is used because 2011 results were unavailable at the time of benchmarking.
2. INPO set a new standard for classifying work order backlogs with the issuance of AP-928 Work Management Process Description, revision 3, in June 2010.

   New metrics have been implemented industry-wide to ensure more effective and accurate comparisons between utilities. Data collected is as of September 2011.

Green = maximum NPI points achieved or best quartile performance

White = 2nd quartile performance

Yellow = 3rd quartile performance

Red = worst quartile performance

⇩ Declining Benchmark Quartile Performance vs. 2010

⇧ Improving Benchmark Quartile Performance vs. 2010

Comparison of 2012 OPG Nuclear Performance to Industry Benchmarks

Metric	NPI Max	2012 Actuals Best Quartile	Median	Pickering	Darlington
Safety					
All Injury Rate (#/200k hours worked)		1.01	N/A[1]	0.33	0.34
Rolling Average Industrial Safety Accident Rate (#/200k hours worked)	0.20	0.00	0.03	0.03	0.10
Rolling Average Collective Radiation Exposure (Person-rem per unit)	80.00	40.50	83.32	124.06 ⇩	58.55
Airborne Tritium Emissions (Curies) per Unit[2]		1,196	2,577	2,491	973
Fuel Reliability Index (microcuries per gram)	0.000500	0.000001	0.000048	0.000129	0.000194 ⇧
2-Year Reactor Trip Rate (# per 7,000 hours)	0.50	0.000	0.104	0.517 ⇧	0.208
3-Year Auxiliary Feedwater System Unavailability (#)	0.0200	0.0000	0.0003	0.0116	0.0000
3-Year Emergency AC Power Unavailability (#)	0.0250	0.0005	0.0026	0.0037	0.0000
3-Year High Pressure Safety Injection Unavailability (#)	0.0200	0.00000	0.00006	0.0001	0.0000
Reliability					
WANO NPI (Index)		98.3	89.1	64.7	96.3 ⇩
Rolling Average Forced Loss Rate (%)	1.00	0.65	1.03	9.23	2.02 ⇩
Rolling Average Unit Capability Factor (%)	92.0	93.78	92.08	75.62	92.0 ⇧
Rolling Average Chemistry Performance Indicator (Index)	1.01	1.00	1.01	1.10	1.03
1-Year On-line Deficient Maintenance Backlog (work orders per unit)		222	313	232	203 ⇧
1-Year On-line Corrective Maintenance Backlog (work orders per unit)		8	28	118	66
Value for Money					
3-Year Total Generating Cost per MWh ($ per Net MWh)		36.30	43.40	67.16	31.67
3-Year Non-Fuel Operating Cost per MWh ($ per Net MWh)		21.76	24.65	57.21	24.76
3-Year Fuel Cost per MWh ($ per Net MWh)		7.24	8.03	5.00	4.69
3-Year Capital Cost per MW DER (k$ per MW)		52.46	70.96	31.84	17.66
Human Performance					
18-Month Human Performance Error Rate (# per 10k ISAR hours)		0.00400	0.00700	0.00800 ⇩	0.00760 ⇩

Notes
1. No median benchmark available.
2. 2011 data is used because 2012 results were unavailable at the time of benchmarking.

New metrics have been implemented industry-wide to ensure more effective and accurate comparisons between utilities. Data collected is as of December :

Green = maximum NPI points achieved or best quartile performance

White = 2nd quartile performance

Yellow = 3rd quartile performance

Red = worst quartile performance

⇩ Declining Benchmark Quartile Performance vs. 2011

⇧ Improving Benchmark Quartile Performance vs. 2011

Filed: 2013-09-27
EB-2013-0321
Ex. F2-1-1
Attachment 2

Nuclear Operations - Generation Plan

	2013	2014	2015
Pickering Nuclear			
Net Generation in TWh	21.1	21.3	21.9
Planned Outage Days	304	293	288
Forced Loss Rate %	8.1	7.8	5.5
Unit Capability Factor %	79.2	79.9	82.1
Darlington Nuclear			
Net Generation in TWh	26.9	28.4	26.1
Planned Outage Days	144	77	188
Forced Loss Rate %	1.5	1.3	1.0
Unit Capability Factor %	88.8	93.5	86.3
OPG Nuclear			
Net Generation in TWh	48.0	49.7	48.0
Planned Outage Days	448	370	476
Forced Loss Rate %	4.5	4.1	3.1
Unit Capability Factor %	84.3	87.2	84.3

Highlights

- The Generation Plan maintains Nuclear's planned production level in 2013 from the previous plan. In 2014 planned production level decreases by 0.1 TWh, from the previous plan, due to additional inspection and outage work required to extend Pickering's operating life to 247k EFPH.
- Reliability of critical equipment at Pickering station will be improved, resulting in a step change in performance by 2015 (i.e., FLR target of 5.5%).
- Pickering's Net Generation in TWh reflects additional planned outage days for Continued Operations. The impact on 2013 and 2014 is -0.7 TWh in each year.
- There are two Darlington planned outages in 2013.
- A significant portion of the planned D1711 outage work has been advanced to 2014 and 2015 to minimize 2017 outage duration during Darlington Refurbishment.

2015 targeted staff reductions requires continuous reassessment of existing fleet and site targets and initiatives, as well as, developing new initiatives.

3.4 Gap Based Business Planning: Target Setting

Top-down targets are performance improvement targets designed to close performance gaps and significantly drive OPG nuclear operations closer to top quartile industry performance over the duration of a business plan. The CNO, in consultation with OPG's Nuclear Executive Committee ("NEC"), provided direction on top-down performance targets for each nuclear station for the planning period (i.e. 2013 - 2015). The top-down approach establishes operational, financial, generation and staff targets set by reference to historical performance, targets established in the prior years, and updated benchmarking results.

Chart 3 sets out the final OPG operational and financial targets for the 20 benchmark performance indicators for the period 2013 - 2015.

Chart 3

	Pickering Annual Targets			Darlington Annual Targets		
Benchmarking Indicators – Annual Targets	**2013**	**2014**	**2015**	**2013**	**2014**	**2015**
Safety						
All Injury Rate (#/200k hours worked)	0.89	0.89	0.89	0.89	0.89	0.89
Industrial Safety Accident Rate (#/200k hours worked)	0.15	0.15	0.15	0.15	0.15	0.15
Collective Radiation Exposure (person-rem per unit)	101.95	100.95	98.71	96.73	56.00	73.80
Airborne Tritium Emissions (Curies) per Unit	2,350	1,900	1,800	1,000	1,000	1,000
Fuel Reliability (microcuries per gram)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Reactor Trip Rate (# per 7,000 hours)	0.5	0.5	0.5	0.5	0.5	0.5
Auxiliary Feedwater System Unavailability (#)	0.02	0.02	0.02	0.02	0.02	0.02
Emergency AC Power Unavailability (#)	0.025	0.025	0.025	0.025	0.025	0.025

High Pressure Safety Injection Unavailability (#)	0.02	0.02	0.02	0.02	0.02	0.02
Reliability						
WANO NPI (Index)	66.0	72.0	74.2	97.7	97.9	96.1
Forced Loss Rate (%)	8.09	7.76	5.5	1.50	1.25	1.00
Unit Capability Factor (%)	79.2	79.9	82.1	88.8	93.5	86.3
Chemistry Performance Indicator (Index)	1.06	1.05	1.04	1.01	1.01	1.01
On-line Deficient Critical and Non-Critical Mtce Backlog (work orders/unit).	207	197	<197	200	190	180
On-Line Corrective Critical and Non-critical Mtce Backlog (work orders/unit).	104	85	78	50	29	25
Value for Money						
Total Generating Costs per MWh ($/Net MWh) [1]	65.99	66.08	60.25	40.25	36.21	42.78
Non-Fuel Operating Costs per MWh ($/Net MWh) [1]	55.83	55.71	53.34	31.76	27.21	32.82
Fuel Costs per MWh ($/Net MWh)	6.04	6.02	5.93	5.39	5.36	5.28
Capital Costs per MW DER (k$/MW) [2]	28.05	29.98	6.98	23.76	29.48	34.82
Human Performance						
Human Performance Error Rate (# per 10k ISAR hours)	.005	.004	.004	.004	.004	.004

[1] Excludes OPEB, Pension, and Asset Service Fees
[2] Design Electrical Rating (DER)

OPG is targeting improved performance by 2015 in each of its four cornerstones. Specifically:

- OPG will continue to target first quartile performance in safety for Pickering and Darlington. OPG is targeting improvements in Fuel Reliability at Darlington and Reactor Trip Rate at Pickering.

- OPG will focus on improved reliability at both Pickering and Darlington. OPG is targeting improved FLR at Darlington but its UCF will decline in 2015 due to the VBO which will take all four units off-line for more than 1 month. For Pickering, OPG is

Canadian Nuclear Safety Commission
Commission canadienne de sûreté nucléaire

Summary Record of Proceedings and Decision

In the Matter of

Applicant	Ontario Power Generation Inc.
Subject	Application to Request a Removal of the Hold Point for the Pickering Nuclear Generating Station
Public Hearing Date	May 7, 2014

Edocs PDF 4448178

SUMMARY RECORD OF PROCEEDINGS

Applicant:	Ontario Power Generation Inc.
Address/Location:	700 University Avenue, Toronto, Ontario, M5G 1X6
Purpose:	Application to request a removal of the hold point for the Pickering Nuclear Generating Station.
Application received:	February 3, 2014
Date of public hearing:	May 7, 2014
Location:	Canadian Nuclear Safety Commission (CNSC) Public Hearing Room, 280 Slater St., 14th. Floor, Ottawa, Ontario
Members present:	M. Binder, Chair R. J. Barriault D. D. Tolgyesi A. Harvey R. Velshi M. J. McDill
Secretary:	M.A. Leblanc
Recording Secretary:	S. Dimitrijevic
General Counsel:	L. Thiele

Applicant Represented By	Document Number
• B. Phillips, Senior Vice President • M. Elliott, Chief Nuclear Engineer • K. Dehdashtian, Manager of Pickering Public Affairs and Regulatory Affairs • K. Powers, Director of Public Affairs • L. Swami, Vice President, Nuclear Services • C. Lorencez, Director, Nuclear Safety • J. Coles, Director, Emergency Management and Fire Protection • R. Manley, Director, Nuclear Regulatory Affairs • P. Spekkens, Vice President of Science and Technology Development • C. Mathias, Legal Counsel	CMD 14-H2.1 CMD 14-H2.1A CMD 14-H2.1B CMD 14-H2.1C

CNSC staff			Document Number
• G. Rzentkowski • M. Santini • P. Elder • J. Jin	• R. Jammal • S. Yolaoui • G. Frappier • P. Thompson	• L. Sigouin • Y. Akl • C. Purvis	CMD 14-H2 CMD 14-H2.A CMD 14-H2.B CMD 14-H2.C

Intervenors	Document Number
See appendix A	
Others	
• Office of the Fire Marshal and Emergency Management: D Nodwell • Kinectrics: P. Lawrence	

Hold point: Removed

Table of Contents

INTRODUCTION

1. Ontario Power Generation Inc. (OPG) has applied to the Canadian Nuclear Safety Commission[1] to request the removal of the regulatory hold point pursuant to licence condition 16.3 of the Power Reactor Operating Licence PROL 48.00/2018, issued for the Pickering Nuclear Generating Station (NGS). The facility is located in Pickering, Ontario and consists of eight CANDU pressurized heavy water reactors and their associated equipment. The current operating licence expires on August 31, 2018.

