K4.1

AMPCO

EB-2010-0008

CROSS-EXAMINATION OF

OPG PANEL 3

COMPENDIUM OF MATERIAL

DAVIS LLP

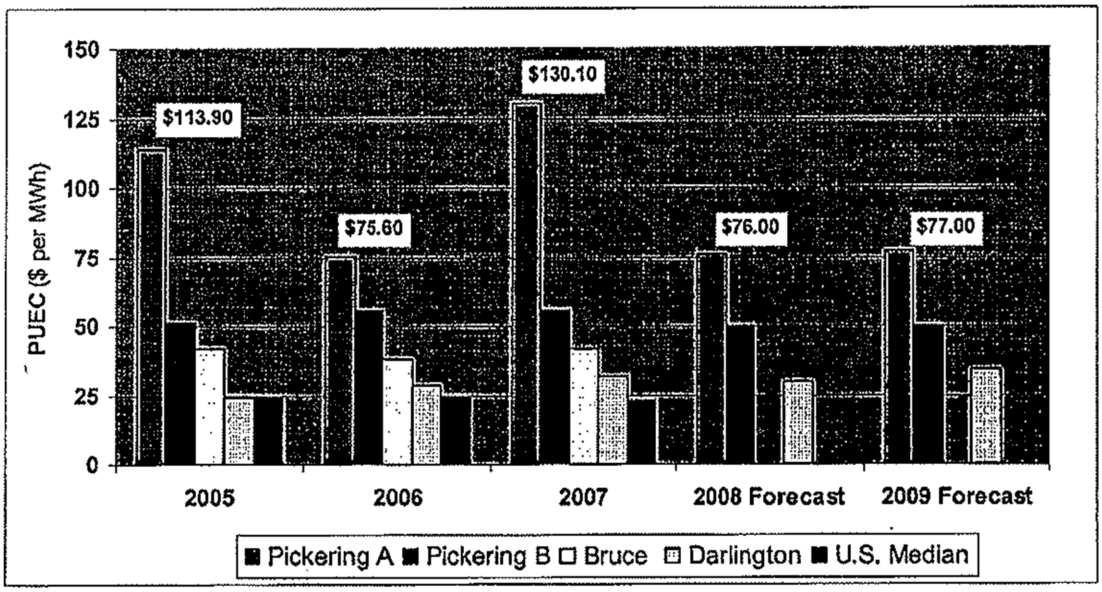
DAVID CROCKER

INDEX

period. The per MWh amounts shown on the face of the chart are for the Pickering A station, which has the highest PUEC of the stations shown on the chart.

Chart 2-1 shows that the production cost per MWh for Pickering A and Pickering B have been substantially greater than for Bruce Power. Over the three years 2005 to 2007, Pickering A's unit production cost was on average three times higher than Bruce Power and four times the U.S. median. Darlington's performance is better than Bruce Power, but is worse than the U.S. median. The average cost per MWh at Pickering A over the three-year period was $107 compared to $24 for the U.S. median and $41 for Bruce Power.

Chart 2-1: Comparative Nuclear PUEC Costs



Sources: Ex. J5.4; Ex. L-4-2, Attachment 3, pp. 18, 21, and 24.

Many intervenors were critical of both the results of OPG's benchmarking and what they viewed as the apparent reluctance to engage in benchmarking. AMPCO submitted that Pickering A is almost five times more costly than the top quartile of U.S. operations, while Pickering B is two and a half times more costly.

The PUEC of a generating plant is a function of both the level of costs incurred and the plant's capacity factor. Even a very low-cost facility can have a high PUEC if the plant has an extended outage in a period.

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2.

The Board directs OPG to produce further benchmarking studies in its next application that specifically address the questions raised in the proposed Phase 2 and Phase 3 of the Navigant Report. Whether these studies are performed by Navigant or another firm is a matter to be determined by the applicant.

