



EB-2007-0905

OEB Application

for

Payment Amounts for OPG's Prescribed Facilities

Argument-in-Chief

Ontario Power Generation Inc.

July 4, 2008

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OVERVIEW

This is Ontario Power Generation Inc.'s first application under section 78.1 of the *Ontario Energy Board Act, 1998* and O. Reg. 53/05.

OPG was incorporated in 1998 under the *Ontario Business Corporations Act*. Its sole shareholder is the Province of Ontario. OPG is subject to a Memorandum of Agreement with the Province (Ex. A1-T4-S1, Appendix B) and has from time to time been directed to undertake special initiatives by its sole shareholder.

OPG is Ontario's largest electricity generator, producing approximately 70 percent of the electricity consumed in Ontario.

The assets prescribed by O. Reg. 53/05 consist of OPG's nuclear generating stations, Pickering A and B and Darlington, as well as the Niagara Plant Group and the R.H. Saunders Hydroelectric Generating Station. These prescribed assets produce 43 percent of Ontario's electricity. About 75 percent of the generation from the prescribed assets comes from the nuclear plants, the remainder from the hydroelectric assets.

The key legislative provisions governing the Ontario Energy Board's jurisdiction and mandate are sections 78.1 of the *Ontario Energy Board Act* and O. Reg. 53/05. OPG is, however, subject to many additional regulatory constraints under various additional enactments, regulations and agreements (Ex. A1-T6-S1).

OPG is, for example, subject to the authority of the Canadian Nuclear Safety Commission and the federal *Nuclear Safety and Control Act*. Nuclear waste is also regulated through the *Nuclear Fuel Waste Act*. As a result of these statutory obligations, OPG is required to fund its existing and future nuclear waste and decommissioning obligations. It has done so through the Ontario Nuclear Funds Agreement with the Province.

Under O. Reg. 53/05, the amounts the IESO paid for the output of OPG's prescribed assets was fixed from April 1, 2005 to March 31, 2008 at \$33 per megawatt hour for regulated

1 hydroelectric generation and \$49.50 per megawatt hour for nuclear generation. After March
2 31, 2008, the OEB has jurisdiction to set new payment amounts in accordance with the just
3 and reasonable standard and the specific provisions of the regulation. In its November 30,
4 2006 report on regulatory methodology for OPG, the OEB determined that its first order
5 setting payment amounts for the regulated facilities would be based on a cost of service
6 review. The OEB recognized that this cost of service review would be limited in nature due to
7 the existence of O. Reg. 53/05 and certain constraints on the OEB's jurisdiction contained in
8 those regulations. The OEB ordered that OPG's payment amounts be made interim as of
9 April 1, 2008 pending the outcome of this proceeding.

11 **RIGHT TO RECOVERY OF PRUDENTLY INCURRED COSTS**

12 Section 78.1 of the Act adopts the "just and reasonable" standard for the OEB's
13 determination of payment amounts the IESO must make to OPG for the output of the
14 prescribed facilities. This is the same standard prescribed in the Act for gas and electricity
15 distribution companies. Comparable legislation also exists in other provinces and in the U.S.

16
17 Mr. Justice Lamont described just and reasonable rates as "rates, which, under the
18 circumstances, would be fair to the consumer on the one hand, and which, on the other
19 hand, would secure to the company a fair return for the capital invested."¹

20
21 These two components of the just and reasonable standard — that rates be fair to the
22 consumer and yield fair compensation to the utility and its owner — are also embodied in the
23 OEB's objects regarding the regulation of electricity: 1) the protection of consumer interests;
24 and 2) facilitating a financially viable electricity industry.

25
26 Fair compensation to the utility is comprised of two elements: 1) the right to recover all
27 prudently incurred costs (where prudence is evaluated without the benefit of hindsight but on
28 the basis of information that was reasonably available to management at the time the
29 relevant decisions were made); and 2) the right to a fair return on invested capital. The fair
30 return on capital is dealt with in Issue 2 of the argument below.

¹ *Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] S.C.R. 186 at 192-93 (Lamont J.); see also *British Columbia Electric Railway Co. Ltd. v. British Columbia (Utilities Commission)*, [1960] S.C.R. 837 at 855.

1 The principle of entitlement to recovery of prudently incurred costs has been widely accepted
2 in Canada and the U.S.²

3
4 Expenditures are deemed to be prudent in the absence of reasonable grounds to suggest the
5 contrary. Only costs that are found to be dishonestly incurred, or which are negligent or
6 wasteful losses, may be excluded from the legitimate operating costs of the utility in
7 determining the rates that may be charged. The examination of prudence must be based on
8 the particular circumstances at the time the decision which led to incurring those costs was
9 made. That is so even if, in hindsight, it is apparent that the decision was wrong.³

10
11 The OEB correctly defined the prudence standard at paragraph 3.12.2 of its decision in RP-
12 2001-0032 as follows:

- 13 • Decisions made by the utility's management should generally be presumed to be prudent
14 unless challenged on reasonable grounds.
- 15 • To be prudent, a decision must have been reasonable under the circumstances that were
16 known or ought to have been known to the utility at the time the decision was made.
- 17 • Hindsight should not be used in determining prudence, although consideration of the
18 outcome of the decision may legitimately be used to overcome the presumption of
19 prudence.
- 20 • Prudence must be determined in a retrospective factual inquiry, in that the evidence must
21 be concerned with the time the decision was made and must be based on facts about the
22 elements that could or did enter into the decision at the time.

23 This approach has been explicitly affirmed by the Ontario Divisional Court and the Court of
24 Appeal in *Enbridge Gas Distribution Inc. v. Ontario Energy Board*⁴.

² *State of Missouri ex. rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri*, 262 U.S. 276 (1923) at p. 289; *British Columbia Electric Railway Co. Ltd. v. British Columbia (Utilities Commission)*, [1960] S.C.R. 837 [*British Columbia Electric Railway Co. Ltd.*] at p. 854; *TransCanada Pipelines Ltd. v. National Energy Board et al.* (2004), 319 N.R. 172 (F.C.A) at paras. 35-36; *West Ohio Gas Co. v. Public Utilities Commission of Ohio (No. 1)*, 294 U.S. 63 (1935) at p. 68; *Re Union Gas Limited* (September 20, 2002), Ontario Energy Board Decision RP-2001-0029, online: OEB <http://www.oeb.gov.on.ca/documents/cases/RP-2001-0029/decision_200902.pdf>, at pp. 20-24; *Re Enbridge Gas Distribution Inc.* (December 13, 2002), Ontario Energy Board Decision RP-2001-0032, online: OEB <http://www.oeb.gov.on.ca/documents/cases/RP-2001-0032/decision_171202.pdf>, at pp. 62-63; *Enbridge Gas Distribution Inc. v. Ontario Energy Board* (2005), 75 O.R. (3d) 72 (Div. Ct.); rev'd on other grounds, (2006), 41 Admin L.R. (4th) 69

³ *Violet v. FERC*, 800 F. 2d 280 at p. 282 (1st Cir. 1986), cited with approval in *Enbridge v. Ontario Energy Board* (2005), 75 O.R. (3d) 72 (Div. Ct.) at para. 9

⁴ See footnotes 2 and 3 *supra*.

OVERVIEW OF OPG'S REVENUE REQUIREMENT

As a starting point, O. Reg. 53/05 requires the OEB to accept OPG's assets and liabilities as established by OPG's 2007 audited financial statements. Thus, the starting point for determining OPG's rate base for the test period is the fixed asset values from OPG's audited financial statements for 2007, which must be accepted by the Board, together with in-service additions for 2008 and 2009 (Ex. A2-T1-S1, Appendix A, Note 18, page 51; Ex. B1-T1-S1, Chart 1, page 8). The regulated hydroelectric rate base is approximately \$3.9B. The nuclear rate base is approximately \$3.5B, for a combined rate base total of approximately \$7.4B. A summary of the revenue requirement is at Ex. A1-T3-S1, Tables 1 and 2.

The regulated facilities are extremely large and capital intensive, employing complex technologies. They provide almost half of Ontario's electricity needs. The revenue requirement needed to operate these facilities safely and efficiently is correspondingly large. For example, OPG employs, either directly or indirectly, over 9,000 people in the operation of the regulated assets. As a result, a significant portion of OPG's operating costs are labour-related.

The continued and reliable operation of the regulated facilities requires an appropriate level of maintenance and investment. Without the funds necessary to conduct required maintenance and to make required investments in these facilities, OPG will not be able to maintain the value or reliability of these assets.

The revenue requirement for the entire 21 month test period is approximately \$1.3B for regulated hydroelectric and \$5.1B for nuclear, for a combined revenue requirement, before mitigation, of \$6.4B. Unless otherwise specified throughout this argument, however, the 2008 figures presented are annual amounts to enable consistent and transparent year-over-year comparisons. The adjusted 21 month figures for the test period are identified and explained under Issue 10.3 of this argument and in Ex. K1-T1-S1.