2. The Pickering NGS Power Reactor Operating Licence was renewed by the Commission after a public hearing held on February 20 and May 29 to 31, 2013[2]. In its decision, the Commission did not accept CNSC staff's proposed delegation of authority to remove the regulatory hold point to allow OPG to proceed with Pickering NGS operation beyond 210,000 Equivalent Full Power Hours (EFPH). Instead, the Commission decided to consider this matter in a future proceeding of the Commission with public participation. The milestone limit of 210,000 EFPH is the assumed design life of the pressure tubes and is expected to be reached on Pickering NGS Unit 6 in June 2014.

3. As part of its decision, the Commission directed OPG to provide the following before the removal of the hold point could be approved:

    - the revised PSA for Pickering A that meets the requirements of CNSC Regulatory Standard S-294;
    - an updated PSA for both Pickering A and Pickering B that takes into account the enhancements required under the Fukushima Action Plan; and
    - a whole-site PSA or a methodology for a whole-site PSA, specific to the Pickering NGS site.

4. In addition, the Commission directed OPG to report, at the time of OPG's request to remove the hold point, on its analysis on filtered containment venting, as a future enhancement to protect containment through OPG's Fukushima Action Items.

5. The Commission further directed OPG to ensure, by the end of June 2014, the production of an emergency management public information document that would be distributed to all households in the Pickering area.

6. The Commission also directed CNSC staff to review the Pickering PSA methodology, and provide its recommendation for the Commission's consideration at the time of OPG's request for the release of the hold point.

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[1] The *Canadian Nuclear Safety Commission* is referred to as the "CNSC" when referring to the organization and its staff in general, and as the "Commission" when referring to the tribunal component.

[2] *Record of Proceedings, Including Reasons for Decision*, in the matter of Application to Renew the Power Reactor Operating Licence for the Pickering Nuclear Generating Station, CNSC, August 9, 2013, Ottawa.

Issues

7. In considering the application, the Commission was required to decide if OPG has met all necessary pre-requirements and additional requirements associated with licence condition 16.3, including the Commission's requests for additional information as directed in the *Record of Proceedings* for the Pickering NGS licence renewal[3].

Public Hearing

8. Pursuant to section 22 of the NSCA, the President of the Commission established a Panel of the Commission to review the application. The Commission, in making its decision, considered information presented for a hearing held on May 7, 2014 in Ottawa, Ontario. The public hearing was conducted in accordance with the *Canadian Nuclear Safety Commission Rules of Procedure*[4]. During the public hearing, the Commission considered written submissions and heard oral presentations from CNSC staff (CMD 14-H2, CMD 14-H2.A, and CMD 14-H2.B) and OPG (CMD 14-H2.1, CMD 14-H2.1A, and CMD 14-H2.1B). The Commission also considered written submissions from 55 intervenors (see Appendix A for a detailed list of interventions). The hearing was webcasted live via the CNSC website, and video archives are available for a three-month period following this decision.

9. Following the public hearing, further to request for ruling, the Commission provided a further opportunity to hearing participants to submit supplementary comments on the following documents:

- Pickering A Risk Assessment Summary Report;
- Pickering B Risk Assessment Summary Report; and
- Pickering NGS Probabilistic Safety Analysis to Include Enhancements from the Fukushima Integrated Action Plan.

The Commission received and considered submissions from six intervenors, CNSC staff and OPG.

DECISION

10. The Commission is satisfied that OPG has met all necessary pre-requirements and additional requirements associated with licence condition 16.3, as directed in the *Record of Proceedings* for the Pickering NGS licence renewal, and the Commission's requests for additional information. Based on its consideration of the matter, the

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[3] CNSC *Record of Proceedings, Including Reasons for Decision*, "Ontario Power Generation Inc. – Application to Renew the Power Reactor Operating Licence for the Pickering Nuclear Generating Station", Public Hearing Dates: February 20 and May 29 to 31, 2013.
[4] Statutory Orders and Regulations (SOR)/2000-211.

Commission is satisfied that OPG will continue to make adequate provision for the protection of the environment, the health and safety of persons and the maintenance of national security and measures required to implement international obligations to which Canada has agreed. Therefore,

> the Commission removes the hold point associated with licence condition 16.3 of the Pickering Nuclear Generating Station Power Reactor Operating Licence, PROL 48.00/2018**.**

11. With this decision, the Commission allows OPG to proceed with Pickering NGS operation beyond 210,000 EFPH, up to 247,000 EFPH.

12. The Commission directs OPG to submit to the Commission a report on the detailed risk improvement plan for Pickering NGS. This report will be submitted two weeks before the Commission Meeting to be held in August 2014. The Commission also directs CNSC staff to present its review of the detailed risk improvement plan for Pickering NGS, as part of the annual *Integrated Safety Assessment of Canadian Nuclear Power Plants*, at the Commission Meeting to be held in August 2014. The detailed risk improvement plan shall encompass a combination of physical improvements, changes to operating procedures, and improvements to the PSAs, including but not limited to the improvements to plant design and improvements to the methodologies, as specified by CNSC staff and set out in the section 3.1 of the CMD 14-H2.C. The improvements will include additional Fukushima related actions as well as improvements identified through the PSA.

13. The Commission requests that the annual *2013 Integrated Safety Assessment of Canadian Nuclear Power Plants* include clear timelines for all aforementioned improvements and related activities. The Commission requests that these improvements be implemented as soon as possible.

14. The Commission requires increased monitoring, inspection and reporting by OPG and CNSC staff on the operation of the Pickering reactor units. The annual *Integrated Safety Assessment of Canadian Nuclear Power Plants* should include, every year, clear descriptions of measures implemented to enable the requested increased monitoring, inspection and reporting. The Commission further requests that this and future annual Integrated Safety Assessments and reports include updates to the Commission regarding enhancements of OPG's ageing management program, status of pressure tubes, feeder pipes and other safety issues, such as evolution of safety margins as the operation approaches the planned end of life of the facility.

15. The Commission expects annual reports to include the status of additional Fukushima related actions and improvements identified through the PSA, as well as clear timeline for the development and implementation of whole-site based safety goals and PSA methodology.

ISSUES AND COMMISSION FINDINGS

16. In making its decision, the Commission considered a number of issues and submissions relating to OPG's response to the Commission's requirements and criteria to be met before the removal of the hold point. The Commission also considered the adequacy of the proposed measures for protecting the environment, the health and safety of persons and the maintenance of national security and measures required to implement international obligations to which Canada has agreed.

17. The findings of the Commission will be presented in a *Record of Proceedings, including Reasons for Decision*, to be published at a later date.

M. Binder

Michael Binder
President,
Canadian Nuclear Safety Commission

JUN 0 3 2014

Date

HYDROELECTRIC INCENTIVE MECHANISM AND SURPLUS BASELOAD GENERATION

1.0 PURPOSE

This evidence describes OPG's proposed treatment of Surplus Baseload Generation ("SBG") during the test period and explains OPG's proposed Enhanced Hydroelectric Incentive Mechanism ("eHIM").

2.0 OVERVIEW

OPG's operation of the Sir Adam Beck Pump Generating Station ("PGS") under the Hydroelectric Incentive Mechanism ("HIM") reduces SBG spill to the maximum extent possible and provides a consumer benefit through reduced consumer costs. In order to address an unintended interaction between HIM and the SBG Variance Account, a modification to the HIM, or enhanced HIM ("eHIM"), is proposed. Compared to the alternatives considered, eHIM is the best choice and is proposed for both the existing regulated and the newly regulated hydroelectric facilities.

The evidence is organized as follows:

- Section 3.0 addresses the methodology for determining entries in the SBG Variance Account;
- Section 4.0 addresses the usage of the Pump Generating Station (PGS) during periods of SBG;
- Section 5.0 addresses the proposed enhanced incentive payment mechanism;
- Section 6.0 addresses the proposed payment mechanism for the test period;
- Attachment 1 presents a review of the proposed eHIM prepared by Cliff Hamal of Navigant Economics.

benefits of production above Ontario demand, that example the impact of potential surplus energy."

So I am wondering where, if at all, you have account for that impact.

I'm sorry, I might have misspoke myself. It was OPA has advised, yes.

MR. KEIZER: Sorry, I am trying to understand the question.

So you are asking whether OPG has accounted for it, even though it is OPA calculation?

MR. POCH: You have indicated OPA hasn't accounted for it. That, I think, is clear from your answer; correct? That's at the bottom of page 4 of 5 of this answer.

MS. SWAMI: That's correct.

MR. POCH: I am wondering if OPG has anywhere analyzed the impact of these life extensions at Pickering on surplus base load generation during the period it will operate.

MS. SWAMI: No. OPG did not consider that in its business case.

OPG relies on the OPA and others to plan the system, and we looked at the business case with respect to our generation.

MR. POCH: Okay. And did you -- excuse me one sec.

In answer to part (f), we were asking you about if you had done an analysis of overall system benefit; that was part of my earlier question.

And we were asking you specifically about the -- in your response, rather, you mention that OPA provided

From: Bashir Bhana
Sent: March-21-12 3:33 PM
To: Bob Gibbons; Andrew Pietrewicz; Victor Stein; Bonnie Chan; Steve Chui
Cc: Nancy Marconi; Wajiha Shoaib
Subject: Pickering Study - Review of OPG Results

Sorry for this long email. I've reviewed OPG's modelling results (provided in this morning's meeting) and have come to the conclusion that key differences between our two assessments are with respect to *export price* and *renewable curtailment* assumptions:

Export Prices

OPG prices exports at its value to the overall electricity market whereas the OPA prices exports at the Ontario marginal cost (consistent with current market rules). OPG said they will look into this.

Section 17 [redacted]

Renewable Curtailment

In our assessment, we observe a 9 TWh reduction in renewable production in the presence of continued operation

Section 17 [redacted]

Impact on Pickering Net Benefit

Accounting for the above differences and including the impact of Clarington TS, the net impact on OPG's assessment would be as follows:

Section 17 [redacted]

Section 17 [redacted]

Electricity resource costs to meet energy needs (baseload and intermediate resources)

Electricity Resource Costs to Meet Energy Needs (Baseload and Intermediate Resources)				
Fuel Type/ Technology	**Procurement**	**Historical Years**	**Average Annual Production (MWh)**	**Unit Cost Energy Production ($/MWh)**
Generation Resources				
Nuclear	Bruce Power Refurbishment Implementation Agreement	2009-2012	35,000,000	58
Hydroelectric	Renewable Energy Supply, Hydro Contract Initiative, Hydro Electric Supply Agreement	2009-2012	2,290,000	81
Wind	Renewable Energy Supply/FIT	2009-2012	3,364,000	90
Bioenergy	Renewable Energy Supply	2009-2012	53,000	84
Combined Heat and Power	Combined Heat and Power (various phases)	2009-2012	1,380,000	111
Combined Cycle Gas	Accelerated Clean Energy Supply Clean Energy Supply Early Movers CES	2009-2012	10,887,000	86

http://www.powerauthority.on.ca/about-us/electricity-pricing-ontario/opa-generation-and-conservation-resource-costs/resource-costs-meet-needs

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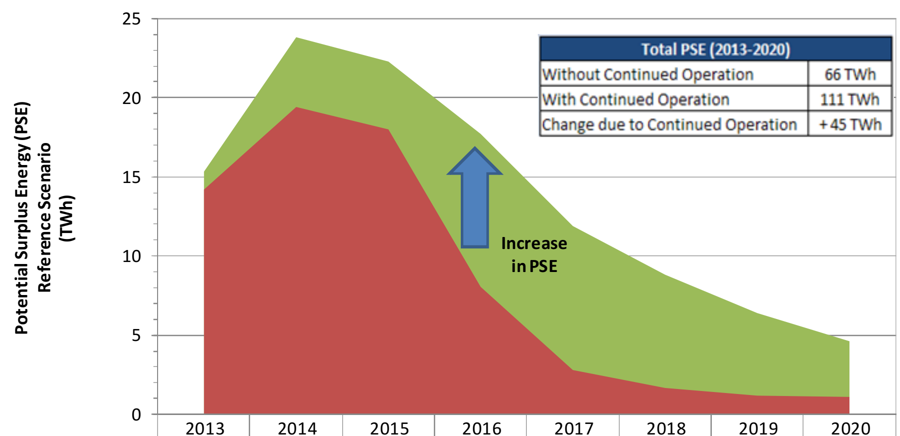
amounts due to even minor changes in actual production by specific generators like hydroelectric or nuclear facilities or due to changes in demand (due to, for example, weather).

