Board Staff Interrogatory #109

Ref: Ex. F4-T1-S1, Attachment 1

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

OPG as a publicly accountable enterprise for financial accounting reporting purposes will be required to adopt IFRS on January 1, 2011. Page 5 of the 2009 Depreciation Review Committee (DRC) Report states, “The move to International Financial Reporting Standards (IFRS) has added another dimension to the DRC review…The 2009 DRC review addressed IFRS requirements and concluded that the components’ lives within each asset class are consistent.”

a) The above statements appear to suggest that there would be no changes to the basis upon which OPG’s depreciation expenses would be determined when IFRS is adopted. Please confirm, and provide an explanation.

b) Please provide the documentation including the analysis reviewed in the DRC’s review of this matter.

c) Please provide the reasons why the DRC has concluded that the components’ lives within each asset class are consistent.

Response

a), b) and c) See the response to Ex. L-01-010.

Board Staff Interrogatory #110

Ref: Ex. F4-T1-S1, Attachment1, page 8

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

Please identify the methodology used to select the regulated nuclear and hydroelectric asset classes for review in 2009.

Response

As outlined in Ex. F4-T1-S1, OPG's Depreciation Review Committee ("DRC") conducts a review of the service lives of its generating stations, including the Bruce A and B nuclear stations, and a selection of asset classes every year, with the objective of reviewing all significant asset classes over a five-year cycle.

The selection of asset classes for review in 2009 was based, in part, on: the dollar value of the asset class; whether it has been reviewed in the previous five years; and, whether the particular asset class has undergone any changes in its business environment based on feedback from technical contacts in the lines of business. All asset classes selected for review are approved by the Approvals Committee, which is made up of OPG's senior management. The methodology followed by the DRC for 2009 was the same methodology used in the DRC Reports filed in EB-2007-0905.

Board Staff Interrogatory #111

Ref: Ex. F4-T1-S1, Attachment 1, page 8

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

Comparative data was obtained from other utilities as part of the DRC's regulated hydroelectric asset class review. Please outline the methodology used for benchmarking against other utilities.

Response

For hydroelectric asset classes selected for review, the hydroelectric engineering department assessed the service life based on lifecycle planning data, site condition assessments and comparative data from other utilities. The comparative data is obtained by senior technical staff through their industry contacts, and is submitted to the Depreciation Review Committee ("DRC") for the asset classes identified for review through a standardized template.

General reviews were conducted in 2007 and 2008, based on service-life information from BC Hydro and Hydro Quebec. In addition, in 2008 and 2009, comparative data was obtained from Manitoba Hydro, TransAlta and Saskatchewan Power on specific asset classes. Asset service lives used by OPG for its hydroelectric asset classes lend themselves to comparison with assets of other utilities due to the similar nature of the technology used in hydroelectric energy production. OPG has found that the lives of its hydroelectric assets are typically comparable with those of other utilities.

The benchmarking of hydroelectric asset classes against other utilities is demonstrated in the 2009 DRC report (Ex. F4-T1-S1, Attachment 1, page 8), where the life for the Outdoor Structures asset class was recommended for change by the DRC from 75 years to 60 years. In that instance, data from BC Hydro, Manitoba Hydro, TransAlta and Saskatchewan Power indicated that OPG's life of 75 years for this class was above the average range used by these utilities. This was considered by the DRC, along with in-house assessments by hydroelectric engineering staff, in arriving at the recommended change.

Board Staff Interrogatory #112

Ref: Ex. F4-T1-S1, Attachment 1, pages 5 and 11

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

Why was a benchmarking approach not included in the regulated nuclear asset classes review given that there are a number of other CANDU reactor stations worldwide?

Response

OPG believes that it is more appropriate to use its own internal technical expertise and knowledge of nuclear equipment degradation mechanisms and equipment lives, as opposed to implementing a benchmarking-based approach, in reviewing asset class lives for its nuclear stations. The reasons are outlined below.

While the nuclear stations owned by OPG have many common design features, each of the five stations (Pickering A, Pickering B, Bruce A, Bruce B and Darlington) are slightly different in design. In addition, each of these stations is of a slightly different vintage. Also, OPG's nuclear stations are different in design from the CANDU plants operated in New Brunswick, Quebec, Argentina, Korea, China and Romania.

OPG is the world's largest operator of CANDU units, has some of the oldest CANDU units, and also has the most operational experience of all CANDU operators world-wide. OPG is heavily involved in technical exchanges with other CANDU operators, through organizations such as the CANDU Owners Group, and closely monitors equipment degradation issues in order to assess potential impacts on OPG's units. However, because OPG's units are among the oldest CANDU units, OPG is often the "lead" utility in terms of the knowledge of degradation issues, which may affect unit and component lives, and as such relies primarily on its own internal technical analyses.

Board Staff Interrogatory #113

Ref: Ex. F4-T1-S1, Attachment 1, page 8

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

What were the reasons for concluding that there is no evidence to support changes to the service lives for any regulated hydroelectric asset classes except for outdoor structures?

Response

This decision was made by the 2009 Depreciation Review Committee, which accepted the results of the technical reviews conducted by OPG's hydroelectric engineering staff. These reviews found no evidence to support a change to existing asset service lives other than for outdoor structures. See the response to L-01-111 for a discussion of the review process followed by hydroelectric engineering staff.

Board Staff Interrogatory #114

Ref: Ex. F4-T1-S1

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

When is DRC review of the service lives of asset classes for generating stations, including Bruce stations, expected to reach 100%?

Response

Through the Depreciation Review Committee ("DRC") reviews conducted for the years 2006 – 2009, OPG has completed reviews for the majority of its asset classes. These reviews have provided significant coverage of asset class values for the nuclear and regulated hydroelectric facilities (i.e., 100 per cent coverage for hydroelectric and 74 per cent coverage for nuclear, as noted in Ex. F4-T1-S1, Attachment 1, pages 13 and 14, note ***). As stated in Ex. F4-T1-S1, page 4, line 18, OPG is targeting DRC review of all significant asset classes over a five year cycle. The remaining significant nuclear asset class reviews are expected to be substantially completed by the end of 2010.

Board Staff Interrogatory #115

Ref: Ex. F4-T1-S1

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

Please provide a copy of the 2008 Regulated Depreciation Review Committee Report.

Response

Attachment 1 is the requested copy of the 2008 Regulated Depreciation Review Committee Report.

ONTARIO POWER GENERATION

DEPRECIATION REVIEW COMMITTEE RECOMMENDATIONS

Regulated Business

December 2, 2008

Regulated - Depreciation Review Committee Recommendations

EXECUTIVE SUMMARY

Background and Scope of 2008 Review

The Depreciation Review Committee (DRC) annually reviews the service lives of all major facilities and a selection of asset classes with the objective of reviewing all significant asset classes over a five year period. The facilities and assets of the regulated business are selected for review by the Approval Committee, which is comprised of the Chief Operating Officer, Chief Financial Officer, Chief Nuclear Officer, EVP Hydro and SVP, Corporate Affairs. The Approval Committee also approves the recommendations of the DRC. The scope of the 2008 DRC review focused on continuing the five year cyclical review of assets.

Nuclear Review

For the Nuclear line of business, in addition to dollar value as a basis for selection, selections also included those asset classes that are close to station life in terms of remaining service years. For Nuclear, asset classes with a net book value of $1,055 million were reviewed in 2008 (see Appendix C for details). The total asset classes reviewed included $415 million of asset classes not reviewed in previous five years and $640 million pertaining to Process System and Instrumentation & Control asset classes that had been previously identified for further follow up in the 2006 DRC report.

In this year's review of Nuclear station end of life dates, consideration was given to refurbishment plans around Pickering B and Darlington. With respect to the refurbishment of these stations, feasibility studies are currently underway. As a result, the impact on station end of life dates from potential refurbishment at Pickering B and Darlington will be considered in the 2009 DRC review. As such, no changes were made to the station end of life dates for the nuclear generating facilities.

Regulated Hydroelectric Review

For the Regulated Hydroelectric line of business asset classes of $417 million were reviewed in 2008 (see Appendix C for details). The total asset classes reviewed included, $305 million of asset classes not reviewed in the previous five years and $112 million pertaining to asset classes that were reviewed in the 2006 DRC.

This year's review of asset classes included obtaining comparative data from other utilities to address recommendations from the OEB.

IFRS Requirements

With the move to International Financial Reporting Standards (IFRS), another dimension to this year's DRC review has been added. While conducting the DRC review a detailed review of the fixed assets was performed to assess whether components within a significant asset class have consistent lives. A separate IFRS results report has been prepared indicating that the components within the asset class lives are relatively consistent.

Recommendations from 2008 Review

Based on its review of the evidence submitted, the DRC recommends the following:

- The service lives of Nuclear asset classes listed in Appendix C remain unchanged.
- The average service lives of the Nuclear stations remain unchanged as follows:
  - Pickering A units 1 and 4 2021
  - Pickering B 2014
  - Darlington 2019
  - Bruce A 2035
  - Bruce B 2014
- The service lives of Regulated Hydroelectric stations and asset classes listed in Appendix C remain unchanged with the exception of the following:
  - Specified bridges within asset class # 10709000 have a reduced service life which will result in an annual increase to depreciation of less than $1million.

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1.0 INTRODUCTION

1.1 Work of the Depreciation Review Committee

The DRC annually reviews the service lives of all major facilities and a selection of asset classes, with the objective of reviewing all significant asset classes over a five year period. The selection of asset classes to be reviewed and the approach to be taken are documented in a plan prepared by the DRC which requires the approval of a committee made up of OPG's senior executives (The Approval Committee). This committee includes the Chief Operating Officer, Chief Financial Officer, Chief Nuclear Officer, EVP Hydroelectric and the SVP, Corporate Affairs. On completion of each annual review, the DRC prepares a report that documents both the engineering and financial/accounting aspects of the review. The recommendations from the DRC reviews are used to estimate the depreciation expense that is recorded in OPG's consolidated financial statements, in the business plan and in periodic payment amount applications to the Ontario Energy Board (OEB).

Since the main purpose of the DRC review is to support depreciation expense to be reported in OPG's consolidated financial statements, business plans and OEB periodic payment amount applications, the DRC is led by staff members from Corporate Finance, particularly in Corporate Accounting, External Reporting, Financial Planning and Regulatory Finance. However, in order to properly assess the service lives of each major facility and the selected asset classes, the DRC carries out its review from an engineering and technical perspective. As such, it is important for the DRC to have the support of representatives from the various lines of business who have substantial knowledge and expertise in the operations of each of the various plants operated by OPG. This support is provided by senior management for each line of business who appoint the appropriate technical and engineering staff to assist the DRC in their review. Appendix A provides a listing of DRC members and supporting members.

In addition to providing support for depreciation expense used in OPG's consolidated financial statements, business plans and periodic payment amount applications to the OEB, the move to International Financial Reporting Standards (IFRS) has added another dimension to this year's DRC review. For IFRS the objective is to provide assurance that components within each class have a relatively consistent service life. The Approval Committee decided that the 2008 DRC review could address IFRS requirements. IFRS issues will however be addressed separately by the DRC and will not be part of the scope of this report. The conclusion of the IFRS report is that the components within the asset class lives are relatively consistent and the dollar impact on depreciation of the exceptions was less than $1 million.

1.2 Scope of the Review for 2008

In order to achieve sufficient asset coverage in support of recorded depreciation in OPG's consolidated financial statements and business plans, the DRC's deliberations for 2008 continued to focus on the review of both station service lives and asset classes. Appendix C provides a listing of assets that were reviewed by the DRC in 2008 along with the percentage of asset coverage to date. The selection of these assets was both reviewed and approved by the Approval Committee.

2.0 Review of Nuclear Assets

2.0.1 Overview

In conducting its 2008 review of fixed assets at Pickering and Darlington sites, technical staff considered both station service life as well as fixed asset service lives as indicated in Appendix C. Total net book value of nuclear assets reviewed was $1,055 million, representing 26% of total nuclear fixed assets in service as at December 31, 2007. In estimating service lives, assessments were performed by the designated site technical staff and approved by nuclear senior management. In many cases, service life assumptions for asset classes are limited or capped by station end of life assumptions. The technical assessments have been documented in various plant reviews, assessments and inspections. Station technical end of life determinations are primarily driven by forecast pressure tube life but must also take into account decisions and risks in the refurbishment decision making process.

In establishing an end of life date for Bruce B, the 2007 DRC used the published OPA Integrated Power System Plan filed to the OEB on August 29, 2007 and historical performance of the station, to estimate a 2014 average end of life date for Bruce B. Regarding the 2008 review of Bruce B, there has been no official notification by Bruce Power for changing the service life expectancy.

In establishing an end of life date for the Bruce A facility, the DRC has relied on press releases issued by Bruce Power. For the 2007 review, the DRC relied on a press release issued in 2007 by Bruce Power to estimate a 2035 average end of life date. For the 2008 DRC review, there has been no additional information issued by Bruce Power or other sources for changing the service life expectancy.

Regarding the review of service life for station or unit end of life date, the DRC has set out the following principles supported by the Approval Committee that will apply to the 2008 review:

a) Service lives for depreciation purposes are assessed at the station level based on average unit lives.

b) Station end of life date estimates recommended by the DRC are based on technical and risk assessments prepared by site engineering staff and reviewed by senior management. In order to evaluate these assessments in an effective manner, the DRC has requested that engineering staff attach confidence levels to any recommendations proposed with regards to station end of life date estimates. The DRC considers recommendations on station end of life dates if confidence levels are 70% or higher.

2.1.1 Pickering A, Units 1 and 4

The technical/engineering review of Pickering A, Units 1 and 4's selected asset classes (see Appendix C) and estimated average station end of life date was based on plant reviews, assessments and inspections. This review indicated no change to the service lives of the asset classes and to the average end of life date of the station. Risks have been identified pertaining to the station end of life determination, which is currently related to the pressure tube end of life for the earlier of Units 1 and 4. A technical report was commissioned during 2008 to assess the impact on the operation of Pickering A without Pickering B in operation subsequent to 2014. Management is currently assessing the technical and economic implications from this report and as such, a change to the Pickering A station life is not warranted at this time.

2.1.2 Pickering B

The technical/engineering review of Pickering B's selected asset classes (see Appendix C) and estimated average station end of life date was based on plant reviews, assessments and inspections. This review indicated no change to the service lives of the asset classes and to the average end of life date of the station. A feasibility assessment is currently underway regarding the refurbishment of Pickering B. In addition, OPG is also investigating the potential to continue to operate the station by up to 4 years beyond its current nominal end of life whether or not refurbishment proceeds. This review needs to address all technical risks as well as the regulatory risk of obtaining CNSC concurrence to operate the existing station assets for the continued operation period. Currently, it is too early to conclude that there is a high degree of confidence that continued operation of up to 4 years will be achieved. As a result, no change to the station end of life date is being proposed at this time.