The production costs of the Pickering A station are a particular concern. In the past, a major reason for the high PUEC for Pickering A has been the extent of unplanned outages and the resulting low capacity utilization. OPG has forecast significantly higher capacity factors for Pickering A in 2008 and 2009. But, as Chart 2-1 illustrates, even at those higher production levels, the PUEC for Pickering will still remain well above the PUEC for Pickering B, will be significantly higher than the PUEC of the Darlington station, and will stay well above the PUEC achieved by the Bruce station over the period 2005 to 2007. Thus, poor capacity factors are not the whole reason for a high PUEC at Pickering A.

The Board estimated the PUEC for Pickering A assuming it were able to reach the forecast capacity factors of the Pickering B station in 2008 and 2009. Even if Pickering A were able to increase its planned capacity factors by that much (from 79% in 2008 and 81% in 2009 to 86% in both years), the Board estimates that the PUEC of Pickering A would only fall to around $70 per MWh, a level that is still much higher than the next highest cost station in Chart 2-1. In the Board's view, this indicates an issue with the overall level of production costs at Pickering A.

Under these circumstances, the Board believes that a reasonable action is to disallow 10% of the Base OM&A costs of Pickering A. This represents a test period disallowance of $14.9 million in 2008 and $20.1 million in 2009. Even with those amounts removed from the revenue requirement, the amount of the operating costs of Pickering A will still remain well above those of other nuclear plants.

The Board will have an opportunity to reexamine this issue when the benchmarking studies are updated in the next proceeding. At that time the Board will examine any improvement or deterioration in production unit energy costs compared to other utilities, and the reasons for those changes.

Aside from this adjustment, the Board will allow the OM&A forecast by OPG. The Board understands the concern of the intervenors regarding the level of costs, but believes it is important to examine underlying cost drivers. A number of the planned expenditures are

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Numbers may not add due to rounding.

Table 1
Base OM&A - Nuclear ($M)

Line No.	Division	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Nuclear Stations						
1	Darlington NGS	294.6	304.7	308.2	291.5	302.1	317.8
2	Pickering A NGS	162.5	187.6	187.3	175.9	172.9	170.6
3	Pickering B NGS	287.4	306.6	292.2	285.3	279.1	288.6
4	Pickering B Continued Operations	0.0	0.0	1.6	9.8	17.7	14.7
5	Pickering B Refurbishment	23.3	9.0	4.3	1.2	0.0	0.0
6	**Total Stations**	767.9	807.9	793.7	763.7	771.8	791.5
	Nuclear Support Divisions						
7	Engineering	60.5	62.4	59.9	56.6	55.8	56.5
8	Projects & Modifications	10.7	12.2	13.9	7.6	5.4	5.1
9	Facilities Management	41.8	38.4	41.8	41.5	42.5	43.4
10	Programs & Training	160.1	169.5	198.4	191.5	193.3	195.1
11	Supply Chain	80.2	77.0	63.6	67.0	67.0	67.7
12	Performance Imprvmnt & Oversight	28.8	29.5	8.5	9.1	9.2	9.4
13	Inspection & Mtce Services	37.7	45.6	38.1	30.8	31.2	31.4
14	Commercial Services[1]	1.3	1.4	1.5	1.7	1.3	1.4
15	Waste & Transportation Services	4.8	5.7	4.2	4.8	5.0	5.1
16	Nuclear Level Common	11.1	2.9	(7.1)	12.6	9.9	13.1
17	**Total Support**	437.0	444.5	422.8	423.4	420.6	428.3
18	**Total**	1,204.9	1,252.4	1,216.5	1,187.0	1,192.3	1,219.8

Notes:
1. Previously Commercial Activities.

4.

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.

5.