Between 2013 and 2020, PSE exists in all years but is observed to increase by 45 TWh due to Pickering NGS continued operation. The increase in PSE is equivalent to 40% of the increase in Pickering NGS energy production during the period 2013 through 2020 (Table 2). This means that in the absence of Pickering NGS continued operation, 60% of the energy that would have been produced by Pickering NGS throughout the continued operation period would be replaced by renewable resources that would have otherwise been curtailed and by additional gas-fired generation (as seen in Figure 12). The remaining 40% would have been surplus to Ontario.

Figure 14: Potential Surplus Energy (Reference Scenario)



	2013	2014	2015	2016	2017	2018	2019	2020
With Pickering NGS Continued Operation	15.3	23.8	22.3	17.7	11.9	8.8	6.4	4.6
Without Pickering NGS Continued Operation	14.2	19.4	18.0	8.1	2.8	1.7	1.2	1.1
Increase in PSE with Pickering Continued Operation	1.1	4.4	4.3	9.7	9.1	7.2	5.2	3.5

Source: OPA

Table 2: Potential Surplus Energy (PSE) Production from Pickering

	2013	2014	2015	2016	2017	2018	2019	2020	Total
Change in PSE Relative to the Increase in Nuclear Energy Production Due to Pickering NGS Continued Operations	87%	93%	94%	58%	40%	32%	25%	20%	40%

Source: OPA

5.1.5 System Operating and Capital Costs

The availability of Pickering NGS affects the operating cost of Ontario's electricity system and associated capital investments.

In the reference scenario, the net system operating cost ("system variable costs"), which include variable operating costs and fuel costs, decrease by $2.51 billion (net present value) between 2013 and 2020 with Pickering NGS continued operation (Figure 15).

The savings in system variable costs consist of approximately $1.42 billion in reduced dispatch costs from Ontario resources (as production from Pickering NGS offsets production

Extract from OPA F.O.I. response pp. 1-4

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

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.

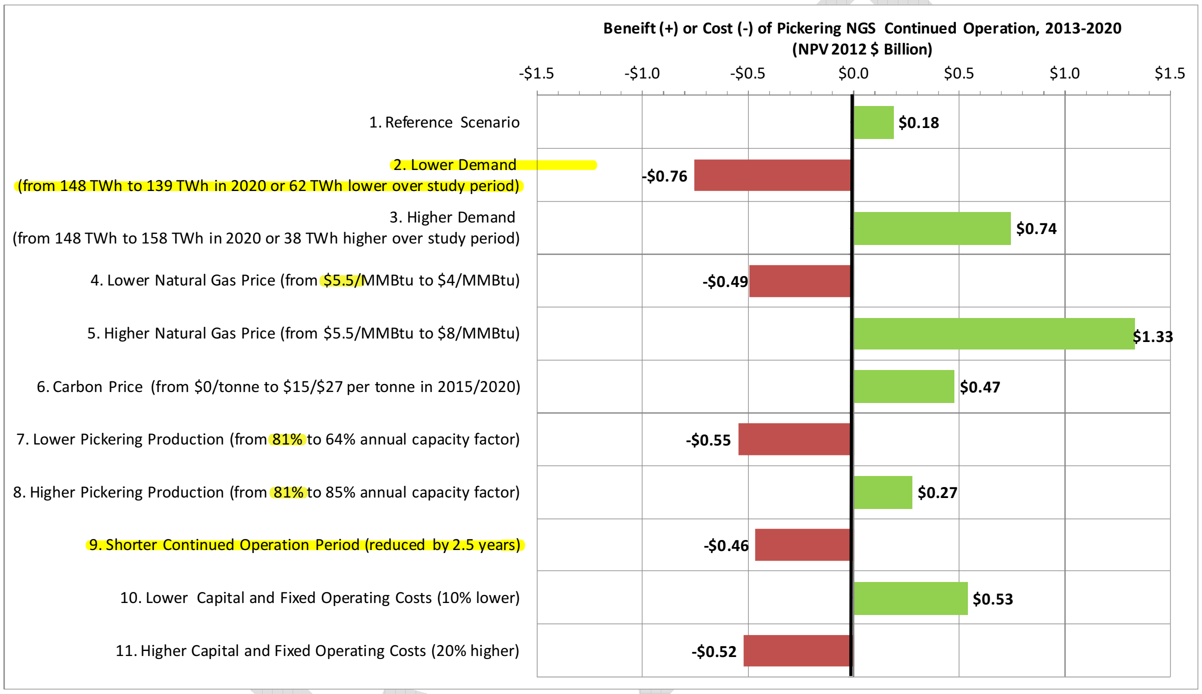
The OPA therefore considers it prudent, on balance, to spend funds in 2013 and 2014 for Pickering NGS continued operation should it prove to be technically feasible.

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 work. The remaining $105 million is associated with the operation of Pickering NGS during the 2013 to 2014 period.

The OPA has evaluated the effect of Pickering NGS continued operation on various factors including capacity and energy requirements, system costs, Ontario CO_2 emissions, and transmission impacts. The OPA's assessment assumes that resources directed by the Ontario government will proceed as planned.

Figure 1: Net System Benefit–Cost of Pickering Continued Operation for a Range of System Conditions 2013 – 2020



Source: OPA

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August 15, 2012

Mr. Pankaj Sardana
Vice President, Regulatory Affairs
Ontario Power Generation
700 University Avenue
Toronto, Ontario M5G 1X6

Dear Pankaj,

Re: Pickering NGS Continued Operation and Darlington NGS Refurbishment

The Ontario Power Authority supports Ontario Power Generation's proposals for expenditures in 2013 and 2014 to maintain the options of continued operation at Pickering NGS and refurbishment of Darlington NGS.

The Ontario Power Authority ("OPA") has evaluated the merit of these options and will continue to evaluate them as circumstances evolve.

Pickering NGS Continued Operation

In absence of continued operation, the six generating units (3,094 MW) that are currently in operation at Pickering NGS are expected to cease operation beginning around 2015. The feasibility of continued operation is expected to be confirmed by the end of 2012. If feasible, it would provide the option to continue to operate the units at Pickering NGS through to approximately 2020.

From 2013 to 2014, it will be necessary for OPG to incur up to $85 million at Pickering NGS to preserve 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 work.

OPG has provided the OPA with updated information regarding their proposal for the continued operation of Pickering NGS (Appendix 1). The OPA has evaluated the effects of Pickering NGS continued operation on various aspects of the integrated power system, including capacity and energy requirements, system costs, Ontario CO_2 emissions, and transmission implications.

The OPA's analysis to date identifies a number of potential merits to preserving the option of continued operation at Pickering NGS. These include:

- Reduced need for replacement capacity and energy during part of the nuclear refurbishment period. Without continued operation and if all currently directed resources proceed as planned, between nearly 1,000 MW and 3,000 MW of capacity replacement would be required between 2016 and 2020.

- An approximately 11 megatonne reduction in Ontario CO_2 emissions between 2015 and 2020.

- Potential for deferral of some investments in transmission enhancements needed to maintain reliable load supply to customers in the east GTA upon retirement of Pickering NGS. This is further described in OPA's evidence to Hydro One regarding the need and rationale for "Oshawa Area" TS (EB-2012-0031, Exhibit D1-3-3 Appendix B).

- A hedge against mid-term uncertainties that could result in additional replacement requirements.

The OPA's assessment illustrates that cost implications of Pickering continued operation could vary across a wide range of potential circumstances. Key factors in this context include electricity demand, price of natural gas; price of carbon; length of the continued operation period; magnitude of capital and fixed operating costs and quantity of production from Pickering NGS during the continued operation period.

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 predominantly 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 operation. Some of the factors outlined are out of OPG's control, while others, such as station operational performance and cost, are within OPG's control. Opportunities for enhancing value through further coordination of other nuclear plans with plans for continued operations at Pickering have not yet been considered in the OPA's assessment. The OPA expects to explore such opportunities over the coming year.

An additional consideration that was not quantitatively reflected in its cost assessment of Pickering continued operation, but which informs the OPA's perspective on the option is the hedge that Pickering continued operation could provide against mid-term uncertainties. Continued operations at Pickering would see approximately 3,000 MW of nuclear supply remain available during a period of significant transition in the Ontario power system. This mid-term period, roughly spanning the years 2015 to 2020, immediately follows the shutdown of coal-fired generation in Ontario and features the following:

- Multiple concurrent refurbishment outages and restarts among Ontario's nuclear stations (the plans for which remain in development in some instances)

- Potential unit retirements at several currently existing natural gas-fired generators

- Sizeable expected contributions from conservation programs over and above already significant levels of anticipated natural efficiency gains in the Ontario economy

- Expected implementation of a substantial number of supply resources that are presently contractually committed or directed, and

- Uncertainty related to the pace of economic recovery in the province.

In short, the mid-term period involves significant transition and many moving pieces, some of which remain to be resolved and each of which present some degree of risk. Continued operation at Pickering is seen by the OPA as a timely and potentially helpful source of insurance within this dynamic context.

Darlington NGS Refurbishment

The four-units at Darlington NGS (3,512 MW) entered service between 1990 and 1993. The Darlington design includes the need for major refurbishment at mid-life. Without refurbishment, Darlington NGS would cease production in 2020. With refurbishment, Darlington NGS would continue production until 2054 (Appendix 2).

OPG has been active on Darlington NGS refurbishment planning and development work since 2007. Total investment in capital and OM&A is expected to total approximately $370 M by the end of 2012. To date, there has been significant refinement in scope and OPG has expressed high confidence in project costs and project execution. The Darlington Refurbishment Project is now in the Definition Phase and OPG has proceeded with contracting and procurement of labour and materials.

The OPA's support for expenditures in 2013-2014 to preserve the option of Darlington refurbishment is based on strategic considerations supported by cost comparisons. Strategic considerations prevail given the long time-period under consideration (to 2054) and correspondingly high degree of uncertainty. The cost comparisons developed by the OPA are to be taken in the context of uncertainty, including with respect to the long-term supply and price of natural gas, value of carbon and cost of new nuclear - all three come with a wide range of uncertainty.

On balance, the preservation of approximately 3,500 MW and 28 TWh of nuclear supply on an existing site with access to services and transmission is seen to have merit in terms of shorter lead-time, community acceptance, impacts on the environment and cost. In consideration of the longer-term uncertainties, the OPA's probabilistic analysis suggests a high likelihood that refurbishing Darlington NGS would be less costly than other sources of supply, including new nuclear or new gas-fired facilities, for a wide range of potential future conditions.

In addition to the above considerations, the OPA estimates that the option would not add significantly to carbon emissions in the province. In comparison, an equivalent natural gas-fired alternative would increase CO_2emissions by an average of 10 megatonnes annually between 2024 and 2054. This would approximately triple the annual volume of CO2 emissions for Ontario that is otherwise projected for the long-term.