2.1.3 Darlington

The technical/engineering review of Darlington's selected asset classes (see Appendix C) and estimated average station end of life date was based on plant reviews, assessments and inspections. This review indicated no change to the service lives of the asset classes and to the average end of life date of the station. As with Pickering B, a feasibility assessment is also currently underway regarding the refurbishment potential of the Darlington station. This assessment is in its early stages and it is too early to conclude with a high degree of confidence on the path forward. As such, a high confidence for extension does not exist and no change to the station end of life date is being proposed at this time.

2.2.0 DRC Recommendations – Nuclear End of Life Dates

Based on the review of the documentation submitted and discussions with nuclear technical personnel, the DRC recommends the following:

- No changes to the asset classes reviewed and to the average service lives of the nuclear stations.

- For next year's DRC process, consider placing capital expenditures for new "feeder tube" investments into a separate class as they are currently embedded within the Process Systems asset class. The rationale for this recommendation relates to evidence from Pickering A and Darlington suggesting that feeder tubes could be a life limiting component and would not last the assumed 40 years assigned to this asset class.

  When the relative magnitude of these components within the overall magnitude of the asset class was assessed, it was concluded that the dollar impact on depreciation for this change was not significant. Furthermore, since none of the station lives have been extended this year, the immediate need to separate existing feeder tubes as a separate asset class does not exist. Should the decision to refurbish existing plants be made at a future date, investment in new feeder tube construction should be segregated from the existing Process Systems class and assigned a shorter life span when placed in service.

- For next year's DRC process, explore the potential to tie asset class technical lives that are floating and dependent on station end of life assumptions. Several asset classes in the nuclear technology represent support infrastructure that is intended to last until station end of life. As such, the lives of these asset classes can vary depending on changes to the station end of life date. Allowing these infrastructure process type systems to be depreciated specifically to the station end of life reduces the possibility of depreciating them too quickly if station end of life dates are extended. It also more directly reflects their period of technical value.

Table 2.2.0

Summary of End of Life Dates - Nuclear

Station	**Current End of Life Date** *(no changes proposed)* **(Dec. 31, unless otherwise stated)**
Pickering A Unit 1	2021
Pickering A Units 2 & 3*	n/a
Pickering A Unit 4	2021
Pickering B	2014***
Darlington	2019
Bruce A**	2035
Bruce B**	2014

* Assets written off in 2005 as a result of the decision not to proceed with the refurbishment of the units.
** Assets are on lease to Bruce Power for 17 year term (commenced May 1, 2001).
***End of life occurs on September 30, 2014.

3.0 Review of Station End of Life - Regulated - Hydroelectric Facilities

3.0.1 Overview

Hydroelectric facilities have 6 regulated stations (Sir Adam Beck One, Sir Adam Beck Two, Sir Adam Beck Pump Generating Station, DeCew Falls One, DeCew Falls Two and R.H. Saunders). OPG has 27 dams that are associated with stations in the Niagara Plant Group stations and 3 dams are associated with the R.H. Saunders Generating Station.

In conducting its 2008 review of Niagara Plant Group and R.H. Saunders stations, the DRC has relied extensively on recent technical assessments and comparative utility data obtained by site technical staff and approved by hydroelectric management. Comparative data was obtained from the following utilities for the majority of the asset classes: BC Hydro, TranAlta Utilities Corp, Manitoba Hydro and Sask Power.

Total net book value of hydroelectric assets reviewed was $417 million, representing 11% of total regulated hydroelectric fixed assets in service as at December 31, 2007. Appendix C lists the asset classes that were reviewed.

3.0.2 Niagara Plant Group and R.H. Saunders

The review of the asset classes for Niagara Plant Group and R.H. Saunders sites as indicated in Appendix C was conducted by senior Hydroelectric engineering personnel. With the exception of land, the asset classes reviewed for which comparative data was available were consistent with those of the peer utilities. For any differences in the service life, the estimated annual depreciation impact was less than $1M.

The review indicated the following:

Asset Class #10100000 Land – Comparative data from TransAlta, Manitoba Hydro and BC Hydro indicated that land was not depreciated (no land data comparatives were provided by Sask Power). Currently OPG depreciates Hydroelectric land over 100 years.

Asset Class #10709000 Bridges – A third party consultant review was conducted for all the Niagara Plant Group bridges. This review recommended service life changes to the following bridges relating to the Niagara Plant Group, all other service lives remained unchanged at 65 years:

- Merritville Highway Bridge should have 2010 end of life date;
- Beaverdam Road Bridge should have 2010 end of life date;
- Niagara Falls Road Bridge should have 2009 end of life date;
- Laura Secord Bridge should have 2008 end of life date.

Hydroelectric engineering staff has recommended that the DRC accept the recommendations provided for the two asset classes discussed above.

For all remaining asset classes in Appendix C, the review was based on technical engineering assessments and comparative data obtained from the following utilities: BC Hydro, TransAlta Utilities Corp., Manitoba Hydro and Sask Power. Based on this review, hydroelectric engineering staff has concluded that there is no evidence to support a change in any of these asset service lives (other the land asset class noted previously), and that components within each asset class have a consistent service life.

3.1.0 DRC Recommendations

Based on the evidence submitted and discussions with engineering staff concerning the asset classes reviewed, the DRC recommends the following with respect to asset end of life dates:

1. No change to asset class #10100000 (land) end of life date.

Although the review conducted by hydroelectric staff has indicated that the service life should be changed to an infinite life based on comparative data obtained from other utilities, the DRC is recommending no change to this asset class for the following reasons:

- It has been accepted past practice for OPG to depreciate hydroelectric land over a life of 100 years to account for the eroding of land due to flooding;
- Annual depreciation of regulated hydroelectric land is insignificant (approximately $0.2 million per annum).

In addition, the technical review of land has resulted in a recommendation that site improvements be removed from this asset class and set up as a stand alone asset class with a life of 75 years. The DRC is recommending that this change not be adopted as the net book value in question is less than $0.5 million.

2. No change overall to asset class #10709000 (bridges) end of life date.

Specific changes within the class are recommended as follows:
The DRC recommends that we accept the service life changes recommended to the Merritville Highway Bridge, Beaverdam Road Bridge, Niagara Falls Road Bridge and Laura Secord Bridge. The estimated impact to annual depreciation will be under $1 million.

3. The DRC has accepted the recommendation, from the review conducted by hydroelectric technical and engineering staff of the remaining asset classes outlined in Appendix C, that no change to the end of life dates be made.

APPENDIX A

THE DEPRECIATION REVIEW COMMITTEE

The DRC includes a representatives from each operating business unit, as nominated by the business unit representatives of the Approval Committee, as well as representatives having experience in finance, investment planning and rate regulation.

Representatives on the DRC are shown in the following section.

<u>DRC members</u>

Tom Staines (Chairperson), Corporate Accounting
Dave Bell, Corporate Accounting
John Tipold, Corporate Accounting
Vassa Chase, Corporate Accounting
Ian Rhoden, External Reporting and Policy
Lubna Ladak, Regulatory Finance
Sandra Radcliffe, Financial Forecasts
Randy Pugh, Regulatory Affairs & Corporate Strategy
Eleen Louie, Asset Management
Stephen Rogers, Corporate Business & Investment Planning
Jack Fong, Corporate Business & Investment Planning

Business Unit Representatives:
Don Brazier – Hydroelectric Finance
Rani Iyer – Hydroelectric Finance
Mike Cooke - Hydroelectric Engineering
Gord Haines - Hydroelectric Engineering
Ian Munroe - Hydroelectric Engineering
Pius Ko – Hydroelectric Engineering
Jeff Tenant – Hydroelectric Engineering
Jim Wagner – Hydroelectric Engineering
Jamie Deforge – NEPG Asset Manager
John Mauti – Nuclear Finance
Bob Morrison – Nuclear Engineering

APPENDIX B

ONTARIO POWER GENERATION'S FIXED ASSETS

Ontario Power Generation categorizes its fixed assets as follows:

- major fixed assets under construction;
- major fixed assets in service; and
- minor fixed assets

Major fixed assets under construction are comprised of land, buildings, plant, and equipment in the process of being acquired or constructed. The ultimate economic benefit of acquiring and constructing these assets is considered to relate to future periods.

Major fixed assets in-service consist of land, buildings, plant and equipment that have been declared in-service.

Minor fixed assets are comprised of transport and work equipment, service equipment, office furniture and equipment, computers other than those directly supporting the bulk electricity system and railway equipment. These assets are accounted for on a more detailed unit basis for control reasons.

OPG maintains accounting records of the costs of its fixed assets. Their accumulated depreciation and retirements provide a history of the assets constructed or acquired by OPG. Consistent with the other major electrical utilities in North America, OPG maintains its fixed asset accounting records on the basis of asset classes.

For depreciation purposes, plant components having compatible service lives are aggregated into the standardized asset class accounts established for each of the following major fixed asset classifications:

- generation facilities
  - Nuclear
  - Hydroelectric
  - Fossil
- communications and system control facilities
- administration and service facilities

Aggregates of the values recorded in the asset classes form a property record for accounting purposes. A property record establishes a physical entity such as a generating station.

APPENDIX C

Assets Reviewed for 2008 DRC (million dollars)

Nuclear

Class #	Description	Cost	Acc Dep	NBV	Life (Years)	Previous DRC Review
15340000	Process Systems	606	268	338	40	2006
15460000	Auxiliary Systems	110	51	59	40	
15550000	Reactor Bldg Cable	90	29	61	40	
15600000	Instrument & Control	539	237	302	30	2006
15701000	Water& Fire Protection	282	99	183	25	
15720000	Common Service Systems	225	113	112	35	
	Total Nuclear Reviewed in 2008	**1,852**	**797**	**1,055**		

Hydroelectric

Class #	Description	Cost	Acc Dep	NBV	Life (Years)	Previous DRC Review
10100000	Land	24	2	22	100	
10210000	Service & Equipment Bldg	62	9	53	50	
10300000	Linings of canal	69	6	63	75	
10306000	Surge tanks, pipeline, conduit, penstock	102	12	90	75	
10502000	Switching & Power Cable	62	13	49	45	2006
10601000	Mechanical Equipment	32	11	21	55	
10700000	Auxiliary Systems	86	23	63	30	2006
10709000	Owned Bridges	65	9	56	65	
	Total Hyel Reviewed in 2008	**502**	**85**	**417**		

Asset Coverage to date (million dollars)

	Nuclear	Hydroelectric	% of Regulated Fixed Assets in Service Reviewed by DRC
Total Reviewed 2003 to 2007	1,540	3,552	
New Asset Classes reviewed in 2008	415	305	
Total Reg Reviewed to Date	**1,955**	**3,501**	**69%**

Board Staff Interrogatory #116

Ref: Ex. F4-T1-S1, page 3

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

OPG stated that since it does not operate the nuclear units that are on lease to Bruce Power, the assessment of end-of-life dates for depreciation purposes for the Bruce Nuclear Generating Stations were not based on life limiting components. Key factors used included: information relating to the operation and refurbishment of the Bruce stations made publicly available by Bruce Power, publicly available information on the Bruce stations' performance since their lease to Bruce Power and information on plans for the Bruce stations were inferred from publicly available reports from the IESO and the OPA.

a) Why is the station end-of-service life dates for depreciation purposes for the Bruce Nuclear Generating Stations not determined based on life-limiting components used for the regulated nuclear stations?

b) Please explain the methodology used to determine end-of-service life dates for the Bruce Nuclear Generating Stations.

c) Why is significant reliance placed on "publicly available" information in the assessment of the end-of-service dates for the Bruce Nuclear Generating Stations given the complexity of the nuclear technology?

d) If technical data is not available to conduct an engineering analysis on the life-limiting components for Bruce Nuclear Generating Stations, why does OPG as owners of the stations not have an agreement in place to obtain this information?

Response

The preamble to the question is incomplete and the related inference that publicly available information is the dominant factor in determining end-of-life service dates is incorrect. The preamble excludes the other factors that were identified by OPG in its prefiled evidence as relevant in assessing end-of-life dates for depreciation purposes of the Bruce Generating Stations. Exhibit F4-T1-S1, page 3, lines 24-30 states that, in addition to the factors cited above, key factors include "historical performance of the Bruce stations prior to their transfer via lease to Bruce Power" and "the performance and equipment condition of similar stations that continue to be owned and operated by OPG".

a) The basis of the question is incorrect since life-limiting components are considered in the analysis of end-of-service life dates for depreciation purposes for the Bruce Generating Stations. Specifically, OPG understands, as is outlined in the 2009 Depreciation Review Committee ("DRC") report in Ex. F4-T1-S1, Attachment 1, page 6, that the service lives of the Bruce B Generating Station units are limited by the expected lives of the pressure tubes, similar to OPG's Pickering B Generating Station. As indicated in Ex. F4-T1-S1, page 7 and in Ex. F2-T2-S3, OPG is currently collaborating with Bruce Power under the auspices of the CANDU Owners Group to assess whether the life of the pressure tubes, and therefore the end of service life dates for the Bruce B and Pickering B Nuclear Generating Stations, could be extended. The findings of the DRC, based on the information available at that time, as described in Ex. F4-T1-S1, page 7, lines 30-31 and page 8, lines 1-4, found "no reason to conclude that sufficient confidence exists for extending the operating lives of the Bruce B units in the absence of such confidence for the Pickering B units".

The consideration of additional factors, including publicly available information, cited in the question is a prudent and practical way to address the fact that OPG does not operate the nuclear units on lease to Bruce Power and, consequently, the fact that the degree and currency of detailed technical information and access to in-house experts, which OPG has for the stations it operates, are not as readily available for the purposes of assessing end-of-life dates for depreciation purposes. As a result of these limitations, OPG also cannot unilaterally apply the assumptions used around life-limiting components for the prescribed nuclear stations to the Bruce Generating Stations.

b) The methodology OPG uses to determine the end-of-life dates for depreciation purposes for the Bruce Generating Stations is similar to the approach used for OPG's Pickering and Darlington Generating Stations, as described in Ex. F4-T1-S1, Attachment 1, pages 5-7. OPG requires the same high degree of confidence in order to change the life of Bruce stations as it does for the stations it operates.

OPG's approach can be summarized as follows:

1. OPG forecasts the projected dates that the Bruce units will reach "nominal" end of life of the pressure tubes (the typical life limiting component) by:

    i. Reviewing information available through the CANDU Users Group on current effective full power hours on the existing pressure tubes of each Bruce unit; and

    ii. Applying a reasonable forecast of a future capacity factor to each of the Bruce units (e.g., 80 per cent or 85 per cent) to project the date at which the Bruce units will reach the nominal pressure tube end-of-life (i.e., 210,000 Effective Full Power Hours ("EFPH")). These dates for each unit are then averaged to derive a date for the station, which is then further adjusted either to the end of the previous year or the end of the current year, based on whether the average date for the station is in the first or second half of the year.