OPG has tax loss carry forwards available from the operation of the regulated facilities from 2005 to 2007, the period prior to the OEB assuming jurisdiction over these facilities. OPG has decided that it is appropriate to return these tax losses to ratepayers by applying a

1 portion of them to eliminate all tax obligations attributable to the regulated portion of the
2 business during the test period (Ex. F3-T2-S1, Table 9). OPG has used the remaining tax
3 losses from the prior period as a form of additional rate mitigation to reduce the revenue
4 requirement in the test period by a further \$228M.

5
6 O. Reg. 53/05 also requires the recovery of certain amounts. These items are largely
7 covered in OPG's argument on deferral and variance accounts (Issues 9.1 through 9.7
8 below) and include:

- 9 • Differences in production due to differences between forecast and actual water
10 conditions, differences in ancillary service revenues, and costs associated with
11 transmission outages (Ex. J1-T1-S1, Sections 3.1 and 4.4);
12 • The funding of nuclear liabilities (Ex. H1-T1-S3);
13 • Costs incurred to increase the output of prescribed facilities (Ex. D1-T1-S2; Ex. D2-T1-
14 S3);
15 • Costs of planning and preparation for new nuclear facilities (Ex. D2-T1-S3);
16 • Costs incurred with respect to the Bruce Generating Stations (Ex. G2-T2-S1); and
17 • Costs of the Pickering A return to service project (Ex. J1-T1-S1, Section 4.1).

18
19 Offsetting OPG's costs for the test period are revenues from forecast nuclear production
20 (88.2 TWh, Ex. K1-T3-S1, Table 1) and regulated hydroelectric production (31.5 TWh, Ex.
21 K1-T2-S1, Table 1), "other" revenues from the regulated hydroelectric facilities (\$57.4M, Ex.
22 K1-T1-S1, Tables 1 and 2) and non-generation revenues from the nuclear facilities
23 (\$234.6M, Ex. K1-T1-S1, Tables 1 and 2), as well as revenues resulting from OPG's decision
24 to return to ratepayers a share of the revenues earned in the prior period from Segregated
25 Mode Operations and Water Transactions (\$16.2M, Ex. J1-T2-S1, Table 2).

26 27 **OPG'S REVENUE DEFICIENCY**

28 During 2005 to 2008, the payment amounts fixed by the Regulation were based on an
29 average of a three year forecast, which produced a constant, fixed payment amount for each
30 technology for the entire period.

1 OPG's revenue deficiency for the 2008 to 2009 test period is, therefore, measured in relation
2 to the three-year average of 2005 to 2007 costs based on a forecast originally done in 2004,
3 not OPG's actual costs of operation for 2007.

4
5 The pre-mitigation revenue deficiency relative to that average fixed payment amount for 2005
6 to 2007 is shown by technology in Ex. A1-T3-S1, Table 3. The deficiency in the regulated
7 hydroelectric business is \$241.2M. The deficiency in the nuclear business is \$784.6M for a
8 combined total of \$1,025.8M, pre-mitigation. The drivers of this deficiency are detailed in Ex.
9 A1-T3-S1, pages 8 to 10 and Ex. L-3-49.

10
11 The four most significant contributors to the revenue deficiency are:

- 12 (1) OPG's application for a commercial cost-of-capital;
- 13 (2) Increases in OPG's cost of providing for nuclear liabilities;
- 14 (3) Operating cost increases, the main one of which is labour-related costs including:
 - 15 (a) general labour rate escalation
 - 16 (b) increases in pension and other post-employment benefits
 - 17 (c) the additional cost of providing for new skilled labour in the face of an aging
18 workforce; and
- 19 (4) Additional expenditures arising out of a variety of initiatives mandated by OPG's
20 shareholder, including improving the material condition of the nuclear plants and
21 planning and preparation for new nuclear facilities.

22 23 **COST OF CAPITAL**

24 The Memorandum of Agreement directs OPG to operate as a commercial enterprise with an
25 independent Board of Directors. As an *OBCA* corporation with a commercial mandate, OPG
26 is required to "operate on a financially sustainable basis and maintain the value of its assets"
27 (Ex. A1-T4-S1, Appendix B, page 3).

28
29 In accordance with this directive from its shareholder, OPG is seeking a capital structure for
30 the prescribed assets consisting of 57.5 percent equity and 42.5 percent debt and a return on
31 the equity portion of that capital structure of 10.5 percent (Ex. C2-T1-S1). The payments

1 prescribed by the Regulation assumed a 45 percent equity/55 percent debt capital structure
2 and only a 5 percent return on equity. A 5 percent return is “clearly inappropriate”, not
3 sustainable on any commercial basis, out of line with the returns awarded to lower risk
4 utilities and is inconsistent with the policy directive that OPG is to operate as a commercial
5 enterprise and become financially self-sustaining.

6
7 OPG faces considerably higher risks than a typical regulated utility in Canada. As a
8 generation only business, OPG’s regulated operations have no low risk monopoly wires or
9 distribution pipe operations. Generation is inherently subject to higher market risks and is
10 also subject to higher operating and production risks than transmission, distribution and
11 vertically integrated utilities.

12
13 Because this is OPG’s first application, there is no track record of stable or consistent
14 regulation and, therefore, there is also regulatory uncertainty about the end state and about
15 OPG’s ability under regulation to recover its reasonable costs. As a result, there is a risk of
16 unintended consequences from specific decisions until there is a track record of consistent,
17 stable regulation. In addition, OPG faces uncertainty around how its payment amounts will be
18 established and the risk of further political intervention in the electricity industry. Uncertainty
19 also results from the hybrid nature of Ontario’s energy market.

20
21 While there is some risk sharing of nuclear waste obligations with the government, the long
22 run risk of nuclear liability remains a significant factor for OPG. OPG also faces significant
23 levels of capital expenditure in the future for refurbishment and new plant development.
24 These too will expose OPG to significant cost recovery risk in the future.

25
26 OPG’s dominant risk, however, is that the nuclear generating plants will not operate as
27 planned. Nuclear technology is complex. OPG’s fleet is an amalgamation of three
28 generations of CANDU reactor, the newest of which, Darlington, was built more than 20
29 years ago and the oldest of which, Pickering A, was built over 40 years ago. As a result,
30 OPG tends to be one of the first in the industry to encounter maintenance and reliability
31 issues with the aging CANDU fleet.

32

1 OPG, therefore, faces significant risk of revenue variability due to longer or more frequent
2 outages and higher than expected costs to repair and maintain the nuclear facilities. Every
3 TWh shortfall, at the proposed variable payment of \$41.50 per MWh, is equal to a \$41.5M
4 reduction in OPG's revenue.

5 6 **NUCLEAR LIABILITIES**

7 The nuclear liability increases in the test period result from a revised reference plan under
8 the Ontario Nuclear Funds Agreement in 2006. As a result of the new approved reference
9 plan, OPG was obliged to record an additional \$1.386B of nuclear waste liabilities in its
10 financial statements. The increased nuclear liabilities largely resulted from updated financial
11 parameters, such as discount rate, the extended life of the Bruce units and recent experience
12 in the U.S. around the forecast cost of nuclear plant decommissioning.

13
14 The fixed nuclear assets of \$4.030B in OPG's audited financial statements include the asset
15 retirement cost ("ARC") of OPG's nuclear liabilities. During the interim rate period, OPG
16 recovered the cost of its nuclear liabilities through both a return of, and return on, capital in
17 rate base that included the ARC. This was the method recommended by the province's
18 financial advisor, CIBC World Markets, and adopted in O. Reg. 53/05 as the basis for the
19 interim payment amounts. OPG submits that this method of recovering its nuclear liability
20 costs is required by O. Reg. 53/05 and is proposing to continue with this approach.

21 22 **LABOUR COSTS**

23 Significantly, 90 percent of OPG's work force is unionized. OPG's operations also require
24 unusually high skill levels from its employees. These people are not easy to find and other
25 employers in the electricity sector compete for them. The demographic of OPG's work force
26 is aging. It is estimated that over 30 percent of OPG's work force will need to be replaced
27 over the next four years.

28
29 Another implication of aging workforce demographics is the cost of pension and other post
30 employment benefits. Like many industries with a maturing workforce, OPG is facing higher
31 costs in order to fund its pension and OPEB benefits.

1 **NEW INITIATIVES**

2 OPG has been mandated by its shareholder to pursue certain initiatives, including the
3 investigation of possible Pickering B and Darlington refurbishments, improvement of the
4 material condition of the nuclear plants and the investigation of new nuclear development.
5 Provision for recovering the costs of these initiatives is dealt with in the Regulation. These
6 costs also contribute to the revenue deficiency in the test period.

7
8 **STRUCTURE OF PAYMENT AMOUNTS**

9 OPG is proposing an improved incentive mechanism for the regulated hydroelectric payment
10 amounts.

11
12 The regulation already provides an incentive to OPG for its regulated hydroelectric
13 generation. Although this incentive was, in the historical period, 2005-2007, financially
14 advantageous to OPG, the company's experience has shown that the existing mechanism
15 does not always provide the correct market signals to maximize production to meet peak
16 demand. Accordingly, OPG has developed a more nuanced mechanism, based on the
17 relationship of production to market signals, in order to further improve OPG's incentive to
18 maximize production during times when the electricity is most needed and, therefore, when it
19 is more valuable.