Further, the OPA views Darlington refurbishment as supportive of the diversity and performance of Ontario's long-term electricity supply mix. The rationale for a diverse supply mix relates to considerations of uncertainty, risk mitigation and security of supply. Recognition of nuclear energy in these and other regards is found in the OPA's Supply Mix Advice provided to the Ontario Government in December 2005, the Integrated Power System Plan submitted to the Ontario Energy Board in 2007 (EB-2007-0707), the Ontario Government's Long-Term Energy Plan issued in 2010 and, subsequently, in the 2011 Supply Mix Directive. Each of these identifies an important role for nuclear energy in Ontario's long-term supply mix. Refurbishment of Darlington, in addition to the merits outlined above, is consistent with this direction.

In closing, the OPA supports OPG's proposals for expenditures in 2013 and 2014 to maintain the options of continued operation at Pickering NGS and refurbishment of Darlington NGS. The OPA has evaluated the options and will continue to evaluate them as circumstances evolve. Please feel free to contact us should you require additional information.

Regards,

Amir Shalaby
Vice-President, Power System Planning
Ontario Power Authority

CC
Ethan Kohn
Joel Sheinfield
Colin Andersen
Michael Lyle
Andrew Pietrewicz

Appendix 1 - Information Received from OPG Regarding Pickering NGS Continued Operation

Incremental Generation in 2013 to 2020 Due to Continued Operation (TWh)								
Year	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Pickering A (TWh)	0.0	0.0	0.0	5.2	7.3	7.3	7.3	8.2
Pickering B (TWh)	1.3	4.7	4.6	11.4	15.3	14.7	13.0	9.1
Total	1.3	4.7	4.6	16.6	22.6	21.9	20.3	17.2

Incremental Costs in 2013 to 2020 Due to Continued Operation (2012 $ M) (1)								
Year	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Capital and OM&A For Plant Operation	$18	$52	$282	$764	$878	$889	$821	$575
Costs to Enable Continued Operation in 2013-2014	$38	$47	$0	$0	$0	$0	$0	$0
Fuel & Fuel Related Costs	$8	$28	$27	$94	$135	$114	$110	$93
Total Continued Operation Cost	$64	$126	$310	$858	$1,013	$1,003	$931	$668

(1) Total OM&A & Capital includes station OM&A (base, outage, projects) and sustaining capital projects and the station's share of incremental allocated nuclear and corporate support costs. These costs do not include the severance costs associated with each scenario.

Incremental Planned Outage Days in 2013 to 2020 Due to Continued Operation								
Year	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Pickering A Incremental Planned Outage Days	0	0	0	78	87	85	76	0
Pickering B Incremental Planned Outage Days	-114	-157	337	297	146	196	73	0

From: Bashir Bhana
Sent: April-24-12 4:51 PM
To: Andrew Pietrewicz
Cc: Bob Gibbons
Subject: Updated Demand/Pickering

Andrew – here is a quick comparison of the new demand forecast relative to the LTEP forecasts (used in the Pickering study).

The updated peak demand forecast is about the same as in the LTEP low growth forecast up to 2018 (~23,000 MW). Between 2019-2020, the updated peak demand forecast falls between the LTEP low and LTEP medium forecasts (23,400 MW).

The updated energy demand forecast is lower than the LTEP low growth forecast by an average 3 TWh per year beginning in 2015. The average updated energy demand forecast between 2013-2020 is 136 TWh/year. In comparison, the LTEP low and medium forecasts average 138 TWh/year and 146 TWh/year, respectively between 2013-2020.

Regarding the Pickering study, I would expect the new demand forecast to produce a net benefit similar to that in the low demand sensitivity case (net cost of $760M).

[redacted]

Section 18

From: Bashir Bhana
Sent: August-02-12 2:51 PM
To: Andrew Pietrewicz
Subject: Exports in Pickering Study

Looks like we gutted the section on "export profits" from the report. What we say with respect to export revenues is:

"Hourly exports occur due to economic opportunities that exist between Ontario and external electricity markets. The revenues associated with these transactions are based on the Hourly Ontario Electricity Price (HOEP). Export revenues decrease by $0.05 billion over the period as the average value of HOEP decreases due to the lower cost of supply resulting from Pickering NGS continued operation."

Here's what I had written in an older draft:

"In the absence of bilateral contracts between Ontario and external electricity markets, the full value of electricity exports is not received by Ontario ratepayers. The value or profit from Ontario electricity exports is currently captured by energy traders, including OPG. OPG as an energy trader may be able to return some of these proceeds to Ontario ratepayers by way of a reduction in the revenue they seek in rate applications before the Ontario Energy Board or to Ontario taxpayers by way of dividend payments to government and increased government tax revenues."

Bashir

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GEC Interrogatory #007

Ref:

Issue Number: 6.6
Issue: Are the test period expenditures related to continued operations for Pickering Units 5 to 8 appropriate?

Interrogatory

In the government's 2013 Long Term Energy Plan (LTEP), it states:

> *The Pickering Generating Station is expected to be in service until 2020. An earlier shutdown of the Pickering units may be possible depending on projected demand going forward, the progress of the fleet refurbishment program, and the timely completion of the Clarington Transformer Station. (LTEP 2013, p5)*

The OPA states in F2-2-3, Attachment 2 states that in absence of OPG's proposal to continue operating the Pickering nuclear station the six operating reactors "are currently expected to operate around 2015." The OPA also provides its updated 2012 assessment of the prudency of Pickering's continued operation. It states:

> "*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 contrast, the OPA's 2010 analysis provided to the OEB (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."*

In 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)."*

a) Please provide the low, mid and high demand forecast, including the implied baseload demand, in terawatt hours until 2020 used to calculate OPG's 2012 assessment of the net present value of the Pickering continued operation.

b) Please describe how OPG estimated implied baseload demand in its forecast?

c) Please provide the low, mid and high demand forecast, including the implied baseload demand, in terawatt hours until 2020 to calculate the OPA's 2012 assessment of the net present value of Pickering continued operation.

d) Please describe how the OPA estimated implied baseload demand in its forecast?

e) Please provide the demand forecast used in the government's 2013 Long Term Energy Plan, including the implied baseload demand, in terawatt hours until 2020?

f) Please discuss define "overall system benefit"? What value have these analyses placed on the impact of Pickering operations on SBG and export prices?

g) What work is being delayed or could be delayed until such time as a decision by government has been made in accord with the recent LTEP policy recognizing the possibility of earlier Pickering shutdowns?

Response

a) Please see Chart 1 (below) for OPG's low, mid and high demand forecast.

Chart 1

Ontario Demand Forecast (TWh) Underlying OPG's Pickering Continued Ops Evaluation Provided in Ex. F2-2-3, Attachment 1

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base	141.9	142.2	142.6	143.0	144.0	144.2	145.6	147.2	148.4
Low	141.2	140.8	140.4	140.1	140.4	139.8	140.5	141.2	141.7
High	143.4	145.1	147.0	149.0	151.6	153.4	156.5	159.8	162.9

The term "implied baseload demand" is not used in OPG's materials on Pickering Continued Operations, therefore OPG cannot respond to this part of the request.

b) Please see answer to part a).

c) The Ontario Power Authority ("OPA") has provided Table 1 (below) with the annual Ontario electricity demand projections used in its 2012 assessment of Pickering Continued Operations for the years 2014 - 2020. The projections have been reduced to take into account conservation and are expressed in Terawatt hours. Please refer to the response to part d) for OPA information on "implied baseload demand".

Table 1
2012 OPA Assessment of Pickering Continued Operations: Annual Forecast Demand, Net of Conservation (TWh)

Annual Energy (TWh)	OPA 2012 Assessment Medium Demand Forecast	OPA 2012 Assessment Low Demand Forecast	OPA 2012 Assessment High Demand Forecast
2014	145.0	138.6	147.0
2015	146.0	138.0	148.5
2016	146.3	138.4	150.4
2017	145.9	138.0	151.0
2018	146.5	138.0	153.0
2019	147.3	138.5	154.5
2020	148.9	138.9	158.1

d) Source: OPA

d) The OPA has advised OPG that it employed production simulation modeling — in which supply and demand for each hour of each year within the study period is considered — for the purpose of its 2012 assessment of Pickering Continued Operations. The OPA further advised that it did not estimate baseload demand, as it did not require this for the purposes of the assessment.

e) The OPA has advised OPG that Table 2 provides the annual Ontario electricity demand projections reflected in the Government's 2013 Long-Term Energy Plan ("LTEP") for the years 2014 - 2020. The projections are net of conservation and are expressed in Terawatt-hours. This information is publicly available on the OPA's website at http://www.powerauthority.on.ca/power-planning/long-term-energy-plan-2013 in Module 3: Generation and Conservation Tabulations and the Supply/Demand Balance.

Table 2
2013 LTEP: Annual Forecast Demand, Net of Conservation (TWh)

Year	2013 LTEP Annual Demand Forecast (TWh)
2014	140.8
2015	140.2
2016	140.4
2017	139.6
2018	139.9
2019	141.1
2020	141.5

Source: OPA

Furthermore, the OPA has advised OPG that Table 3 provides the annual energy, expressed in Terawatt-hours, associated with the minimum demand levels for the LTEP forecast for the years 2014 - 2020. The OPA cautions that, while minimum hourly load can be a useful indicator for some purposes, it is not determinative in planning for baseload requirements. That is because, among other things, relatively few hours separate the single lowest demand hour in all hours in the year from hours with considerably higher demand levels. By way of example, an average of 102 and 577 hours (or approximately 1.2% and 6.6% of the hours in a year respectively) separate the lowest annual demand hour from hours with 1,000 MW and 2,000 MW higher demand.

Table 3
2013 LTEP: Annual Energy Associated with Minimum Demand Level, Net of Conservation (TWh)

Year	2013 LTEP: Annual Energy Associated with Minimum Demand (TWh)
2014	91.6
2015	91.8
2016	92.9
2017	93.0
2018	93.4
2019	94.4
2020	94.6

Source: OPA

f) The term “overall system benefit” is not used in OPG’s materials on Pickering Continued Operations. However, the term “system benefit” is normally used to refer to reduced system costs, which normally translate into reduced customer costs. However, as pointed out in the OPA’s letter (Ex. F2-2-3, Attachment 2); system benefits can also include reductions in CO_2 emissions, deferral of some investments, and a hedge against mid-term uncertainties.

g) The OPA has advised OPG that their reference to “overall system benefit” includes both quantitative and qualitative aspects. Quantitative aspects include Ontario electricity system variable costs, capital and fixed operating costs and the deferral of decommissioning and severance costs. Where Pickering Continued Operations results in greater savings than costs in these areas, there is a net system benefit. Qualitative factors considered relate to uncertainty/risk and environmental performance, and were not monetized in the OPA’s assessment.

The OPA has advised that it did not estimate the costs or benefits of production above Ontario demand (e.g., the impact of potential surplus energy)

Exports and export revenues were also estimated by the OPA. Export revenues were assessed against import costs – the net import and export cost/benefit was included in the OPA's assessment of overall net cost/benefit of Pickering continued operation.

h) OPG's plan is to operate the Pickering station until 2020. OPG has not delayed and has no plans to delay work on the Pickering units, based on an indicative statement in the LTEP. Delaying work could have a negative effect on the reliability and safety of the station. The OPA has informed OPG that Pickering GS should not be expected to be removed from service before the in-service date of Clarington TS. Please see response to IR L-06-6-8 GEC-006.

