AMPCO

EB-2010-0008

CROSS-EXAMINATION OF

OPG PANEL 6

COMPENDIUM OF MATERIAL

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1.

AECL starts again on retubing Point Lepreau

11 October 2010

All of the 380 new calandria tubes installed as part of the major ongoing refurbishment of the Point Lepreau Candu-6 nuclear power plant in Canada are to be removed and reinstalled.

NB Power, operator of the 635 MWe Candu 6 reactor in the province of New Brunswick, issued a brief note confirming that refurbishment contractor Atomic Energy of Canada Ltd (AECL) had begun work on the removal of the 380 tubes.

Point Lepreau (Image: NB Power)

Point Lepreau is the first Candu 6 unit to undergo major refurbishment, involving replacement of all calandria tubes, steam generators and instrument and control systems. Work began in April 2008 and was originally expected to be complete by late 2009. The project should ensure an operating life until at least 2034 for the plant, as well as a 25 MWe power uprate, but is now the subject of political fighting with the province of New Brunswick seeking federal mediation over the issue of cost overruns.

Replacement of the calandria tubes, which form channels in which uranium fuel is inserted and through which the heavy water moderator flows in the core of the reactor, has turned out to be one of the most complex aspects of the entire project. Insertion of the 380 tubes was completed in April 2010, but AECL subsequently reported that it was encountering problems with producing consistently tight seals in the tubes. An insert at the end of each tube must be rolled and tested, but as of June 2010 AECL reported that only 421 of the 760 inserts had been tested successfully. AECL had been working to address the issue by removing roughness on some tube join surfaces as well as using metal inserts to reach the proper tightness.

The likely impact of the decision to remove all the tubes on the overall schedule is not yet known, according to NB Power.