20
21 OPG can use its regulated hydroelectric assets to shift water, and the resulting electricity
22 production, from periods of low demand to periods of peak demand. As a result, under the
23 new proposed incentive mechanism, OPG estimates that time shifting water and operating
24 the Sir Adam Beck Pump Generating Station units during peak hours could reduce the hourly
25 Ontario energy price by between \$0.40 and \$1.20 per megawatt hour with an annual
26 estimated savings for customers ranging between \$80M and \$270M. OPG's incentive
27 payment for achieving these efficiencies is forecast to be about \$12M in 2009.

28
29 OPG is also seeking to restructure payment amounts for nuclear production from 100
30 percent variable to a combination of a fixed monthly payment and a variable payment. The
31 costs of OPG's nuclear facilities are over 90 percent fixed. OPG accordingly bears a
32 significant risk when its entire revenue requirement is recovered through a variable payment.

1 Other utilities and generators in Ontario and other jurisdictions recover fixed costs through
2 fixed payments. Accordingly, OPG is seeking a payment amount structure which will enable
3 it to recover 25 percent of its revenue requirement for the nuclear facilities through a fixed
4 monthly payment, leaving 75 percent to be recovered on the basis of variable energy
5 payments.

6
7 As noted, the OEB made OPG's payment amounts interim as of April 1, 2008. OPG is
8 seeking recovery of its forecast revenue requirement from that date. OPG proposes that the
9 retrospective amounts from April 1, 2008 be recovered over the balance of the test period
10 following issuance of the Board's order, based on actual consumption during the "interim"
11 period.

12 13 **CONCLUSION**

14 OPG has presented a detailed and complete record to allow the OEB to evaluate its
15 proposed return on equity, capital structure, costs and revenues. Based on this record, the
16 OEB should establish the payments amounts requested by OPG, and grant the orders
17 requested in Ex. A1-T2-S2.

1. RATE BASE

Issue 1.1

Is the rate base appropriately determined in accordance with regulatory and accounting requirements?

OPG requests approval of the rate base forecasts set out in Exhibit B of the pre-filed evidence. For the regulated hydroelectric facilities, OPG seeks approval of its rate base forecasts of \$3,885.5M for 2008 and \$3,869.9M for 2009 (Ex. B1-T1-S1, Table 1). For the nuclear facilities, OPG seeks approval of its rate base forecasts of \$3,515.4M for 2008 and \$3,483.8M for 2009 (Ex. B1-T1-S1, Table 2).

These amounts reflect OPG's forecasts of net fixed assets and working capital, using the 2007 audited financial statements as the starting point. Fixed assets that are shared between OPG's regulated and unregulated businesses are held centrally and are not included in rate base but, rather, are charged to the regulated business through asset service fees (Ex. F3-T3-S1). The asset service fee is discussed under Issue 5.5 below. As explained in Ex. H1-T1-S2, nuclear net fixed assets also include asset retirement costs ("ARCs"). This matter is fully explored under Issue 7.1 below.

Net fixed asset in-service values were established - consistent with the provisions of section 6(2)5 of O. Reg. 53/05 - based on the property, plant and equipment values in OPG's 2007 audited financial statements (Ex. J2.7). From that starting point, adjustments were made to account for forecast fixed asset additions, retirements, impairments and depreciation in each of 2008 and 2009. For in-service additions, a mid-year average methodology was employed, under which additions were deemed to occur at mid-year based on the assumption that capital projects will come into service throughout the year (Ex. B1-T1-S1, page 2).

Fixed assets under construction are excluded from rate base until they are declared in-service, consistent with OPG's capitalization policy (Ex. A2-T2-S1, Section 4.0). However, to the extent that amounts for future in-service additions are shown as construction work in progress ("CIP") in OPG's 2007 audited financial statement, the capital costs represented by

1 these amounts must be accepted by the OEB pursuant to section 6(2)5 of O. Reg. 53/05,
2 when these projects come into service (Ex. A2-T1-S1, Appendix A, page 51; Ex. J2.7; Ex.
3 J6.5). OPG used a rate of 6 percent to record interest carrying charges added to CIP for
4 2005 through 2007, but proposes to use the weighted-average cost of capital going forward
5 (Ex. L-1-20).

6
7 Depreciation forecasts were determined from the forecast net fixed asset values and
8 expected remaining lives of the prescribed facilities (Ex. F3-T2-S1, Tables 1 and 4). OPG's
9 depreciation rates and expenses are further discussed under Issue 5.2 below.

10
11 Working capital amounts were established based on the fuel inventory and materials and
12 supplies values in OPG's 2007 audited financial statements, and cash working capital was
13 based on a lead-lag study (Ex. A2-T1-S1, Appendix A, page 51; J2.7; Ex. B1-T1-S1, page 5).
14 Working capital represents \$21.8M of the total regulated hydroelectric rate base in each of
15 2008 and 2009 and is almost entirely cash working capital (Ex. B1-T1-S1, Table 1). Working
16 capital represents \$721.4M of the total nuclear rate base in 2008 and \$787.8M of the total
17 nuclear rate base in 2009, of which only \$16.0M is cash working capital (Ex. B1-T1-S1, Table
18 2).

19
20 The non-cash working capital amounts for the nuclear facilities are comprised of fuel
21 inventory and materials and supplies as shown in Ex. B1-T1-S1, Table 2. The materials and
22 supplies component of working capital is based on the values set out in OPG's 2007 audited
23 financial statements, projected forward to the test years. To arrive at the test year values,
24 OPG uses the average of the opening and closing balances for consumables and inventory
25 during the period, net of accumulated obsolescence (Ex. B1-T1-S1, pages 6-7). The fuel
26 inventory component of working capital is also based on values in the 2007 audited financial
27 statements. These values are projected forward to the test years based on planned or
28 expected fuel procurement and usage, as presented in Ex. F2-T5-S1 and discussed under
29 Issue 5.7 below.

30
31 Consistent with regulatory and accounting requirements, OPG has appropriately reflected the
32 2007 audited financial statements, the forecast in-service additions, depreciation and other

adjustments to net fixed assets in its forecast of rate base for the test period. Similarly, OPG has calculated the working capital component of rate base appropriately, including the use of a lead-lag study and forecasts of fuel inventory, materials and supplies.

2. CAPITAL STRUCTURE AND COST OF CAPITAL

OPG has applied for payment amounts based on a deemed capital structure of 57.5 percent equity and 42.5 percent debt. OPG is seeking a return on the equity portion of its capital structure of 10.5 percent. The interim rates were based on a 55/45 debt/equity ratio and a 5 percent return on equity. This capital structure and return are clearly inappropriate for OPG, particularly given its mandate to operate as a commercial enterprise. The capital structure and returns recommended by intervenor cost of capital witnesses are also inadequate and should be rejected because they do not meet any of the three tests of comparable returns, capital attraction or financial integrity.

OPG opposes the use of separate capital structures and rates of return on equity for its two regulated technologies. OPG is seeking the application of a formula to adjust its return in future, so that the OEB does not need to re-assess capital structure and return in every application to set new payment amounts. OPG's cost of debt for the test period is based on both existing issues and forecast issues, the cost of which is based on estimates of future debt costs.

Issue 2.1

What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Issue 2.2

What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated

1 **hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each**
2 **business?**

3
4 **FAIR RETURN STANDARD**

5 An essential component of the just and reasonable standard, described in the overview
6 section, is the requirement to set rates at a level that permits a utility to earn a fair return on
7 invested capital. Mr. Justice Lamont, of the Supreme Court of Canada, defined a fair return
8 as follows:

9
10 “By a fair return is meant that the company will be allowed as large a
11 return on the capital invested in its enterprise (which will be net to the
12 company) as it would receive if it were investing the same amount in
13 other securities possessing an attractiveness, stability and certainty
14 equal to that of the company’s enterprise.”⁵
15

16 The Supreme Court of Canada reaffirmed this definition in 1960.⁶ Mr. Justice Locke
17 concluded that “the [return] must be sufficient to enable it to pay reasonable dividends and
18 attract capital...”. He also concluded that “the obligation to approve rates which will give a fair
19 and reasonable return is absolute”.⁷
20

21 The absolute nature of the obligation to apply the fair return standard was also endorsed by
22 the Federal Court of Appeal. In *TransCanada Pipelines Ltd. v. National Energy Board*, the
23 Court agreed that the “absolute” nature of the obligation to approve rates that will enable the
24 company to earn a fair return means that the required return must be determined solely on
25 the basis of the company’s cost of equity and is not influenced by any resulting rate impact
26 on customers.⁸
27

28 The legal requirement to apply the fair return standard has also been recognized by the
29 OEB. In EB-2005-0421 (Toronto Hydro), the OEB noted that “as a matter of law, utilities are
30 entitled to earn a rate-of-return that not only enables them to attract capital on reasonable

⁵ *Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] S.C.R. 186 at 193.