GEC Interrogatory #005

Ref: Ex. D2-1-3

Issue Number: 6.6
Issue: Are the test period expenditures related to continued operations for Pickering Units 5 to 8 appropriate?

Interrogatory

Re: Pickering Continued Operations

The LTEP notes that "an earlier shutdown of the Pickering units may be possible depending on projected demand, the progress of the fleet refurbishment program, and the timely completion of the Clarington Transformer Station". Please provide any information that OPG has about the timing of the Clarington Transformer Station completion, and the dates when uncertainties in that regard are expected to be reduced.

Response

The construction of Clarington Transformer Station is a Hydro One Networks Inc. ("Hydro One") project; OPG has no specific project information on either the completion of the project or uncertainties associated with the project.

Information obtained from the IESO web site indicates Clarington Transformer Station is expected to be in service in the fall of 2017[1].

[1] 18 Month Outlook from the IESO http://www.ieso.ca/Documents/marketReports/18MonthOutlook_2014feb.pdf. Page **V** of the Executive Summary indicates Clarington TS is expected in service in the fall of 2017.

Costs & Generation Impacts (2012- 2014)	LTD 2009-11	2012 Proj	2013	2014	2015 - 2020	2013-2014 Tot	Overall Total
OM&A ($M)	55.1	42.8	37.2	47.9	N/A	85.1	183.0
Fuel Channel Life Mgmt Proj. (OM&A) ($M)(1)	8.8	6.2	1.7	0.9	0.2	2.6	17.8
Total Costs ($M)	**63.9**	**49.0**	**38.9**	**48.8**	**0.2**	**87.7**	**200.7**
Generation Impact (Planned Outage Days)	119	53	64	40	N/A	104	276
Generation Impact (TWh)	-1.5	-0.7	-0.8	-0.5	N/A	-1.3	3.5

Note 1: This is the Pickering station's share of the Fuel Channel Life Management Project's costs

This assessment also includes the assumption that Pickering Unit 7 will be life-managed in order to match its life to that of Pickering Unit 8 in both the No Continued Operations Case and in the Continued Operations case, thereby allowing Units 1 and 4 to operate until the projected end-of-life of Pickering Unit 8.

Risks to being able to achieve Continued Operations fall into the following 3 main categories:

1. Technical/Fitness-for-service Risks: i.e. risk that a major component does not continue to meet fitness-for-service requirements (e.g. being unable to demonstrate that the pressure tubes continue to be fit-for-service based on established technical criteria).

   In order to manage the technical risks around the pressure tubes life, management launched the Fuel Channel Life Management Project (FCLM) in 2009 and has made good progress on addressing any technical issues which are required to be resolved. Compared to early 2010 when the FCLM project was in its early stages, management now has medium confidence with an improving trend that achievement of 247,000 EFPH will be possible.

2. Regulatory: i.e. risk that the proposed disposition is not accepted by the CNSC or that there is a change to regulatory limits resulting in OPG being unable to demonstrate continued compliance.

   In order to manage the regulatory risks, and as part of the FCLM project, management has consulted with the CNSC to get agreement on the techniques and process for demonstrating the fitness-for-service of the pressure tubes. A protocol agreement has been established with the CNSC which identifies the 18 deliverables to be completed to demonstrate that pressure tubes will be fit for service up to at least 247,000 EFPH. Management believes that the regulatory risk is reduced compared to the 2009 assessment and issues will be manageable.

3. Economic: e.g. risk that a previously unknown issue is discovered leading to expensive repair costs and early shutdown of the units.

   In order to manage the economic risks, OPG has implemented a program of increased inspections and continues to monitor operating experience from other units and industry reports. Specific to Pickering Units 5-8, OPG has included additional maintenance work in the Continued Operations plan to reduce the likelihood of technical issues developing. Also, a phased approach to the release of funds is being taken. In addition, during the assessment of the business case for the refurbishment of Pickering B, a comprehensive plant condition assessment was completed. With the exception of the fuel channel issues mentioned above, there were no technical issues identified that would preclude operation to 247,000 EFPH. The risk of a discovery issue resulting in the non-achievement of Continued Operations is low and is reduced relative to the previous assessment in 2009.

Comparison of 2010 OPG Nuclear Performance to Industry Benchmarks

		2010 Actuals				
Metric	**NPI Max**	**Best Quartile**	**Median**	**Pickering A**	**Pickering B**	**Darlington**
Safety						
All Injury Rate (#/200k hours worked)		0.88	N/A[1]	0.77	0.60	0.74
Rolling Average Industrial Safety Accident Rate (#/200k hours worked)	0.20	0.05	0.10	0.14 ⇧	0.07	0.09
Rolling Average Collective Radiation Exposure (Person-rem per unit)	80.00	68.64	96.73	138.30 ⇩	93.00	71.55
Airborne Tritium Emissions (Curies) per Unit[2]		2,041	3,784	3,790 ⇧	1,953	969
Fuel Reliability (microcuries per gram)	0.000500	0.000001	0.000036	0.003460 ⇩	0.000205	0.000241
2-Year Reactor Trip Rate (# per 7,000 hours)	0.50	0.06	0.22	0.77	0.24	0.12
3-Year Auxiliary Feedwater System Unavailability (#)	0.0200	0.0000	0.0006	0.0003	0.0000	0.0000
3-Year Emergency AC Power Unavailability (#)	0.0250	0.0008	0.0077	0.0088	0.0125	0.0067
3-Year High Pressure Safety Injection Unavailability (#)	0.0200	0.0000	0.0005	0.0010	0.0000	0.0001
Reliability						
WANO NPI (Index)		86.7	77.4	47.7 ⇩	72.6	94.1
Rolling Average Forced Loss Rate (%)	1.00	1.40	3.35	22.52	5.06	1.84
Rolling Average Unit Capability Factor (%)	92.0	91.7	83.7	63.3	80.2	89.4
Rolling Average Chemistry Performance Indicator (Index)	1.01	1.00	1.02	1.24 ⇩	1.09 ⇧	1.03 ⇩
1-Year Online Elective Maintenance (work orders per unit)[3]		213	261	333 ⇧	544	281
1-Year Online Corrective Maintenance (work orders per unit)[3]		2	4	14	29	9
Value for Money						
3-Year Total Generating Costs per MWh ($ per Net MWh)		32.54	38.53	90.21	54.79	33.55
3-Year Non-Fuel Operating Costs per MWh ($ per Net MWh)		19.00	23.13	75.51	48.49	27.09
3-Year Fuel Costs per MWh ($ per Net MWh)		5.92	6.37	3.70	3.70	3.71
3-Year Capital Costs per MW DER (k$ per MW)		46.30	62.80	62.80	17.41	21.28
Human Performance						
18-Month Human Performance Error Rate (# per 10k ISAR hours)		0.00700	0.01000	0.01150	0.00920	0.00700

Notes
1. No median benchmark available.
2. 2008 data is used for non-OPG CANDU plants because 2010 data is unavailable at the time of benchmarking.
3. Last backlog benchmark in 2010 was as of June 1, 2010.

Green = maximum NPI points achieved or best quartile performance

White = 2nd quartile performance

Yellow = 3rd quartile performance

Red = worst quartile performance

⇩ Declining Benchmark Quartile Performance vs. 2009

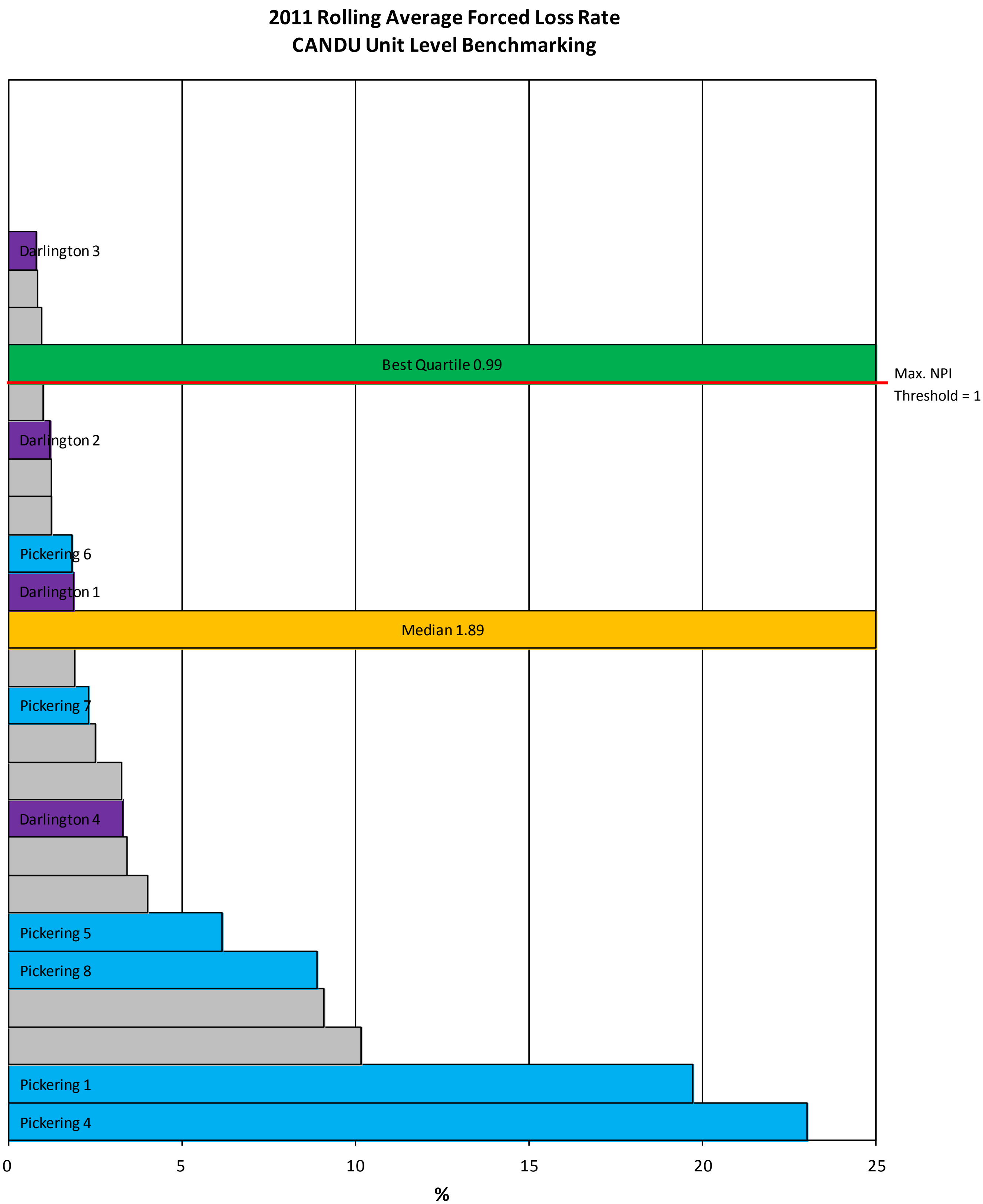
⇧ Improving Benchmark Quartile Performance vs. 2009