Researched and written by World Nuclear News

WNN RELATED STORIES

'Ambitious' Point Lepreau refurbishment delayed

AECL under pressure in New Brunswick

New Brunswick wants mediation as delays confirmed

RELATED LINKS

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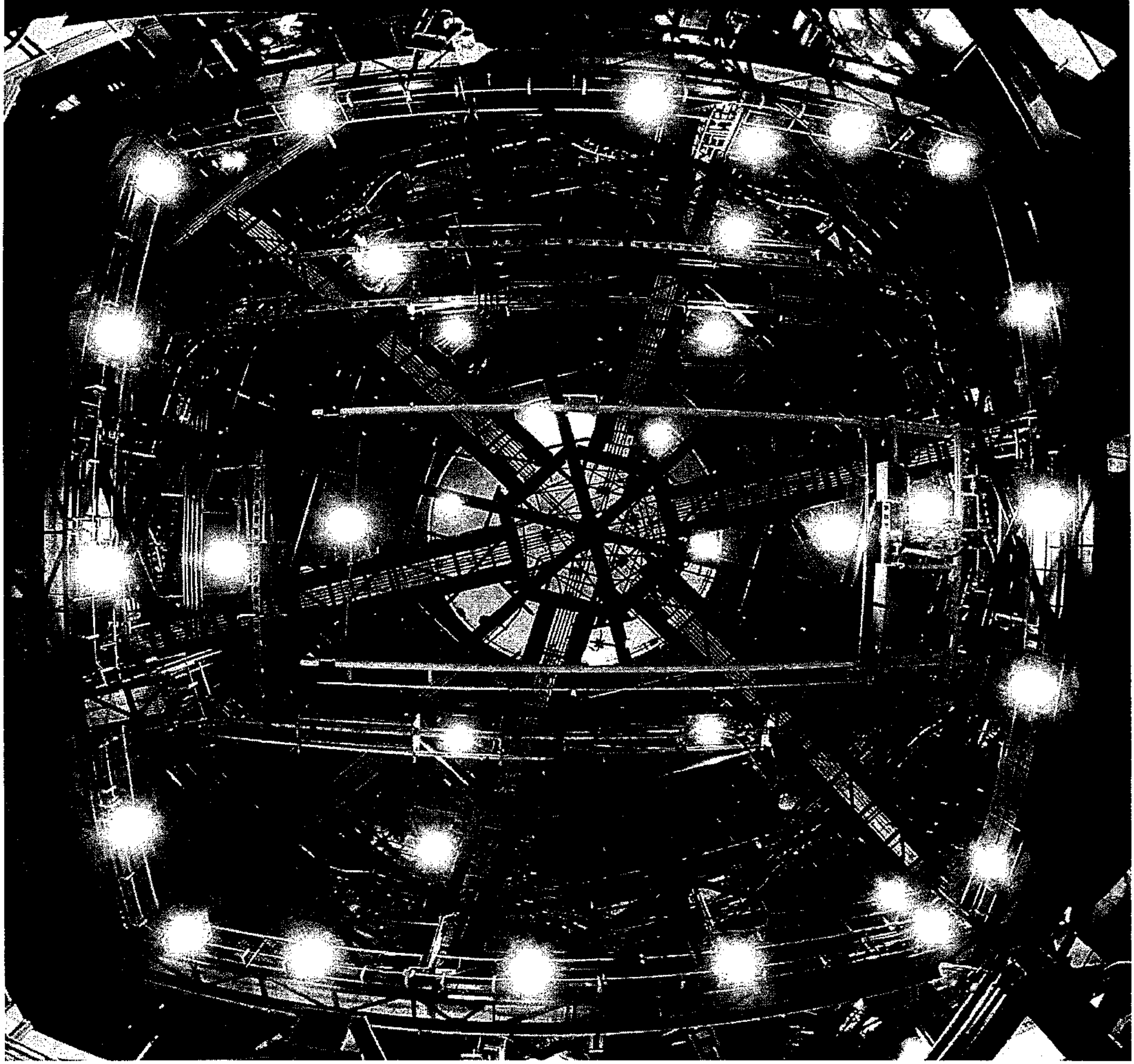
2010 ANNUAL FINANCIAL REPORT



Revenue

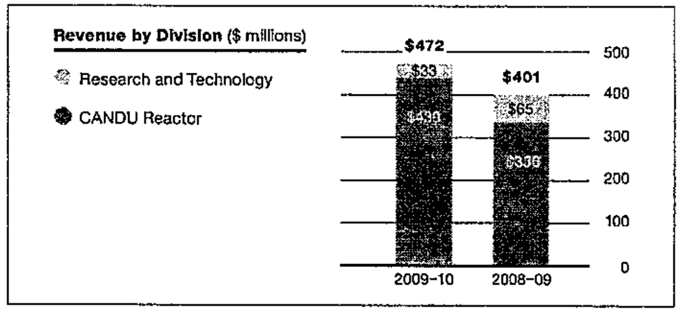
Consolidated commercial revenues increased 18% to $472 million in 2009–2010. This improvement mainly resulted from increased activity on the CANDU Reactor Division's life extension projects. Revenue from the Services business in 2009–2010 remained consistent with the previous year.

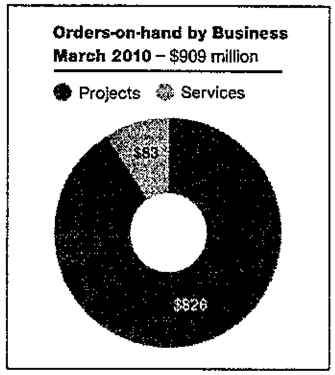
Research and Technology commercial revenue decreased by 49% to $33 million, reflecting lower isotope sales. This decline resulted from the extended shutdown of the NRU in May 2009 to repair a heavy water leak. The shutdown extended beyond the end of the fiscal year.

