AMPCO Interrogatory #002

Ref: Ex. B1-T1-S1, Table 1 and Table 2

Issue Number: 2.2
Issue: Is OPG's proposal to include CWIP in rate base for the Darlington Refurbishment Project appropriate?

Interrogatory

With respect to projects closed to rate base in each year 2008 through 2012:

a) Please identify those projects where the actual or forecast final cost is greater than the budget originally approved by the OPG Board of Directors.

b) For each, please indicate OPG's view of how the provisions of O.Reg. 53/05 apply.

Response

a) The OPG Board of Directors ("OPG Board") approves all projects with a total project cost greater than $25M. There are no projects closing to rate base in 2008 through 2012 where the actual or forecast final cost is greater than the original OPG Board-approved project cost.

b) Not applicable.

AMPCO Interrogatory #003

Ref: Ex. B3-T5-S, Table 1

Issue Number: 2.1
Issue: What is the appropriate amount for rate base?

Interrogatory

a) With respect to OPG's nuclear fuel inventory over the period 2007 through 2012, please indicate the average cost of uranium in each year.

b) With respect to OPG's nuclear fuel inventory for 2008 through 2010, please indicate the amount included in rates and the amount approved by the Board.

c) Please provide any benchmarking data OPG has with respect to the level of nuclear materials and supplies included in working capital.

Response

a) Please see Table 1 below.

Table 1

Year	Closing Balance – Fuel Inventory (Ex. B3-T5-S1) ($M)	Average Cost of Uranium Concentrate in Closing Year Inventory (Cdn$/lb U)
2007	233.0	49.6
2008	300.7	59.4
2009	333.0	66.7
2010	381.7	76.0
2011	377.9	82.2
2012	343.8	77.4

b) In its Decision and Payment Amounts Order in EB-2007-0905, the OEB accepted and approved OPG's proposed nuclear working capital forecast of $705.4M for 2008 and $771.8M for 2009, which included nuclear fuel inventory of $281.1M and $330.1M for 2008 and 2009, respectively. The nuclear fuel inventory amounts included in the working capital that underpin the current payment amounts are found in Table 8-1 on page 133 of the Decision. The payment amounts established in EB-2007-0905 continue into 2010.

c) OPG has recently obtained a ScottMadden report ("2007 Utility Materials Management Benchmarks – Nuclear Generation") which indicates a median benchmark value for nuclear inventory of $32.8k per MW.

AMPCO Interrogatory #007

Ref: Ex. D1-T1-S1

Issue Number: 4.2
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

Interrogatory

OPG reports at page 5 that a section of tunnel liner failed after the renegotiation with Strabag was completed. Please indicate the cost, cost responsibility, and schedule implications of this failure.

Response

The cost of the failed initial lining remedial work is approximately $2M and is part of the actual tunnel construction cost paid by OPG. Although the remedial work delayed the tunnel boring machine mining by seven weeks, the contractor's current forecast indicates that tunnel construction will be completed by the negotiated target completion date.

AMPCO Interrogatory #008

Ref: Ex. D1-T1-S2

Issue Number: 4.2
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

Interrogatory

a) Throughout the evidence with respect to the tunnel project, OPG identifies the original in-service as June 2010. On September 14, 2005 OPG issued a press release identifying the in-service date as "late 2009". Please comment on this difference.

b) In EB-2007-0905 Exhibit D1/1/1, OPG's evidence was that the non-tunnel Beck expenditures were primarily focused on the rehabilitation of generators G7, G9, and G10 at the SAB 1, with planned in-service dates of 2008, 2009, and 2010 respectively. G7 was completed in June 2009. G9 is forecast to be completed at the end of 2010 according to D1/1/2 Attachment 1 Tab 4 p. 7 and is described in D1/1/2 p. 10 as "on schedule". G10 is now scheduled to be in-service in December 2014. Please discuss the factors that are causing across-the-board schedule slippage.

Response

a) The difference is schedule contingency included in the originally approved Business Case Summary ("BCS") for risks retained by OPG as discussed on page 7 of the original Niagara Tunnel project BCS (EB-2007-0905, Ex. D1-T1-S2, Attachment A).

b) The G7, G9 and G10 upgrade program was originally planned such that the units would be available in time to take advantage of the additional water supply associated with the Niagara Tunnel project. As described in Ex. D1-T1-S1, page 6, this schedule was revised for the G7 frequency conversion because the time required to complete the necessary work exceeded the estimated outage duration. Lessons learned from this first unit rehabilitation have been applied in the planning for the subsequent rehabilitation projects. Also, given the revised tunnel in-service date, it was decided that unnecessarily compressing the unit upgrade schedules with additional engineering resources, additional construction crews as well as overlapping unit outages was not preferable from a cost or resourcing perspective.

AMPCO Interrogatory #010

Ref:

Issue Number: 4.3
Issue: Are the proposed in-service additions for regulated hydroelectric projects appropriate?

Interrogatory

Please provide the Post Implementation Review report for the SAB 1 G7 project.

Response

The Post Implementation Review ("PIR") for the Sir Adam Beck I Generating Station G7 Frequency Conversion project has not yet been performed. PIRs are typically completed six months to one year after a project is completed. The Niagara Plant Group is targeting completion of the PIR by the end of 2010.

AMPCO Interrogatory #012

Ref: Ex. D2-T1-S2, Table 1a, 2a and 2b

Issue Number: 4.5
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

Interrogatory

Please produce a revision of Table 1a to include the originally approved final in-service date. Please produce a revision of Tables 2a and 2b to include the originally approved final in-service date and cost, where different from the figures shown.