2. After calculating the dates, OPG performs several additional evaluations, including:

   i. Assessment of any evidence that may suggest that the "nominal life" dates are not based on high confidence and therefore should be moved earlier;

   ii. Assessment whether there is sufficient, if any, evidence that there is high confidence that these "nominal life" dates on the current pressure tubes could be exceeded;

   iii. Assessment whether there is sufficient, if any, evidence that Bruce Power has firm plans to refurbish the units. These firm plans would consist of signed agreements to refurbish the units, on a known timeline, with the OPA and/or evidence that the project is underway. In the case that it is determined that high confidence exists, a post-refurbishment end-of-life date is established.

3. OPG also assesses whether it is aware of any other major components, other than pressure tubes, which could limit the lives of the Bruce units.

Using this approach, OPG has established the Bruce A Generating Station end-of-life date for depreciation purposes is a post-refurbishment average date of 2035, and the Bruce B Generating Station end-of-life date for depreciation purposes is 2014, based on the nominal design life of pressure tubes of 210,000 EFPH. The approaches to these two stations are largely consistent with OPG's approaches to determining Darlington Generating Station and Pickering B Generating Station end-of-life dates, respectively. For Darlington Generating Station, the service life was not extended until OPG's Board of Directors had approved, and the shareholder had concurred with, proceeding with the definition phase of the Darlington Refurbishment Project. For Bruce A Generating Station a "post-refurbishment" expected life is used for depreciation purposes based on a known project underway to refurbish Bruce Units 1 and 2 and a signed agreement with the Ontario Power Authority to refurbish Bruce Units 3 and 4. This is noted in the 2009 DRC report (Ex. F4-T1-S1, Attachment 1, page 6). For both Pickering B Generating Station and Bruce B Generating Station, the level of confidence regarding the extension of the lives of the pressure tubes is a key factor, based on which neither station's life has been extended for accounting purposes. This is noted in Ex. F4-T1-S1, page 7, lines 30-31 and page 8, lines 1-4, and on pages 6 and 7 of the 2009 DRC Report.

c) As indicated in the introduction to the answer and part a) above, publicly available information is one of several sources of information considered in the assessment of the end-of-life dates for the Bruce nuclear stations, and OPG has not suggested in its pre-filed evidence that it places unduly high reliance on publicly available information versus other information. The reference to publicly available information for the purposes of assessing depreciation end-of-service life dates is relevant in the context of (i) information regarding plans for the Bruce units made available by Bruce Power or through OPA and IESO documents; and (ii) information regarding performance of the nuclear units since OPG leased these units to Bruce Power, available through published documents and industry web sites. This information has been used to establish a post-refurbishment end-of-life depreciation date for Bruce A Generating Station units, as described in part b).

d) OPG's agreement with Bruce Power does allow OPG to obtain certain information and certain physical access with respect to the condition of the Bruce stations. The lease agreement also requires Bruce Power to operate, repair and maintain the leased premises and assets in a manner consistent with Good Utility Practices, and stipulates that the premises must continue to meet the Minimum Handback Condition under the lease. However, the "Minimum Handback Condition" is defined as being the state of repair one would expect the premises to be in if Bruce Power had complied with all its obligations under the lease. This information alone is not sufficient for assessing end-of-life dates for depreciation purposes.

To date, OPG has not requested any further information beyond what it receives on an annual interval pursuant to the lease agreement, nor requested physical access to inspect the leased premises. No information has been received to date that would indicate that the assets are not being maintained appropriately. In addition, OPG must comply with its obligation under the lease not to unduly interfere with the leased premises and with Bruce Power operations. At the time the Bruce Lease was entered into in 2001, it was anticipated that OPG and Bruce Power would be in direct competition with each other in an open and competitive electricity marketplace in Ontario. As a result, the provision of information from Bruce Power to OPG with respect to the condition of the Bruce assets was to be minimized to the amount necessary for OPG to assure itself that the assets were being operated and maintained in accordance with Bruce Power's obligations under the lease.

Board Staff Interrogatory #117

Ref: Ex. EB-2007-0905, Payment Amounts Order, Appendix A, Table 3

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

a) Please confirm that the approved revenue requirement before mitigation (line 4) of $6,173.0 M does not include any income tax PILs.

b) Please confirm that the revenue deficiency before mitigation (line 5) of $767.0 M does not include any income tax PILs.

c) Please confirm that the mitigation prescribed by the Board: 22% of revenue deficiency (line 6) of $168.6 M, does not include any income tax PILs.

d) Please provide a calculation of regulatory income taxes for 2008 (9 months) and 2009 (whole year) based on the total test period revenue requirement before mitigation of $6,173.0 M. From the referenced Table 3, the total revenue requirement amounts for 2008 were $2,638.5 (506.2 + 2,132.3) M and $3,534.5 (674.2 + 2,860.3) M for 2009.

Response

a) OPG confirms that the approved revenue requirement before mitigation of $6,173.0M (EB-2007-0905, Payment Amounts Order, Appendix A, Table 3, line 4) does not include any regulatory income tax.

This is evident from the same appendix in Tables 1 and 2 that builds up the total approved revenue requirement before mitigation ($1,180.4M for regulated hydroelectric in Table 1, line 24 and $4,992.6M for nuclear in Table 2, line 24). Line 23 on Tables 1 and 2 entitled “Income Tax” shows $Nil.

b) OPG confirms that the revenue deficiency before mitigation of $767.0M (EB-2007-0905, Payment Amounts Order, Appendix A, Table 3, line 5) does not include any regulatory income tax.

As this revenue deficiency amount represents the difference between the indicated production revenue on line 3 based on the then existing payment amounts and the approved revenue requirement (before mitigation) on line 4 that does not include any regulatory income tax per part a) above, the revenue deficiency figure is understated by the amount of income tax related to the approved revenue requirement (before mitigation) of $6,173.0M. This figure is $172.5M as discussed in part d) below. As such, the revenue deficiency figure on line 5 would have been $939.5M and the approved revenue requirement before mitigation would have been $6,345.5M if regulatory income tax was included.

c) OPG confirms that 22 per cent of the revenue deficiency of $168.6M (EB-2007-0905, Payment Amounts Order, Appendix A, Table 3, line 6) does not include any regulatory income taxes because, as explained above in part b), the revenue deficiency itself does not contain any regulatory income taxes.

d) The requested calculation is found in the attached Table 1. Based on the table, the total regulatory income tax (including the tax gross-up) for the 21-month period ended December 31, 2009 associated with the approved revenue requirement before mitigation is $172.5M ($88.0M for 2008 plus $84.6M for 2009, difference due to rounding). Therefore, this amount forms part of the revenue requirement reduction calculation of $341.2M for the Tax Loss Variance Account shown in Ex. H1-T1-S1, Table 4, Note 1 ($66.0M + $106.5M = $172.5M).

OPG notes that the calculation of regulatory income taxes based on the pre-mitigation revenue requirement of $6,173.0M in Table 1 recognizes that this revenue requirement itself excludes regulatory taxes (as noted in part a)), and therefore the appropriate calculation of regulatory income taxes based on this revenue requirement should provide for both the incremental taxes associated with adding back the mitigation amount of $168.6M and the foregone tax expense for 2008-2009 on the post-mitigation revenue requirement. This approach is consistent with OEB's findings in EB-2009-0038 that the OEB ordered <u>both</u> the exclusion of the 2008 – 2009 regulatory income tax expense[1] and a further mitigation amount of $168.6M[2].

[1] On page 12 of Decision and Order in EB-2009-0038, the OEB stated regarding EB-2007-0905 that "the Board found that OPG should reduce its revenue requirement by eliminating any tax provision for 2008 and 2009."

[2] On page 13 of Decision and Order in EB-2009-0038, the OEB stated regarding EB-2007-0905 that "in addition, the Board ordered OPG to reduce its revenue requirement by 22 per cent of its revenue deficiency."

Table 1
Calculation of Regulatory Income Tax Expense Based on Pre-Mitigation Revenue Requirement ($M)
Nine Months Ending December 31, 2008 and Year Ending December 31, 2009

Line No.	Particulars	April 1 to Dec 31, 2008 Budget	2009 Plan
		(a)	(b)
		Note 1	Note 1
	Determination of Regulatory Taxable Income		
1	**Regulatory Earnings Before Tax**[2]	201.0	230.5
2	**Additions for Regulatory Tax Purposes:**		
3	**Depreciation and Amortization**	264.1	376.3
4	**Nuclear Waste Management Expenses**	25.4	24.2
5	**Receipts from Nuclear Segregated Funds**	25.5	29.0
6	**Pension and OPEB/SPP Accrual**	264.8	337.0
7	**Regulatory Asset Amortization - Nuclear Liability Deferral Account**	36.0	48.0
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**	44.5	56.7
9	**Other**	6.8	10.0
10	**Total Additions**	667.1	881.2
	Deductions for Regulatory Tax Purposes:		
11	**CCA**	226.5	306.0
12	**Cash Expenditures for Nuclear Waste & Decommissioning**	72.7	83.0
13	**Contributions to Nuclear Segregated Funds**	54.7	135.0
14	**Pension Plan Contributions**	174.8	239.0
15	**OPEB/SPP Payments**	51.0	73.0
16	**Regulatory Asset Deduction - Nuclear Liability Deferral Account**	2.0	2.3
17	**Other**	6.9	0.6
18	**Total Deductions**	588.6	838.9
19	**Regulatory Taxable Income**	279.5	272.8
20	**Income Tax Rate**	31.50%	31.00%
21	**Regulatory Income Taxes**	88.0	84.6
	Income Tax Rate:		
22	**Federal Tax**	19.50%	19.00%
23	**Provincial Tax**	14.00%	14.00%
24	**Provincial Manufacturing & Processing Profits Deduction**	-2.00%	-2.00%
25	**Total Income Tax Rate**	31.50%	31.00%

Notes:
1 All additions and deductions for regulatory tax purposes (Lines 2-18) are in the same amount as presented in Ex. F4-T2-S1, Table 9 in EB-2010-0008.

2 Regulatory Earnings Before Tax are computed as follows ($M):

Line No.	Particulars	2008	2009
1	Regulatory Earnings Before Tax from Ex. F4-T2-S1, Table 9, Line 1	40.7	49.5
2	Tax on Post-Mitigation Revenue Requirement per EB-2007-0905, Payment Amounts Order (Ex. F4-T2-S1, Table 9, Line 21 x 1 / (1-tax rate))	54.7	41.3
3	Mitigation per EB-2007-0905, Payment Amounts Order, App A, Table 3, Note 3	72.3	96.4
4	Tax on Mitigation Amount per Line 3 above (Line 3 x tax rate / (1-tax rate))	33.2	43.3
5	Regulatory Earnings Before Tax (Line 1+2+3+4)	201.0	230.5

Board Staff Interrogatory #118

Ref: Ex. F4-T2-S1, Table 6 - Actual Regulatory Income Taxes for 2008 and 2009

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

a) Please describe how OPG ensured that the calculations shown on Table 6 for actual 2008 and 2009 are consistent with the methodology used by Ernst & Young in ExhF4/Tab2/Sch1/Attachment1 for the years 2005 through 2007. Please provide the supporting analysis and worksheets.

b) Are the numbers shown in Table 6 derived from the actual tax returns for 2008 and 2009? If not, please provide alternate calculations that are derived from the actual tax returns.

c) In Table 7 the actual regulatory taxable income for January 1 to March 31, 2008 is shown as a profit of $77.6 M. In Table 6 the regulatory taxable income for the whole year 2008 is only $116.9 M. By subtraction, the regulatory taxable income for the 9 months of the prior 2008 test period was only $39.3 M.

   i) Please explain the steps OPG took to ensure that the financial and accounting cut-off procedures for the first quarter 2008 were correct, and that the procedures resulted in the correct taxable income for the first quarter.

   ii) Why was the taxable income for the first quarter 2008 so large in comparison to the last 9 months of 2008?

Response

a) The calculations and reconciliations to corporate income tax returns for 2005 – 2007 as presented in Ex. F4-T2-S1, Schedule A of Attachment 1 were prepared by OPG in accordance with the methodology outlined in sections 3 and 4 of Ex. F4-T2-S1 (these calculations are also presented in Ex. F4-T2-S1, Tables 10-12). Specifically, section 4.3 outlines the methodology used by OPG in preparing the reconciliations of the regulatory income tax calculations to corporate income tax returns. Ernst & Young was then engaged to perform and report on specified procedures relating to the OPG-prepared schedules to reconcile the tax return information to the regulatory tax expense for OPG's prescribed facilities. For each of the years, the procedures were applied and a separate report was produced by Ernst & Young. The reports provide a detailed account of the exact procedures performed and the specific results of those procedures. By applying the specified procedures, Ernst & Young found no exceptions.

The calculations of actual regulatory annual income tax expense for the prescribed facilities for years 2008 and 2009, presented in Ex. F4-T2-S1, Table 6, have been prepared by OPG using the same approach as outlined in section 3 of Ex. F4-T2-S1 and used by OPG in preparing the calculations for 2005 – 2007. In response to the interrogatory in Ex. L-1-120, part c), OPG also provides reconciliations to the corporate income returns for 2008 and 2009 prepared using the same methodology as outlined in section 4.3 of Ex. F4-T2-S1.

b) The numbers shown in Table 6 for 2008 are derived from the actual tax returns. The 2009 numbers are derived from the year-end tax provision, as the tax returns had not yet been filed with the tax authorities at the time of the submission of the pre-filed evidence for this Application. The attached Table 1 is presented in the same format as Table 6 noted above, with updated calculations for 2009 based on the actual tax returns. In response to the interrogatory in Ex. L-1-120, part c), OPG also provides reconciliations to the corporate income tax returns for 2008 and 2009.

OPG notes that the updated calculations in Table 1 based on the 2009 actual tax returns result in a small change to the amount of regulatory income taxes. Table 1 shows $67.0M as compared to $68.0M in Ex. F4-T2-S1, Table 6.

c) (i) Assurance for adequate financial and accounting cut-off is primarily based on financial system period end cut-offs, which are clearly established and communicated with finance contacts through the use of formal planning meetings and a documented fiscal calendar that is available to all staff. OPG's financial systems restrict access to only authorized individuals within the period and any financial changes required subsequent to the period-end must be specifically authorized by management.

For the calculation of the taxable income, the Tax Department uses the accounting data based on the financial period end cut-offs established by OPG. As explained in Ex. F4-T2-S1, sections 3.2 and 3.3, OPG computes the regulatory taxable income by making additions and deductions to the regulatory earnings before tax for items affected by different regulatory accounting and tax treatment, applying the same principles used for the calculation of actual income taxes under applicable legislation as well as regulatory principles. In calculating the taxable income for the first quarter of 2008, OPG used the actual numbers recorded in OPG’s accounting records (e.g., depreciation, nuclear waste management expenses, etc.). For certain items (e.g., capital cost allowance), which are only available on an annual basis, OPG used the budget amount and prorated it for the first quarter.

ii) The regulatory taxable income for the first quarter 2008 was $77.6M as compared to the regulatory taxable income of $39.2M for the last nine months of 2008. The lower regulatory taxable income in the last nine months of 2008 reflects the impact on regulatory earnings before tax of lower than forecast nuclear production and higher gross revenue charge ("GRC") at regulated hydroelectric facilities (as a result of the property component of the GRC rates increasing as production levels increase) during the last nine months of 2008.