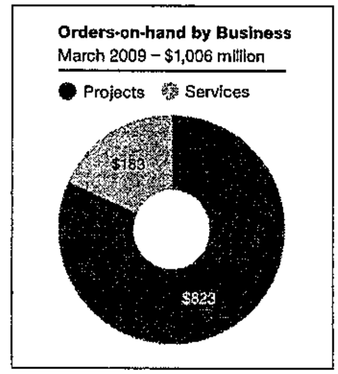
Funding

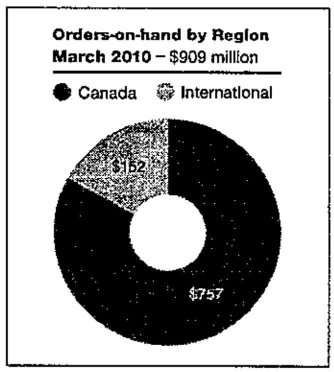
Total funding recognized in 2009–2010 for operating and capital activities was $948 million (2008–2009: $642 million). This included:

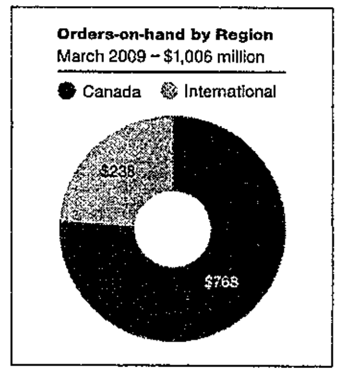
- $108 million for the ACR-1000 program. $29 million was used for research and overhead costs, while $79 million was capitalized on the Consolidated Balance Sheet in accordance with accounting standards.
- A $346 million cash infusion to support reactor life extension projects within the CANDU Reactor Division and meet contractual obligations. Three life extension projects are planned to be completed in 2010–2011.
- $154 million for research and development, mainly supporting ongoing Chalk River site operations.
- $120 million to address regulatory, health, safety and environmental needs. The funding supported the Project New Lease (infrastructure renewal) and Isotope Supply Reliability Program (NRU operations and licence renewal) initiatives, at AECL's Chalk River site. Capital funding totalled $47 million.
- Cost recoveries and other funding totalled $12 million. This includes amortization of deferred capital funding related to Government-funded infrastructure, mainly at Chalk River. In addition, cost recoveries include support for activities under the Low-Level Radioactive Waste Management Office, reported under the Research and Technology Division.
- Funding of $21 million for the Dedicated Isotope Facilities, which include the MAPLE 1 and 2 reactors, the New Processing Facility and the Calcined Waste Storage Canisters. Operational costs have been significantly reduced since the facilities were placed in an extended shutdown state in June 2009. The CNSC granted a licence in March to formalize the status of the facilities. Funding was also used to meet contractual obligations.
- Decommissioning and waste management activities recognized increased funding of $115 million from $105 million in 2008–2009. Funding is provided through Natural Resources Canada and is based on AECL's expenditures.
- Specific funding of $72 million was provided to support NRU return-to-service activities. The NRU was shut down in May 2009 to allow for repairs to the reactor vessel.