Response

The modified Tables 1a, 2a and 2b are presented as Attachment 1.

In preparing this response, OPG discovered transcription errors in the supporting tables, specifically:

- Ex. D2-T1-S2, Table 1a, line 14, “Final In-service Date”’ should be Aug-10.
- Ex. D2-T1-S2, Table 1a, line 19, “Total Project Cost” should be $15M.
- Ex. D2-T1-S2, Table 2a, line 4, “Final In-service Date” should be Dec-12. “Total Project Cost”’ should be $6.9M and “In-Service 2012” should be $1.5M.

These corrections have been incorporated into the modified tables.

Numbers may not add due to rounding.

Table 1a - Modified for Ex. L-2-12
Capital Project Listing - Nuclear Operations Facility Projects
Projects >$10M Total Project Cost[1]

Line No.	Facility	Project Name	Project Number	Category	Start Date	Original In-Service Date	Final In-Service Date	Total Project Cost (M$) (Note 2)	Partial/Devmt Release ($M)	Initial Full Release ($M)	Superceding Full Release ($M) (Note 3)
	(a)	(b)	(c)	(d)	(e)	**(New)**	(f)	(g)	(h)	(i)	(j)
		ONGOING PROJECTS FROM EB-2007-0905									
1	DN	DLC Modifications – Simulator Based Training	28453	Sustaining	Sep-06	May-09	Mar-10	11.8		11.8	
2	DN	Fuel Handling Power Track Improvement	31438	Sustaining	Sep-06	Mar-10	Mar-10	17.4	14.3		
3	DN	Improve Maintenance Facilities at Darlington	31717	Sustaining	Jan-02	Dec-11	Dec-11	57.7	6.9		
4	DN	New Change Room Facility	31718	Sustaining	Jul-07	Sep-09	Jun-10	23.8		23.8	
5	DN	Chiller Replacement to Reduce CFC Emissions	33631	Regulatory	Jan-04	Dec-11	Dec-11	14.9	10.4		
6	DN	FH Computer Replacement	33815	Sustaining	Aug-05	Oct-06	Feb-12	12.5		12.5	
7	DN	Shutdown System Computer Aging Management	33955	Sustaining	Nov-06	Nov-13	Nov-13	17.2	1.8		
8	DN	DN SG Controls Replacement	33973	Sustaining	Dec-06	Apr-13	May-12	17.9	1.5		
9	DN	DN DCC Replacement / Refurbishment / Upgrades	33977	Sustaining	Sep-03	Dec-10	Dec-10	82.2	22.1		
10	PA	Reactor Structures-Calandria Vault Inspection	46537	Sustaining	Aug-06	Feb-08	Apr-10	26.4		23.9	**26.4**
11	PA	PA Unit 2/3 D2O Storage Tanks	46576	Sustaining	Dec-06	Mar-08	Mar-10	16.3		11.2	**16.3**
12	PA	New Redundant Calandria Vault Dryer	49252	Sustaining	Sep-05	Jun-08	Mar-10	11.0		7.2	**11.0**
13	PA	Switchyard Relay Building Cable Replacement	49266	Value Enhancing	Dec-06	Jun-10	Jun-10	15.8		15.8	
14	PA	P2/P3 Isolation Project	Various	Sustaining	Aug-05	Aug-10	*Aug-10*	38.5		38.5	
15	PB	Emergency Power Generator Control Upgrade	49110	Sustaining	Mar-06	Jan-10	Jan-10	12.3	9.5		
16	PB	Chemistry Standards (CH-002) at PB	79147	Sustaining	Jan-01	Sep-03	Mar-10	18.4		17.4	18.4
17	NPT	Physical Barrier System	25609	Regulatory	Nov-05	Sep-09	Jun-10	49.4		49.4	
18	NPT	Security Hardening Project	25901	Regulatory	Nov-05	Nov-11	Dec-11	14.4	5.5		
19	NPT	Controlled Area Improvements	25902	Regulatory	Nov-05	Nov-13	Nov-13	*15.0*	2.0		
20	NPT	Security Monitoring Room	25905	Regulatory	Nov-05	Dec-08	Nov-10	20.4		20.4	
21	NPT	Security Doors Upgrade	25908	Regulatory	Aug-06	Nov-10	Nov-10	15.0	9.0		
22		**Subtotal**						508.4			
		COMPLETED/DEFERRED FROM EB-2007-0905									
23	DN	Second Darlington Full Scope Simulator	28452	Sustaining	Sep-06	Jul-09	Nov-09	16.2		16.2	
24	DN	Main Control Room HVAC	33293	Sustaining	May-01	Mar-05	Jan-09	11.9		6.0	11.9
25	DN	Used Fuel Dry Storage In Station Modifications	33925	Sustaining	Jan-01	Mar-08	Jan-09	44.6		47.8	
26	DN	DND Feeder Replacement ALARA/Optimization	34008	Value Enhancing	Jan-06	Jun-08	Nov-09	14.0		11.7	**14.0**
27	DN	Fire Protection Upgrade Program Phase 3	79148	Regulatory	Aug-01	Dec-05	Dec-08	29.7		23.5	**29.7**
28	PB	CFC Replacement (Freon Removal)	40543	Regulatory	Oct-03	Aug-09	Dec-09	19.5		22.4	
29	PB	Auxilliary Power System for PB	49104	Regulatory	May-04	Sep-07	Dec-09	107.2		116.7	
30	PB	Standby Generator Governor Upgrade	49109	Sustaining	Oct-05	Apr-08	Aug-08	22.3		23.3	
31	PB	Fire Protection Phase 2	79016	Regulatory	Oct-97	Oct-02	Jul-08	19.0		18.7	19.1
32	ENG	Additional Feeder Cut and Weld Tooling	62567	Sustaining	Jun-07	Dec-08	Dec-08	10.7		15.8	
33	NPT	Security Optimization (Capital)	62558	Regulatory	Jan-02	Jan-08	Nov-09	172.3		174.7	
34	DN	D2O Storage Facility	31555	Sustaining	Nov-06	N/A	Deferred	36.4	3.6		
35	DN	Auxiliary Heating System	34000	Regulatory	Mar-06	N/A	Deferred	23.5	2.2		
36	PA	PA Site - D2O Storage Facility	49251	Sustaining	Nov-06	Jul-10	Deferred	17.4	2.5		
37		**Subtotal**						544.6			
		PROJECTS NOT IN EB-2007-0905									
38	DN	Vacuum Building Outage Recurring Alterations	34012	Sustaining	Jan-09	Dec-09	Dec-09	11.4		11.4	
39	PA	Replacement of Standby Boilers	49267	Sustaining	Sep-06	N/A	Dec-12	17.0	1.6		
40	PA	PA ISTB Cabling Permanent Modification	49270	Regulatory	May-08	Dec-09	Jun-10	19.4		19.4	
41	ENG	Feeder Repair by Weld Overlay	62568	Sustaining	May-09	Jun-11	Jun-11	53.2		53.2	
42	IMS	Upper Feeder Cabinet Inspection Robot	66266	Sustaining	Jun-06	Aug-10	Aug-10	11.4	6.2		
43	NPT	Security Project F	25909	Regulatory	May-08	Nov-11	Oct-11	30.5	16.4		
44		**Subtotal**						142.8			
	Table continues on Ex. D2, Tab 1, Sch 2 Table 1b										