⁶ *British Columbia Electric Railway Co. Ltd. v. British Columbia (Utilities Commission)*, [1960] S.C.R. 837 at 854.

⁷ *Ibid.* ; see also *Union Gas Ltd. v. Ontario (Energy Board)* (1983), 1 D.L.R. (4th) 698 at 711 and *Hemlock Valley Electrical Services Ltd. v. British Columbia (Utilities Commission)* (1992), 66 B.C.L.R. (2d) 1 (B.C.C.A.).

⁸ 2004 FCA at para. 36; see also *Hemlock Valley*, *supra*.

1 terms but is comparable to the return granted other utilities with a similar risk profile” (April
2 12, 2006, pages 32 to 33).

3
4 The Supreme Court of the United States has also adopted the fair return standard. Rates
5 that are not sufficient to yield a reasonable return on the value of a utility’s property used to
6 provide service are unjust, unreasonable, and confiscatory. The return must correspond to
7 the return to other businesses of similar risk, be sufficient to assure confidence in the
8 financial integrity of the utility and be adequate to support its credit and enable it to raise
9 money for the conduct of its business.⁹

10
11 The fair return standard, therefore, must meet three requirements:

- 12 1. Comparable returns.
13 2. Financial integrity.
14 3. Capital attraction.

15
16 **THE STAND ALONE PRINCIPLE**

17 Most of the cost of capital witnesses who testified in this proceeding agree that OPG’s cost of
18 capital should be determined on a “stand alone” basis. By stand alone, Ms. McShane meant
19 that the cost of capital incurred by ratepayers should be equivalent to that which would be
20 faced by the regulated operations if they were raising capital in the public markets on the
21 strength of their own business and financial parameters. The evidence of Mr. Goulding, of
22 London Economics, retained by Board Staff, was that as an *OBCA* corporation, OPG should
23 be treated no differently from any other entity that the OEB regulates and that provincial
24 ownership “should not influence the OEB any more than if OPG was 100 percent owned by a
25 private entity” (Tr. Vol. 12, page 111). Accordingly, Mr. Goulding confirmed that OPG should
26 be viewed on a stand alone basis, disregarding the fact of its ownership by the Province
27 (*Ibid.*, pages 111-112).

28
29 Mr. Goulding agreed that provinces which sell power at less than full value lose out twice:
30 first as shareholders because they receive less revenue and lower profits than would

⁹ *Bluefield Water Works & Improvement Company v. Public Service Commission of the State of West Virginia et al.*, 262 U.S. 679 (1923) at 692; *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) at 603.

1 otherwise be achieved by their investments; and second, as policy makers, they lose again
2 because under-priced electricity encourages over-consumption and all of its attendant
3 adverse environmental impacts (Tr. Vol. 12, page 143).

4
5 Drs. Kryzanowski and Roberts, corporate finance experts retained by Pollution Probe, also
6 took the position that OPG's "risk" should be determined on the stand alone principle, by
7 which they meant setting aside the impact of provincial ownership. Under the stand alone
8 principle, one should assess the appropriate capital structure from the standpoint of an
9 investor-owned utility of comparable risk (Tr. Vol. 13, page 57).

10
11 Professor Booth, retained by CCC/VECC, while somewhat ambivalent on this issue, agreed
12 that from a standpoint of corporate finance principles, we should be asking 'what is the
13 appropriate value of the resources controlled by the entity and what is the entities cost of
14 capital, i.e., the opportunity cost of those resources?' In H.R. 15, Professor Booth said that
15 the stand alone approach to the cost of capital should be used to improve resource allocation
16 and that customers should have to pay a price for electricity that reflects the opportunity cost
17 of production. Professor Booth confirmed this evidence and further confirmed that he did not
18 resile from that approach now (Ex. K12.3; Tr. Vol. 2 pages 16-18; Tr. Vol. 13, pages 170-
19 171).

20
21 Professor Booth admitted that his views on the impact of the shareholder being the province
22 of Ontario were not founded in principles of corporate finance (his area of expertise) but were
23 matters of regulatory policy (Tr. Vol. 13, page 161). Accordingly, Professor Booth's views on
24 the implications of provincial government ownership in this case are personal in nature and
25 not founded in his area of qualified expertise.

26
27 Dr. Schwartz testified that whether or not there were subsidies between ratepayers and
28 taxpayers it was not a principle that informed his opinion in this case (Tr. Vol. 14, page 61).

29
30 The stand alone principle is not only supported by logic and the evidence of most of the cost
31 of capital experts. It is also supported by extensive regulatory precedent. Canadian
32 regulators, including the OEB, have a long history of assessing regulated operations,

1 including their risk and cost of capital, irrespective of who their owner, parent or affiliate may
2 be¹⁰.

3
4 In H.R. 15, the Report of the Board, page 14/5, the OEB emphasized the necessity of
5 separating ratepayers from taxpayers conceptually and rejected the notion that because "the
6 customers are the shareholders" reducing the required level of net income from what it would
7 otherwise be was justified. The OEB went on to say:

8
9 14.77 This Board is concerned that Hydro's failure to reflect the cost
10 of equity capital in determining net income may amount to serious
11 cross-subsidizations of all electricity usage (H.R. 15, Report of the
12 Board, page 14/32).

13
14 14.80 The Board believes that consumers and owner-like equity
15 interest problems can be solved by having Hydro treat consumer
16 interests separately from owner-like interests, and recommends that
17 Hydro treat such interests separately (H.R. 15, Report of the Board,
18 page 14/33).

19
20 Subsequently, in H.R. 16, the OEB again considered the issue of the government's debt
21 guarantee for Ontario's Hydro and again expressed concern that Hydro's lower cost of
22 capital may lead over time to non-optimal use of capital and labour resources. The OEB was
23 concerned that a combination of lower capital costs and lower prices may have various
24 ramifications for the economy in Ontario such as excessive use of electricity. At pages 10/9
25 to 10/10) the OEB said:

26
27 "The Board has concluded that a payment in the form of a fee paid by
28 Hydro to the Ontario Government should be introduced to compensate
29 taxpayers of the Province for the risk they bear by guaranteeing
30 Hydro's debt and for which they are not now appropriately
31 compensated."

32
33 Further, although the matter was not explicitly addressed, it necessarily follows from the
34 OEB's decision to award government-owned electric Local Distribution Companies such as

¹⁰ See: *TransCanada Pipelines, (National Energy Board, Reasons for Decision, In the matter of the Application Under Part IV of the National Energy Board Act, (Rates Application of Transcanada Pipelines Limited, August 1980); the Public Utilities Board, Alberta, Decision E93060, re: NOVA Corporation of Alberta, August 20, 1993.*

Toronto Hydro and Hydro One commercially-based capital structures and rates of return that the OEB did not regard government ownership as a material consideration.

TESTIMONY OF KATHLEEN C. MCSHANE

Like all the other cost of capital experts (except Schwartz) in this case, Ms. McShane conducted two analytically distinct analyses. The capital structure (the ratio of debt and equity used to finance the company's rate base) was determined on a deemed basis to reflect the probability that future returns to investors will fall short of their expected and required returns (business risks). The proposed deemed capital structure is also intended to ensure that OPG's regulated business would have access to the public debt markets on the basis of a stand alone credit ratings in the A category. Ms. McShane's concept of a benchmark return on equity, on the other hand, was used to determine, for a given deemed capital structure, the appropriate cost of, or return on, equity ("ROE"). Ms. McShane relied on the equity risk premium approach to determine ROE, as well as on a discounted cash flow analysis and an analysis of earnings from comparable companies.

RETURN ON EQUITY

The equity risk premium test recognizes that an investor in common equity takes greater risks than an investor in bonds. Accordingly, the equity investor requires a premium above bond yields as compensation for the greater risk. The risk premium test is forward-looking. To develop an appropriate risk premium, data must be analyzed in the context of current and anticipated market conditions which, in turn, requires the exercise of informed judgment.¹¹ Historical risk premium data, while informative, are not determinative because of the differences in market conditions from one period to the next.

Like Professors Kryzanowski, Roberts and Booth, Ms. McShane began her analysis with a risk-free rate, which, for these purposes, is equal to the forecast long-term Government of Canada bond yield. The forecast involved the use of *Consensus Forecasts* for ten year yields and an adjustment to capture the appropriate spread between the ten year and thirty year Canada bonds. She concluded that long-term Canada bond yields were forecast at 4.5

¹¹ (Goulding, Tr. Vol. 12, page 104; Kryzanowsky and Roberts, Tr. Vol. 13, page 106; Booth, Tr. Vol. 13, page 151)

1 percent for the test period. Ms. McShane employed three equity risk premium tests which
2 produced an equity risk premium range of 4.5 to 5.25 percent, with a midpoint of 4.875
3 percent. This, combined with the anticipated risk-free rate, produced a cost of equity in the
4 range of 9 to 9.75 percent. Ms. McShane added a floatation/financial flexibility cost allowance
5 (discussed below) of fifty basis points to the mid-point of this range to produce an ROE for
6 the test period, using the equity risk premium approach, of 9.875 percent (Tr. Vol. 10, pages
7 11-13).