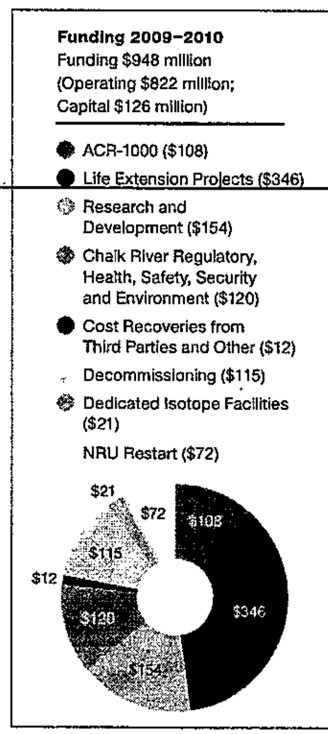


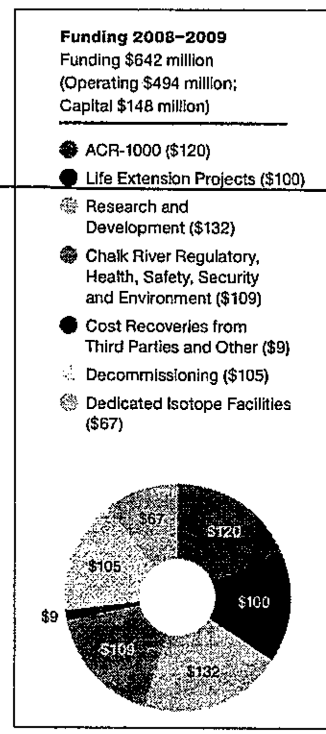












4.

Consolidated Cash Flow and Working Capital

SOURCE AND USES OF CASH	*Actual Results*	
($ millions)	*2009–10*	*2008–09*
Cash from (used in) operating activities	**$ 1**	$ (39)
Cash used in investing activities	**(129)**	(138)
Cash from financing activities	**143**	155
Cash and cash equivalents		
Increase (decrease)	**15**	(22)
Balance at beginning of the year	**33**	55
Balance at end of the year	**$ 48**	$ 33

Operating Activities

Operating activities resulted in a net cash inflow of $1 million compared to a net cash outflow of $39 million in 2008–2009. AECL received funding of $915 million in 2009–2010, representing an increased level of Government support from prior years. The increased level of funding was required to support a number of activities including the ongoing commercial life extension projects within the CANDU Reactor Division and the Research and Technology Division's NRU return-to-service project.

Investing Activities

Investing activities involved a net outlay of $129 million compared to $138 million in the previous year. Continued investment in the ACR-1000 program largely contributed to this outflow, which was down from the previous year as Government funding was reallocated to the ongoing life extension projects. Project New Lease undertook significant investments, including the completion of an administrative building and various site refurbishment and equipment purchases. The investment program, which is ongoing, aims to renew infrastructure at the Chalk River site and ensure safe operations at the nuclear facility.

Financing Activities

Financing activities generated proceeds of $143 million (2008–2009: $155 million), consisting of Parliamentary appropriations for capital expenditures associated with ACR-1000 development and infrastructure development at the Chalk River site, including Project New Lease and the Isotope Supply Reliability Program.

Overall, AECL's year-end closing cash position increased to $48 million from the previous year's level of $33 million.

Off-Balance Sheet Arrangements

In the normal course of business, AECL enters into the following Off-Balance Sheet arrangements:

Bank Guarantees and Standby Letters of Credit

These instruments are used in connection with performance guarantees on major contracts. The guarantees generally relate to project and product performance and advance payments. In addition, AECL guarantees that certain projects will be completed within a specified time, and if the Corporation does not fulfill its obligations, it will assume responsibility for liquidated damages. The aggregate amount of AECL's potential exposure through liquidated damages ($99 million) and guarantees ($500 million) as at March 2010 was $599 million (2008–2009: $639 million). Management has assessed the impact of liquidated damages penalties on the active life extension projects and incorporated it in the calculation of liabilities in the financial statements.

Indemnification Arrangements

These arrangements are part of the standard contractual terms to counterparties in transactions such as service agreements, sale and purchase contracts. These indemnification agreements may require AECL to compensate the counterparties for costs incurred as a result of certain events. The nature of these indemnification agreements prevents AECL from making a reasonable estimate of the likely maximum amount to be paid out by the Corporation. Management does not expect these arrangements to have a material current or future effect on the consolidated financial statements of the Corporation.