Table 1
Calculation of Regulatory Income Taxes - Updated for 2009 Tax Returns ($M)
Years Ending December 31, 2008 and 2009

Line No.	Particulars	2008 Actual	2009 Actual
		(a)	(b)
	Determination of Regulatory Taxable Income		
1	**Regulatory Earnings Before Tax**[1]	20.8	257.3
	Additions for Regulatory Tax Purposes:		
2	**Depreciation and Amortization**	350.9	379.6
3	**Nuclear Waste Management Expenses**	21.4	22.7
4	**Receipts from Nuclear Segregated Funds**	62.5	65.7
5	**Pension and OPEB/SPP Accrual**	324.8	193.3
6	**Regulatory Asset Amortization - Nuclear Liability Deferral Account**	35.6	47.5
7	**Reversal of Amounts Recorded in Income and Other Taxes Variance Account**	0.0	17.0
8	**Adjustment Related to Duplicate Interest Deduction (Q1 2008)**	10.0	0.0
9	**Adjustment Related to Financing Cost for Nuclear Liabilities**	53.9	65.0
10	**Taxable SR&ED Investment Tax Credits of Prior Periods**	0.0	37.9
11	**Other**	41.5	61.1
12	**Total Additions**	900.7	889.7
	Deductions for Regulatory Tax Purposes:		
13	**CCA**	298.8	294.1
14	**Cash Expenditures for Nuclear Waste & Decommissioning**	122.6	129.3
15	**Contributions to Nuclear Segregated Funds**	58.9	124.7
16	**Pension Plan Contributions**	198.6	211.1
17	**OPEB/SPP Payments**	63.6	61.8
18	**Regulatory Asset Deduction - Nuclear Liability Deferral Account**	1.8	2.4
19	**SR&ED Qualifying Capital Expenditures**	16.8	0.0
20	**SR&ED Investment Tax Credits Recognized in Regulatory Earnings Before Tax**	28.3	19.3
21	**Other**	15.2	2.1
22	**Total Deductions**	804.6	844.7
23	**Regulatory Taxable Income Before Carry Over of Loss Available for Mitigation in EB-2007-0905**	116.9	302.3
24	**Carry Over of Loss Available for Mitigation in EB-2007-0905**	(116.9)	(71.6)
25	**Regulatory Taxable Income After Loss Carry-Over**	0.0	230.6
26	**Regulatory Income Taxes - Federal** (line 25 x line 29)	0.0	43.8
27	**Regulatory Income Taxes - Provincial** (line 25 - line 10) x (line 30 + line 31)	0.0	23.1
28	**Total Regulatory Income Taxes**	0.0	67.0
	Income Tax Rate:		
29	**Federal Tax**	19.50%	19.00%
30	**Provincial Tax**	14.00%	14.00%
31	**Provincial Manufacturing & Processing Profits Deduction**	-2.00%	-2.00%
32	**Total Income Tax Rate**	31.50%	31.00%

Notes:

1 Regulatory Earnings Before Tax for 2008 and 2009 are reconciled to the corresponding Earnings Before Interest and Tax per the audited financial statements for OPG's Prescribed Facilities in Ex. C1-T1-S1, Table 7, Line 13.

Board Staff Interrogatory #119

Ref: Ex. F4-T2-S1, Table 9 Benchmark Regulatory Income Taxes 2008 and 2009

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

a) Please provide the supporting documents and calculations that show how the regulatory earnings before tax were derived for 9 months 2008 of $40.7M, and $49.5M for the whole year 2009.

b) Please provide the budget numbers for the first quarter 2008, and the whole year 2008 that support the numbers shown for the last 9 months of 2008 Budget. Please provide any explanations necessary to understand the process in creating these numbers.

c) Why is one column called 2008 Budget and the other 2009 Plan? What are the differences between a Budget and a Plan?

d) Are the 2008 Budget and 2009 Plan the same numbers that were used in EB-2007-0905 to derive the Payment Amounts Order? If not, please explain and provide all of the necessary reconciliations to explain the differences.

e) Regulatory earnings are shown as $257.3M in the 2009 Actual numbers in Table 6. In Table 9 the 2009 Plan shows regulatory earnings of only $49.5M. Please explain the significant difference between the Actual and the Plan regulatory earnings for 2009.

Response

a) Refer to Attachment 1.

b) Refer to Attachment 2 and accompanying notes.

c) When OPG's Board of Directors approves the annual Business Plan, it approves the first year of the plan as the "Budget", which becomes the reporting and accountability base against which corporate performance is monitored during the upcoming year. Subsequent years of the plan are referred to as the "Plan", which becomes a reference base for planning.

The calculation provided in Ex. F4-T2-S1, Table 9 was based on OPG's 2008 – 2012 Business Plan, which was the basis of OPG's Application in EB-2007-0905. In that business plan, 2008 was the budget year, and years 2009 and onwards were considered the "Plan" years.

This naming convention is used throughout this Application.

d) Yes, the numbers used in the calculation of the Benchmark Regulatory Taxes for 2008 and 2009 presented in Ex. F4-T2-S1, Table 9 are the same numbers that were used in EB-2007-0905 to derive the Payment Amounts Order.

e) The actual regulatory earnings for 2009, as shown in Ex. F4-T2-S1, Table 6, were significantly higher than the regulatory earnings underlying the calculation of the benchmark tax expense, as shown in Ex. F4-T2-S1, Table 9, primarily due to the recognition of the Tax Loss Variance Account amount of $292M in 2009 income for accounting purposes. Refer to Ex. L-12-041 for discussion of accounting for the Tax Loss Variance Account.

Numbers may not add due to rounding.

Table 1
Calculation of Regulatory Earnings Before Tax for Benchmark Tax Expense ($M)
Nine Months Ending December 31, 2008 and Year Ending December 31, 2009

Line No.	Particulars	EB-2007-0905 Payment Amounts Order Reference	Apr-Dec 2008	Jan-Dec 2009
			(a)	(b)
1	**Nuclear Return on Equity**	App. A, Table 2, Line 12, cols. (c) and (f)	74.7	100.5
2	**Less: Bruce Lease Net Revenues**	App A, Table 2, Line 20, cols. (c) and (f)	80.0	111.9
3	**Regulated Hydroelectric Return on Equity**	App A, Table 1, Line 12, cols. (c) and (f)	118.3	157.3
4	**Less: Mitigation Amount Ordered by the OEB**	App A, Table 3, Note 3	72.3	96.4
5	**Regulatory Earnings Before Tax** (Lines 1-2+3-4)		40.7	49.5

Numbers may not add due to rounding.

Table 2
Calculation of Benchmark Regulatory Income Tax Expense ($M)
For the Period April 1, 2008 to December 31, 2008

Line No.	Description	Note	2008 Full Year (unadjusted)	Q1 2008 (unadjusted)	April 1 to Dec. 31, 2008 (unadjusted)	Adjustments	April 1 to Dec. 31, 2008 Benchmark
			(a)	(b)	(c)	(d)	(e)
			Note 1		Note 2		
1	**Regulatory Earnings Before Tax**	3, 8	472.0	(79.0)	393.0	(352.3)	40.7
	Additions for Tax Purposes:						
2	**Depreciation and Amortization**	4, 9	408.0	(91.5)	316.5	(52.4)	264.1
3	**Nuclear Waste Management Expenses**	2, 9	48.0	(12.0)	36.0	(10.6)	25.4
4	**Receipts from Nuclear Segregated Funds**	2, 9	49.0	(12.2)	36.8	(11.3)	25.5
5	**Pension and OPEB/SPP Accrual**	2	353.0	(88.2)	264.8	0.0	264.8
6	**Regulatory Asset Amortization - PARTS Deferred Costs**	5, 10, 17	39.0	(27.4)	11.6	24.0	35.6
7	**Regulatory Asset Amortization - Nuclear Development Deferral Account and Capacity Refurbishment Variance Account**	6, 11, 16	8.0	-	8.0	(4.4)	3.6
8	**Regulatory Asset Amortization - Nuclear Liability Deferral Account**	6	36.0	-	36.0	0.0	36.0
9	**Adjustment Related to Duplicate Interest Deduction**	2, 15	56.0	(14.0)	42.0	(42.0)	0.0
10	**Adjustment Related to Financing Cost for Nuclear Liabilities**	15			0.0	44.5	44.5
11	**Other**	2, 9	11.0	(2.7)	8.3	(1.5)	6.8
12	**Total Additions**		1,008.0	(248.0)	760.0	(53.7)	706.3
	Deductions for Tax Purposes:						
13	**CCA**	2, 9	311.0	(77.7)	233.3	(6.8)	226.5
14	**Cash Expenditures for Nuclear Waste & Decommissioning**	2, 9	226.0	(56.5)	169.5	(96.8)	72.7
15	**Contributions to Nuclear Segregated Funds**	2, 9	454.0	(113.5)	340.5	(285.8)	54.7
16	**Pension Plan Contributions**	2	233.0	(58.2)	174.8	0.0	174.8
17	**OPEB/SPP Payments**	2	68.0	(17.0)	51.0	0.0	51.0
18	**Regulatory Asset Deduction - PARTS Deferred Costs**	12, 17	-	-	0.0	36.8	36.8
19	**Regulatory Asset Deduction - Nuclear Development Deferral Account and Capacity Refurbishment Variance Account**	6, 13, 16	7.0	-	7.0	(3.4)	3.6
20	**Regulatory Asset Deduction - Nuclear Liability Deferral Account**	6, 14	1.0	-	1.0	1.0	2.0
21	**Other**	7, 9, 17	17.0	(7.5)	9.5	(3.8)	5.7
22	**Total Deductions**		1,317.0	(330.4)	986.6	(358.8)	627.8
23	**Regulatory Taxable Income**		163.0	3.4	166.4	(47.2)	119.2
24	**Income Tax Rate**		31.50%		31.50%		31.50%
25	**Regulatory Income Taxes**		51.3		52.4		37.5

Notes:

1 Full year amounts for 2008 as filed in EB-2007-0905, Ex F3-T2-S1, Table 7, Column (b), reproduced as Attachment 2 to EB-2010-0008, Ex. F4-T2-S1. Amounts are not adjusted for OEB findings in EB-2007-0905.

2 Amounts in col. (c) are 3/4ths of the full year 2008 balances in col. (a) with the exception of the items discussed in the notes below. Amounts are not adjusted for OEB findings in EB-2007-0905.

3 Details of the 2008 first quarter adjustment amount of $79M were provided EB-2007-0905, Undertaking Response Ex J9.4.

4 Depreciation expense in column (c) is derived as follows ($M):

2008 annual amount per EB-2007-0905 Ex. F3-T2-S1, Table 7, Line 3. Column b)	408.0
Add: Budgeted amount for depreciation deferred in the Nuclear Liability Deferral Account for Q1 2008	14.0
Adjusted annual amount	422.0
Adjusted annual amount x 3/4	316.5

5 To arrive at column (c) amount, column (a) amount is reduced by Q1 2008 budget amount of $27.4M.

6 No recovery of deferral/variance accounts were forecast for Q1 2008; therefore the amortization amount is all related to the Apr 1 to Dec 31, 2008 period only.

7 Other deductions for tax purposes for April 1, 2008 to December 31, 2008 to arrive at col. (c) are derived as follows ($M):

2008 annual amount per EB-2007-0905 Ex. F3-T2-S1, Table 7, Line 21, Column (b)	17.0
Remove budgeted amount for variance account additions during Q1 2008	(4.3)
Adjusted annual amount	12.7
Adjusted annual amount x 3/4	9.5

8 Refer to L-01-119 part (a) in EB-2010-0008 for calcuation of regulatory earnings before tax in column (e).

9

Removal of Bruce Lease Revenues and Costs from col. (c) to arrive at col. (e) (consistent with OEB's findings in EB-2007-0905)	2008 Full Year	Apr 1-Dec 31 (2008 Full Year x 3/4)
Depreciation, full year 2008: Payment Amounts Order, App A, Table 7, line 4, column (c)	(69.8)	(52.4)
Waste Mgmt, full year 2008: Payment Amounts Order, App A, Table 7, line 7. column (c)	(14.1)	(10.6)
Receipts from Nuclear Segregated Funds	(15.0)	(11.3)
Other Additions	(2.0)	(1.5)
CCA	(9.0)	(6.8)
Cash Expenditures For Nuclear Waste and Decommissioning, full year 2008: EB-2007-0905, Ex J1.5	(129.0)	(96.8)
Contributions to Nuclear Segregated Funds	(381.0)	(285.8)
Other Deductions	(5.0)	(3.8)

10 Reduced PARTS Recovery period prescribed by the OEB increases amortization expense in col (e): Payment Amounts Order, App A, Table 2a, Note 5

11 Remove recovery of refurbishment costs incurred prior to April 1, 2008 to arrive at col (e): Payment Amounts Order, App A, Table 2a, Note 5

12 The PARTS cost deduction/recovery in payment amounts over the test period is $85.8M per Payment Amounts Order App D, Line 1, Column f) pro-rated on a monthly basis:
9 months / 21 months = $85.8M * 9/21 = $36.8M

13 The nuclear development and capacity refurbishment cost tax deduction is adjusted to reflect the recovery of these costs at Line 7.
Interest of $1M was being recovered from customers during 2008. This amount was not originally reflected in the tax deduction in EB-2007-0905. As ratepayers bear the cost of this interest expense, the tax deduction in col. (e) has been increased in accordance with the "benefits follow costs" principle.

14 Adjusted in col. (d) to reflect the recovery of a portion of previously accrued interest on the outstanding balance of the nuclear liability deferral account in the amount of $1.0M in 2008 ($3.5M per EB-2007-0905 Ex. J1-T1-S1, Page 12, Chart 2--total interest is recovered over 33 months).
An adjustment is made to reflect the tax benefit of the deduction for the deferred interest accruing to consumers, in accordance with the EB-2007-0905 Decision With Reasons finding at Page 170 that states: "the party who bears a cost should be entitled to any related tax savings or benefits."

15 The OEB determined that OPG's nuclear liabilities would be reflected in the capital structure at OPG's average accreation rate. This deduction is effectively included in the segregated fund contributions and therefore is removed to avoid double-counting the adjustment. The duplicate interest adjustment is replaced in column (e) by the financing cost allowed by the OEB for OPG's unfunded nuclear liabilities per Payment Amounts Order, App. A, Table 5b, Line 7. The Adjustment related to duplicate interest deduction and the adjustment related to financing cost for nuclear liabilities are described in Ex. F4-T2-S1, section 3.3.6.

16 For presentation purposes, amounts in Col. (e), Lines 7 and 19 are not shown in Ex. F4-T2-S1, Table 9 because they net to $nil

17 For presentation purposes, amounts in Col. (e), Lines 6, 18 and 21 are shown as a net figure of $6.9M in Ex. F4-T2-S1, Table 9, Col (a) , Line 17.