8
9 The first of Ms. McShane's equity risk premium tests, also known as the Capital Asset
10 Pricing Method ("CAPM"), has three pieces: (1) the risk-free rate; (2) the market risk
11 premium; and (3) the beta. Of these three, only the risk free rate is observable. The other
12 pieces have to be inferred (Tr. Vol. 10, page 17). Ms. McShane analyzed historical equity
13 market and bond returns and expected bond yields and concluded that a reasonable
14 expected value of the equity market risk premium is 6.5 percent (which, at a forecast long-
15 term Government of Canada bond yield of 4.5 percent is equal to an equity market return of
16 11.0 percent). She estimated the beta, or relative risk adjustment, for a benchmark Canadian
17 utility at 0.65-0.70.

18
19 The CAPM does not lend itself very well to tracking changes in the cost of equity because
20 the market risk premium is based on long-term averages and the beta is based on historical
21 values. By way of illustration, Ms. McShane noted that when her evidence was originally
22 prepared in November 2007, the long-term Canada bond yield was about 4.5 percent and
23 the yield on long-term utility bonds rated in the A category by DBRS was 5.75 percent. At the
24 end of May 2008, the yield of long-term Canada bond yields had gone down by 40 basis
25 points to 4.1 percent but the yield on long-term utility bonds had actually gone up to 6
26 percent. If you looked only at the CAPM, you would conclude that the cost of equity had gone
27 down, but if you looked at the change in corporate bond yields as an indicator of where
28 equity costs had gone, you would come to a totally different conclusion, i.e., that the cost of
29 equity had gone up.

30
31 Accordingly, there are a number of reasons why it is important to look at more than one test
32 and, in particular, to consider a test that directly estimates trends in the cost of equity.

1 Ms. McShane, therefore, in contrast to most of the other cost of capital experts who
2 expressed an opinion on return on equity, also used two additional risk premium tests
3 (historical utility risk premium and DCF-based risk premium), the DCF test and the
4 comparable earnings test. Although the CAPM is now the dominant methodology in Canada
5 for determining ROE in the context of rate setting for regulated utilities, it is by no means
6 perfect. The CAPM involves the exercise of considerable professional judgment. This was
7 acknowledged by Professors Kryzanowski, Roberts and Booth (Tr. Vol. 13, pages 106 and
8 151).

9
10 The DCF model has a distinct advantage over the risk premium estimates, particularly those
11 made using the CAPM, in that the DCF approach allows the analyst to estimate directly the
12 utility cost of equity. In contrast, the CAPM *indirectly* estimates the cost of equity.
13 Ms. McShane applied both the constant growth and the two-stage model in her DCF
14 analysis. In both cases, the discounted cash flow approach was applied to a sample of low-
15 risk U.S. “pure play” electric and gas distributors that were intended to serve as a proxy for a
16 benchmark Canadian utility. The DCF method produced a cost of equity, inclusive of 50
17 basis points for financing flexibility, of 10.0 to 10.5 percent. Ms. McShane tested this
18 conclusion for reasonableness by reference to the Value Line forecast of expected returns on
19 equity of 11 to 12 percent (Ex. C2-T1-S1, page 44).

20
21 One criticism of the DCF approach is that it relies on analysts’ projections. There are studies
22 which suggest that there is an upward analyst estimation bias in growth stocks. Ms.
23 McShane pointed out, however, that none of these studies involved forecasts of utility
24 earnings. There are good reasons to think that analyst bias is not a factor in estimating utility
25 earnings. Utilities are the quintessential mature industry. Investors would expect the growth
26 of utilities, therefore, to parallel the growth of the economy as a whole. Analysts’ forecasts for
27 utilities’ growth were, on average, 60 basis points lower than the expected growth in the
28 economy, supporting the conclusion that analysts’ estimates in the utility context, at least (as
29 distinct from “growth” stocks), are not systematically optimistic (Tr. Vol. 10, pages 21-22).

30
31 Both the equity risk premium and discounted cash flow approaches require an allowance for
32 financing flexibility. This is an integral part of the cost of capital and is well recognized by

1 Canadian regulators as a required element in the concept of a fair return. The financing and
2 flexibility allowance is required to allow the utility to recover financing costs as well as to be in
3 a position to raise new equity without impairing its financial integrity. Ms. McShane, and
4 Professors Kryzanowski, Roberts and Booth all recommend the same allowance for
5 financing flexibility of 50 basis points.

6
7 The concept of a financing flexibility/flotation cost allowance has been accepted by most
8 Canadian regulators. Although OPG has not raised equity capital in the public equity
9 markets, an allowance for unanticipated capital market conditions is appropriate. It has been
10 expressly recognized by the OEB in connection with its transitional rate order for Hydro One,
11 in RP-1998-0001, in setting returns for the transmission and distribution portions of the
12 former Ontario Hydro that are comparable to those allowed for investor-owned utilities. It is
13 also justified on the basis of OPG's plans to enter the capital markets in late 2009/early 2010
14 as indicated by OPG's Treasurer, Ms. Sidford (Tr. Vol. 1, pages 32-33).

15
16 Ms. McShane also used the comparable earnings test. The comparable earnings test
17 remains the only test that explicitly recognizes that, in the North American regulatory
18 framework, the return is applied to an original cost (book value) rate base. The persistence of
19 inflation creates systematic deviation between book and market value. The equity risk
20 premium and discounted cash flow tests require adjustments to allow for the discrepancy
21 between the return on market value and the corresponding fair return on book value. The
22 comparable earnings test, however, requires no such adjustment. It applies "apples to
23 apples", i.e., a book value measured return is applied to a book value measured equity
24 investment. Using the comparable earnings method, Ms. McShane concluded that a fair
25 return for a benchmark Canadian utility is approximately 12.5 percent.

26
27 In arriving at a reasonable return for a benchmark utility, Ms. McShane gave primary weight
28 to the cost of attracting capital, as measured by both the equity risk premium and DCF tests.
29 Based on all three test results, Ms. McShane concluded that a fair return for a benchmark
30 Canadian utility is 10.5 percent.

1 Ms. McShane was also asked to comment on the ROE embedded in the OPA's recent
2 agreement with Bruce Power. Exhibit K11.3 was the fairness opinion given by CIBC World
3 Markets to the Ministry of Energy concerning the Bruce Power refurbishment agreement.
4 CIBC concluded that a reasonable capital structure would have 20 to 40 percent debt and 60
5 to 80 percent equity and that an appropriate after-tax weighted average cost of capital would
6 be 10.6 percent to 13.8 percent based on a cost of equity of 13.7 percent to 18 percent (Ex.
7 K11.3, pages 9-10).

8
9 Ms. McShane qualified her comments on the fairness opinion by acknowledging that the
10 agreement involved some construction/refurbishment cost overrun risk (albeit, shared with
11 the province) as well as both operational and market risk (again, however, tempered by a
12 guaranteed floor price). Nevertheless, she noted that the Bruce Generating Station is really
13 the only operation that, from a fundamental operating perspective, is closely comparable to
14 OPG's nuclear assets. CIBC took a similar approach to Ms. McShane in their analysis, using
15 an equity risk premium approach based on a market risk premium and estimated betas. In
16 Ms. McShane's view, CIBC's conclusions on the appropriate debt to equity ratio and return
17 on equity for Bruce Power provide some comfort that the recommendations she has made
18 are not unreasonable (Tr. Vol. 11, pages 44-45).

19
20 **BUSINESS RISKS**

21 In arriving at her capital structure recommendations, Ms. McShane considered the business
22 risks of both the regulated hydroelectric and nuclear operations. These risks included
23 revenue and market related risks, production and operating risks, cost recovery risks and
24 regulatory risks.

25
26 Ms. McShane's views on the relative hierarchy of risks among energy companies were
27 shared by most of the other cost of capital experts in this case. The lowest risk utilities are
28 electricity transmission companies; next are gas and electric distribution companies; followed
29 by vertically integrated (transmission, distribution and generation) companies. At the upper
30 end of the regulated spectrum is generation - nuclear being considerably more risky than
31 hydroelectric, but both hydroelectric and nuclear being more risky than an integrated electric
32 utility.

1 Clearly for OPG, operating and production risk is the largest risk it faces. Although there is a
2 proposal for a deferral account covering fluctuations in the available water during the test
3 period, no other aspect of production risk on a going-forward basis (particularly for nuclear) is
4 subject to variance or deferral treatment.

5
6 Although much has been made of alleged deferral and variance account “protection” in this
7 case, the fact of the matter is that most of the regulated deferral and variance accounts are
8 simply reflections of the well recognized prohibition against retroactive rate making. In other
9 words, most of the mandated recovery provisions of O. Reg. 53/05 simply ensure the
10 recovery of costs associated with initiatives that were directed, authorized or approved by the
11 government before the introduction of rate regulation by the OEB. These include recovery of
12 Bruce Generating Station costs, recovery of certain costs to increase production so long as
13 they fall within project budgets approved by OPG’s board of directors prior to the effective
14 date of the OEB’s first order, acceptance of certain asset and liability values in OPG’s most
15 recently audited financial statements, Pickering A return to service costs and nuclear waste
16 and decommissioning liability costs associated with the Ontario Nuclear Funds Agreement.