Notes:
1 Projects with expenditures during Test Period OR In-Service Amounts in Bridge or Test Period, AND Completed/Deferred Projects (from EB-2007-0905 or subsequent).
2 "Total Project Cost" reflects BCS amounts, with the exception of Completed/Deferred Projects (for which actual costs are shown).
3 Bold font indicates variance ≥ 10%, with explanation in Exhibit D2-T1-S2. Superceding Full Release is the new Total Project Cost.
4 Italicised entries reflect corrections as indicated in the Response to Ex. L-2-12 (lines 14 and 19).

Numbers may not add due to rounding.

Table 2a - Modified for Ex. L-2-12
Capital Project Listing - Nuclear Operations Facility Projects
Projects $5M - $10M Total Project Cost[1]

Line No.	Facility	Project Name	Category	Project Description	Start Date	Original In-Service Date	Final In-Service Date	Original Final Cost ($M)	Total Project Cost ($M) (Note 2)	In-Service 2010 ($M)	In-Service 2011 ($M)	In-Service 2012 ($M)
	(a)	(b)	(c)	(d)	(e)	(New)	(f)	(New)	(g)	(h)	(i)	(j)
		ONGOING PROJECTS FROM EB-2007-0905										
1	DN	Replacement of Obsolete Computer Components	Sustaining	Replace components of the digital control computers that are obsolete.	Jun-00	Nov-06	Aug-10	9.1	9.1	1.5	0.0	0.0
2	DN	Turbine Generator Vibration Monitor System Replacement	Sustaining	Upgrade the turbine generator vibration monitoring system. Current system has already reached end of life and uses obsolete hardware & software with no spares.	Mar-06	Dec-13	Dec-13	8.0	8.0	0.0	3.4	0.6
3	DN	Reactivity Mechanism Replacement Tooling	Sustaining	Develop tooling for the replacement of reactivity mechanisms.	Oct-01	Dec-05	Oct-10	8.0	8.0	0.8	0.0	0.0
4	PB	Radioactive Emission Reduction (EV-005)	Regulatory	Improve the Radioactive emissions monitoring and control performance per CNSC Operating License requirements	Mar-99	Dec-12	*Dec-12*	6.9	*6.9*	0.0	0.0	*1.5*
5	IMS	CIGAR Control System Replacement Obsolescence/Configuration Management (Channel Inspection, Gauging and Relocation System)	Sustaining	Upgrade the CIGAR control system by replacing obsolete PDP computer hardware, drive system hardware and software.	Feb-06	Dec-10	Dec-10	6.7	6.7	4.6	0.0	0.0
6		**Subtotal**							38.7	6.9	3.4	2.1
		COMPLETED PROJECTS FROM EB-2007-0905										
7	DN	Liquid Chlorination System Upgrade	Sustaining	Improve reliability of chlorination system to more effectively combat zebra mussel infestation.	Jun-00	Dec-08	Dec-09	7.5	8.7	0.0	0.0	0.0
8	PA	Pickering Admin Building Cafeteria Modifications	Sustaining	Refurbish Cafeteria to address health & safety concerns, improve functionality and upgrade systems to current requirements.	Aug-05	Dec-07	Apr-09	5.6	8.2	0.0	0.0	0.0
9	PB	Reactor Controller Upgrades	Sustaining	Improve reliability of reactor and safety system controllers, which have reached design life.	Apr-01	Dec-06	Dec-08	6.4	9.2	0.0	0.0	0.0
10	NPT	Pickering A Modular Buildings 1,2 & 3 Refurbishment	Sustaining	Carry out major renovation of the existing modular buildings to address issues relating to aged building structure and health & safety concerns arising from potential mold infestation.	Oct-07	Jun-08	Sep-09	6.3	5.1	0.1	0.0	0.0
11		**Subtotal**							31.2	0.1	0.0	0.0
	Table continues on Ex. D2, Tab 1, Sch 2 Table 2b											

Notes:
1 Projects with expenditures during Test Period OR In-Service Amounts in Bridge or Test Period, AND Completed/Deferred Projects (from EB-2007-0905 or subsequent).
2 "Total Project Cost" reflects BCS amounts, with the exception of Completed/Deferred Projects (for which actual costs are shown).
3 Italicised entries reflect corrections as indicated in the Response to Ex. L-2-12 (line 4).