Board Staff Interrogatory #120
(NON-CONFIDENTIAL VERSION)

Ref: Ex. F4-T2-S1, page 10 - Tax Losses Prior to April 1, 2008

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

a) Please provide the T2 tax return Schedule 4 "Corporation Loss Continuity and Application" for each year from 1999 to 2007 for each company for which OPG provided tax returns on a confidential basis.

b) Please provide a summary of the losses incurred and applied in each year from 1999 to 2008 from the Schedule 4 documents provided in (a) above.

c) Please provide a reconciliation of tax return to regulatory similar to that provided in Table 12 for 2007 for each of 2008 and 2009 tax returns.

Response

Historical information for the period from 1999 to 2004 is not provided. The data from before 2005 is not relevant as OPG was not regulated prior to April 1, 2005.

a) The T2 tax return Schedule 4 "Corporation Loss Continuity and Application" for 2005 to 2007 for the companies included in the confidential tax returns previously filed with the OEB in this proceeding are included in a confidential submission accompanying this response (Attachment 1).

b) Included in Schedule 4 "Corporation Loss Continuity and Application" for each year per a) above is a Non-Capital Loss Continuity Workchart, which provides an analysis of the balance of losses by year of origin.

c) Attachment 2, Tables 1 (2008) and 2 (2009) reconcile the tax return to regulatory for 2008 and 2009 in a form similar to 2007 as filed in Ex. F4-T2-S1, Table 12. For 2009, the reconciliation includes two additional columns to reconcile from the tax return to the year-end tax provision and then, to revised regulatory. The revised regulatory calculation based on the 2009 tax return is provided and discussed in Ex. L-1-118.

Year 2008 - Reconciliation of Tax Return to Regulatory

		2008 Tax Return					Adjustments		
		1	2	3	4	5	6	7	8
Line No.	Particulars	OPG Parent	Subs	Total	UnReg	Regulated	Bruce	Other Adj.	Regulatory[1]
	Determination of Taxable Income								
1	Earnings Before Tax	314.4	(43.2)	271.2	(491.0)	(219.8)	283.3	(42.7)	20.8
2	Adj negative earnings to $0								-
3		314.4	(43.2)	271.2	(491.0)	(219.8)	283.3	(42.7)	20.8
	Additions for Tax Purposes:								
4	Depreciation	564.2	54.0	618.2	(201.0)	417.2	(61.1)	(5.2)	350.9
5	Nuclear Waste Management Expenses	646.5		646.5		646.5	(292.6)	(332.5)	21.4
6	Receipts from Nuclear Segregated Funds	81.5		81.5		81.5	(19.0)	-	62.5
7	Pension and OPEB/SPP Accrual	414.1		414.1	(88.8)	325.3		(0.5)	324.8
8	One-Time Adjustment: P2P3 Inventory Write-offs			-		-		-	-
9	One-Time Adjustment: P2P3 CIP Write-offs			-		-		-	-
10	Regulatory Asset Amortization - PARTS Deferred Costs	66.5		66.5		66.5		(66.5)	-
11	Regulatory Asset Amortization - Nucl Development Deferral & Capacity Refurbishment Variance	3.2		3.2		3.2		(3.2)	-
12	Regulatory Asset Amortization - Nucl Liability Deferral	35.6		35.6		35.6		-	35.6
13	First Nations Past Grievances Provision			-		-		-	-
14	Adjustment Related to Duplicate Interest Deduction (Q1 2008)			-		-		10.0	10.0
15	Adjustment related to Financing Cost for Nuclear Liabilities					-		53.9	53.9
16	Lennox impairment			-		-		-	-
17	Other	173.7	2.7	176.4	(52.4)	124.0	(2.0)	(80.5)	41.5
18	Total Additions	1,985.3	56.7	2,042.0	(342.2)	1,699.8	(374.7)	(424.5)	900.6
	Deductions for Tax Purposes:								
19	CCA	528.7	8.9	537.6	(229.7)	307.9	(9.1)	(0.0)	298.8
20	Cash Expenditures for Nuclear Waste & Decommissioning	195.0		195.0		195.0	(72.4)	-	122.6
21	Contributions to Nuclear Segregated Funds and Earnings	27.9		27.9		27.9	(211.1)	242.1	58.9
22	Pension Plan Contributions	253.0		253.0	(54.0)	199.0	-	(0.4)	198.6
23	OPEB/SPP Payments	81.0		81.0	(17.0)	64.0	-	(0.4)	63.6
24	Regulatory Asset Deduction - PARTS Deferred Costs	6.3		6.3		6.3		(6.3)	-
25	Regulatory Asset Amortization - Nucl Development Deferral & Capacity Refurbishment Variance	-		-		-	-	-	-
26	Regulatory Asset Amortization - Nucl Liability Deferral	-		-		-	-	1.8	1.8
27	Reversal of Bruce Regulatory Asset	354.7		354.7	-	354.7		(354.7)	-
28	SR&ED Qualifying Capital Expenditures	25.7		25.7	(9.0)	16.7		0.1	16.8
29	SR&ED Investment Tax Credits Recognized in Regulatory Earnings Before Tax	30.0		30.0	(1.7)	28.3		-	28.3
30	Construction In Progress Interest Capitalized	56.2		56.2	(25.0)	31.2		(31.2)	-
31	Other	110.8	2.6	113.4	(28.6)	84.8	(13.7)	(59.4)	11.7
32	Total Deductions	1,669.3	11.5	1,680.8	(365.0)	1,315.8	(306.3)	(208.4)	801.1
33	Net Income/(Loss) for income tax purposes	630.4	2.0	632.4	(468.2)	164.2	214.9	(258.7)	120.4
	Deduct:								
34	Charitable donations	8.6	-	8.6	(5.0)	3.6	-	(0.1)	3.5
35	Taxable Income	621.8	2.0	623.8	(463.2)	160.6	214.9	(258.6)	116.9

Notes:

1 Regulatory as per pre-filed evidence Ex. F4-T2-S1, Table 6.

Year 2009 - Reconciliation of Tax Return to Regulatory

		2009 Tax Return					Adjustment					
		1	2	3	4	5	6	7	8	9	10	11
Line No.	**Particulars**	**OPG Parent**	**Subs**	**Total**	**UnReg**	**Regulated**	**Return to Provision Adj**	**Bruce**	**Other Adj**	**Regulatory[1]**	**Regulatory Provision to Return Adj**	**Revised Regulatory[2]**
	Determination of Taxable Income											
1	**Earnings Before Tax**	807.3	(39.1)	768.2	(97.7)	670.5	-	(42.7)	(370.5)	257.3		257.3
2	**Adj negative earnings to $0**								-	-	-	-
3		807.3	(39.1)	768.2	(97.7)	670.5	-	(42.7)	(370.5)	257.3	-	257.3
	Additions for Tax Purposes:											
4	**Depreciation**	564.1	53.6	617.7	(177.7)	440.0	-	(60.4)	0.0	379.6		379.6
5	**Nuclear Waste Management Expenses**	666.2	-	666.2	-	666.2	(0.4)	(296.8)	(346.3)	22.7		22.7
6	**Receipts from Nuclear Segregated Funds**	103.9	-	103.9	-	103.9	-	(38.2)	-	65.7		65.7
7	**Pension and OPEB/SPP Accrual**	247.7	-	247.7	(54.4)	193.3	-		0.0	193.3		193.3
8	**Regulatory Asset Amortization - PARTS Deferred Costs**	43.3		43.3		43.3	-		(43.3)	-		-
9	**Regulatory Asset Amortization - Nucl Development Deferral & Capacity Refurbishment Variance**	4.3		4.3		4.3	(0.1)		(4.2)	-		-
10	**Regulatory Asset Amortization - Nucl Liability Deferral**	47.5		47.5		47.5	(0.1)		0.1	47.5		47.5
11	**Reversal of Amounts Recorded in Income and Other Taxes Variance Account**	17.0		17.0		17.0	-		-	17.0		17.0
12	**Adjustment Related to Financing Cost for Nuclear Liabilities**	-		-		-	-		65.0	65.0		65.0
13	**Taxable SR&ED Investment Tax Credits of Prior Periods**	55.9		55.9	(18.0)	37.9	-		-	37.9		37.9
14	**Other**	331.6	7.9	339.6	(38.7)	300.8	5.4	(151.1)	(95.6)	59.5	1.6	61.1
15	**Total Additions**	2,081.5	61.5	2,143.1	(288.8)	1,854.2	4.8	(546.5)	(424.3)	888.2	1.6	889.8
	Deductions for Tax Purposes:											
16	**CCA**	516.1	8.0	524.1	(221.8)	302.3	1.1	(8.2)	(0.0)	295.2	(1.1)	294.1
17	**Cash Expenditures for Nuclear Waste & Decommissioning**	191.2		191.2	-	191.2	-	(62.0)	0.1	129.3		129.3
18	**Contributions to Nuclear Segregated Funds and Earnings**	1,140.5		1,140.5	-	1,140.5	-	(600.3)	(415.5)	124.7		124.7
19	**Pension Plan Contributions**	269.1		269.1	(57.9)	211.2	(6.0)		(0.1)	205.1	6.0	211.1
20	**OPEB/SPP Payments**	79.5		79.5	(17.8)	61.7	0.1		(0.0)	61.8		61.8
21	**Regulatory Asset Deduction - PARTS Deferred Costs**	1.4		1.4		1.4	(0.4)		(1.0)	-		-
22	**Regulatory Asset Amortization - Nucl Liability Deferral**	-		-		-	-		2.4	2.4		2.4
23	**Reversal of Bruce Regulatory Asset**	104.0		104.0	-	104.0	(0.1)		(103.9)	-		-
24	**Tax Loss Revenue & Interest**	295.0		295.0	-	295.0	(0.1)		(294.9)	-		-
25	**SR&ED Qualifying Capital Expenditures**	-		-		-	-		-	-		-
26	**SR&ED Investment Tax Credits Recognized in Regulatory Earnings Before Tax**	22.1		22.1	(2.8)	19.3	-		-	19.3		19.3
27	**Construction in Progress Interest Capitalized**	57.7		57.7	(16.1)	41.6	-		(41.6)	-		-
28	**Other**	48.0	12.5	60.5	(22.7)	37.8	(0.6)	(11.8)	(23.3)	2.1		2.1
29	**Total Deductions**	2,724.6	20.5	2,745.1	(339.1)	2,406.0	(6.0)	(682.3)	(877.8)	839.9	4.9	844.8
30	**Net Income/(Loss) for income tax purposes**	164.2	1.9	166.1	(47.4)	118.7	10.8	93.1	83.0	305.6	(3.3)	302.3
	Deduct:											
31	**Charitable donations**	3.1		3.1	(3.1)	-						
32	**Taxable Income**	161.1	1.9	163.0	(44.3)	118.7	10.8	93.1	83.0	305.6	(3.3)	302.3

Notes:

1 Regulatory as per pre-filed evidence Ex. F4-T2-S1, Table 6.

2 Revised regulatory as filed in Ex. L-T01-S118, Table 1.

Board Staff Interrogatory #121

(NON –CONFIDENTIAL VERSION)

Ref: Ex. F4-T2-S1, Table 6 Actual Regulatory Income Taxes for 2008 and 2009

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

a) Please provide the tax returns for 2008 and 2009, including Schedule 1, Schedule 4 and Schedule 8, for all of the companies already included in the confidential tax returns filed with the Board in this proceeding.

b) In EB-2007-0905, L-1-117, Attachment 1, Please provide a Schedule 8 for 2008 and 2009 based on the actual tax return numbers for the UCC and CCA for OPG's regulated operations.

Response

a) The tax returns for 2008 and 2009 (Attachment 1), including the requested schedules, for the companies included in the confidential tax returns previously filed with the OEB in this proceeding are included in a confidential submission accompanying this response.

b) Attachment 2, Tables 1 and 2 are schedules 8 for 2008 and 2009 based on the actual tax return numbers for UCC and CCA for OPG's regulated operations.

   OPG notes that the 2008 information provided in EB-2010-0008, Ex. F4-T2-S1, Table 6 was based on OPG's tax returns for that year. The 2009 tax return CCA amount for the regulated operations is $294.1M compared to $295.2M as shown in Ex. F4-T2-S1, Table 6. The amount per Table 6 for 2009 as filed was based on the year-end tax provision, as the tax returns had not yet been filed with the tax authorities at the time of the submission of the pre-filed evidence for this Application.

   OPG also notes that the forecast CCA amounts per EB-2007-0905, Ex. L-1-117, Attachment 1 were $311M and $314.4M for 2008 and 2009 compared to the amounts per actual tax returns in the attached tables of $298.8M and $294.1M for 2008 and 2009, respectively. The actual amounts were lower than the forecasted amounts primarily due to the removal of the Bruce assets from regulatory tax calculations (they were included at the time Ex. L-1-117 was filed), as per the OEB's Decision in EB-2007-0905.

Numbers may not add due to rounding.

Table 1 - Schedule 8

Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Operations - Year Ending December 31, 2008 ($M)

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)-(j)+(i) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,186.0	185.0	0.0	0.0	1,371.0	92.5	1,278.5	4%	0.0	51.1	1,319.9
2	**1-rolling start**	58.8	79.9	0.0	0.0	138.8	0.0	138.8	4%	0.0	5.6	133.2
3	**1.1**	5.6	18.1	0.0	0.0	23.7	9.1	14.6	6%	0.0	0.9	22.8
4	**2**	1,614.6	0.0	0.0	0.0	1,614.6	0.0	1,614.6	6%	0.0	96.9	1,517.7
5	**8**	265.4	39.2	1.0	0.7	304.9	19.2	285.6	20%	0.0	57.1	247.7
6	**10**	28.8	1.7	0.1	0.3	30.4	0.7	29.7	30%	0.0	8.9	21.5
7	**12**	7.8	11.1	0.0	0.0	18.9	5.6	13.3	100%	0.0	13.3	5.6
8	**17**	589.5	6.0	0.0	9.5	586.0	0.0	586.0	8%	0.0	47.0	539.0
9	**38**	41.9	0.0	0.0	0.0	41.9	0.0	41.9	30%	0.0	12.6	29.3
10	**42**	0.3	0.0	0.0	0.0	0.3	0.0	0.3	12%	0.0	0.0	0.3
11	**45**	1.6	0.0	0.0	0.0	1.6	0.0	1.6	45%	0.0	0.7	0.9
12	**50**	4.3	8.4	0.0	0.0	12.7	4.2	8.5	55%	0.0	4.7	8.0
13	**52**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100%	0.0	0.0	0.0
14	**Total**	3,804.5	349.5	1.2	10.5	4,144.7	131.3	4,013.4		0.0	298.8	3,845.9

Numbers may not add due to rounding.