AMPCO Interrogatory #015

Ref: Ex. D2-T2-S1

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) For the Darlington refurbishment project, please provide a PPA equivalent and revenue requirement for the first full year in service for the first unit equivalent to the LUEC prices OPG has claimed.

b) Please provide the analysis that OPG relies upon in its "review of current refurbishment experience in the industry." For each of the following, provide the originally approved cost and final costs whether estimated or actual: Bruce 3 and 4 return to service; Bruce 1 and 2 retubing, reboilering and return to service; Pickering A retubing; Pickering A return for service; and Point Lepreau retubing. If the data is available, do not include replacement power costs but include interest cost.

c) In Figure #1 OPG expresses near-100% confidence that the LUEC cost for Darlington could never exceed 8 cents/kWh. Given the uncertainties with respect to capital costs, contractor reliability, operating costs, productivity, life expectancy, interest costs, fuel costs, changing safety requirements, and other cost factors, please explain how OPG supports its assertion of near-100% certainty that the LUEC cost will never exceed 8 cents/kWh.

d) What assumptions have OPG made with respect to the role of AECL in the Darlington refurbishment project?

e) What is the lead time currently estimated for ordering pressure and calandria tubes? Please comment on factors driving the trend in recent years toward longer lead times for ordering pressure and calandria tubes.

f) What is the currently estimated date to begin replacement of Darlington's boilers?

Response

a) OPG has not calculated a power purchase agreement ("PPA") equivalent and revenue requirement for the Darlington Refurbishment project. However, OPG has provided (see Ex. D2-T2-S1, Attachment 4, page 32) a fully allocated Levelized Unit Energy Cost ("LUEC") range of \$0.053/kWh – \$0.077/kWh.

b) OPG has reviewed the publicly available information on similar nuclear refurbishment projects which included Bruce Units 1 and 2 refurbishment (retubing and re-boilering) and Point Lepreau retubing. The Bruce Units 3 and 4 return to service and the Pickering A Generating Station return to service are not projects of similar scope.

Provided below is the information OPG has on original cost estimates for these projects and the estimated final costs, based on publicly available information. In its review, OPG notes that the refurbishment of Bruce Units 1 and 2 includes the replacement of steam generators, while the planned refurbishment of Darlington Generating Station does not include replacement of the steam generators.

	Bruce Units 1& 2 Refurbishment	**Pt. Lepreau Refurbishment**
Original Estimates	\$2.75B[1] = \$1.38 B/Unit	\$1.02 B[2]
Estimated Cost at Completion	\$3.8 B[3] = \$1.9 B/Unit	\$1.5 B[4]

c) OPG has high confidence that the LUEC of Darlington Generating Station will be less than \$0.08/kWh based on the methodology used and the conservative assumptions that underpin the analysis.

OPG has included a significant degree of variability into the inputs to the LUEC calculation (e.g., refurbishment costs, post-refurbishment costs and performance, and post-refurbishment station life). This variability in inputs was used, in conjunction with a Monte Carlo analysis, to derive the distribution of potential Darlington Refurbishment project costs as shown in the curve in Figure 1, Ex. D2-T2-S1, Attachment 4, Appendix C page 28. A Monte Carlo analysis is a standard approach to quantifying the impact on expected outcomes of variability in inputs. OPG has also been careful to ensure that its preliminary estimates of refurbishment costs are conservative based on prior experience with complex projects.

In addition, as noted in the interrogatory in Ex. L-10-003, approximately 55 per cent of the typical LUEC for Darlington Refurbishment is associated with OM&A. Given that OPG has over 20 years of operational experience with the Darlington Generating Station, OPG does not expect that there would be significant unanticipated increases in the future operating costs of Darlington over the post-refurbishment life.

d) OPG has made no assumptions with respect to the role of Atomic Energy of Canada Limited ("AECL") in the Darlington Refurbishment project.

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[1] Ministry of Energy, Ontario (News Release), Oct. 17, 2005; TransCanada News Release, October 17, 2005.
[2] FAQs on Point Lepreau Refurbishment, New Brunswick Power internet site.
[3] TransCanada Q4 2009 Investor Report, February 23, 2010, TCP Internet site.
[4] "Premier confident of results from talks on Lepreau refit", New Brunswick Telegraph-Journal, Apr 29, 2010.