Numbers may not add due to rounding.

Table 2b - Modified for Ex. L-2-12
Capital Project Listing - Nuclear Operations Facility Projects
Projects \$5M - \$10M Total Project Cost[1]

Line No.	Facility	Project Name	Category	Project Description	Start Date	Original In-Service Date	Final In-Service Date	Original Final Cost ($M)	Total Project Cost ($M) (Note 2)	In-Service 2010 ($M)	In-Service 2011 ($M)	In-Service 2012 ($M)
	(a)	(b)	(c)	(d)	(e)	**(New)**	(f)	**(New)**	(g)	(h)	(i)	(j)
		PROJECTS NOT IN EB-2007-0905										
12	DN	Main Generator/Hydrogen Slipring Cooling	Sustaining	Modify generator slipring cooling system to add humidification to prevent sparking.	Apr-00	Dec-04	Nov-09 (Completed)	5.1	5.1	0.0	0.0	0.0
13	DN	Fuel Handling Simulator Project	Sustaining	Develop and install a simulator to train operators on the fuel handling systems instead of on the actual equipment, thereby minimizing wear on equipment.	May-06	Dec-09	Dec-13	3.4	5.9	0.0	0.0	0.0
14	PA	Feeder Weld Area Thickness Measurement	Sustaining	Develop remote tooling to measure thickness of feeders in the area of welds for fitness-for-service determination.	Jun-06	Nov-07	Jan-09 (Completed)	0.5	8.3	0.0	0.0	0.0
15	PB	Calandria Tube Cutting Tool	Sustaining	Develop tooling to cut and remove calandria tubes.	Jan-08	Jul-08	May-09 (Completed)	6.3	5.9	0.0	0.0	0.0
16	PA	Channel Isolation and Draining Tool for Feeder Replacement	Sustaining	Develop tools to isolate and drain fuel channels without tying up the fuelling machines	Aug-08	Mar-10	Mar-10	5.9	5.9	5.3	0.0	0.0
17	IMS	ANDE/CIGAR Hybrid	Sustaining	Increase the speed of fuel channel inspections by integrating the ANDE (Advanced Non-Destructive Examination) probe with the CIGAR delivery system	Apr-09	Dec-11	Dec-11	6.5	6.5	0.0	5.7	0.0
18		**Subtotal**							37.6	5.3	5.7	0.0
19		**Total**								12.4	9.1	0.6
		DIVISION TOTALS										
20		**Darlington**								2.3	3.4	0.6
21		**Pickering A**								5.3	0.0	0.0
22		**Pickering B**								0.0	0.0	0.0
23		**Nuclear Support Divisions**								4.8	5.7	0.0
24		**Total**								12.4	9.1	0.6

Notes:
1 Projects with expenditures during Test Period OR In-Service Amounts in Bridge or Test Period, AND Completed/Deferred Projects (from EB-2007-0905 or subsequent).
2 "Total Project Cost" reflects BCS amounts, with the exception of Completed/Deferred Projects (for which actual costs are shown).

AMPCO Interrogatory #013

Ref: Ex. D2-T1-S2, Table 2a, line 8

Issue Number: 4.5
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

Interrogatory

Renovations to Pickering's administrative building cafeteria took almost 4 years from the time of project approval. Please comment on why such conventional commercial renovation requires such a protracted time period when implemented by OPG.

Response

OPG financial approval for projects occurs before project execution begins. This allows for better planning and execution. Typically a project is approved in the year before execution begins, making it appear that the duration of the project has increased by as much as a year. OPG's project management process also allows six months after the project being placed in-service for close-out of documentation and declaration of final In-service. The timeline for the referenced project was less than three years from start of work to in-service date. The BCS was approved in August 2005 with work starting in mid-2006.

Unlike a standard conventional commercial renovation, this work was carried out within the protected area of a nuclear power station. The schedule of the project was driven by the location. Constructing inside the protected area of a nuclear facility requires the design, procurement and installation to follow the nuclear engineering change process. This process is more rigorous than a standard commercial process. It needs to take into account the potential impact on safe operation through the engineering, procurement, planning, construction and commissioning phases of the project, and it needs to provide more detailed documentation supporting the modification. Building inside the protected area also requires that materials and staff entering the area follow the nuclear security requirements. These requirements did not allow the use of a standard Engineer-Procure-Construct contract that would be used for a conventional commercial facility located off-site.

AMPCO Interrogatory #014

Ref: Ex. D2-T1-S2, Attachment 1, Tab 4

Issue Number: 4.5
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

Interrogatory

The replacement of Darlington change rooms is scheduled to take almost three and a half years from the time of first approval for developmental funding. The cost of the project is in the order of $1,260/square foot. Please comment on why such conventional commercial construction requires such a protracted time period and significant cost when implemented by OPG.