Table 2 - Schedule 8
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Operations - Year Ending December 31, 2009 ($M)

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)-(j)+(i) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,319.9	94.4	0.2	0.0	1,414.4	47.2	1,367.3	4%	0.0	54.7	1,359.8
2	**1-rolling start**	133.2	0.0	0.0	0.0	133.2	0.0	133.2	4%	0.0	5.3	127.9
3	**1.1**	22.8	40.4	0.3	0.0	63.5	20.2	43.3	6%	0.0	2.6	60.9
4	**2**	1,517.7	0.0	0.0	0.2	1,517.5	0.0	1,517.5	6%	0.0	91.0	1,426.4
5	**8**	247.7	75.9	2.4	0.8	325.2	37.5	287.7	20%	0.0	57.5	267.7
6	**10**	21.5	22.5	0.0	0.1	43.9	11.2	32.7	30%	0.0	9.8	34.1
7	**12**	5.6	9.0	(0.6)	0.0	13.9	4.5	9.4	100%	0.0	9.4	4.5
8	**17**	539.0	38.9	0.1	0.0	578.1	19.5	558.6	8%	0.0	44.7	533.4
9	**38**	29.3	0.0	0.0	0.0	29.3	0.0	29.3	30%	0.0	8.8	20.5
10	**42**	0.3	0.0	0.0	0.0	0.3	0.0	0.3	12%	0.0	0.0	0.3
11	**45**	0.9	0.0	0.0	0.0	0.9	0.0	0.9	45%	0.0	0.4	0.5
12	**50**	8.0	0.0	0.0	0.0	8.0	0.0	8.0	55%	0.0	4.4	3.6
13	**52**	0.0	5.4	0.0	0.0	5.4	0.0	5.4	100%	0.0	5.4	0.0
14	**Total**	3,845.9	286.5	2.3	1.1	4,133.6	140.1	3,993.5		0.0	294.1	3,839.5

Board Staff Interrogatory #122
(NON-CONFIDENTIAL VERSION)

Ref: Ex. A2-T1-T1 Attachment 2 - 2009 Audited Financial Statements, page 128

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

In the 2009 audited financial statements under *Note 11 Income Taxes* on page 128 OPG provided the following information.

> In the third quarter of 2006, OPG received a preliminary communication from the Provincial Tax Auditors ("Tax Auditors") with respect to their initial findings from their audit of OPG's 1999 taxation year. Many of the issues raised through the audit were unique to OPG and related either to start-up matters and positions taken on April 1, 1999 upon commencement of operations, or matters that were not adequately addressed through the *Electricity Act, 1998.* In 2008, all outstanding tax matters related to the 1999 tax audit were resolved. As a result, OPG reduced its income tax liability by $106 million.
>
> The audit of OPG's taxation years subsequent to 1999 commenced in 2009. Should the ultimate outcome materially differ from OPG's recorded income tax liabilities, the Company's effective tax rate and its earnings could be affected positively or negatively in the period in which the matters are resolved.

a) Please provide all Notices of Assessment and Reassessment, as well as the related statements of adjustments for all tax years from 1999 through 2009.

b) Please provide the correspondence from the Provincial Tax Auditors that explains each of the 1999 tax matters and how these matters were resolved.

c) Does the resolution of these tax matters affect the calculation of the regulatory tax losses, the balance in the Tax Loss Variance account, benchmark tax expense and the balance in the Income and Other Taxes Variance account? If not, please explain. If yes, please provide updated evidence.

d) Did the reduction in the tax liability by $106 M increase the tax losses available for carry forward? Please explain and update the evidence as required.

e) To which tax years(s) does the $106 M relate?

f) How much of the $106 million relate to regulatory taxes? Please explain and provide the analysis.

g) Does the resolution of these tax matters affect the work that Ernst & Young performed in reconciling the tax returns to regulatory for 2005, 2006 and 2007 as already submitted in evidence? Please explain fully.

h) Are the PILs income tax proxies for 2011 and 2012 affected by the resolution of the tax matters? Please explain. Please update the evidence where required.

Response

Historical information for the period from 1999 – 2004 is not provided. The data from before 2005 is not relevant as OPG was not regulated prior to April 1, 2005.

a) For 2005 – 2008, the Notices of Assessment, Notices of Reassessment and Statements of Adjustments resulting from the 1999 taxation year audit, and Notices of Reassessment and Statements of Adjustments from the 2000 – 2001 taxation year audit for each of the companies included in the confidential tax returns filed with the OEB in this proceeding are included as Attachment 1 which is confidential.

   The Notices of Reassessment for 2005 – 2008 reflect all cumulative effects of the 1999 and 2000 – 2001 tax audit on taxation years 2005 – 2008. The Notices of Assessment for 2009 have not yet been issued.

   Reassessments resulting from the 2000 – 2001 audit have no impact on regulatory taxes for 2005 onward, and are included in this response for completeness.

b) The Notices of Reassessment and Statements of Adjustments resulting from the 1999 tax audit are the correspondence from the Provincial Tax Auditors that sets out the resolution of the 1999 tax matters. This correspondence is being provided by OPG as discussed in part a) above.

c) No, the resolution of the tax matters related to the 1999 tax audit did not affect the calculation of the regulatory tax losses, the balance of the Tax Loss Variance Account, benchmark tax expense and the balance in the Income and Other Taxes Variance Account. These effects are already reflected in OPG's pre-filed evidence for this Application, with the exception of an adjustment related to the tax deductibility of a portion of nuclear fuel expense discussed below.

   The Income and Other Taxes Variance Account balance as at December 31, 2010 should reflect the additional recovery from ratepayers of $11M relating to an unburned nuclear fuel expense deduction taken by OPG but disallowed by the auditors. The amount of $11M relates to the period from April 1, 2008, the effective date of the Income and Other Taxes Variance Account, to December 31, 2010.

d) No, the reduction in OPG's accounting tax liability by $106M did not increase the regulatory tax losses available for carry forward. As noted in part c), the resolution of the tax matters related to the 1999 tax audit, which gave rise to the accounting entry for $106M, is already reflected in the pre-filed evidence for this Application. As such, no update to the pre-filed evidence is required. OPG also indicated in EB-2007-0905, Ex. L-1-117 that the impact of 1999 tax audit adjustments was incorporated in the calculation of regulatory income taxes as filed in EB-2007-0905.

OPG notes that the $106M amount represents a net accounting impact on OPG's company-wide tax expense, largely as a result of a reduction to future tax expense. The regulatory tax calculations for the prescribed assets are calculated using the methodology outlined in section 3.2 of Ex. F4-T2-S1, and therefore are not the same as the accounting tax expense (e.g., future taxes are not included in the calculation of regulatory taxes).

e) The result of the 1999 tax audit affects all taxation years since 1999, including years beyond 2008. As noted above, the $106M reduction in the accounting income tax liability largely relates to a reduction in future tax expense and, therefore, primarily relates to future taxation years. For accounting purposes, the cumulative impact of the resolution of the audit on OPG's future tax obligations has been recognized in the year the triggering event occurs in accordance with generally accepted accounting principles.

f) As noted above, the $106M reduction represents the accounting impact on OPG as a whole and is largely due to a reduction in future tax expense. Underpinning the $106M amount is a reduction to Capital Cost Allowance, which impacts the regulatory tax expense for the prescribed facilities by $10M (grossed-up) for the years 2005 – 2007. This impact was already reflected in the calculation of regulatory income taxes for these years filed in EB-2007-0905, and no change related to this impact in the calculation of regulatory income taxes for these years filed in this Application was required.

g) No, the resolution of the tax matters related to the 1999 tax audit does not affect the work that Ernst & Young performed on reconciliations of the tax returns to regulatory for 2005, 2006 and 2007. The work by Ernst & Young is not affected because the reconciliation schedules provided to Ernst & Young (presented in Ex. F4-T2-S1, Tables 10-12) already reflected the impact of the resolution of these tax matters.

h) No, the resolution of the tax matters related to the 1999 tax audit does not impact the 2011 and 2012 regulatory income tax calculation submitted in the pre-filed evidence, as the impact of the 1999 tax audit is already reflected in the calculation of regulatory income taxes shown in Ex. F4-T2-S1, Table 5. As such, no update to the evidence is required.

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.

AMPCO Interrogatory #026
(NON-CONFIDENTIAL VERSION)

Ref: Ex. F2-T2-S3, page 4

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

Please provide the analysis presented to the Board of Directors that lead OPG to decide to not refurbish Pickering B.

Response

See the response in Ex. L-01-070 for factors that contributed to the decision not to refurbish Pickering B Generating Station.

A copy of the requested analysis is provided in the confidential attachment (Attachment 1).

UPDATE ON THE PICKERING B REFURBISHMENT PROJECT

1. Background

The Pickering B units were initially placed in service in 1983-1986. The nominal expected life was 30 calendar years, based on a pressure tube life of 210,000 EFPH at 80% capacity factor, with the possibility of extending life through replacement of major components. The current predicted nominal ends of service life are 2014 for Units 5, 6, and 7, and 2016 for Unit 8.

In June 2006, the Ontario Government directed OPG to assess the feasibility of refurbishing the existing nuclear plants and to begin an Environmental Assessment of the impacts of refurbishing Pickering B.

The feasibility assessment has now progressed significantly and management has developed an improved understanding of the regulatory requirements, environmental impacts, the scope of the project, and the costs of refurbishment.

Management has also explored the continued operation of the Pickering B units for an additional two to four years beyond their current nominal operating lives (i.e. until 2016/2018 for Units 5, 6 & 7 and 2018/2020 for Unit 8), and is of the view that continued operation is possible with additional investments. Realization of this option would be of significant benefit to Ontario's electricity system during the 2014 to 2018 period. The work necessary to support continued operation was characterized in a preliminary way in 2008 and Continued Operation of Pickering B has been established as the basis for the 2010 to 2014 Business Plan. Further development and characterization of the work required to achieve Pickering B Continued Operation is being completed as part of the 2010-2014 Business Planning process. As part of this work, a Fuel Channel Life Management initiative is also being launched, in conjunction with Bruce Power and with the participation of other industry partners, to provide Management with greater confidence in the predictions of pressure tube lives for the nuclear fleet.

2. Update on the Planning Activities Phase

Overall, all 2009 deliverables are on track. The following work has been completed to date:

a. Plant Condition Assessment

A rigorous Plant Condition Assessment of all critical components has been completed and forms the basis of the core project scope. No previously unknown component deficiencies were identified. The costs of refurbishing the critical components have been included in the feasibility assessment.

The actual condition of the calandria structure has been evaluated. A recent integrity assessment concluded the calandria structure poses no risk to the safe operation of the reactors to the end of their current operating life. It further concluded that the risk of deteriorating vessel integrity during the post-refurbishment operating period is very low. To achieve greater certainty, information is being obtained and evaluated from NB Power and Bruce Power in their current refurbishment outages.

The calandria structure will be inspected as part of the scope of the refurbishment outages.

b. Environmental Assessment

On January 26, 2009, the CNSC issued their acceptance of the EA Screening Report. The report concluded that, taking into account the identified mitigation measures, the refurbishment and continued operation of the Pickering B nuclear station is not likely to cause significant adverse environmental effects. The mitigation measures identified in the final report have been incorporated into the scope of the refurbishment.

c. Integrated Safety Review (ISR) Update

Work on the Integrated Safety Review (ISR) is on track for submission of the Final report, which includes a summary of the Global Assessment to the CNSC in September 2009.

A Global Assessment team was on site during the week of July 13 to 17, 2009. The team consisted of nuclear industry professionals. The purpose of the team was to review the resolution of issues, identified gaps without adequate strategies and recommendations identified in the August 2008 Global Assessment to ensure that the overall judgement of nuclear safety is still good. The results were 5 out of the 11 issues identified in 2008 have been resolved and of the 126 gaps without acceptable strategies only 6 remain without sufficient information or justification. Management is in the process of resolving the remaining issues prior to finalizing the ISR report. A Global Assessment final report will be issued to OPG in August.

During the 2008 Pickering B re-licensing hearing, a regulatory commitment was made to prepare a regulatory strategy for end-of-life, to be submitted to the CNSC by the end of 2009. The outcome of the ISR is being utilized in the formulation of this regulatory strategy. This strategy is highly dependent upon the ongoing dialogue Management is having with the OPA and the IESO on the utilization of the Pickering station capacity.

It is expected that the CNSC will review and approve the Final ISR Report by the end of Q2, 2010.

An Integrated Implementation Plan (IIP), which must be approved by the CNSC prior to re-starting the refurbished units, will only be developed if the Pickering B Refurbishment project is approved. The IIP document consists of the approved scope and schedule for refurbishment based on completed technical assessments, the Environmental Assessment, the Integrated Safety Review (ISR), which includes a third-party global assessment of plant safety for long term operation to determine the global risk, and an emerging safety issues assessment.

d. Budget Update

Year-to-date expenditures on the project are $2.3M on a plan of $2.4M. The project is forecasting to be $0.1M over plan at year end, or $4.9M. The focus in 2009 is to complete the Final ISR report and submit it to the CNSC on September 25, 2009.

Life-to-date expenditures as of July 1, 2009 for the Pickering B Refurbishment Planning Activities Project are $47.0M, including $44.9M in prior years, assessing the feasibility of refurbishing Pickering B. The project is forecasting to be at $49.8M at year end, 2009. An additional $1.4M is expected to be spent in 2010 in order to obtain approval of the Final ISR report from the CNSC resulting in a project total cost, for this phase of the project, at $51.2M.

3. Summary of the Feasibility Assessment

Management has performed a review of the key inputs to the economic assessment. This includes a review of the cost estimate, the outage schedule, and the key risks considering results of the regulatory work programs including the EA and the comments from the CNSC on the individual Safety Factor Reports. The major assumptions, considerations and conclusions are summarized below.

UPDATE ON THE PICKERING B REFURBISHMENT PROJECT

The following table summarizes the key refurbishment costs, including contingencies, and schedule durations used in the feasibility assessment.

Refurbishment High Confidence Estimates	Average Cost / Unit (Overnight $M 2009)	Comments
Refurbishment Costs		
Fuel Channels and Feeders replacement	[redacted]	Based on Vendor Technical Study. Pt. Lepreau earlier estimate $352M (2005$).
Steam Generators Replacement	[redacted]	Based on Vendor Technical Study.
Plant System & Equipment Maintenance	[redacted]	Based on Plant Condition Assessments, known deficiencies and system upgrades. Estimates by OPG personnel. Pt. Lepreau non-reactor work costs approx. $260 million (2005$)
Other(1)	420	Technical Studies of D2O Management, Waste Management and Construction Islanding. Other estimates by OPG personnel. Overheads comparable to recent OPG experience with major projects.
Contingency for Project Estimate Uncertainties & Risk	[redacted]	Includes contingency for asymmetry in cost estimates and potential labour/materials cost and schedule uncertainties.
Contingency for Regulatory Uncertainties	[redacted]	Based on detailed analysis of gaps and probabilities of needing to implement changes
Total Investment Including Contingencies (2)	[redacted]	**Total Cost of Refurbishing two Bruce units now estimated at $3.1 to $3.4B; Cost of Pt. Lepreau without SG Replacement currently estimated at $1.1 B (includes interest during construction).** **OPG's total high confidence overnight costs for 4 units is [redacted] (2009$).**
Refurbishment Schedule		
Refurbishment Schedule	33 months	Pt. Lepreau target for fuel channels and feeders only was 19 months. Latest Pt. Lepreau forecasts are 26 months. Bruce Unit 1 is estimated to be 33 months. This duration represents OPG's high confidence schedule duration.