7.

e) The current lead time for ordering pressure and calandria tubes is approximately 24 to 27 months. The trend in recent years towards longer lead times was a result of increasing demand from a number of stations embarking on refurbishment work. Until very recently, a single vendor has supplied exclusively all the pressure and calandria tubes to all the existing CANDU units, both domestically and worldwide. A second vendor has now been qualified and is able to supply both pressure tubes and calandria tubes. As a result, lead times may be shorter in the future due to increased manufacturing capacity.

f) The replacement of the Darlington Generating Station steam generators is excluded from the scope of the Darlington Refurbishment project, as indicated in Ex. D2-T2-S1, Attachment 4, page 4 and discussed in Ex. L-7-028.

Numbers may not add due to rounding.

Table 8
Capacity Refurbishment
Summary of Cost Deferrals and Variances - 2008 through 2010 ($M)

Line No.		Jan-Mar 2008	Apr-Dec 2008	2009	2010
		(a)	(b)	(c)	(d)
	Forecast Costs - EB-2007-0905 / EB-2009-0174[1]				
1	Pickering B Refurbishment	0.0	4.6	5.1	5.5
2	Darlington Refurbishment	0.0	13.9	22.7	21.1
3	Fuel Channel Life Cycle Management Project	0.0	0.0	0.0	0.0
4	Pickering B Continued Operations	0.0	0.0	0.0	0.0
5	Total Forecast Costs	0.0	18.5	27.8	26.6
	Actual Costs[2]				
6	Pickering B Refurbishment	0.0	6.1	4.3	1.2
7	Darlington Refurbishment	0.0	6.7	21.7	5.5
8	Fuel Channel Life Cycle Management Project	0.0	0.0	0.0	9.7
9	Pickering B Continued Operations	0.0	0.0	4.8	13.5
10	Total Actual Costs	0.0	12.8	30.8	29.9
	Variance				
11	Pickering B Refurbishment (line 6 - line 1)	0.0	1.5	(0.8)	(4.3)
12	Darlington Refurbishment (line 7 - line 2)	0.0	(7.2)	(1.0)	(15.6)
13	Fuel Channel Life Cycle Management Project (line 8 - line 3)	0.0	0.0	0.0	9.7
14	Pickering B Continued Operations (line 9 - line 4)	0.0	0.0	4.8	13.5
15	**Variance** (line 10 - line 5)	0.0	(5.7)	2.9	3.3

Notes:

1 2010 forecast figure derived from EB-2007-0905 OEB approved forecast as described in Decision and Order in EB-2009-0174.

2 Value for 2010 is OPG's current forecast of the 2010 actual value.

8.

<u>GEC Interrogatory #023</u>

Ref: Ex. D2-T2-S1

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 provide a breakdown of the costs associated with OPG's environmental, safety and economic studies regarding the viability of refurbishing the Pickering B nuclear station?

Response

The breakdown of the costs associated with OPG's environmental, safety and economic studies regarding the viability of refurbishing the Pickering B Generating Station as of December 2009 are:

- Environmental studies $14.2M
- Safety studies $16.1M
- Economic feasibility studies $18.8M

The above includes costs from direct work, as well as allocated costs from the Nuclear Refurbishment project management team.

Numbers may not add due to rounding.

Table 8
Capacity Refurbishment
Summary of Cost Deferrals and Variances - 2008 through 2010 ($M)