Response

OPG approves projects months before the project execution begins. This allows for better planning and execution. The Darlington Generating Station change room project received its developmental release in July 2007 and was placed in-service March 2009, which is 21 months. The remainder of time was required for the demolition of an existing structure and the completion of documentation.

Unlike a standard conventional commercial renovation, this work was carried out within the protected area of a nuclear power station. The cost of the project was driven by the location. Constructing inside the protected area of a nuclear facility requires the design, procurement and installation to follow the nuclear engineering change process. This process is more rigorous than a standard commercial process: it needs to take into account the potential impact on safe operation through the engineering, procurement, planning, construction and commissioning phases of the project, and it needs to provide more detailed documentation supporting the modification. Building inside the protected area also requires that materials and staff entering the area follow the nuclear security requirements. These requirements did not allow the use of a standard Engineer-Procure-Construct contract that would be used for a conventional commercial facility located off site.

AMPCO Interrogatory #016

(NON-CONFIDENTIAL VERSION)

Ref: Ex. D2-T2-S1, Attachment 1

Issue Number: 4.5
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

Interrogatory

a) Regarding page 8, please indicate the total estimated costs for road, parking, vehicle garage, and related projects. Given the size and duration of the original Darlington construction effort, please comment on why existing road, parking, vehicle garage and related facilities are now inadequate. Please compare the peak site employment during construction with the peak site employment during refurbishment.

b) Regarding page 9, the "key risks" identified for the nuclear refurbishment project appear to relate only to risks associated with the timing of initiation of the refurbishment, and not with the undertaking and completion of the refurbishment. Is this a complete list of key risks? If not, please identify and describe any other key risks.

Response

a) The total estimated costs provided at Ex. D2-T2-S1, Attachment 1, page 8 (Darlington Refurbishment Preliminary Planning Release #3 Infrastructure) includes [redacted] for certain road and parking upgrades by 2013. There is an expectation that additional funding will be included in the overall Darlington Campus Plan for additional road and parking upgrades in future years.

   Existing parking spaces will continue to be occupied by staff in support of station operations, outages and station projects. New parking spaces will be required for staff in support of refurbishment. There is no vehicle garage on site except a garage for Transport & Work Equipment. Existing road and bridges are more than 20 years old requiring repairs and resurfacing.

   The peak site employment during construction of four units was about 7,700 as compared to a peak of 1,200 to 1,500 staff during refurbishment.

b) Ex. D2-T2-S1, Attachment 1, page 9 includes key risks relevant to the 2010 – 2014 business plan period only. The Darlington Refurbishment project team is developing a comprehensive risk register as part of the project risk management program. The risk register includes risks that apply to all phases of the project's life cycle, from the present Definition Phase though Execution Phase to Post-Refurbishment Operation. Please refer to the Risk Management and Contingency Plan in the Project Execution Plan (Ex. D2-T2-S1, Attachment 2, pages 27-29) for a description of the process for risk identification and analysis.

AMPCO Interrogatory #019

Ref: Ex. E1-T1-S1, page 5

Issue Number: 5.1
Issue: Is the proposed regulated hydroelectric production forecast appropriate?

Interrogatory

OPG observes that "[d]during 2009, SBG [surplus baseload generation] was more prevalent in Ontario than it has been for many years." Please quantify the SBG impact on OPG for 2008 and 2009, in both energy and financial terms.

Response

Surplus Baseload Generation ("SBG") was negligible in 2008. OPG estimates that in 2009, for the company as a whole, SBG-related production losses were 0.6 TWh. Of this number, OPG estimates that approximately 0.19 TWh is attributable to the regulated hydroelectric facilities.

OPG has no estimates available of the financial impact of SBG during 2009. Because SBG impacts both the regulated and unregulated facilities, and due to the variability of market prices and the dynamic nature of the electricity markets (i.e., many interdependent variables), such quantification would be difficult to perform.

AMPCO Interrogatory #020

Ref: Ex. E2-T1-S1

Issue Number: 5.2
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

What is the status of the Pickering A derate? Please provide a supporting explanation for the derate and measures to mitigate the derate.

Response

The Pickering A Generating Station derate ended in November 2009 and both units were returned to full power operation.

The derate commenced during 2007 due to the inability of OPG to obtain Canadian Nuclear Safety Commission ("CNSC") concurrence with OPG's enhanced Neutron Overpower ("NOP") methodology.

Pickering A Generating Station production was impacted by 0.25 TWh on an annualized basis, starting in 2007. To mitigate and eliminate the derate, the CNSC partially accepted the enhanced NOP methodology. The CNSC concurred with OPG's position that the currently installed NOP trip set points for all OPG reactors are set at appropriate levels and that safety is not in question. As noted above, the units were returned to full power operation in November 2009.

AMPCO Interrogatory #021

Ref: Ex. F1-T1-S1

Issue Number: 6.1
Issue: Is the test period Operations, Maintenance and Administration budget for the regulated hydroelectric facilities appropriate?

Interrogatory

a) How much station service power has been or will be paid by the regulated hydro-electric business each year since 2005 through to the end of the test period? Please include a breakout of GA costs.

b) Please provide an estimate of the impact of the AMPCO High 5 proposal as described in EB-2008-0272 if it were to apply during the test period.

c) How was the $1.2 million O&M reduction allocated to the regulated hydro-electric business allocated internally within the regulated business?