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

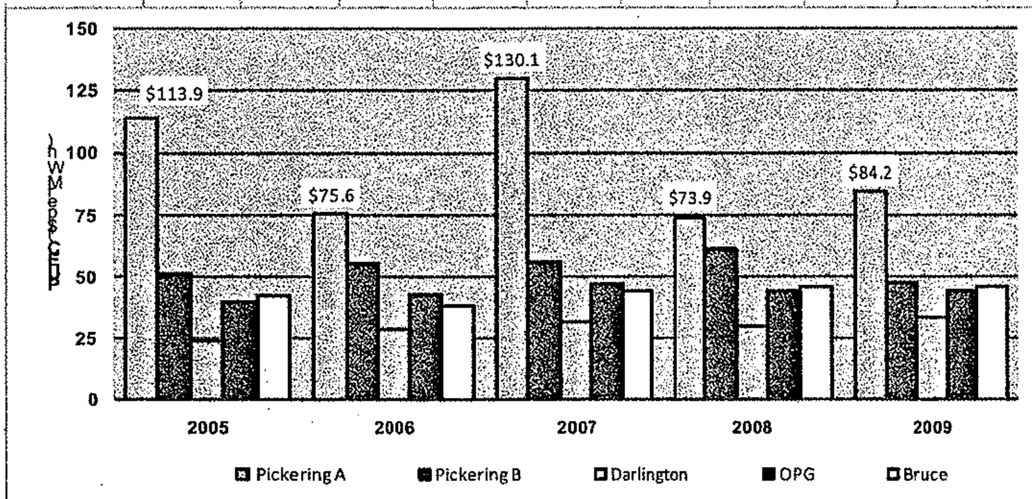
Year	Total Non-Energy Load Charges (Including Global Adjustment)[3] ($M)	Global Adjustment ($M)
2010	26.3	17.0
2011	30.3	21.0
2012	33.5	24.2

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.

ONTARIOPOWER GENERATION

Financial Plan

($ Millions)	Business Plan 2010-2014 2010	2011	2012	2013	2014	Plan-Over-Plan 2010	2011	2012	2013
OM&A Base and Outage Expenditures									
Pickering A	260.1	236.5	235.0	240.7	259.1	(17.3)	(18.1)	(15.7)	(26.0)
Pickering B	371.9	369.5	366.5	373.8	392.8	(13.9)	11.9	5.0	(0.2)
Darlington	398.2	362.6	372.1	471.6	426.9	(17.5)	(23.2)	(28.5)	(39.3)
Engineering & Modifications	68.4	63.9	63.8	66.8	66.9	(11.2)	(14.5)	(16.3)	(16.9)
Nuclear Programs & Training	234.1	249.7	253.9	255.9	264.3	(30.4)	(18.5)	(24.9)	(24.6)
Nuclear Supply Chain	68.6	68.4	69.1	69.3	70.5	(3.3)	(3.4)	(3.8)	(5.2)
Inspection Maintenance & Commercial Services	32.5	32.9	33.2	33.5	33.5	(7.6)	(9.0)	(10.8)	(12.2)
Nuclear Waste Management	4.3	4.4	4.6	5.4	4.3	(0.3)	(0.4)	(0.5)	(0.7)
PINO	9.1	9.2	9.4	9.6	10.0	(0.6)	(0.6)	(0.7)	(0.7)
CNO Office / Other	22.6	9.9	13.1	11.7	11.9	13.4	0.3	0.3	0.3
Total Base & Outage	**1,470.0**	**1,407.0**	**1,420.8**	**1,538.3**	**1,540.4**	**(88.8)**	**(75.3)**	**(96.0)**	**(125.5)**
OM&A Portfolio Projects	111.7	108.3	111.2	115.7	121.2	6.7	11.9	11.2	15.7
OM&A PB Continued Operations	1.8	19.9	17.0	11.9	11.3	(2.0)	19.9	17.0	11.9
OM&A P2/P3 Projects	20.6	0.0	0.0	0.0	0.0	9.1	0.0	0.0	0.0
Total OM&A	**1,604.1**	**1,535.1**	**1,549.0**	**1,665.9**	**1,672.9**	**(75.0)**	**(43.5)**	**(67.8)**	**(97.9)**
Fuel & Waste Provision Expense									
Fuel (Uranium & Combustion Turbine Unit)	178.9	209.1	233.2	232.5	238.6	(0.5)	(14.6)	(17.9)	(16.6)
Fuel Provisions	23.5	25.7	27.2	27.9	29.9	(1.3)	(1.2)	(1.4)	(10.3)
Total - Fuel & Waste Provisions	**202.4**	**234.8**	**260.5**	**260.4**	**268.5**	**(1.7)**	**(15.7)**	**(19.3)**	**(27.0)**

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.