Line No.		Jan-Mar 2008	Apr-Dec 2008	2009	2010
		(a)	(b)	(c)	(d)
	Forecast Costs - EB-2007-0905 / EB-2009-0174[1]				
1	Pickering B Refurbishment	0.0	4.6	5.1	5.5
2	Darlington Refurbishment	0.0	13.9	22.7	21.1
3	Fuel Channel Life Cycle Management Project	0.0	0.0	0.0	0.0
4	Pickering B Continued Operations	0.0	0.0	0.0	0.0
5	Total Forecast Costs	0.0	18.5	27.8	26.6
	Actual Costs[2]				
6	Pickering B Refurbishment	0.0	6.1	4.3	1.2
7	Darlington Refurbishment	0.0	6.7	21.7	5.5
8	Fuel Channel Life Cycle Management Project	0.0	0.0	0.0	9.7
9	Pickering B Continued Operations	0.0	0.0	4.8	13.5
10	Total Actual Costs	0.0	12.8	30.8	29.9
	Variance				
11	Pickering B Refurbishment (line 6 - line 1)	0.0	1.5	(0.8)	(4.3)
12	Darlington Refurbishment (line 7 - line 2)	0.0	(7.2)	(1.0)	(15.6)
13	Fuel Channel Life Cycle Management Project (line 8 - line 3)	0.0	0.0	0.0	9.7
14	Pickering B Continued Operations (line 9 - line 4)	0.0	0.0	4.8	13.5
15	**Variance** (line 10 - line 5)	0.0	(5.7)	2.9	3.3

Notes:
1 2010 forecast figure derived from EB-2007-0905 OEB approved forecast as described in Decision and Order in EB-2009-0174.
2 Value for 2010 is OPG's current forecast of the 2010 actual value.

10.

Chart 2

Pickering B Refurbishment and Continued Operations

Costs ($M)	Life-to-date 2007 (1)	Actual 2008	Actual 2009	Plan 2010	Plan 2011	Plan 2012	Information Source
Pickering B Refurbishment Project							
- Base OM&A	**35.9**	**9.0**	**4.3**	**1.2**	**0.0**	**0.0**	F2-T2-S1 Table 1
Pickering B Continued Operations Initiative							
- Base OM&A	0.0	0.0	1.6	9.8	17.7	14.7	F2-T2-S1 Table 1
- Outage OM&A	0.0	0.0	2.8	1.9	13.0	10.6	F2-T4-S1 Table 1
- Project OM&A	0.0	0.0	0.4	1.8	19.9	17.0	F2-T3-S1 Table 1
Subtotal Nuclear Operations OM&A (PB CO)	**0.0**	**0.0**	**4.8**	**13.5**	**50.6**	**42.3**	
Fuel Channel Life Cycle Management Project							
- Project OM&A	**0.0**	**0.0**	**2.5**	**9.7**	**7.7**	**4.0**	F2-T3-S1 Table 1

Note 1: F2-T2-S1 Table 2 shows 2007 actual costs, whereas this Chart presents all costs to year-end 2007.

6.1 Pickering B Refurbishment

There are no OM&A or capital costs budgeted for Pickering B refurbishment for the test period. The vast majority of Pickering B refurbishment Phase 1 activities have been completed as of the end of 2009, including preparation and approval of the EA and the ISR.

Pickering B Refurbishment base OM&A costs were $9.0M in 2008 and $4.3M in 2009. The 2010 - 2014 Business Plan includes expenditures of $1.2M in 2010 in order to obtain CNSC's acceptance of the final ISR report and to close out the Pickering B refurbishment project. The total actual and forecast costs for Phase 1 of Pickering B refurbishment is $50.4M as shown in Chart 2. Of this amount, $45.8M had been approved for release by the

OPG Board of Directors prior to April 1, 2008 and is therefore eligible for recovery under section 6(2)4 i of O.Reg. 53/05.

The overall project variance is primarily due to the fact that this was the first time the CNSC process was used to prepare an ISR. The completion of the ISR required more work than originally planned. The knowledge gained with Pickering B refurbishment will be valuable in the preparation of the ISR for the Darlington refurbishment project.

6.2 Pickering B Continued Operations

The cost of the Pickering B Continued Operations initiative in the test period is $92.9M, as summarized in Chart 2 above. There were no expenditures during 2008, $4.8M in 2009 and $13.5M is forecast for 2010. The initiative also requires 167.0 additional outage days during 2011 - 2012.