Response

a) At the prescribed hydroelectric stations, some electricity consumption is self-supplied (i.e., supplied directly from the generators), and some consumption is supplied from the Independent Electricity System Operator ("IESO") -controlled grid (i.e., grid withdrawals). As outlined in OPG's response to the interrogatory in Ex. L-1-088 part b), the IESO does not meter self-supplied consumption but the IESO does meter grid withdrawals. All station electricity consumption, self-supplied or grid withdrawals, is paid by OPG:

- Self-supplied consumption reduces the station electricity output into the IESO-controlled grid. Because this consumption is not metered by the IESO, it does not attract non-energy load charges and OPG does not explicitly track the value of this consumption.

- Grid withdrawals are metered by the IESO and they attract non-energy load charges.

Table 1 below outlines the value of grid withdrawals by calendar year from 2005 - 2009. The first column shows the value of grid withdrawals. The second column shows the total non-energy load charges while the third column shows the Global Adjustment component included in the total non-energy load charges.

Table 1
Prescribed Hydroelectric Grid Withdrawal Values: 2005 – 2009

Year	Value of withdrawals ($M)	Total Non-Energy Load Charges (Including Global Adjustment)[1] ($M)	Global Adjustment (Included In Total Non-Energy Load Charges) ($M)
2005	10.7	4.5	(3.0)[2]
2006	9.9	4.4	1.3
2007	9.8	3.4	1.3
2008	9.9	4.3	1.9
2009	10.9	12.7	9.6

In Table 2 below, an explicit forecast of the cost of grid withdrawals is not available. The first column shows the total non-energy charge forecast while the second column shows the Global Adjustment component of the total forecast non-energy load charge.

Table 2
Prescribed Hydroelectric Forecast
Non-Energy Costs: 2010 – 2012

Year	Total Non-Energy Load Charges (Including Global Adjustment)[3] ($M)	Global Adjustment Charges ($M)
2010	10.1	6.3
2011	11.6	7.8
2012	12.8	9.0

b) OPG has no estimate of the impact on its station service costs of this proposal. OPG notes that this matter is before the OEB in EB-2010-0002 and that Hydro One suggests an implementation date of January 1, 2012 in the event that the OEB decides to adopt this proposal.

c) The OM&A cost reductions described in Ex. F1-T1-S1, page 2, lines 6-14 affect only 2010. For the regulated hydroelectric stations, it was the Niagara Plant Group that identified an opportunity to advance $1.2M of work on the repairs to the Sir Adam Beck I Generating Station powerhouse concrete into 2009.

[1] Values for 2005 to 2007 from EB-2007-0905, Ex. F3-T1-S1, Table 13. Values for 2008 – 2009 from EB-2010-0008, Ex. F4-T4-S1, Table 2.
[2] Note that the Global Adjustment in 2005 was a credit and not a cost.
[3] Values for EB-2010-0008, Ex. F4-T4-S1, Table 2.

AMPCO Interrogatory #022

Ref: Ex. F2-T1-S1

Issue Number: 6.3
Issue: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

Interrogatory

a) How much station service power has been or will be paid by the nuclear business each year since 2005 through to the end of the test period? Please include a breakout of GA costs.

b) Please provide an estimate of the impact of the AMPCO High 5 proposal as described in EB-2008-0272 if it were to apply during the test period.

c) Please update Chart 2-1: Comparative Nuclear PUEC Costs from the EB-2007-0905 Decision with Reasons.

Response

a) At the nuclear stations, some electricity consumption is self-supplied (i.e., supplied directly from the generators), and some consumption is supplied from the Independent Electricity System Operator ("IESO") -controlled grid (i.e., grid withdrawals). As outlined in OPG's response to the interrogatory in Ex. L-01-088 part b), the IESO does not meter self-supplied consumption but the IESO does meter grid withdrawals. All station electricity consumption, self-supplied or grid withdrawals, is paid by OPG:

- Self-supplied consumption reduces the station electricity output into the IESO-controlled grid. Because this consumption is not metered by the IESO, it does not attract non-energy load charges and OPG does not explicitly track the value of this consumption.

- Grid withdrawals are metered by the IESO and they attract non-energy load charges.

Table 1 below outlines the value of grid withdrawals by calendar year from 2005 - 2009. The first column shows the value of grid withdrawals. The second column shows the total non-energy load charges while the third column shows the Global Adjustment component included in the total non-energy load charges.

Table 1
Nuclear Grid Withdrawal Values: 2005 – 2009

Year	Value of Withdrawals ($M)	Total Non-Energy Load Charges (Including Global Adjustment)[1] ($M)	Global Adjustment (Included in Total Non-Energy Load Charges) ($M)
2005	55.5	10.8	(6.7)[2]
2006	39.5	10.1	3.2
2007	38.0	9.8	3.3
2008	38.6	10.6	4.9
2009	24.8	36.1	26.8

In Table 2 below, an explicit forecast of the cost of grid withdrawals is not available. The first column shows the total non-energy charge forecast while the second column shows the Global Adjustment component of the total forecast non-energy load charge.