17
18 Ms. McShane’s recommendations on capital structure and ROE for OPG assumed
19 acceptance of the company’s proposals for deferral and variance accounts. In response to
20 various interrogatories and undertakings, she provided her estimate of the impact on her
21 recommendations if the proposed accounts are not approved by the Board (Ex. KT1.6; Ex.
22 J12.2).

23
24 Revenue risks are a function of the high degree of operating leverage characteristic of asset
25 intensive businesses like electricity generation. A high degree of operating leverage means
26 that OPG’s costs are largely fixed. All things equal, the higher the operating leverage, the
27 higher the business risk. In part to mitigate this risk, OPG has proposed that it recover 25
28 percent of its test period nuclear revenue requirement, net of deferral and variance account
29 amortization, through a fixed charge. Ms. McShane estimated that she would increase her
30 recommended ROE by 25 basis points or, alternatively, her recommended percentage of
31 equity in the capital structure to approximately 60 percent, if the 25 percent fixed payment is
32 not accepted by the Board (Ex. L-12-1).

1 Nuclear technology is more complex than other types of generation and is subject to a higher
2 risk of unanticipated costs of repair and loss of production. The nuclear operating
3 environment is much harsher than for other types of a generation. As a result, the complexity
4 and length of time for repair of nuclear plants exceeds those of hydroelectric and other
5 generation technologies. The specific circumstances of OPG entail additional risk as the
6 reactors include early designs and three different variants of CANDU technology. As well,
7 ongoing updates to nuclear operating standards and regulations frequently require
8 modifications to the plants to ensure compliance with safety and other regulatory
9 requirements. The operating environment and the technological characteristics of OPG's
10 nuclear generation fleet are such that maintenance, repair and refurbishment are forecast
11 with a higher degree of uncertainty than for other types of generation. This uncertainty can
12 result in materially longer than anticipated outages or unplanned outages, which lead to loss
13 of production and unanticipated costs of repair or remediation.

14
15 As one of the largest generators of nuclear energy in the country, OPG also bears significant
16 responsibility for the management of nuclear waste. Substantial funding for OPG's future
17 obligations and a partial provincial guarantee of used fuel management costs mitigates the
18 risk of future nuclear waste liabilities, but only to a degree. Although the decommissioning
19 fund is fully funded according to today's estimates, OPG bears the full risk of
20 decommissioning cost increases and the level of fund earnings. Similarly, although the
21 province has capped OPG's liability for used fuel management, the used fuel fund is far from
22 fully funded (only 70 percent) and the protection of the provincial "cap" will not be engaged
23 until OPG's liability has increased by \$2B, using the 1999 present value (see discussion of
24 nuclear waste liabilities under Issue 7.1 below).

25
26 In addition, the estimates which underpin the forecast of required funds are subject to
27 change as a result of many factors outside of OPG's control. An increase in the estimate of
28 the liability or decrease in decommissioning fund earnings could have a significant negative
29 impact on OPG's financial condition.

30
31 OPG also faces higher regulatory and political risk than most regulated utilities in Canada. As
32 the OEB noted in its November 20, 2006 Report, the application of cost of service regulation

1 to generation in general, and OPG in particular, is unique. There are no well-defined
2 procedures or analytical frameworks and no track record upon which to gauge the outcome.
3 The uncertainty of the “end state” is amplified by the fact that OPG will be regulated in an
4 environment which is a hybrid of regulation and competition as noted in Standard and Poor’s
5 2005 rating of OPG (Ex. A2-T3-S1, Attachment B, page 6).

6
7 In Ontario, political invention in the regulatory process has been a factor in the business risk
8 assessment of utilities by debt rating agencies. In this regard, OPG is no different than other
9 utilities. The Province is in the position (and has demonstrated a willingness) to use OPG as
10 an instrument for policy-related purposes that may be inconsistent with its interest as
11 shareholder. Uncertainty about the Province’s future conduct creates additional risk.

12
13 In summary, OPG’s regulated operations face significantly higher business risks than the
14 typical Canadian utility:

- 15 1. As a generation only business, OPG’s regulated operations have no low risk monopoly
16 wires or distribution businesses. Generation is subject to higher operating and production
17 risks than wires or pipes operations.
- 18 2. The existing nuclear plants are subject to significantly higher production/operating risks
19 than other types of generation.
- 20 3. While nuclear waste liabilities are mitigated to some extent by provincial guarantees and
21 the existing fund balances, the long-term risks remain higher for OPG than for utilities
22 with either no nuclear exposure, exposure tempered by a smaller size of nuclear
23 operations or where, as in the United States, the government assumes the entire liability
24 for used fuel management.
- 25 4. Regulatory risks are relatively high. The novelty and uniqueness of OPG’s circumstances
26 creates uncertainty about the regulatory end-state and increases the risk of unintended
27 consequences from regulatory decisions. In addition, there remains the risk of further
28 changes to provincial policy that will have a negative on impact OPG’s finances.

29
30 Another relevant consideration in assessing the appropriate cost of capital for OPG is its
31 “financeability”, i.e., the implications for OPG’s debt ratings. Most utilities in Canada have
32 financial metrics, partly driven off capital structure and ROE, which enable them to enjoy A

1 ratings. OPG's A (low) from DBRS and BBB+ from S&P are higher than they would otherwise
2 be on a stand alone basis as a result of implicit provincial support.

3
4 Ms. McShane's deemed capital structure for OPG's regulated operations is based on an
5 analysis of OPG's business risks, debt rating agencies' quantitative guidelines, financial
6 metrics of the electricity industry and incremental cost of equity for regulated generation
7 relative to that of integrated and other less risky utilities.

8
9 An analysis of stand alone coverage ratios at the benchmark return on equity of 10.5 percent
10 and the common equity ratio of 57.5 percent indicates that, in the absence of actual
11 performance of the regulated operations which falls materially short of expected levels, the
12 principal cash flow metrics for the regulated operations of OPG are expected to be sufficient
13 to achieve and maintain stand alone debt ratings in the A category. Failure to maintain
14 investment grade ratings could have significant financial implications for OPG's ability to
15 raise debt and for its debt cost.

16
17 **BOARD STAFF WITNESS – A. J. GOULDING, LONDON ECONOMICS**

18 Mr. Goulding was asked by OEB staff to review principles and relative risks applicable to
19 determining OPG's capital structure and ROE. He was not asked to, and did not, express
20 any opinion on what the capital structure and ROE should be. Mr. Goulding's analysis was
21 based on three principles:

- 22 1. As an *OBCA* corporation, OPG should be treated no differently from any other entity that
23 the OEB regulates. OPG should not be compelled by the regulator to suppress what
24 would otherwise be just and reasonable equity returns to serve other policy objectives.
25 2. Under the just and reasonable standard of rate setting, OPG should be allowed as large
26 a return on its capital as it would receive if it were investing the same amount in securities
27 possessing an attractiveness, stability and certainty equal to that of OPG.
28 3. Owning and operating hydroelectric and nuclear generating assets is clearly not risk free.
29 As a result, a return of 5 percent for the prescribed assets is "clearly inappropriate" from a
30 financial market and utility perspective (Tr. Vol. 12, pages 111-112).

1 Mr. Goulding noted that one of the Ontario government's objectives in deciding to regulate
2 the prescribed assets was easing the burden on taxpayers. The clear implication of this
3 objective is to reduce the suppression of equity returns for OPG, under which taxpayers are
4 essentially subsidizing the consumers of energy. The suppression of OPG's equity returns is
5 a subsidy because if OPG is earning less than a commercial return on its assets, then the
6 government's equity is being invested at a lower return than it would otherwise earn if
7 invested in something else. Earning less than an appropriate commercial return is contrary to
8 OPG's commercial mandate to operate on a financially sustainable basis and to maintain the
9 value of OPG's assets, as prescribed by the Memorandum of Agreement (Tr. Vol. 12, pages
10 112-113).

11
12 Another objective of the government in regulating OPG's prescribed assets was to better
13 reflect the true cost of producing energy. One of the costs of producing power is the cost of
14 the capital required to create the generating assets. Accordingly, artificially suppressing
15 OPG's cost of capital in rates undermines the objective of designing rates that better reflect
16 the true cost of power (Tr. Vol. 12, pages 113-114).

17
18 In 2005, Mr. Goulding authored an article, "Paying the Full Price of Power", in which he
19 recommended an appropriate capital structure for BC, Manitoba, Newfoundland and Quebec
20 Hydro of 55 percent debt and 45 percent equity. For the purposes of determining appropriate
21 capitalization, Mr. Goulding assumed that each utility maintained an A credit rating and that
22 each would be granted an 11.5 percent return on equity. With respect to this 11.5 percent
23 return, Mr. Goulding said (Tr. Vol. 12, page 141):

24
25 "While Canadian regulators have often limited returns to lower
26 amounts, such values were often for the less risky regulated wires
27 business, as in the 9.88 percent ROE allowed to Ontario distributors."