As noted above, the required incremental work effort during the 2010 bridge year and the 2011 - 2012 test period associated with the Pickering B Continued Operations initiative is in the areas of additional maintenance and additional inspections of life-limiting equipment.

In addition to the Pickering B Continued Operations expenditures presented in Chart 2, expenditures for the Fuel Channel Life Cycle Management project support both Pickering B Continued Operations and Darlington refurbishment.

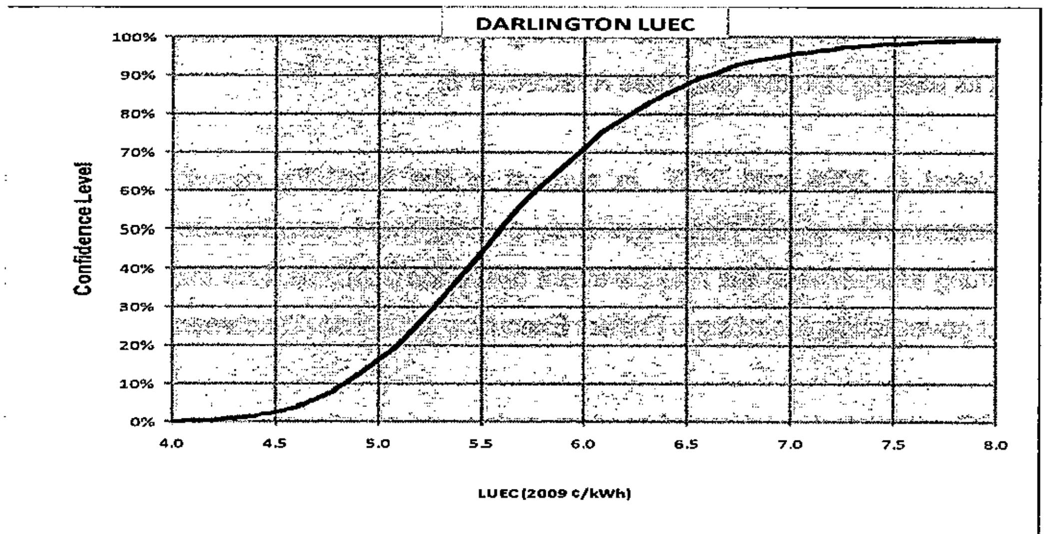
6.3 Capacity Refurbishment Variance Account

In EB-2007-0905, the OEB approved establishment of the Capacity Refurbishment Variance Account to record differences between actual and forecast costs, while in EB-2009-0174 the OEB approved continuation of this variance account for 2010. A description of the variance account is provided in Ex. H1-T1-S1.

OPG is seeking recovery of the variance between actual and forecast 2008 and 2009 costs for the Pickering B Refurbishment and the Pickering B Continued Operations initiative through the Capacity Refurbishment Variance Account as detailed in Ex. H1-T2-S1. OPG

Figure 1

Levelized Unit Energy Cost Confidence Ranges



The LUEC range shown in Figure 1 above is based on a number of planning assumptions; including 1) refurbishment project cost, 2) refurbishment schedule, 3) post refurbishment operations costs, and 4) post refurbishment operating performance:

1) Refurbishment Project Cost - Based on the current level of planning as well as a review of industry experience, the current projected cost of the refurbishment project is in the range of \$6B to \$10B (2009 dollars).
2) Refurbishment Schedule - OPG's planning assumption was that the first unit refurbishment outage would commence in October 2016 and that each unit outage will last approximately 36 months. It is also assumed that unit refurbishment outages will be overlapped with a maximum of two units in a refurbishment state at any point in time. These assumptions are based on the current predicted end of service life, information received from technical studies on the project's critical path duration and replacement costs, and the current experience of other refurbishments.
3) Post-Refurbishment Operations Costs – A range of \$450M to \$525M per year (2009 dollars) of post-refurbishment station costs, including operations, outages, and projects,