Table 2
Nuclear
Forecast Non-Energy Costs: 2010 – 2012

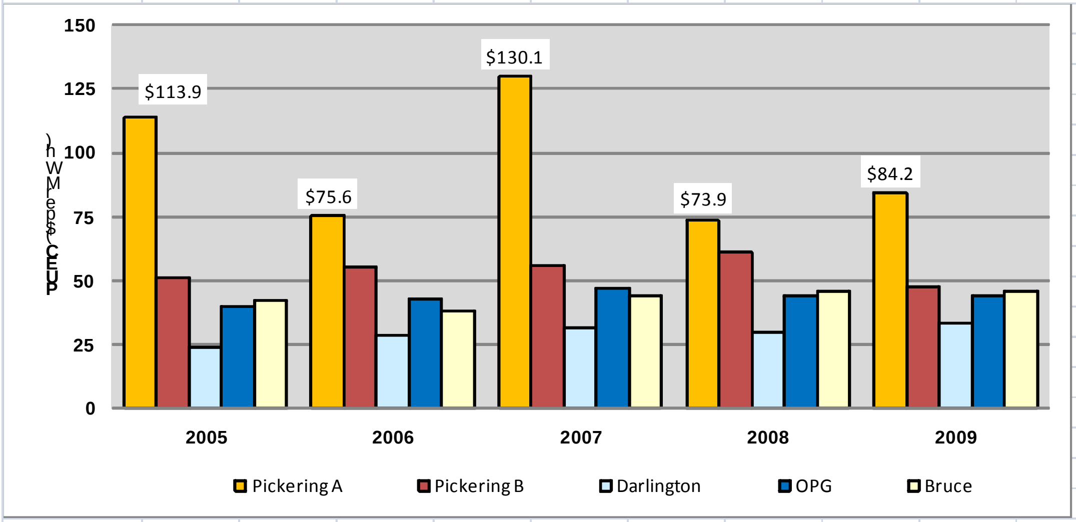
Year	Total Non-Energy Load Charges (Including Global Adjustment)[3] ($M)	Global Adjustment ($M)
2010	26.3	17.0
2011	30.3	21.0
2012	33.5	24.2

b) OPG has no estimate of the impact on its station service costs of this proposal. OPG notes that this matter is before the OEB in EB-2010-0002 and that Hydro One suggests an implementation date of January 1, 2012 in the event that the OEB decides to adopt this proposal.

c) OPG has updated the chart as indicated. OPG does not accept that the Bruce definition of “All In” costs is comparable to the Production Unit Energy Cost (“PUEC”) definition used by OPG.

[1] Values from 2005 – 2007 from EB 2007-0905, Ex. F3-T1-S1, Table 12. Values from 2008 – 2009 from Ex. F4-T4-S1, Table 3.
[2] Note that the Global Adjustment in 2005 was a credit and not a cost.
[3] Values from Ex. F4-T4-S1, Table 3.

Update to Chart 2.1 from EB-2007-0906



	Production Unit Energy Cost (PUEC) $/MWh				
	2005	2006	2007	2008	2009
Pickering A	113.9	75.6	130.1	73.9	84.2
Pickering B	51.3	55.5	55.9	61.3	47.3
Darlington	23.9	28.7	31.6	29.7	33.1
OPG	39.7	42.9	47.2	44.0	43.9
Bruce *	42.0	38.0	44.0	46.0	46.0

* Bruce data for 2007, 2008 and 2009 from Bruce Annual Review documents on its website, defined as “All in Costs”. Please note that the 2007 figure was revised by Bruce Power from $42 to $44 and the 2008 number was revised from $45 to $46 as per the 2009 Annual Review document. No disclosure of the change or rationale was provided.

NOTE: The U.S. Median in EB-2007-0905 Chart 2.1 was extracted by OEB staff from a Nuclear Energy Institute report. OPG does not know the context of this report, nor have direct access and does not represent OPG evidence. Therefore, that data has been removed.

AMPCO Interrogatory #023

Ref: Ex. F5-T1-S1, page 13

Issue Number: 6.4
Issue: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's nuclear facilities reasonable?

Interrogatory

Regarding the statement "Additionally, the WANO NPI results of all CANDU operators are concentrated at the bottom of the peer group for the period 2006-2008":

a) Please provide the year by year WANO NPI results for Candu vs. PWR.

b) Is it the opinion of ScottMadden that the above statement reflects a temporary anomaly? Alternatively, is it the opinion of ScottMadden that the above statement is likely to prevail in future? In either case, please comment on the reasons for the opinion expressed.

Response

a) Year-by-year World Association of Nuclear Operators ("WANO") Nuclear Performance Index ("NPI") results for CANDU vs. PWR are presented in the table below:

Average WANO NPI Rankings

	2006	2007	2008
U.S. PWR 1	9	8	1
U.S. PWR 2	4	5	2
U.S. PWR 3	2	1	3
U.S. PWR 4	7	3	4
U.S. PWR 5	19	17	5
U.S. PWR 6	12	13	6
U.S. PWR 7	5	9	7
U.S. PWR 8	3	4	8
U.S. PWR 9	6	10	9
U.S. PWR 10	11	6	10
U.S. PWR 11	8	11	11
U.S. PWR 12	10	7	12
U.S. PWR 13	1	2	13
U.S. PWR 14	13	12	14

U.S. PWR 15	14	14	15
International CANDUs	15	15	16
OPG CANDU	17	16	17
Canada CANDU 1	20	19	18
Canada CANDU 2	16	20	19
Canada CANDU 3	18	18	20

OPG NPI Scores vs. CANDU NPI Scores:

OPGN Median = 79.1
OPGN Average = 78.9

Candu World Median = 74.0
Candu World Average = 76.6
(excludes OPGN)

Note that in the chart showing ordinal rankings, “International CANDUs” exclude Canadian CANDU, whereas the “Candu World Median” and “Candu World Average” results include Canadian CANDU.

b) Over the 2006 – 2008 time period, CANDU operators have been concentrated at the bottom of the WANO NPI rankings as compared to PWRs. Since the lower NPI results for CANDU have been consistent over this period, these results are not an anomaly during the period examined. ScottMadden has advised OPG that it cannot predict if the results will continue into the future.