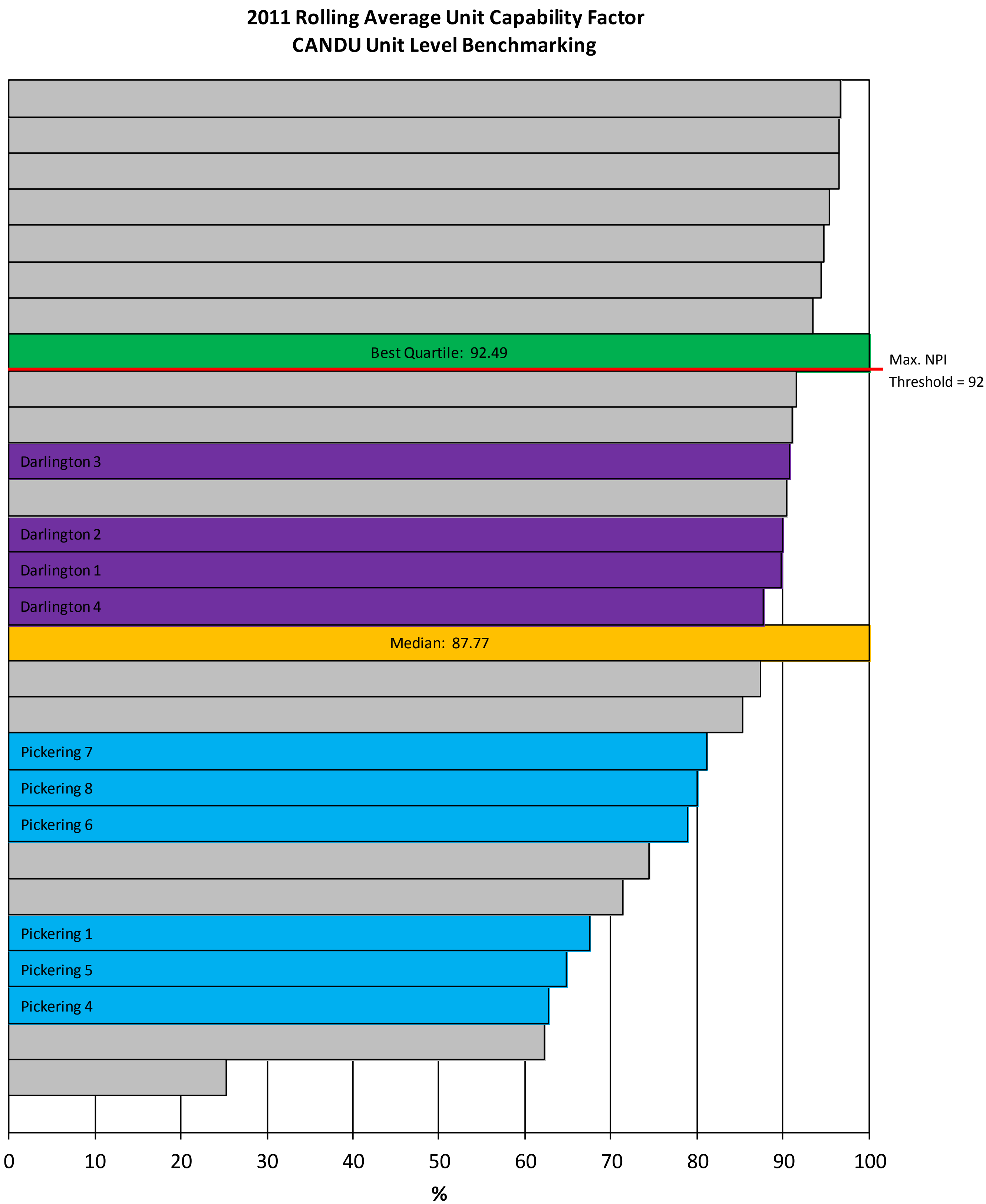
2012 Benchmarking Report Metrics For Pickering A and B

(2011 Actuals)

Metric	Pickering A	Pickering B
Safety		
Rolling Average Collective Radiation Exposure (Person-rem per unit)	136.49	96.86
Airborne Tritium Emissions (Curies) per Unit[1]	3,790	1,953
Fuel Reliability (microcuries per gram)	0.000290	0.000118
2-Year Reactor Trip Rate (# per 7,000 hours)	1.04	0.38
3-Year Auxiliary Feedwater System Unavailability (#)	0.0061	0.0036
3-Year Emergency AC Power Unavailability (#)	0.0152	0.0084
3-Year High Pressure Safety Injection Unavailability (#)	0.0004	0.0000
Reliability		
WANO NPI (Index)	52.8	72.7
Rolling Average Forced Loss Rate (%)	21.39	4.81
Rolling Average Unit Capability Factor (%)	65.1	76.2
Rolling Average Chemistry Performance Indicator (Index)	1.17	1.06

1. 2010 Data is used because 2011 results were unavailable at the time of benchmarking


2011 Rolling Average Forced Loss Rate
CANDU Unit Level Benchmarking
Darlington 3
Best Quartile 0.99
Max. NPI
Threshold = 1
Darlington 2
Pickering 6
Darlington 1
Median 1.89
Pickering 7
Darlington 4
Pickering 5
Pickering 8
Pickering 1
Pickering 4
0
5
10
15
20
25
%


2011 Rolling Average Unit Capability Factor
CANDU Unit Level Benchmarking
Best Quartile: 92.49
Max. NPI
Threshold = 92
Darlington 3
Darlington 2
Darlington 1
Darlington 4
Median: 87.77
Pickering 7
Pickering 8
Pickering 6
Pickering 1
Pickering 5
Pickering 4
0
10
20
30
40
50
60
70
80
90
100
%

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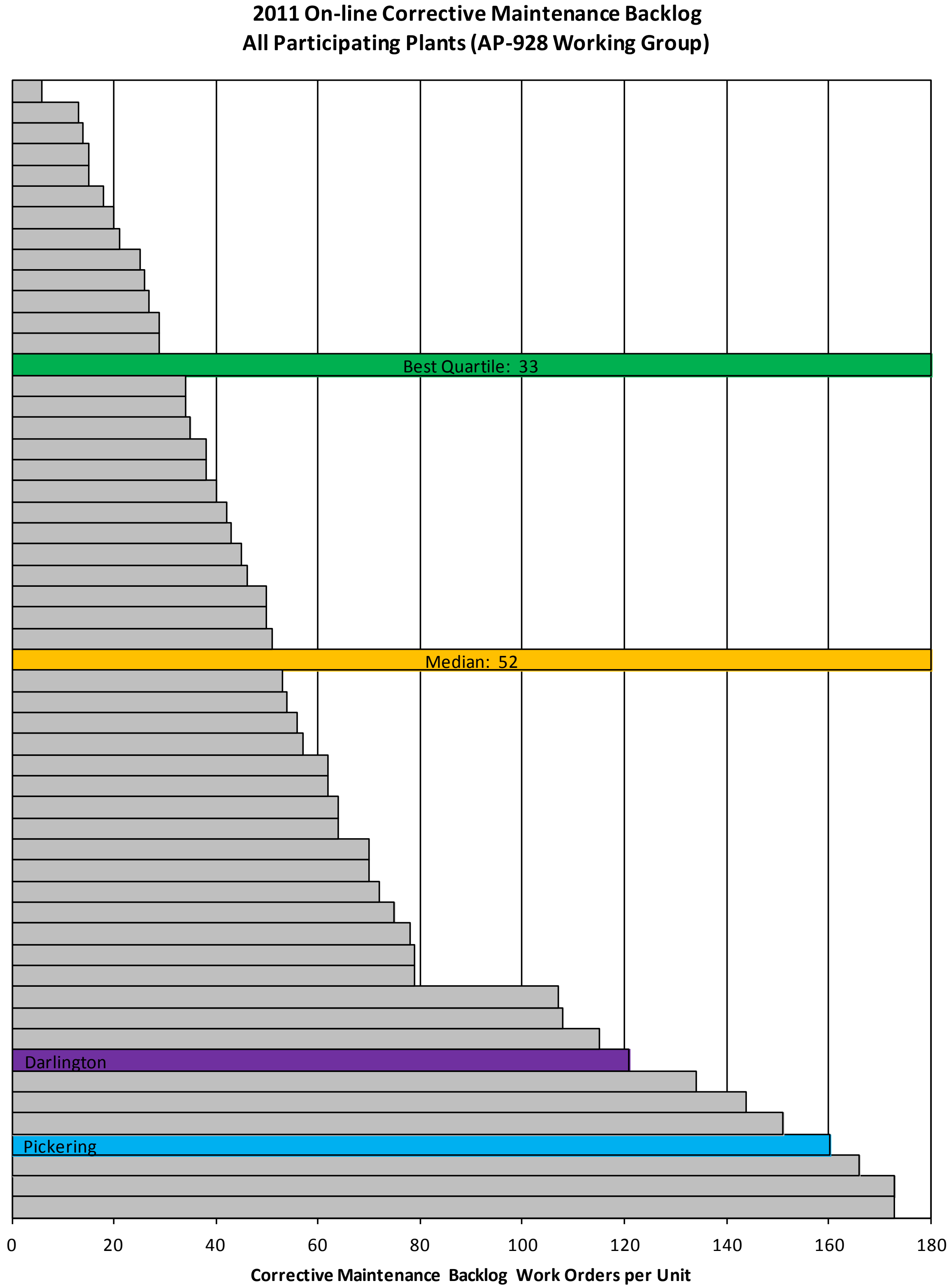
EB-2013-0321
Ex. F2-1-1
Attachment 1

1-Year On-line Corrective Maintenance Backlog



GEC Interrogatory #008

Ref:

Issue Number: 6.6
Issue: Are the test period expenditures related to continued operations for Pickering Units 5 to 8 appropriate?

Interrogatory

At F2-2-3 p. 2 OPG notes that there are significant technical and economic challenges to operating Pickering units 1-4 without two of units 5-8 in operation. Please explain the reasons for that observation.

Response

There are significant physical system interconnections between Pickering Units 1 and 4 and Pickering Units 5-8, many of which are important to the safe operation of the Pickering Units 1 and 4. OPG has completed a feasibility assessment of operating Pickering Units 1 and 4 following the shutdown of the Pickering Units 5-8. The assessment concluded that Pickering Units 1 and 4 cannot continue to operate without significant and costly modifications after the Pickering Units 5-8 shutdown.

The key issue that would be very costly to resolve is to demonstrate acceptable reliability and diversity of power supplies to key safety systems, given that the critical electrical systems would no longer be available for this purpose. Solutions to this loss of electrical reliability and diversity have been reviewed, but they represented significant cost (at least $100M) and a high degree of technical and regulatory uncertainty.

There are other technical issues (approximately 25 issues have been identified) that would need to be addressed, also at significant cost (at least $100M). These included:

- Isolation of Pickering B units from the Pressure Relief Duct
- Provision for other Pickering Unit 5-8 electrical supplies to critical Pickering Unit 1 and 4 loads
- Provision for Pickering Unit 1 and 4 reliance on in-service Pickering Units 5-8 water systems
- Installation of alternate supplies/controls for key safety systems available from Pickering Units 5-8
- Provision for station standby heating, which is supplied by Pickering Units 5-8

Numbers may not add due to rounding.