9.

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.

administrative buildings), maintenance of OPG work equipment and vehicles, and travel and accommodations for staff (associated with off-site technical training, participation in industry conferences, technical standard working committees, World Association of Nuclear Operators audits as well as conducting supplier audits by Supply Chain). The final component of Other is inventory adjustments, which are addressed in two ways:

- An inventory valuation provision, which is assessed on a quarterly basis and adjusted as required. The provision addresses inventory which has been de-valued due to shelf-life expiry and subsequent disposal, and inventory losses identified through the cycle count or physical verification process.
- An obsolescence provision, which is assessed on an annual basis. The provision recognizes the unique nature of the majority of nuclear materials, and their limited use outside of OPG, by allocating (depreciating) the expected residual inventory value at end of station life over the remaining station life. This provision also addresses the cost impact of technical obsolescence, due to design changes or other technical factors that would preclude inventory use within the stations.

License: The resource type License (averaging 1.7 percent of total base OM&A over the test period) covers fixed costs of the station operating licences, as well as a forecast of the costs to be charged by CNSC on a fee-for-service basis relating to services for review of additional work programs such as refurbishment and new nuclear build programs.

Augmented Staff: The resource type Augmented Staff (averaging less than 0.3 per cent of total Base OM&A over the test period) reflects the limited costs of engaging external personnel to backfill for vacancies within the organization or provide specialized expertise within an organization.

3.0 INITIATIVES AND TRENDS

As outlined in Ex. F2-T1-S1, the 2010 - 2014 Nuclear business planning process incorporated the recommendations from the 2009 nuclear benchmarking initiative. The resulting OPG Nuclear business plan therefore specifies financial and operational targets to address performance gaps identified during the benchmarking initiative.

Numbers may not add due to rounding.

Table 2
Base OM&A - Nuclear ($M)

Line No	Resource Type	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan	Test Period Percentage[1]
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Labour Regular**	880.4	902.9	901.3	898.7	908.9	941.8	76.7%
2	**Overtime**	57.9	62.6	52.0	29.9	31.1	32.6	2.6%
3	**Augmented Staff**	10.2	12.1	13.1	6.9	5.5	1.4	0.3%
4	**Materials**	81.4	88.9	78.3	80.3	81.9	80.7	6.7%
5	**License**	16.9	18.2	22.1	19.6	20.2	20.9	1.7%
6	**Other Purchased Services**	121.7	128.1	114.7	109.7	102.1	99.6	8.4%
7	**Other**	36.4	39.6	34.9	42.0	42.7	42.8	3.5%
8	**Total**	1,204.9	1,252.4	1,216.5	1,187.0	1,192.3	1,219.8	100.0%

Notes:
1 Test Period Percentage = Sum of Test Period Resource Costs divided by Sum of Test Period Base OM&A.

SEC Interrogatory #027

Ref: Ex. F2-T2-S1, Table 2

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

Please explain how the licence fee from the CNSC is calculated. In particular please explain why there is an approximately 22% increase in fees in 2009 and an 11% decrease budgeted for 2010.

Response

Canadian Nuclear Safety Commission ("CNSC") licence fees are based on the level of effort for station regulatory oversight, using a regulated full cost recovery fee model. Licensing costs include the cost of CNSC staff directly involved with OPG issues, as well as an allocation for the associated regulatory support effort, indirect regulatory activities and overheads.