(1) Other refers to D2O Management Strategy, Waste Management, Unit Islanding Work, Construction Island Barriers, New Fuel Charge, Commissioning & Power Ascension and OPG/PMO Project Management, Financial Securities, Project Insurance.
(2) The total investment is higher for the first unit [redacted] than for the subsequent units [redacted]

The future operating costs and performance of Pickering B are another significant aspect of uncertainty related to the feasibility assessment. Analysis has been completed of past performance and of the information from the Plant Condition Assessments in order to forecast the expected capability factor for the Pickering B units in the post-refurbishment period. Given the historical performance and the bottom-up analysis carried out by Pickering B Operations, a high confidence post-refurbishment capability factor of 75% is felt to be a reasonable forecast at this time.

UPDATE ON THE PICKERING B REFURBISHMENT PROJECT

The following table summarizes the key post-refurbishment costs and performance assumptions used in the feasibility assessment.

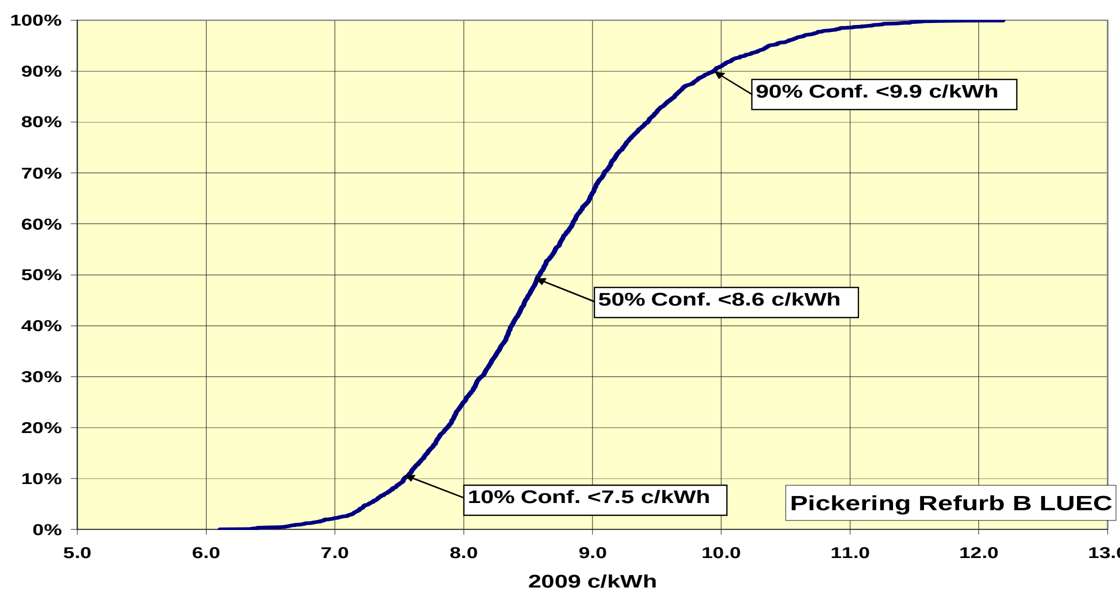
Post-Refurbishment Operations High Confidence Estimates	Average Cost / Unit (Overnight $M 2009)	Comments
Annual Direct Station Costs Post-Refurbishment	130	Current 2008-2010 Business Plan Avg. is $102M. The $130 M used is adjusted for historical average spending on projects and is OPG's high confidence estimate.
Annual Support Costs Post-Refurbishment (1)	30	Consistent with 2008 Business Plan adjusted for high confidence. Incremental analysis performed by OPG personnel
Plant Performance Post Refurbishment	75%	Lifetime performance is 77%; including strikes, management shutdowns, major outages for SLAR, etc. Range of 75% to 85% used. Bottom-up detailed forecast for post-refurbishment period is 84%

(1) The Annual Support Costs shown are the incremental costs of Corporate and Nuclear Support

Based on these inputs, the expected high confidence Levelized Unit Energy Cost (LUEC) for refurbishment of Pickering B, and continued operation for a period of 30 years after refurbishment, is estimated to be approximately 9.9 ¢/kWh (2009$). The high confidence estimated cost for the refurbishment project is [redacted] (overnight 2009$) which includes a total contingency amount of [redacted] The contingency amount of [redacted] includes [redacted] to cover potential costs of major regulatory upgrades required beyond those already included in the base scope of work.

The project uncertainties and future performance have been analyzed in a Monte Carlo analysis resulting in a LUEC range of 7.5 ¢/kWh (low confidence) to 9.9¢/kWh (high confidence). At a medium confidence level the LUEC is 8.6 ¢/kWh.

Figure 1: LUEC Range for Pickering B Refurbishment



4. Continued Operation Of Pickering B

During the initial development of the Pickering B Feasibility Assessment in 2007, it became apparent that there is an opportunity to continue to operate the Pickering B units by 4 years or more beyond their current nominal operating lives of 2014/2016 by taking actions to maximize pressure tube life. Management developed a comprehensive work plan to explore and develop the Continued Operation option, i.e. to take the actions necessary to safely and reliably operate Pickering B for an additional

30,000 effective full power hours at 80% capacity factor, thereby extending the projected end-of-service lives to approximately 2018/2020.

Dependencies of Pickering A upon Pickering B operation were also explored, with the preliminary conclusion that it would be very difficult to operate Pickering A beyond the end of life of the last two units of Pickering B without making significant modifications and seeking regulatory changes. Continued operation of Pickering B during the period 2014 to 2018/2020 is now the basis for the 2010 to 2014 Business Plan. In addition, further work is underway to explore the option to operate the plant beyond 2018, e.g. through prolonged outages or seasonal operation of one or more of the units in order to maximize overall plant life of both Pickering B and A. Management is continuing to explore this option and is in discussions with the Ontario Power Authority (OPA) and the Independent Electricity System Operator (IESO), which have both expressed strong support for the Continued Operation option.

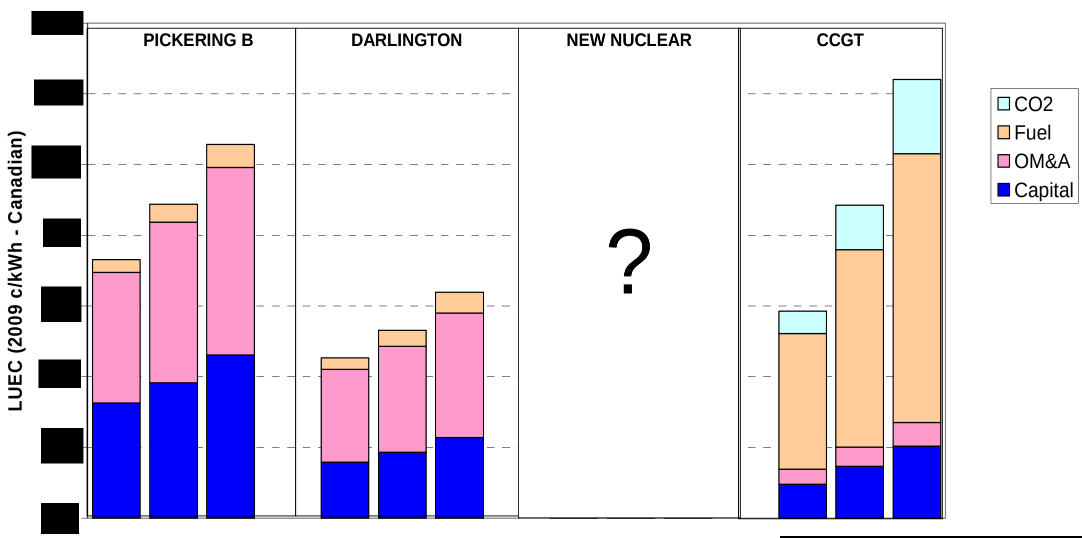
Work continues to improve the confidence that the pressure tubes will remain fit-for-service for the Continued Operation period and also to ensure that any potential regulatory (CNSC) concerns with the Continued Operation option are fully addressed. OPG is in the process of launching a Fuel Channel Life Management initiative, jointly funded with Bruce Power and with the participation of other industry partners, to provide Management with greater confidence in the predictions of pressure tube lives for the nuclear fleet.

5. Analysis of Alternatives

The following (Figure 2) provides a comparison of the Pickering B Refurbishment LUEC to other generation options. The assessment found that the Levelized Unit Energy Cost (LUEC) of refurbishing and continuing to operate the Pickering B units for a further 30 years would be between 7.5 ¢/kWh and 9.9 ¢/kWh. Within this LUEC range, the Pickering B Refurbishment is less favourable than Darlington Refurbishment and Combined Cycle Gas Turbines (CCGT) at gas prices reflective of recent experience.

The costs of New Nuclear remain speculative and this time, thus, a firm comparison to Pickering is not possible.

Figure 2: LUEC Range for Pickering B Refurbishment and Comparators



[redacted]

[redacted]

New Nuclear		
Low	Med	High

[redacted]

(1) If only ten years of post-refurbishment operation were achieved, the LUEC of Pickering B would increase by approximately 4 ¢/kWh (high confidence).

6. Next Steps

Over the course of the next few months, Management will complete the Pickering B Final ISR Report and submit it to the CNSC for review and acceptance in Q2, 2010. Management will continue to work with the OPA and the IESO to define the best utilization (refurbishment, continued operation and/or seasonal operations) of the Pickering station capacity and expects to make a recommendation to the Board by year end.

CME Interrogatory #019

Ref: Ex. C1-T1-S1, Tables 1-7

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

What is the total dollar amount OPG seeks to recover in the test period Revenue Requirement (i.e., not through deferral accounts) for payments in lieu of taxes ("PILS") for the test period?

Response

The total payments in lieu of income, capital and property taxes and municipal property taxes[1,2] amounts included in the 24-month test period revenue requirement for prescribed and Bruce facilities is $301.6M. The total municipal property taxes amount included in the 24-month test period revenue requirement for prescribed and Bruce facilities is $29.5M.

Therefore, the total PILS and municipal property taxes for the test period is $331.1M. A detailed breakdown of the components of this amount is presented in Ex. L-05-036.

[1] Municipal property taxes are included to enable amounts to be reconciled to the pre-filed evidence (which combines both Payment in Lieu of property tax paid to the OEFC and property taxes paid to municipalities) and to enable results to be reconciled to results from other CME interrogatories, which request information related to taxes generally.

[2] OPG is expected to become subject to the water taking charges during the test period. As the test period amount is only approximately $0.5M per year, it has been presented in OPG's property taxes amounts for the test period in the pre-filed evidence (refer to Ex. F4-T2-S1, section 10.5). Inclusion of WTC in this response is required to reconcile to the breakdown of taxes requested by CME at Ex. L-5-036.

CME Interrogatory #023

Ref: Ex. C1-T1-S1, Tables 1-7

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

What amount of tax does OPG, the corporation, actually expect to pay to the Ontario Electricity Financial Corporation ("OEFC") for 2010?

Response

OPG declines to provide the requested 2010 information with respect to income and capital taxes because it has not been previously filed with the OEB, it is not publicly available and it is not relevant to this proceeding. It is not relevant because it is a forecast for OPG's company-wide operations, including unregulated operations. OPG does not make separate income or capital tax payments for its regulated operations, as the payments are made on a legal entity basis. A budget calculation for the 2010 tax expense for the regulated facilities is provided at Ex. F4-T2-S1, Table 5. OPG has filed its tax returns for 2005 – 2009, in confidence, in response to the OEB's direction in EB-2007-0905 to provide a reconciliation of prior period tax expense and the calculation of tax expense for the regulated facilities.

With respect to payments in lieu of property tax made to the OEFC, the projected amount that will be paid in cash property taxes for OPG's regulated operations (including Bruce assets), based on the 2010 – 2014 business plan, is $15.2M. Additionally, OPG expects to pay $14.8M in municipal property taxes for the regulated operations (including Bruce assets).

CME Interrogatory #026

Ref: Ex. F4-T2-S1, Attachment 3
Ex. G2-T2-S1
Ex. H1-T2-S1

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

All taxes that OPG pays are effectively paid to its owner, the Province of Ontario. All return on equity OPG earns is either paid to or attributable to its owner, the Province of Ontario. In these circumstances, please respond to the following questions:

a) Does OPG make any effort to minimize or eliminate its tax burden? If so, then please list all of the tax reduction initiatives in which OPG engaged in each of the years 2005 to 2010, inclusive.

b) Please list whether OPG has adopted any tax planning measures for the test period to minimize the amount of taxes it will be called upon to pay to the Province of Ontario.

c) Please provide the names of any consultant(s) OPG uses to help it with its tax planning.

Response

a) Yes. As any prudent commercial taxable entity would, OPG has made and continues to make (including the period 2005 – 2010) all appropriate efforts to structure and conduct its business and operations in a tax-effective manner while operating in accordance with the rules and regulations of the *Income Tax Act* (Canada) and the *Electricity Act, 1998*. OPG considers all potentially relevant allowable tax deductions and tax credits in the filing of its tax returns in order to minimize its tax burden.

   OPG's Finance department has a dedicated group of experienced tax professionals. To fulfill the objective of tax minimization and assessment of related risks, tax filing positions are taken after appropriate research into case laws and technical interpretations where available. OPG's tax professionals engage in continuing professional development training such as attending the Canadian Tax Foundation and Tax Executive Institute seminars, and participate in the Canadian Electricity Association's tax consultation group. OPG also consults with external tax advisors to optimize the tax effectiveness of its business activities.

b) As part of OPG's normal business operations, tax planning measures noted in part a) are carried out to minimize the amount of taxes OPG will be required to pay for the test period.

c) OPG engages the following consultants for tax planning, depending on the nature of the area of tax:

- PricewaterhouseCoopers LLP
- KPMG LLP
- Deloitte & Touch LLP
- Ernst & Young LLP
- Blake, Cassels and Graydon LLP
- Torys LLP

CME Interrogatory #027
(NON-CONFIDENTIAL VERSION)

Ref: Ex. F4-T2-S1, Attachment 3
Ex. G2-T2-S1
Ex. H1-T2-S1

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

What amount did OPG, the corporation, actually pay to the Province of Ontario in taxes in each of the years 2005 to 2009, inclusive?

Response

OPG makes payments in lieu of income, capital and property tax to the Ontario Electricity Financial Corporation ("OEFC") and property tax payments to municipalities[1]. This information for 2005 – 2009 is provided in the table below.

While the amounts for income and capital taxes relate to OPG's total operations, the payments in lieu of property taxes and municipal property taxes shown below only relate to OPG's regulated operations (including Bruce assets). OPG does not make separate payments for income and capital taxes for regulated operations, as noted in Ex. L-5-023.