Filed: 2013-09-27
EB-2013-0321
Exhibit E2
Tab 1
Schedule 2
Table 1

Table 1
Comparison of Production Forecast - Nuclear

Line No.	Prescribed Facility	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Board Approved	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Darlington NGS									
1	**TWh**	27.8	(1.3)	26.5	2.4	28.9	0.0	29.0	(0.6)	28.3
2	**Unit Capability Factor (%)**	90.3	(2.7)	87.6	7.6	93.9	1.3	95.2	(2.0)	93.2
3	**PO Days**	118.8	4.2	123.0	(62.7)	68.3	(8.0)	60.3	3.4	63.7
4	**FEPO Days**	0.0	13.9	13.9	(13.9)	0.0	0.0	0.0	0.0	0.0
5	**FLR (%)**	1.7	1.5	3.2	(2.6)	1.5	(0.9)	0.6	1.7	2.3
6	**FLR Days Equivalent**	22.5	20.2	42.7	(34.5)	20.9	(12.7)	8.2	24.1	32.3
	Pickering NGS									
7	**TWh**	20.4	(1.1)	19.2	0.4	22.0	(2.3)	19.7	1.0	20.7
8	**Unit Capability Factor (%)**	75.3	(3.6)	71.7	1.7	81.5	(8.1)	73.4	4.4	77.8
9	**PO Days**	436.0	(16.7)	419.3	(124.3)	304.0	(9.0)	295.0	57.3	352.3
10	**FEPO Days**	0.0	21.5	21.5	49.2	0.0	70.7	70.7	(44.5)	26.2
11	**FLR (%)**	6.0	3.3	9.3	2.3	5.4	6.2	11.6	(4.6)	7.0
12	**FLR Days Equivalent**	105.3	55.9	161.2	49.2	101.1	109.3	210.4	(81.5)	128.9
	Totals									
13	**Unit Capability Factor (%)**	83.3	(3.1)	80.2	4.9	88.1	(3.0)	85.1	(0.6)	84.5
14	**PO Days**	554.8	(12.5)	542.3	(187.0)	372.3	(17.0)	355.3	60.7	416.0
15	**FEPO Days**	0.0	35.4	35.4	35.3	0.0	70.7	70.7	(44.5)	26.2
16	**FLR (%)**	3.5	2.4	5.9	(0.6)	3.2	2.1	5.3	(1.0)	4.4
17	**FLR Days Equivalent**	127.8	76.1	203.9	14.7	122.0	96.6	218.6	(57.4)	161.2
18	**TWh**	48.2	(2.4)	45.8	2.8	50.9	(2.3)	48.6	0.4	49.0
19	**Forecast for Major Unforeseen Events**	2.0	(2.0)	0.0	0.0	0.5	(0.5)	0.0	0.0	0.0
20	**Total TWh**	46.2	(0.4)	45.8	2.8	50.4	(1.8)	48.6	0.4	49.0

Line No.	Prescribed Facility	2012 Board Approved	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Darlington NGS									
21	**TWh**	29.0	(0.7)	28.3	(1.4)	26.9	1.5	28.4	(2.3)	26.1
22	**Unit Capability Factor (%)**	94.1	(0.9)	93.2	(4.4)	88.8	4.7	93.5	(7.2)	86.3
23	**PO Days**	65.5	(1.8)	63.7	80.7	144.4	(67.3)	77.1	110.9	188.0
24	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	**FLR (%)**	1.5	0.8	2.3	(0.8)	1.5	(0.3)	1.3	(0.3)	1.0
26	**FLR Days Equivalent**	21.0	11.3	32.3	(12.6)	19.7	(5.1)	14.6	(1.9)	12.7
	Pickering NGS									
27	**TWh**	23.0	(2.3)	20.7	0.4	21.1	0.2	21.3	0.6	21.9
28	**Unit Capability Factor (%)**	84.9	(7.1)	77.8	1.4	79.2	0.7	79.9	2.2	82.1
29	**PO Days**	247.0	105.3	352.3	(48.8)	303.5	(10.6)	292.9	(5.0)	287.9
30	**FEPO Days**	0.0	26.2	26.2	(26.2)	0.0	0.0	0.0	0.0	0.0
31	**FLR (%)**	4.3	2.7	7.0	1.1	8.1	(0.3)	7.8	(2.3)	5.5
32	**FLR Days Equivalent**	84.6	44.3	128.9	23.5	152.4	(5.4)	147.0	(42.5)	104.5
	Totals									
33	**Unit Capability Factor (%)**	89.8	(5.3)	84.5	(0.2)	84.3	3.3	87.6	(3.6)	84.0
34	**PO Days**	312.5	103.5	416.0	31.9	447.9	(77.9)	370.0	105.9	475.9
35	**FEPO Days**	0.0	26.2	26.2	(26.2)	0.0	0.0	0.0	0.0	0.0
36	**FLR (%)**	2.8	1.6	4.4	0.1	4.5	(0.4)	4.1	(1.0)	3.1
37	**FLR Days Equivalent**	105.6	55.6	161.2	10.9	172.1	(10.5)	161.6	(44.4)	117.2
38	**TWh**	52.0	(3.0)	49.0	(1.0)	48.0	1.7	49.7	(1.7)	48.0
39	**Forecast for Major Unforeseen Events**	0.5	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	**Total TWh**	51.5	(2.5)	49.0	(1.0)	48.0	1.7	49.7	(1.7)	48.0

7. Perform simulations to give insight into the operation of the proposed resource mix using the OPA's energy production simulation software. Simulations consider intra- and inter-jurisdictional electricity transactions for each hour of each year between 2013 and 2020.

Each case is based on reference scenario conditions as described in Section 4.0 and modified as required for each sensitivity scenario as described in Section 4.3. Economic advantages or disadvantages of continued operation of Pickering NGS were identified by comparing the net present value of costs of the "with continued operation" case for the period 2013 to 2020 to the net present value of costs of the "without continued operation" case for the same period. The net present value of costs consisted of the following cost components:

- Generation operating costs;
- Capital investments in electricity resources; and
- Import costs and export revenues.

In practice, there could be opportunity for deferring or avoiding other supply investments that would otherwise have been made in absence of continued operation. It is assumed the capacity and energy supplied by Pickering NGS during the continued operation period would be replaced by alternative sources of supply *as needed to meet system requirements.*

A number of options were considered to meet additional short-term capacity and energy needs that may arise in the absence of Pickering NGS continued operation:

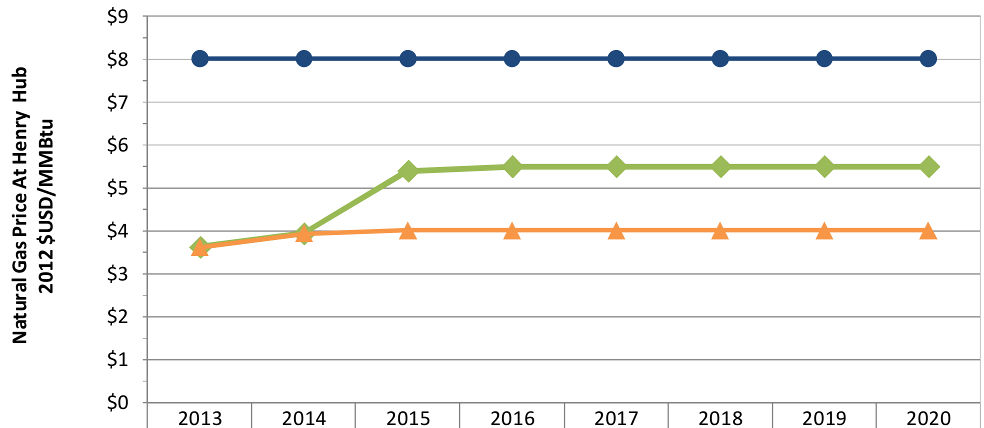
- Gas-fired Generation – May consist of new simple-cycle gas turbines or equivalent coal units converted to gas for capacity and existing combined-cycle gas turbines for energy. The lead time required is shorter than other alternatives and capital costs are lower. Operating costs are higher and CO_2 emissions are increased as compared to a case with continued operations.
- Additional Conservation and Demand Response – This alternative would require a large amount of energy savings to offset the reduction in energy production from Pickering NGS. The additional effort to achieve this, beyond the current aggressive conservation targets, was considered to be an unrealistic planning assumption.
- Firm Imports – An option that would require a significant amount of firm inter-tie capacity to be purchased and is expected to be priced similar to gas-fired generation capacity.

Based on the above considerations, gas-fired generation ("unspecified gas-fired generation") was assumed to be a feasible alternative for meeting additional short-term capacity and energy needs.

4.0 ASSUMPTIONS

In formulating each case, it is necessary to make assumptions with respect to the continued operation of Pickering NGS and with respect to future system demand and supply. The study period is from 2013 to 2020, as preparation for continued operation occurs during the

Figure 9: Forecast Natural Gas Price at Henry Hub



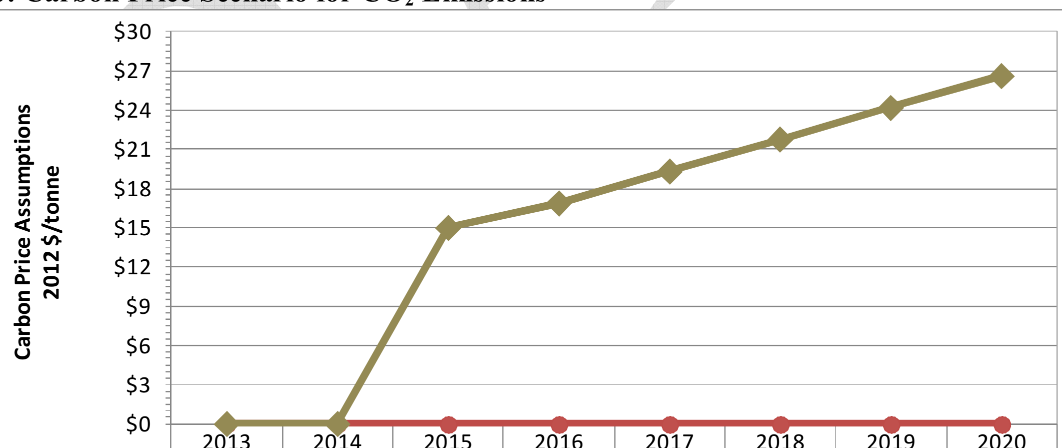
	2013	2014	2015	2016	2017	2018	2019	2020
Reference Scenario	$3.61	$3.93	$5.39	$5.50	$5.50	$5.50	$5.50	$5.50
Lower Natural Gas Price Scenario	$3.61	$3.93	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00
Higher Natural Gas Price Scenario	$8.00	$8.00	$8.00	$8.00	$8.00	$8.00	$8.00	$8.00

Source: Sproule, OPA

4.2.6 Price of CO_2 Emissions

Projections of future carbon prices vary widely.[8] Figure 10 shows the carbon price scenario assumed in the reference scenario and sensitivity scenario. The reference scenario assumes a carbon price of $0/tonne between 2013 and 2020 which is consistent with the LTEP.

Figure 10: Carbon Price Scenario for CO_2 Emissions



	2013	2014	2015	2016	2017	2018	2019	2020
Reference Scenario	$0	$0	$0	$0	$0	$0	$0	$0
Carbon Price Scenario	$0	$0	$15	$17	$19	$22	$24	$27

Source: OPA

[8] For example, see "Canada's Energy Future Reference Case and Scenarios to 2030" (NEB, 2007); "Design Recommendations for the WCI Regional Cap-and-Trade Program" (WCI, 2008); "Pricing Carbon: Saving Green" A Carbon Price to Lower Emissions, Taxes and Barriers to Green Technology" (David Suzuki Foundation, 2008); "Achieving 2050: A Carbon Pricing Policy for Canada" (NRTEE, 2009); "Climate Leadership, Economic Prosperity: Final Report on an Economic Study of Greenhouse Gas Targets and Policies for Canada" (Pembina Institute and David Suzuki Foundation, 2009).