As indicated in Ex. F2-T2-S1, Table 2, there was a significant increase in 2009 for CNSC fees, as the CNSC had increased staff to support: alignment of regulatory practices to International Atomic Energy Agency guidance documents; the demand for CNSC attention to planning for industry-wide refurbishment activities and new nuclear; and the CNSC need to recruit and train staff to meet the anticipated demands.

The data presented in Ex. F2-T2-S1, Table 2 for 2010 – 2012 was developed based on information provided by the CNSC early in their business planning process. Subsequently, OPG has been informed of increased cost estimates in the order of $6.5M per year throughout 2010 – 2012, reflecting the drivers outlined above.

GEC Interrogatory #023

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.

GEC Interrogatory #022

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

Regarding the statement on page 7 of Attachment D2-2-1: "Time required obtaining CNSC approval of the EA (TCD: October 2012) – currently estimated as approximately 18 months from the submission of the EA Project Description (TCD: May 2011)". How long did it take for OPG to gain approval from the CNSC for its environmental assessment on the proposed Pickering B nuclear station following its submission of an EA project description?

Response

It took 31 months following the submission of the Environment Assessment ("EA") project description until the Canadian Nuclear Safety Commission ("CNSC") accepted its staff EA report for the proposed Pickering B Nuclear Station. The key dates are noted below:

EA project description issued to CNSC	June 15, 2006
OPG Submission of Pickering B EA Screening Report	December 17, 2007
CNSC issued its final Pickering B EA Screening Report	October 10, 2008
One-day public hearing to consider results of EA Screening Report	December 10, 2008
CNSC acceptance of EA Screening Report	January 26, 2009

IMPACT STATEMENT

This exhibit has been prepared to show the impact of three changes since OPG filed its application in May 2010. The three changes are:

1. Increased fees for 2011 and 2012 from the Canadian Nuclear Safety Commission ("CNSC") which impact Nuclear Base OM&A;
2. Changes to Management compensation as a result of the *Public Sector Compensation Restraint to Protect Public Services Act, 2010* (the "Public Sector Compensation Restraint Act"); and
3. Changes to forecast pension and other post employment benefit ("OPEB") costs, primarily as a result of changes to forecasts of discount rates and actual pension fund performance.

Each of these matters is described separately below.

CNSC Fees

As indicated in the response to interrogatory L-12-027, OPG has been informed by the CNSC of increased regulatory fees for the test period. Licensing costs include the cost of CNSC staff directly involved with OPG issues, as well as an allocation for the associated regulatory support effort, indirect regulatory activities and overheads. The drivers of the increased fees include: alignment of regulatory practices to International Atomic Energy Agency guidance documents; the demand for CNSC attention to planning for industry-wide refurbishment activities and new nuclear; and the CNSC need to recruit and train staff to meet the anticipated demands.

The estimated revenue requirement impact of the increase in CNSC fees is $13M over the test period.

Management Compensation

The Public Sector Compensation Restraint Act was introduced after OPG's business plan for

2010-2014 had been approved. The Act addresses restrictions to increases in compensation for employees that do not collectively bargain compensation. For OPG, the Public Sector Compensation Restraint Act will impact Management employees.

As indicated in interrogatory L-01-075, OPG included an increase of 3 per cent in each of 2011 and 2012 in its Management compensation levels. As a result of the *Public Sector Compensation Restraint Act*, OPG is removing Management wage escalation for the period to April 1, 2012 from its test period revenue requirement for the regulated facilities, reducing costs by $12M.

<u>Pension and OPEB Costs</u>

As discussed in section 6.3.2 of Ex. F4-T3-S1, the projection of pension and OPEB costs requires an estimate of the value of the benefit obligations and the pension fund assets. Pension and OPEB costs are subject to significant variability to the extent that forecast assumptions, such as the discount rates, and assumed pension fund performance are different from actual values as of the end of the year preceding the forecast year.

