CENTRALLY-HELD COSTS

1.0 PURPOSE

This evidence presents OPG's centrally-held costs and the period-over-period comparisons of centrally-held costs that are directly assigned and allocated to OPG's regulated facilities.

2.0 OVERVIEW

This evidence supports the approval sought for the centrally-held costs included in the previously regulated hydroelectric, newly regulated hydroelectric and nuclear revenue requirements. The amounts included in revenue requirement for the 2014 - 2015 test period are $52.1M for the previously regulated hydroelectric facilities, $98.3M for the newly regulated hydroelectric facilities, and $838.0M for the nuclear facilities. Pension and OPEB-related costs comprise the majority of these amounts.

Centrally-held costs are an integral part of the costs of operating OPG's generation facilities. They are company-wide costs that are recorded centrally for a variety of reasons, such as achieving record-keeping efficiency and maintaining proper oversight. They are not support services costs.

Categories of centrally-held costs are separately identified for those exceeding $10M in either 2014 or 2015. The category of "Other" reflects the remaining centrally-held costs and includes a description of some of the more significant costs. The centrally-held cost items described below were identified in EB-2010-0008 and the nature of these costs is substantially unchanged.[1]

Centrally-held costs are directly assigned or allocated to OPG's regulated operations using the same methodology as in EB-2010-0008. The methodology was previously reviewed and

[1] As discussed in EB-2012-0002 and highlighted in Ex. A2-1-1, the adoption of USGAAP results in a reclassification of Scientific Research and Experimental Development investment tax credits from OM&A expenses to income tax expense. These credits are discussed in Ex. F4-2-1, Section 3.5. For 2010 and OEB-approved amounts for 2011 and 2012, amounts are presented on the basis of Canadian GAAP and therefore reflect these credits.

found to be appropriate by Black & Veatch Corporation in EB-2010-0008. The methodology was similarly found to be appropriate as part of the independent review of OPG's cost allocation methodology provided in this Application in Ex. F5-5-1.

In addition, centrally-held costs attributed to each of the hydroelectric plant groups are subsequently assigned and allocated between the newly regulated hydroelectric stations and unregulated stations. With the exception of pension and OPEB costs which are allocated using a labour-related allocator, all other centrally-held costs are allocated and assigned on the same basis as hydroelectric plant group costs are assigned and allocated between regulated and unregulated hydroelectric stations, as discussed in Ex F1-2-1. OPG uses a standardized allocation methodology for attributing costs within plant groups that include newly regulated and unregulated hydroelectric stations.

The above methodologies are applied to total OPG-wide centrally-held costs presented in Ex. F4-4-1 Table 1, which results in costs attributed to the regulated operations as presented in Ex. F4-4-1 Table 2 for the previously regulated hydroelectric facilities, Ex. F4-4-1 Table 3 for the newly regulated hydroelectric facilities and Ex. F4-4-1 Table 4 for the nuclear facilities.

Ex. F4-4-2 Tables 1, 2 and 3 provide the period-over-period comparisons for the historical, bridge and test periods for the previously regulated hydroelectric, newly regulated hydroelectric and nuclear facilities, respectively. Tables 1 and 3 also include a comparison to the OEB-approved amounts for 2011 and 2012 and budget amounts for 2010.

This evidence provides a description of the categories of centrally held costs and discusses trends and variances for each category. The key drivers of these costs are identified within the discussions of trends and variances. Where these drivers do not adequately explain a year-over-year variance, a specific explanation is provided to the extent the variance is equal to or greater than 10 per cent of category expenses. Similarly, a specific variance explanation is provided for historical years if the variance between the actual and budget or OEB-approved amount for a specific category of costs is not explained by the key drivers and is equal to or greater than 10 per cent of the budget or OEB-approved amount.

Total centrally-held costs increase from 2010 to 2013 primarily as a result of higher pension and OPEB-related costs, which represent over 65 per cent of the total forecast centrally-held costs attributed to the regulated facilities during the test period. The costs are forecast to remain relatively stable for 2013 to 2015.

3.0 PENSION AND OPEB-RELATED COSTS

3.1 Description

Certain components of pension and OPEB-related costs for all of OPG's employees and retirees continue to be included in centrally-held costs. These cost components continue to include interest costs on the obligations, the expected return on pension plan assets, amounts in respect of past service costs, actuarial gains and losses, and variances from the forecast current service costs reflected in the standard labour rates.

As in EB-2010-0008, the pension and OPEB-related costs are directly assigned and allocated to business units in proportion to the pension and OPEB costs directly charged to the business units. For a further discussion of OPG's pension and OPEB plans and costs, refer to Ex. F4-3-1, Section 6.