28
29 Mr. Goulding agreed that rates for a large integrated business incorporating generation risk
30 would need to be higher.

31
32 Mr. Goulding, in his 2005 article, also took the position that the 11.5 percent return adopted
33 for his analysis of the full cost of power for BC Hydro et al was consistent with the overall
34 North American average (Tr. Vol. 12, page 141). Mr. Goulding confirmed that he still regards

1 the North American market (i.e., U.S. capital structures and ROEs) as a relevant
2 consideration in considering the cost of capital of Canadian utilities (Tr. Vol. 12, page 162).

3
4 Ms. McShane prepared a table which shows the returns awarded to most Canadian energy
5 utilities (Ex. J11.1 Attachment). The lowest return is for Hydro One Transmission at 8.35
6 percent. Most were between 8.5 and 9.5 percent. Having regard to his second foundational
7 principle, that OPG should earn as large a return as would be earned on an investment in an
8 enterprise of equivalent attractiveness, stability and certainty, Mr. Goulding agreed that a
9 return for OPG below the returns shown in Ex. J11.1 would be insufficient (Tr. Vol. 12,
10 page 171).

11
12 **POLLUTION PROBE WITNESSES - DRS. KRYZANOWSKI AND ROBERTS**

13 Drs. Kryzanowski and Roberts relied exclusively on a single equity risk premium approach
14 for ROE. They recommend a combined capital structure for the prescribed assets of 47
15 percent equity and 53 percent debt and an ROE of 7.35 percent for 2008 and 7.4 percent for
16 2009.

17
18 In OPG's submission, the Kryzanowski and Roberts recommendations on equity are too low.
19 Their capital structure is too debt oriented for the inherent risks of the combined generation
20 business and the equity returns falls below any reasonable level of comparable returns and
21 do not meet the capital attraction or financial integrity standard.

22
23 Drs. Kryzanowski and Roberts' business risk analysis, which leads to their combined
24 weighted average equity ratio of 47 percent, is not convincing. Drs. Kryzanowski and Roberts
25 subscribe to the commonly held view that electricity transmission carries the lowest risk in
26 the utility field, followed by distribution and then by generation. Indeed, the business risks
27 associated with OPG's hydroelectric generation alone are above those of a transmission
28 distribution or integrated utility. OPG's nuclear generation business carries an even higher
29 level of risk overall compared to OPG's hydroelectric (Tr. Vol. 13, pages 58-59). However,
30 their recommendations are not consistent with this view.

31

1 Drs. Kryzanowski and Roberts recommended ROEs of 7.35 percent and 7.4 percent for 2008
2 and 2009 suffer from two fundamental flaws. First, their estimated market premium is
3 downwardly biased because they have not given sufficient recognition to current and
4 anticipated lower bond market yields. Second, their analysis suffers from a fundamental
5 contradiction. While they agree that OPG's prescribed assets make its regulated business
6 riskier than any other regulated energy utility in Canada, their recommended ROE falls
7 significantly below that of even the least risky Canadian utility. With respect to their
8 calculated market risk premium, Kryzanowski and Roberts claim that market risk premiums
9 have been shrinking and will remain much smaller in the future.

10
11 Ms. McShane testified, however, that while it is undeniable that achieved market risk
12 premiums have been declining, it is necessary to ask, 'why they have been declining?'. The
13 decline is due to the fact that achieved bond returns in the recent past have been high
14 relative to the level of bond returns expected in the future. For example, bond yields were 18
15 percent in 1982. Today, they are expected to be approximately 4.5 percent over the test
16 period. This recent experience with high bond yields coupled with equity returns that have
17 remained relatively constant has resulted in a declining risk premium (Tr. Vol. 10, page 19).

18
19 Schedule 4.3 of the Kryzanowski and Roberts evidence, page 211, is consistent with Ms.
20 McShane's testimony. Schedule 4.3 shows historical stock returns being relatively constant
21 at 11.2 to 11.6 percent (Tr. Vol. 13, page 112). Long Canada returns, by contrast, are shown
22 to be steadily increasing as shorter time series are used (Tr. Vol. 13, pages 112-113).

23
24 As indicated in Ms. McShane's testimony: "[T]he 1947-2006 average bond return of
25 approximately 7.0 percent overstates the forward looking expectation of bond returns, as
26 embedded in both current yields and long-term forecasts. The current low level of long-
27 Canada yields limits the possibility of future capital gains, which arise from a decline in
28 interest rates. Thus, a reasonable expected value of the long Canada bond return is the
29 forecast long Canada yield, rather than the historic average." (Ex. C2-T1-S1, Appendix C,
30 page 150).

1 Finally, Drs. Kryzanowski and Roberts admitted that all entities listed in Ex. J11.1 were lower
2 risk than OPG's prescribed assets. They also admitted that the returns awarded to all of the
3 electric and gas utilities listed in Ex. J11.1 were higher by a significant margin than the
4 Kryzanowski and Roberts recommended ROEs (Tr. Vol. 13, page 116-117).

5
6 Drs. Kryzanowski and Roberts had no explanation for this fundamental inconsistency in their
7 conclusions. Their only comment was that the awarded returns in Ex. J11.1, while higher
8 than their recommendations, were lower than Ms. McShane's.

9
10 **CCC & VECC WITNESS - PROFESSOR BOOTH**

11 Professor Booth also relies entirely on the CAPM's approach. His recommended debt/equity
12 ratio is 60/40 with a ROE of 7.75 percent.

13
14 Professor Booth's risk analysis simply discounts all business risks of OPG on the basis of
15 either government ownership or the proposed deferral and variance accounts. Professor
16 Booth rejects the stand-alone principle in this case, even though he has endorsed it in the
17 past. In this case, he advocates "piercing the corporate veil" and would have the OEB ignore
18 the "normal" and legally distinct roles of ratepayer, taxpayer and shareholder in analyzing the
19 cost of capital for OPG. This approach is inconsistent with his testimony in H.R. 16 and with
20 the explicit findings of the OEB in H.R. 15 and 16.

21
22 Professor Booth's view that allowed ROEs across Canada are "excessive" is well known. His
23 opinion in this case is no exception. However, no regulatory tribunal in Canada has adopted
24 his recommendations (Ex. K12.3, page 12). Dr. Booth also conceded that many people
25 disagree with him about this opinion. Examples of recent studies and reports coming to the
26 conclusion that allowed ROEs in Canada are too low are presented in Ex. K12.3 at Tabs 3,
27 4, 5, 6, 7 and 8.

28
29 Also, like Drs. Kryzanowski and Roberts, Professor Booth's evidence embodies an essential
30 contradiction. Although he concedes that electric transmission utilities bear the lowest risk,
31 followed by distribution companies, integrated electric utilities and then generation with the

1 highest risk, his recommended ROE for OPG is significantly lower than the allowed ROE of
2 every utility, whether transmission, distribution or vertically integrated, in Canada (Ex. J11.1).

3
4 **ENERGY PROBE WITNESS - DR. SCHWARTZ**

5 Dr. Schwartz is not a cost of capital expert, although he has some background in corporate
6 finance. He has no experience in determining deemed capital structure or cost of equity for a
7 rate regulated entity. He has never prepared evidence or testified in this area before.

8
9 Dr. Schwartz not only lacked familiarity with the concepts of deemed capital structure and
10 ROE determination for rate regulated entities, his report also contained a number of errors.
11 First, Dr. Schwartz used Treasury bill yields as a risk free rate instead of the long term risk
12 free rate that all other experts, and indeed all other regulatory tribunals in Canada, use.
13 Treasury bill yields, which are short term instruments, are not appropriate as a risk free rate
14 in the context of estimating return on equity for a regulated utility.

15
16 Dr. Schwartz also based his market risk premium on only 13 years of data. Returns were in
17 fact random and volatile over this period. Ms. McShane testified that 13 years of data was
18 nowhere close to being an appropriate range or period for measuring these premiums (Tr.
19 Vol. 10, page 24).

20
21 The most serious flaw, however, was Dr. Schwartz's attempt to justify his proposed capital
22 structure and return on equity by claiming that using his proposed cost of capital to discount
23 the cash flows arising from OPG's proposed revenues resulted in a higher market value of
24 the prescribed assets than discounting the cash flows at OPG's proposed cost of capital (Ex.
25 M-T6, page 3).

26
27 There are two flaws in Dr. Schwartz's argument. First, his market value of the assets
28 represents the present value of cash flows in perpetuity. Dr. Schwartz assumed that the cash
29 flows in each year beyond the test period would be the same as the test period cash flows.
30 This assumption is not realistic. Second, when Dr. Schwartz discounts the cash flows at his
31 proposed cost of capital, he is discounting cash flows which contain OPG's proposed cost of
32 capital. This is simply incorrect.