The pension and OPEB costs forecasts in OPG's application for 2011 and 2012 were based on discount rates (presented in Chart 8 of Ex. F4-T3-S1) forecast during the 2010-2014 business planning process. Since the beginning of 2010, these discount rates have declined significantly. This decline has caused an increase in the forecast pension and OPEB costs for the test period. Specifically, the discount rates used to project pension, other post retirement benefits and the long-term disability plan costs have decreased from 6.80%, 7.00% and 5.25%, respectively, to 5.70%, 5.70% and 4.40%, respectively, as of the end of August 2010. The updated estimates of discount rates were provided by external actuaries.

Chart 8 of Ex. F4-T3-S1 also shows that pension cost forecasts were based on assumed rates of return on the pension fund assets of 9.0% in 2009 and 7.0% in 2010. The actual return for 2009 was approximately 15%, and the 2010 actual return as of the end of August 2010 is approximately 2.5%. The net effect of the updated returns for the two years is to offset, in part, the increase in pension costs due to changes in forecast discount rates.

OPG's updated total pension and OPEB costs for 2011 and 2012 have been projected by external actuaries as of the end of August 2010. The chart below shows the portion of these updated costs for 2011 and 2012 attributable to the prescribed facilities, as compared to the amounts included in the application per Ex. F4-T3-S1, Chart 9. The total projected increase over the two test years is $251.5M for nuclear and $12.7M for regulated hydroelectric.

Updated Pension and OPEB Costs ($M)

	Nuclear		Regulated Hydroelectric	
	2011	**2012**	**2011**	**2012**
Pension Cost				
As per Chart 9, Ex. F4-T3-S1	114.0	162.8	5.8	8.1
Projection as of August 2010	210.2	245.9	10.6	12.3
Increase	96.2	83.1	4.8	4.2
OPEB Cost[1]				
As per Chart 9, Ex. F4-T3-S1	159.3	166.7	8.0	8.3
Projection as of August 2010	196.5	201.7	9.9	10.1
Increase	37.2	35.0	1.9	1.8
Total Test Period Increase	251.5		12.7	

[1]Supplementary pension plans costs are included with OPEB costs.

Conclusion

The first two changes considered in this impact statement are effectively offsetting and OPG does not propose to revise its revenue requirement or payment amounts to reflect them.

Given the potential for significant variability between the updated forecast and actual pension and OPEB costs, OPG is not proposing to revise its proposed payment amounts or payments riders to address the projected increase in these costs. Instead, OPG proposes to address the forecast change to pension and OPEB costs by requesting that the OEB establish a variance account to record the revenue requirement impact of differences between forecast and actual pension and OPEB costs. For the 2011-2012 test period, OPG would bring the balance in this account forward for disposition during its next payment amounts application. OPG will file additional evidence supporting this request when it files the update to its variance and deferral account evidence with updated forecasts of balances for December 31, 2010.

business case summaries and also in a post-implementation review report.

These reports have been requested in the question. We are -- we have pulled these for submission, and are in the process of redacting employee names and other personal information from the documents before submission.

MR. KEIZER: Moving on, then, to AMPCO question No. 5, relating to Pickering B integrated safety report.

MR. REINER: This question asks for a status update on the approval of the Pickering B integrated safety review.

The Pickering B integrated safety review report was submitted to the Canadian Nuclear Safety Commission on September 25th, 2009.

The OPG board decided not to proceed with the Pickering B refurbishment project on November 19th, 2009, and that decision was concurred by the Minister of Energy on February 4th, 2010.

The decision was formally communicated to the Canadian Nuclear Safety Commission on March 31st, 2010, and although the documents have all been submitted to the Canadian Nuclear Safety Commission, and some have been approved, OPG and the Canadian Nuclear Safety Commission are not proceeding with any further review.

MR. KEIZER: Thank you.

Moving on to page 20 of the compendium and AMPCO question No. 7, related to long lead time items.

MR. REINER: So this question asks for major categories of items that require long lead times and what