Source: U.S. Energy Information Administration

Chart Tools

no analysis applied

Henry Hub Natural Gas Spot Price (Dollars per Million Btu)

Week Of	Mon	Tue	Wed	Thu	Fri
2013 Dec-30 to Jan- 3	4.41	4.31		4.32	4.39
2014 Jan- 6 to Jan-10	4.50	4.58	4.36	4.15	3.95
2014 Jan-13 to Jan-17	4.19	4.36	4.45	4.55	4.39
2014 Jan-20 to Jan-24		4.61	4.92	5.64	5.17
2014 Jan-27 to Jan-31	5.66	5.25	5.23	5.27	5.04
2014 Feb- 3 to Feb- 7	5.04	5.78	8.12	6.90	5.92
2014 Feb-10 to Feb-14	8.15	7.75	5.96	5.34	5.54
2014 Feb-17 to Feb-21		5.80	6.00	5.96	6.24
2014 Feb-24 to Feb-28	6.08	5.21	4.81	4.61	4.80
2014 Mar- 3 to Mar- 7	7.09	7.98	6.46	4.89	4.78
2014 Mar-10 to Mar-14	4.67	4.67	4.72	4.41	4.40
2014 Mar-17 to Mar-21	4.57	4.42	4.43	4.39	4.33
2014 Mar-24 to Mar-28	4.42	4.53	4.44	4.39	4.50
2014 Mar-31 to Apr- 4	4.48	4.39	4.39	4.51	4.49
2014 Apr- 7 to Apr-11	4.58	4.57	4.67	4.67	4.67
2014 Apr-14 to Apr-18	4.64	4.69	4.64	4.64	
2014 Apr-21 to Apr-25	4.76	4.76	4.81	4.81	4.83
2014 Apr-28 to May- 2	4.72	4.78	4.79	4.79	4.73
2014 May- 5 to May- 9	4.73	4.80	4.82	4.77	4.59
2014 May-12 to May-16	4.52	4.47	4.47	4.42	4.42
2014 May-19 to May-23	4.54	4.53	4.57	4.57	4.40
2014 May-26 to May-30		4.40	4.56	4.63	4.49
2014 Jun- 2 to Jun- 6	4.49	4.62	4.62	4.66	4.66
2014 Jun- 9 to Jun-13	4.67				

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Release Date: 6/11/2014
Next Release Date: 6/18/2014

Natural Gas (Henry Hub) Physical Futures Quotes

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Month	Options	Charts	Last	Change	Prior Settle	Open	High	Low	Volume	Hi / Low Limit	Updated
JUL 2014	OPT		**4.747**	-0.015	4.762	4.754	4.793	4.716	73,697	6.262 / 3.262	11:09:28 CT 13 Jun 2014
AUG 2014	OPT		**4.761**	-0.002	4.763	4.753	4.794	4.725	41,748	6.263 / 3.263	11:09:28 CT 13 Jun 2014
SEP 2014	OPT		**4.743**	0.000	4.743	4.747	4.776	4.708	17,646	6.243 / 3.243	11:09:08 CT 13 Jun 2014
OCT 2014	OPT		**4.736**	0.000	4.736	4.728	4.767	4.710	17,328	6.236 / 3.236	11:09:16 CT 13 Jun 2014
NOV 2014	OPT		**4.767**	-0.003	4.770	4.796	4.799	4.740	9,084	6.270 / 3.270	11:09:08 CT 13 Jun 2014
DEC 2014	OPT		**4.841**	+0.005	4.836	4.850	4.862	4.812	3,477	6.336 / 3.336	11:09:08 CT 13 Jun 2014
JAN 2015	OPT		**4.895**	+0.004	4.891	4.895	4.917	4.869	7,290	6.391 / 3.391	11:09:28 CT 13 Jun 2014
FEB 2015	OPT		**4.850**	+0.003	4.847	4.860	4.867	4.833	2,032	6.347 / 3.347	11:05:40 CT 13 Jun 2014
MAR 2015	OPT		**4.738 b**	-0.003	4.741	4.746	4.767	4.724	4,063	6.241 / 3.241	11:07:00 CT 13 Jun 2014

APR 2016	OPT		**4.180**	+0.008	4.172	4.180	4.180	4.180	1	5.672 / 2.672	10:21:19 CT 13 Jun 2014
MAY 2016	OPT		-	-	4.183	-	-	-	0	5.683 / 2.683	09:05:52 CT 13 Jun 2014
JUN 2016	OPT		**4.230**	+0.017	4.213	4.230	4.230	4.230	21	5.713 / 2.713	09:55:13 CT 13 Jun 2014
JUL 2016	OPT		**4.250 b**	+0.010	4.240	4.245	4.250 b	4.245	1	5.740 / 2.740	09:05:52 CT 13 Jun 2014
AUG 2016	OPT		-	-	4.248	-	-	-	0	5.748 / 2.748	09:05:52 CT 13 Jun 2014
SEP 2016	OPT		-	-	4.241	-	-	-	0	5.741 / 2.741	09:05:52 CT 13 Jun 2014
OCT 2016	OPT		-	-	4.264	-	-	-	0	5.764 / 2.764	09:05:52 CT 13 Jun 2014
NOV 2016	OPT		-	-	4.340	-	-	-	0	5.840 / 2.840	09:05:52 CT 13 Jun 2014
DEC 2016	OPT		-	-	4.510	-	-	-	0	6.010 / 3.010	09:05:52 CT 13 Jun 2014
JAN 2017	OPT		-	-	4.663	-	-	-	0	6.163 / 3.163	09:05:52 CT 13 Jun 2014
FEB 2017	OPT		**4.645**	+0.002	4.643	4.645	4.645	4.645	1	6.143 / 3.143	10:37:28 CT 13 Jun 2014
MAR 2017	OPT		-	-	4.583	-	-	-	0	6.083 / 3.083	09:05:52 CT 13 Jun 2014
APR 2017	OPT		-	-	4.313	-	-	-	0	5.813 / 2.813	09:05:52 CT 13 Jun 2014
MAY 2017	OPT		-	-	4.325	-	-	-	0	5.825 / 2.825	09:05:52 CT 13 Jun 2014
JUN 2017	OPT		-	-	4.355	-	-	-	0	5.855 / 2.855	09:05:52 CT 13 Jun 2014
JUL 2017	OPT		-	-	4.390	-	-	-	0	5.890 / 2.890	09:05:52 CT 13 Jun 2014
AUG 2017	OPT		-	-	4.404	-	-	-	0	5.904 / 2.904	09:05:52 CT 13 Jun 2014

SEP 2017	OPT		-	-	4.398	-	-	-	0	5.898 / 2.898	09:05:52 CT 13 Jun 2014
OCT 2017	OPT		-	-	4.422	-	-	-	0	5.922 / 2.922	09:05:52 CT 13 Jun 2014
NOV 2017	OPT		-	-	4.504	-	-	-	0	6.004 / 3.004	09:05:52 CT 13 Jun 2014
DEC 2017	OPT		-	-	4.682	-	-	-	0	6.182 / 3.182	09:05:52 CT 13 Jun 2014
JAN 2018	OPT		-	-	4.822	-	-	-	0	6.322 / 3.322	09:05:52 CT 13 Jun 2014
FEB 2018	OPT		-	-	4.801	-	-	-	0	6.301 / 3.301	09:05:52 CT 13 Jun 2014
MAR 2018	OPT		-	-	4.739	-	-	-	0	6.239 / 3.239	09:05:52 CT 13 Jun 2014
APR 2018	OPT		-	-	4.469	-	-	-	0	5.969 / 2.969	09:05:52 CT 13 Jun 2014
MAY 2018	OPT		**4.495**	+0.013	4.482	4.495	4.495	4.495	1	5.982 / 2.982	09:05:52 CT 13 Jun 2014
JUN 2018	OPT		-	-	4.504	-	-	-	0	6.004 / 3.004	09:05:52 CT 13 Jun 2014
JUL 2018	OPT		-	-	4.532	-	-	-	0	6.032 / 3.032	09:05:52 CT 13 Jun 2014
AUG 2018	OPT		-	-	4.549	-	-	-	0	6.049 / 3.049	09:05:52 CT 13 Jun 2014
SEP 2018	OPT		-	-	4.554	-	-	-	0	6.054 / 3.054	09:05:52 CT 13 Jun 2014
OCT 2018	OPT		-	-	4.581	-	-	-	0	6.081 / 3.081	09:05:52 CT 13 Jun 2014
NOV 2018	OPT		-	-	4.675	-	-	-	0	6.175 / 3.175	09:05:52 CT 13 Jun 2014
DEC 2018	OPT		-	-	4.854	-	-	-	0	6.354 / 3.354	09:05:52 CT 13 Jun 2014

JAN 2019	OPT		-	-	4.978	-	-	-	0	6.478 / 3.478	09:05:52 CT 13 Jun 2014
FEB 2019	OPT		-	-	4.956	-	-	-	0	6.456 / 3.456	09:05:52 CT 13 Jun 2014
MAR 2019	OPT		-	-	4.893	-	-	-	0	6.393 / 3.393	09:05:52 CT 13 Jun 2014
APR 2019	OPT		-	-	4.613	-	-	-	0	6.113 / 3.113	09:05:52 CT 13 Jun 2014
MAY 2019	OPT		-	-	4.627	-	-	-	0	6.127 / 3.127	09:05:52 CT 13 Jun 2014
JUN 2019	OPT		-	-	4.649	-	-	-	0	6.149 / 3.149	09:05:52 CT 13 Jun 2014
JUL 2019	OPT		-	-	4.677	-	-	-	0	6.177 / 3.177	09:05:52 CT 13 Jun 2014
AUG 2019	OPT		-	-	4.700	-	-	-	0	6.200 / 3.200	09:05:52 CT 13 Jun 2014
SEP 2019	OPT		-	-	4.706	-	-	-	0	6.206 / 3.206	09:05:52 CT 13 Jun 2014
OCT 2019	OPT		-	-	4.740	-	-	-	0	6.240 / 3.240	09:05:52 CT 13 Jun 2014
NOV 2019	OPT		-	-	4.840	-	-	-	0	6.340 / 3.340	09:05:52 CT 13 Jun 2014
DEC 2019	OPT		-	-	5.032	-	-	-	0	6.532 / 3.532	09:05:52 CT 13 Jun 2014
JAN 2020	OPT		-	-	5.143	-	-	-	0	6.643 / 3.643	09:05:52 CT 13 Jun 2014

FEB 2020	OPT		-	-	5.121	-	-	-	0	6.621 / 3.621	09:05:52 CT 13 Jun 2014
MAR 2020	OPT		-	-	5.058	-	-	-	0	6.558 / 3.558	09:05:52 CT 13 Jun 2014
APR 2020	OPT		-	-	4.778	-	-	-	0	6.278 / 3.278	09:05:53 CT 13 Jun 2014
MAY 2020	OPT		-	-	4.804	-	-	-	0	6.304 / 3.304	09:05:53 CT 13 Jun 2014
JUN 2020	OPT		-	-	4.834	-	-	-	0	6.334 / 3.334	09:05:53 CT 13 Jun 2014
JUL 2020	OPT		-	-	4.876	-	-	-	0	6.376 / 3.376	09:05:53 CT 13 Jun 2014
AUG 2020	OPT		-	-	4.908	-	-	-	0	6.408 / 3.408	09:05:53 CT 13 Jun 2014
SEP 2020	OPT		-	-	4.915	-	-	-	0	6.415 / 3.415	09:05:53 CT 13 Jun 2014
OCT 2020	OPT		-	-	4.951	-	-	-	0	6.451 / 3.451	09:05:53 CT 13 Jun 2014
NOV 2020	OPT		-	-	5.040	-	-	-	0	6.540 / 3.540	09:05:53 CT 13 Jun 2014
DEC 2020	OPT		-	-	5.229	-	-	-	0	6.729 / 3.729	09:05:53 CT 13 Jun 2014