$M	**2005**	**2006**	**2007**	**2008**	**2009**
OEFC – income and capital taxes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OEFC – property tax	12.3	13.8	13.6	14.7	14.5
Municipalities – property tax	12.5	12.8	13.3	14.1	14.1
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[1] Municipal property taxes are included to enable amounts to be reconciled to the pre-filed evidence (which combines both Payment in Lieu of property tax paid to the OEFC and property taxes paid to municipalities) and to enable results to be reconciled to results from other CME interrogatories, which request information related to taxes generally.

CME Interrogatory #028

Ref: Ex. F4-T2-S1, Attachment 3
Ex. G2-T2-S1
Ex. H1-T2-S1

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

What amount does OPG, the corporation, actually expect to pay in taxes to the Province of Ontario in 2010, 2011 and 2012?

Response

OPG declines to provide the requested 2010, 2011 and 2012 information with respect to income and capital taxes because it has not been previously filed with the OEB, it is not publicly available and it is not relevant to this proceeding. It is not relevant because it is a forecast for OPG's company-wide operations, including unregulated operations. OPG does not make separate income or capital tax payments for its regulated operations, as the payments are made on a legal entity basis. A forecast of the 2010, 2011 and 2012 tax expense for the regulated facilities is provided at Ex. F4-T2-S1, Table 5.

With respect to payments in lieu of property tax made to the Ontario Electricity Financial Corporation ("OEFC") and payments for municipal property tax[1] related to OPG's regulated operations (including Bruce assets), the projected amounts, based on the 2010 – 2014 business plan, are as follows:

	2010[2]	**2011**	**2012**
Payments in lieu of property tax	$15.2M	$15.8M	$16.3M
Municipal property taxes	$14.8M	$15.8M	$16.3M

[1] Includes water taking charge as discussed in Ex. L-5-019.
[2] As discussed in Ex. L-5-023.

CME Interrogatory #029

Ref: Ex. F4-T2-S1, Attachment 3
Ex. G2-T2-S1
Ex. H1-T2-S1

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

Were any amounts recovered from ratepayers for taxes during each of the years 2005 to 2009, inclusive? If so, then what amounts were recovered from ratepayers during each of those years?

Response

The table below sets out the requested information to the extent available.

For the period April 1, 2005 – March 31, 2008, OPG is unable to identify the amount of taxes recovered from ratepayers. Rates for that period were set by the Province of Ontario by Regulation. OPG includes the forecast tax information that was provided to the Province of Ontario on an annual basis for 2005 – 2007 for the purposes of setting these rates. This information is from a document referenced in section 5 (1) of O. Reg. 53/05 and available on the Ontario Energy Board website at: http://www.oeb.gov.on.ca/documents/cases/EB-2006-0064/forecast_facilities_opg_20070213.pdf. The document is reproduced as Attachment 1 to this response.

The amounts for 2008 and 2009 in the table below represent the amounts approved by the OEB in the EB-2007-0905 Payment Amounts Order.

<table>
<tr><th>$M</th><th>Notes</th><th>2005</th><th>2006</th><th>2007</th><th>2008</th><th>2009</th></tr>
<tr><td>Property Tax – Prescribed Assets</td><td>1, 4</td><td>22</td><td>28</td><td>29</td><td rowspan="2">22.8</td><td rowspan="2">30.7</td></tr>
<tr><td>Capital Tax – Prescribed Assets</td><td>1, 4</td><td>30</td><td>33</td><td>36</td></tr>
<tr><td>Income Tax – Prescribed Assets</td><td>1, 5</td><td>18</td><td>20</td><td>22</td><td>nil</td><td>nil</td></tr>
<tr><td>Property Tax – Bruce</td><td>2, 3</td><td>N/A</td><td>N/A</td><td>N/A</td><td>11.4</td><td>15.5</td></tr>
<tr><td>Capital Tax – Bruce</td><td>2, 3</td><td>N/A</td><td>N/A</td><td>N/A</td><td>3.3</td><td>3.6</td></tr>
<tr><td>Income Tax – Bruce</td><td>2, 3</td><td>N/A</td><td>N/A</td><td>N/A</td><td>28.3</td><td>37.7</td></tr>
<tr><td>Large Corporations Tax</td><td>1, 2</td><td>20</td><td>18</td><td>11</td><td>nil</td><td>nil</td></tr>
<tr><td>Total</td><td></td><td>90</td><td>99</td><td>98</td><td>65.8</td><td>87.5</td></tr>
</table>

Notes:

1. Amounts for 2005 – 2007 are annual amounts as provided to the Province of Ontario for the purposes of setting interim rates (Attachment 1, sum of Nuclear and Regulated Hydroelectric amounts for each respective year).

2. Amounts for Bruce were included in Nuclear amounts in the information provided to the Province of Ontario shown in Attachment 1.

3. Amounts for 2009 are per EB-2007-0905, Payment Amounts Order, Appendix A, Table 7, line 5 (Property Tax), line 6 (Capital Tax), and line 9 (Income Tax), column (f). For 2008, the amounts are 3/4 of those found in the above lines in Table 7, column (c) to reflect the adjustment for the period January 1, 2008 – March 31, 2008 (shown as total adjustment to Bruce net revenues on Table 7, line 15, column (c)).

4. Property and capital taxes for prescribed assets were approved by the OEB as a single amount for each of Regulated Hydroelectric and Nuclear. Amounts for 2008 are per EB-2007-0905, Payment Amounts Order, Appendix A, Table 1, line 18, column (c) and Table 2, line 18, column (c). For 2009, the amounts are per Tables 1 and 2, line 18, column (f).

5. Income tax for prescribed assets was set at Nil as per EB-2007-0905, Payment Amounts Order, Appendix A, Tables 1 and 2, line 23, columns (c) and (f).

Forecast Information (as of Q3/ 2004) for Facilities Prescribed under O. Reg 53/05

- As part of the establishment of a hybrid electricity market, the Government made Ontario Regulation 53/05 (O. Reg. 53/05) in February 2005. The Regulation prescribes Ontario Power Generation Inc.'s (OPG's) nuclear generating facilities, specifically Pickering A, Pickering B and Darlington Generating Stations, and certain hydroelectric generating facilities, specifically Sir Adam Beck I, Sir Adam Beck II, Sir Adam Beck Pump Generating Station, DeCew Falls I, DeCew Falls II and R.H. Saunders, for the purposes of section 78.1 of the *Ontario Energy Board Act, 1998* and establishes payment amounts for the output from the nuclear and regulated hydroelectric facilities.

- OPG provided forecast information to the Government in support of the development of O.Reg. 53/05. The forecast information was developed in Q3 2004 and is summarized in Table 1 below. This information was the basis upon which the Government established the payment amounts in the Regulation.

- The information in Table 1 represents OPG's forecasts as of Q3 2004 and does not represent OPG’s current forecasts. For example, in Q3 2004, OPG planned to return Pickering A Units 2 and 3 to service and production from these units is included in the 2007 nuclear production forecasts in Table 1. In August 2005, OPG’s Board of Directors accepted management’s recommendation not to refurbish Pickering Units 2 and 3 and OPG is placing the units in a safe storage state. As a result, current forecasts of nuclear production are less than the forecasts provided in Table 1. Hydroelectric production forecasts are dependent on forecasts of water levels and outflows which can change with time.

Table 1: Forecast Information (as of Q3/ 2004) for Facilities Prescribed under O. Reg 53/05

	Nuclear			Regulated Hydroelectric		
	2005	2006	2007	2005	2006	2007
Average Rate Base ($M)	2,988	3,200	3,712	4,015	3,967	3,916
Energy Generated - TWh	45.2	50.6	53.0	18.0	18.4	18.7
Costs ($M)						
Fuel /GRC Costs	100	112	128	236	243	249
Station Service Charges	11	11	11	5	5	5
OM&A	1,769	1,805	1,889	76	81	82
Property Tax	22	28	29	0	0	0
Capital Tax	19	22	24	11	11	12
Depreciation	292	343	467	65	65	66
Interest	99	107	123	132	134	131
Current Income Taxes	8	9	11	10	11	11
Large Corporate Tax	13	12	8	7	6	3
Return on Equity at 10%	134	144	167	181	179	176
Required Revenues ($M)	**2,466**	**2,593**	**2,857**	**723**	**734**	**735**
Less:						
Bruce Lease - Earnings in Excess of Costs	85	96	117			
Revenues From:						
Ancillary Services	2	3	3	38	40	41
Other Services	21	23	23			
Net Revenue Requirement ($M)	2,358	2,472	2,714	685	694	694
Forecast Interim Rate at 10% ROE ($/MWh)	**52.2**	**48.9**	**51.2**	**38.1**	**37.7**	**37.1**

Forward looking information used in the development of the interim rates was based on planning information developed in Q3 2004 and should not be used for any other purpose.

CME Interrogatory #032
(NON-CONFIDENTIAL VERSION)

Ref: Ex. F4-T2-S1, Attachment 3
Ex. G2-T2-S1
Ex. H1-T2-S1

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

For the years 2005 to 2009, inclusive, does the total amount for taxes in each year that OPG has either recovered or now seeks to recover from ratepayers exceed the amount for taxes actually paid by OPG, the corporation, to the Province of Ontario? If so, then what is the amount of the excess for each year and cumulatively?

Response

OPG makes payments in lieu of income, capital and property tax to the Ontario Electricity Financial Corporation ("OEFC") and property tax payments to municipalities. The table below sets out the comparison between these amounts paid for 2005 – 2009, as per Ex. L-5-027, and the amount of taxes OPG has either recovered or seeks to recover from ratepayers for those years (as per Ex. L-5-029, Ex. L-5-030 and Ex. L-5-031), to the extent information is available.

The requested comparison is not meaningful because:

- As noted in Ex. L-5-023 and Ex. L-5-027, information for income and capital taxes paid is only available for OPG as a whole, and not regulated operations separately. Therefore, the amounts paid for income and capital taxes relate to OPG's total operations while the amounts recovered relate to regulated operations (including Bruce assets) only.

- As noted in Ex. L-5-029, for the period April 1, 2005 – March 31, 2008, OPG is unable to identify the amount of taxes, if any, recovered from ratepayers through the interim rates set by the Province of Ontario. The information regarding amounts recovered for the years 2005 – 2007 presented below is based on amounts OPG submitted to the Province for the purposes of setting interim rates.

- The calculation of regulatory income and capital taxes involves the application of regulatory principles, whereas amounts paid by OPG do not.

$M	2005	2006	2007	2008	2009
OEFC – Income and Capital Taxes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OEFC – Property Tax	12.3	13.8	13.6	14.7	14.5
Municipalities – Property Tax	12.5	12.8	13.3	14.1	14.1
Total Tax Paid (A)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Payment Amounts	90.0	99.0	98.0	65.8	87.5
Tax Loss Variance Account	N/A	N/A	N/A	66.3	55.9
Bruce Variance Account	N/A	N/A	N/A	(98.3)	(35.2)
Total Tax Recovered/Recoverable (B)	**90.0**	**99.0**	**98.0**	**33.8**	**108.2**
Difference = (B) – (A)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cumulative Difference (A > B)					[redacted]

As per the table above, there is no cumulative excess, as defined in the question.

CME Interrogatory #033

Ref: Ex. F4-T2-S1, Attachment 3
Ex. G2-T2-S1
Ex. H1-T2-S1

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

Did the payment amounts that OPG received from ratepayers in 2010 include any amount for taxes? If so, then what is that amount?

Response

Yes, the payment amounts received in 2010 include amounts for capital and property taxes for the prescribed facilities, and capital, property and income taxes related to the Bruce facilities.

The table below sets out the requested information.

$M	Notes	2010
Property and Capital Tax – Prescribed Assets	1	30.6
Income Tax – Prescribed Assets	2	nil
Property Tax – Bruce	3	15.4
Capital Tax – Bruce	3	3.9
Income Tax – Bruce	3	37.7
Total		**87.6**

Notes:

1. Amount is calculated as 12/21 of property and capital tax amounts approved by the OEB as part of OPG's revenue requirement in EB-2007-0905 (all references are to EB-2007-0905, Payment Amounts Order, Appendix A):

	$M
Total Regulated Hydroelectric (Table 1, line 18, col. (i))	15.2
Total Nuclear (Table 2, line 18, col. (i))	38.3
Total for the period April 1, 2008 – December 31, 2009	**53.5**
Amount for 2010: 12/21 x $53.5M	**30.6**

2. Income tax for prescribed assets was set at Nil as per EB-2007-0905, Payment Amounts Order, Appendix A, Tables 1 and 2, line 23, columns (i).

3. As shown in Ex. L-5-031, amounts for Bruce taxes are calculated as 12/21 of amounts approved as part of OPG's revenue requirement in EB-2007-0905:

	$M
Property Tax for full year 2008	15.2
Property Tax for full year 2009	15.5
Less: Q1 2008 (1/4 x $15.2M)	3.8
Total April 1, 2008 – December 31, 2009	26.9
Amount for 2010: 12/21 x $26.9M	**15.4**
Capital Tax for full year 2008	4.4
Capital Tax for full year 2009	3.6
Less: Q1 2008 (1/4 x $4.4M)	1.1
Total April 1, 2008 – December 31, 2009	6.9
Amount for 2010: 12/21 x $6.9M	**3.9**
Income Tax for full year 2008	37.7
Income Tax for full year 2009	37.7
Less: Q1 2008 (1/4 x $37.7M)	9.4
Total April 1, 2008 – December 31, 2009	66.0
Amount for 2010: 12/21 x $66.0M	**37.7**

CME Interrogatory #036

Ref: Ex. F4-T2-S1, Attachment 3
Ex. G2-T2-S1
Ex. H1-T2-S1

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

For the test period 2011 and 2012, what amount in the test period Revenue Requirement in each year does OPG seek to recover from ratepayers for taxes?

Response

The tax amounts for the 24-month test period for the prescribed assets included in the revenue requirement are as follows (all references are to Ex. I1-T1-S1, Table 1):

	$M
Regulated Hydroelectric Property Taxes (line 18, col. (c))	0.0
Nuclear Property Taxes (line 18, col. (f))[1]	32.6
Regulated Hydroelectric Income Tax (line 23, col. (c))	57.9
Nuclear Income Tax (line 23, col. (f))	129.8
Total Taxes for prescribed assets for 24 months 2011 – 2012	**220.3**

The tax amounts for the 24-month test period 2011 – 2012 for the Bruce assets included in the revenue requirement are as follows (all references are to Ex. G2-T2-S1, Table 5):

	$M
Bruce Property Taxes (line 2, col. (e) + col. (f))	27.7
Bruce Current Income Tax (line 10, col. (e) + col. (f))	8.6
Bruce Future Income Tax (line 11, col. (e) + col. (f))	74.5
Total Taxes for Bruce assets for 24 months 2011 – 2012	**110.8**

The combined amount of taxes for prescribed and Bruce assets included in the 24-month revenue requirement for is therefore $331.1M ($220.3M + $110.8M).

[1] Includes a water taking charge as discussed in Ex. F4-T2-S1, section 10.5, and Ex. L-5-019.