Differences between PWR and CANDU generation technologies impact many of the ten metrics that comprise the Nuclear Performance Index. Unit Capability Factors for CANDUs are typically lower than PWRs due to longer planned outages. Longer outages, in turn, result in higher Collective Radiation Exposure which is another NPI component. In addition, CANDU units are more complex with higher number of components which can be linked to higher FLRs in CANDU technology as well as the potential for greater unplanned work during outages.

AMPCO Interrogatory #024

Ref: Ex. F2-T1-S1

Issue Number: 6.4
Issue: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's nuclear facilities reasonable?

Interrogatory

a) OPG and its predecessor have over the years changed the titles and theme of nuclear performance improvement initiatives every few years for decades, with titles like QIP, NAOP, IIPA, and Say It/Do It. Please provide the most recently available analysis benchmarking the strengths and weaknesses of historic nuclear performance initiatives within OPG and its predecessor.

b) When the A stations were forced to close in the late 1990s, some of the blame was attributed by Ontario Hydro to the predecessor to the QIP program in the early 1990s, under which Ontario Hydro had engaged in a O&M cost control and staff reductions within operational programs. What is different this time?

c) How is staff productivity measured within OPG and what are the trends over the course of the last decade?

d) Please indicate when the problem of calandria vault corrosion was first identified and outline the measures taken to manage the problem since its discovery.

Response

a) No "benchmarking analysis" has been performed on the strengths and weaknesses of past initiatives. The OPGN 2009 benchmarking initiative (Ex. F2-T1-S1) was conducted consistent with the OEB's directive, and provides the latest analysis addressing areas of strength and weaknesses for the organization. This benchmarking initiative and resulting OPGN 2009 Benchmarking Report is the driver for business planning and nuclear improvement efforts.

b) OPG cannot comment on the references to past Ontario Hydro practices. As noted above, the OPGN benchmarking study is consistent with OEB direction regarding external benchmarking, and both the benchmarking initiative study and the 2010 – 2014 gap-based business planning process were carried with the support of ScottMadden, a consulting firm specializing in the provision of benchmarking and business planning services to nuclear utilities.

c) OPG does not measure employee productivity specifically because of the many variables that would be part of the metric. However OPG has taken actions to increase productivity such as:
   - Removing job family barriers to allow broader work scope for individuals.
   - Measuring, tracking and minimizing work backlogs.
   - Ensuring that training requirements are recorded and employee training is kept current.
   - Re-engineering processes to reduce time and labour on business transactions.

d) See response to Ex. L-1-046.

AMPCO Interrogatory #025

Ref: Ex. F4-T1-S1, page 4
Ex. F2-T2-S3, page 5-6
Ex. F2-T2-S3, Attachment 1, page 7

Issue Number: 6.11
Issue: Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes appropriate?

Interrogatory

The end-of-life date for Pickering A extends beyond the life expectancy of Pickering B. In light of the uncertainties surrounding life extension of Pickering B, the practicality of operating Pickering A independently, and the economic viability Pickering A, please comment on the advisability of extending the end-of-life estimate for Pickering A beyond the most aggressive estimate available for the end-of-life of Pickering B.

Response

As outlined in Ex. F4-T1-S1, Attachment 1 - 2009 Depreciation Review Committee Report, Regulated Business, section 2.0, for financial accounting purposes, recommended changes to existing station end-of-life dates and asset class service lives for depreciation require a high degree of confidence (at least 70 per cent) in order for any changes to be considered for recommendation by the Depreciation Review Committee ("DRC"). OPG's senior management and internal and external auditors must be satisfied with the underlying support for any recommended changes.

With reference to Pickering A Generating Station, as explained in Ex. F4-T1-S1, Attachment 1, in its review during 2009, the DRC recognized that there are significant technical and regulatory risks that would make it difficult to operate Pickering A Generating Station Units 1 and 4 as stand-alone units after the last two units of Pickering B Generating Station have reached their end of life. Moreover, should the Pickering B Generating Station units be permanently shut down, there is a high probability that Pickering A Generating Station would prove uneconomical to operate.

The DRC deliberated on the implications of the above on the end-of-life estimate for Pickering A Generating Station and concluded that OPG cannot claim high confidence to support a change in the Pickering A Generating Station service life date for depreciation purpose to align with the Pickering B Generating Station date, until there is a greater certainty around Pickering B Generating Station service lives. Specific factors that informed the DRC's conclusion were:

- OPG has embarked on the Pickering B Continued Operations initiative.

- There are other life management scenarios for Pickering B Generating Station which are being explored and which can result in a longer Pickering B Generating Station calendar life.

- There is the potential to invest in modification work to overcome the technical hurdles to operation of Pickering A Generating Station without Pickering B Generating Station.

With reference to Pickering B Generating Station service lives, as also explained in Ex. F4-T1-S1, Attachment 1, OPG has embarked on a work program (including physical work in the plant, laboratory tests, analytical work and discussions with the nuclear safety regulator) to demonstrate high confidence in extended service lives of the Pickering B Generating Station pressure tubes. This program of work is expected to come to fruition in late 2012. If successful, OPG would expect to be able to operate the Pickering B Generating Station units until 2018 - 2020 (i.e., the Continued Operations initative).

As also explained in Ex. F4-T1-S1, Attachment 1, OPG cannot currently claim high confidence, for accounting purposes, in achieving Continued Operations at Pickering B Generating Station, but expects to be able to claim that high confidence by approximately the end of 2012. Thus, changes to the service life of Pickering B Generating Station for accounting purposes are deferred until there is more certainty in achieving Continued Operations at Pickering B Generating Station.