3.2 Trends and Variances

Pension and OPEB-related costs exhibit an upward trend in the 2010 - 2013 period but are forecast to be largely stable during the 2013 - 2015 period. The primary driver of the increase during the 2010 - 2013 period is a declining trend in discount rates. A decline in the expected long-term rate of return on pension fund assets and expected net growth in pension and OPEB cost components also contribute to the increase in the costs. The discount rates used to calculate pension and other post retirement benefits have decreased from 6.80 per cent and 6.90 per cent, respectively, for 2010 to 4.30 per cent and 4.40 per cent, respectively, for 2013, as shown in Ex. F4-3-1 Chart 8. Also shown in Chart 8 is the expected long-term of rate of return that has decreased from 7.0 per cent for 2010 to 6.25 per cent for 2013. The expected net growth in the pension and OPEB cost components includes impacts of changes in current service costs, higher interest costs on a higher benefit obligation due to the passage of time, and expected changes in the pension asset values. A further discussion of the discount rates is found in Ex. F4-3-1 Section 6.3.

The increase in the pension and OPEB-related costs expected in 2013 over 2012 is due to the above factors, partially offset by the impact of changes in staffing levels. The increase in costs in 2012 over 2011 and in 2011 over 2010, also due to the above factors, was partially offset by the impact of gains on the pension fund assets in 2011 and 2010, respectively.

4.0 OPG-WIDE AND NUCLEAR INSURANCE

4.1 Description

These are the costs of OPG's company-wide insurance program and the additional nuclear-specific insurance program. The company-wide program covers commercial general liability, directors and officers and fiduciary liability, all risk property, boiler and machinery breakdown, including statutory boiler and pressure vessel inspections, and business interruption.

As in EB-2010-0008, the costs of this program are primarily directly assigned to the business units based on the applicability of each type of insurance coverage and the asset replacement cost of the generation facilities. The nuclear-specific insurance program relates to liability insurance associated with nuclear operations and additional property insurance for damage to the nuclear portions of OPG's nuclear generating stations, which complements the conventional property insurance program. This portion of insurance costs continues to be directly assigned to the nuclear facilities.

4.2 Trends and Variances

OPG-wide insurance costs for the regulated facilities are generally stable over the 2010 - 2015 period, with period-over-period fluctuations and budget-to-actual variances attributable mainly to insurance premium escalation.

The fluctuations in nuclear insurance costs over the 2010 - 2015 period have two main drivers. First, the costs were higher in 2012 primarily as a result of expenditures related to a one-time transaction of OPG becoming a purchasing member of a mutual insurance company, which has been authorized to provide limited nuclear liability insurance capacity in Canada. This was also the primary driver of the variance between the actual and OEB-approved costs for that year.

Second, the forecast increases in nuclear insurance costs in 2014 and 2015 primarily reflect increased premiums due to expected higher statutory nuclear liability insurance limits to be phased-in over several years. Higher limits are forecast to result from the proposed federal legislation replacing the 1976 *Nuclear Liability Act*. The legislation is expected to be tabled late 2013[2] and relates to a specific recommendation by the Commissioner of the Environment and Sustainable Development on behalf of the Auditor General of Canada made in the fall of 2012 and accepted by Natural Resources Canada.[3]

5.0 PERFORMANCE INCENTIVES

These costs include performance incentives for OPG's employees. Performance incentive costs continue to be attributed to the business units based on the distribution of past performance incentive payments.

Performance incentive costs are stable over the 2012-2015 period. The decreases in the performance incentives in 2011 and 2012 result from the elimination of PWU goal sharing and the Society performance recognition plan for OPG's represented employees. This is also the primary reason for lower actual performance incentives costs incurred for the regulated facilities in 2011 and 2012, as compared to the OEB-approved amounts. Performance incentive plans are discussed in Ex. F4-3-1, Sections 4.0 and 5.0

6.0 IESO NON-ENERGY CHARGES

6.1 Description

IESO non-energy costs are charges that are applied to withdrawals of energy from the IESO-controlled grid. The charges include transmission charges, the debt retirement charge, the

[2] Further details of the proposed legislation are found on the Natural Resources Canada website at http://www.nrcan.gc.ca/media-room/news-release/2013/7190

[3] The recommendation and the response by Natural Resources of Canada are found in paragraphs 2.45-2.50 of the *Fall 2012 Report of the Commissioner of the Environment and Sustainable Development*, which can be found at http://www.oag-bvg.gc.ca/internet/English/parl_cesd_201212_e_37708.html

rural or remote electricity rate protection charge, charges associated with IESO administration fees, OPA fees, uplift charges and the Global Adjustment. These charges are not discretionary and apply to all energy withdrawals from the IESO-controlled grid. These charges are directly assigned to the specific regulated facilities.

6.2 Trends and Variances

With the exception of the specific variances for the hydroelectric facilities described below, the fluctuations over the period for all regulated facilities are primarily due to the variability in Global Adjustment rates. Differences in Global Adjustment rates also represent the principle cause of differences between actual and OEB-approved amounts for 2011 and 2012 and the variance from budget for 2010.

For the previously regulated hydroelectric facilities, changes in the allocation of the Global Adjustment charges under *Ontario Regulation 429/04* as amended, effective January 1, 2011, are the primary reason for the actual 2011 and 2012 costs being lower than the corresponding OEB-approved amounts. This factor also accounts for the difference between the actual costs for 2010 and 2011.

The actual costs for 2012 for the previously regulated hydroelectric facilities were higher than in 2011 due mainly to a combination of higher rates for non-Global Adjustment charges in 2012 and lower energy withdrawals in 2011 due to an outage at the Sir Adam Beck Pump GS in 2011 discussed, in Ex. F1-1-1. The costs planned for these same facilities for 2014 are projected to be higher than in 2013 chiefly as a result of lower energy withdrawals expected in 2013 due to a separate outage at the Sir Adam Beck Pump GS in 2013, discussed in Ex F1-3-3.

For the newly regulated hydroelectric facilities, the actual costs were higher in 2012 than in 2011 due a combination of higher Global Adjustment rates and rates for non-Global Adjustment charges, as well as higher energy withdrawals in 2012.

7.0 OTHER

7.1 Description

Other centrally-held costs consist of a number of relatively smaller items. In the test period, close to 75 per cent of Other costs is comprised of labour-related costs and the annual Ontario Nuclear Funds Agreement ("ONFA") guarantee fee. Other costs include business claims and settlements and, as discussed in section 7.2, reflect a reduction for Scientific Research and Experimental Development ("SR&ED") investment tax credits ("ITCs") for periods presented under Canadian GAAP.

The labour-related costs include the fiscal calendar and labour balancing adjustments, as well as the vacation accrual. The fiscal calendar adjustment is a wage adjustment covering all business units that reflects the difference in the number of days between the 52 or 53 week fiscal calendar used for payroll accounting and OPG's financial year ending on December 31. The adjustment is temporary and fluctuates from year to year, as the starting and ending days of the fiscal calendar vary from year to year. A negative adjustment (i.e., a reduction to costs) can occur in years when the fiscal calendar has 53 weeks. The costs (or a reduction to costs) are directly assigned to business units on the basis of each unit's payroll.

The labour balancing adjustment relates to non-pension and OPEB components of the standard labour rates. The adjustment captures variances between the amount of such costs reflected in the rates charged to the business units and support services groups and the final amount of these costs.

The vacation accrual represents the cost to OPG of the estimated outstanding vacation entitlement for all of its employees. The 2013 - 2015 forecast expenses are based on an estimated vacation accrual expense for 2012, escalated by up to 2 per cent annually. The vacation accrual is directly assigned to business units on the basis of each unit's payroll.

The annual ONFA guarantee fee is the amount payable by OPG to the Province of Ontario pursuant to the ONFA. In exchange for the fee, the Province of Ontario supports financial guarantees to the Canadian Nuclear Safety Commission by providing a guarantee relating to OPG's nuclear decommissioning and waste management liabilities and nuclear segregated funds pursuant to the ONFA. The fee is calculated as 0.5 per cent of the amount guaranteed, which is currently $1,551M, and is directly assigned to the nuclear facilities.

7.2 Trends and Variances

Variances in Other costs are caused by several main factors over the 2010 - 2015 period, as discussed below.

As a result of the recognition of SR&ED ITCs as a reduction to OM&A expenses in accordance with Canadian GAAP, actual and budgeted Other costs for the nuclear facilities in 2010 were lower by $18.7M and $8.6M, respectively.[4] Similarly, the OEB-approved amounts for 2011 and 2012 were lower by $8.6M per year. As the actual credits for 2011 and 2012 are reported under USGAAP as part of income tax expense (discussed in Ex. A2-1-1), Other costs for the nuclear facilities appear higher in 2011 and 2012 primarily for this reason, compared to the respective OEB-approved amounts and the actual costs for 2010.

Other costs in 2012 are lower than 2011 actual costs and 2013 forecast costs primarily as a result of the negative fiscal calendar adjustment in 2012. The negative fiscal calendar adjustment in 2012 was due to the fact that OPG's 2012 fiscal year was four days longer than the 2012 calendar year (the 2011 and 2013 fiscal years are shorter than the respective calendar years). For the newly regulated hydroelectric facilities, the forecast increase in Other costs in 2013 is primarily attributable to amounts related to settlements, which continue in 2014 and 2015.

Other costs are forecast to increase for all regulated facilities during 2014 and 2015 primarily due to a labour balancing adjustment between burden amounts directly charged to business units and the final planned costs, and additional amounts business claims.

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[4] OPG can claim a non-refundable ITC as a percentage of qualifying SR&ED expenditures incurred in the year and records applicable amounts as a reduction to expenses in the year the ITCs are recognized. Refer to Ex. F4-2-1, Section 3.5 for a further discussion of SR&ED ITCs.