1 Dr. Schwartz assumed OPG's proposed cash flows but used his own lower discount rate.
2 While using a lower discount rate produces a higher estimate of asset value, the result is
3 meaningless.

4
5 Dr. Schwartz's capital structure recommendation is not based on any business risk analysis
6 and his ROE does not follow any accepted methodology for determining cost of capital for
7 rate regulated entities. Dr. Schwartz's opinion should be disregarded.

8
9 **USE OF THE SAME CAPITAL STRUCTURE AND ROE FOR OPG'S REGULATED**
10 **HYDROELECTRIC AND NUCLEAR BUSINESSES**

11 OPG proposes to use the same capital structure and ROE for both its regulated hydroelectric
12 and nuclear businesses. OPG is opposed to the use of separate capital structures and ROEs
13 for the two technologies. OPG is one company with nuclear, hydroelectric and other
14 generating facilities.

15
16 There are a number of pragmatic reasons for rejecting this approach, including, most
17 importantly, that no robust methodology exists for calculating separate capital structures and
18 ROEs for the two generation technologies (Tr. Vol. 15, page 98).

19
20 Difficulties in calculating stand-alone capital structures and ROEs for the nuclear and
21 hydroelectric businesses arise because:

- 22 1. There are no direct proxies for the regulated hydroelectric business. There are no publicly
23 traded electric utilities in Canada that have significant hydroelectric generation, and all of
24 the major hydroelectric intensive utilities are government-owned.
- 25 2. Even on the nuclear side, the results of empirical analysis conducted by Ms. McShane
26 are not robust given the small sample of utilities used to represent the nuclear operations.
27 This is evidenced by 2006 results, which were inconsistent with the higher business risks
28 associated with nuclear operations which have been acknowledged by every expert
29 witness in this proceeding (Ex. L-12-2).

30
31 Given the level of judgment involved in the estimation of separate costs of capital (capital
32 structures and ROEs) for the nuclear and hydroelectric businesses, Ms. McShane did not

1 recommend separate costs of capital for the nuclear and hydroelectric businesses. OPG
2 supports this position.

3
4 **Issue 2.3**

5 **Is it appropriate to establish a formula for an adjustment mechanism? Is the formula**
6 **proposed appropriate?**

7
8 Ms. McShane recommends adoption of the automatic adjustment formula for OPG on the
9 basis that it remains a reasonable approximation of the relationship between cost of equity
10 and long term interest rates (Ex. C2-T1-S1, page 110). OPG supports the adoption of the
11 automatic adjustment mechanism for setting the return on its equity in future periods (Ex. C1-
12 T1-S1, page 3). While the return on equity is clearly an issue in this hearing, the use of the
13 adjustment mechanism may mean that it does not have to be an issue in future proceedings,
14 thus contributing to regulatory efficiency. Of course, the adoption of an adjustment
15 mechanism should not preclude OPG or others from seeking a review of the formula returns
16 should OPG's business risk or access to capital change materially.

17
18 Use of a formula for adjusting equity returns in future periods will simplify future payment
19 amount hearings. The adjustment formula proposed by OPG is appropriate as it is the
20 standard formula used by the OEB for the other utilities that it regulates.

21
22 **Issue 2.4**

23 **Are OPG's proposed costs for its long-term and short-term debt components of its**
24 **capital structure appropriate?**

25
26 OPG's interim payment amounts for fiscal years (2005 - 2007) assumed a 55 percent debt/
27 45 percent equity ratio. For fiscal years 2008 and 2009, OPG has used its proposed deemed
28 capital structure which includes its proposed 42.5 percent debt ratio (Ex. C1-T2-S1, page 1).

29
30 OPG's debt for its regulated operations is comprised of three components: an allocation of
31 OPG's company-wide forecast short-term debt; an allocation of OPG's existing and planned

1 long-term debt issues; and a provision for other long-term debt. The cost rates for each of the
2 three types of debt (Ex. C1-T2-S1, Tables 2 and 3) are:

- 3 • Short term debt rates of 5.83 percent in 2008 and 5.98 percent in 2009.
4 • An existing and planned long term debt rate of 5.79 percent in both years.
5 • Other long term debt provision at 5.65 percent in 2008 and 6.47 percent in 2009.

6
7 **SHORT-TERM DEBT COSTS**

8 OPG uses short-term borrowing to finance its working capital requirements and to provide
9 project financing until long-term financing arrangements are completed. OPG uses a
10 commercial paper program and an accounts receivable securitization program as its two
11 main sources of short-term financing (Ex. C1-T2-S3, page 1).

12
13 The commercial paper program is used to fund intra-month borrowing requirements. A bank
14 credit facility is required as the primary backstop to the program. The pricing under the bank
15 credit facility is market-based and subject to the amount drawn and the term of the financing.
16 The bank credit facility has a forecast \$1.4M fixed cost component, which is independent of
17 the amount borrowed (Ibid.).

18
19 The rate on the commercial paper program is market-based, comprised of a ten basis point
20 dealer fee and a corporate spread over the bankers' acceptances rate for OPG. There has
21 been significant credit tightening since August 2007 causing short-term borrowing cost on
22 bankers' acceptances to increase above the yield on treasury securities. The indicative
23 corporate spread on OPG's short-term borrowings increased from 3 basis points to 20 basis
24 points in the latter part of 2007, and is currently around 10 basis points. OPG's forecast is
25 based on the current corporate spread of 10 basis points in 2008 and 5 basis points in 2009
26 reflecting an anticipated return to more normal business conditions (Ex. C1-T2-S3, page 3).

27
28 OPG used its commercial paper program extensively in 2007 and expects to make even
29 greater use of this program in 2008 and 2009. Over the test period, OPG's forecast
30 requirements are for an average of \$60M on a daily basis to finance its normalized intra-
31 month working capital requirements (Ex. C1-T2-S3, page 2).

1 OPG sold \$300M of accounts receivable in each of 2005, 2006 and 2007 pursuant to its
2 securitization program with the Royal Bank of Canada and forecasts continued borrowing of
3 \$300M under this program throughout the test period. The \$300M is a portion of the month-
4 end accounts receivable balance owing to OPG from the IESO. Under the program, OPG
5 continues to service the receivables and pays a short-term cost of funds on a monthly basis
6 to an independent trust. Although the fee is slightly higher for the securitization program than
7 the rate for the commercial paper program, it provides a measure of diversity in OPG's debt
8 financing (Ex. C1-T2-S3, page 3).

9
10 Pricing uncertainty in the asset-backed commercial paper market in Canada since the
11 August 2007 liquidity crisis increased the borrowing costs of the independent trust from nil to
12 50 basis points over the bankers' acceptances rate in 2007. The spread over the bankers'
13 acceptance rate is forecast to be 20 basis points for 2008. In anticipation of a return to more
14 normal business conditions, for 2009 OPG has forecast a spread of 10 basis points (Ex. C1-
15 T2-S3, page 3).

16
17 OPG has used the Global Insight forecast for December 2007 as the basis for the bankers'
18 acceptances interest rate forecast after adjusting for the spread differential between bankers'
19 acceptances and the yield on treasury securities (Ex. C1-T2-S3, page 4).

20
21 OPG's short-term borrowing is conducted on a company-wide basis. OPG has allocated
22 short-term debt to its regulated operations based on the ratio of construction work in
23 progress and non-cash working capital amounts (fuel inventory and materials/supplies) for
24 the regulated operations to the total construction work in progress and non-cash working
25 capital amounts reported in OPG's last audited financial statements. OPG has used asset
26 and liability balances from its last audited financial statements. The amounts are
27 independently verified, and the allocation ratio (57.1 percent) has been relatively consistent
28 during the interim period (Ex. C1-T1-S3, page 3).

29 30 **LONG-TERM DEBT**

31 OPG's long-term debt outstanding at December 31, 2007, as per OPG's audited financial
32 statements, is comprised of financing for unregulated projects, corporate debt of \$3,195M

1 and Niagara Tunnel project debt of \$240M. While OPG's debt is with the OEFC, it has
2 standard covenant conditions that apply to corporate debt issued in the public debt markets.
3 The average remaining term of these long-term debt issues is approximately 4.7 years (Ex.
4 C1-T2-S2, page 1).

5
6 The forecast long-term debt attributable to specific assets in-service or regulated projects
7 (Niagara Tunnel project) under development is directly assigned to the regulated operations.
8 The Niagara Tunnel project is financed under an agreement with the OEFC to provide \$1B in
9 debt financing. Under this agreement, OPG is able to issue notes each quarter with a term of
10 up to 10-years to meet the financing obligations for the Niagara Tunnel project. The cost of
11 this debt is determined quarterly using the same methodology applied to all OEFC debt.

12
13 Approximately \$1.6B in new borrowing is needed over the 2008 – 2009 period. OPG
14 forecasts that \$350M in replacement debt issues will be financed pursuant to a \$950M
15 refinancing agreement negotiated with the OEFC in 2007. Based on its current business
16 plan, OPG forecasts that it will repay \$350M of debt issues maturing during 2009 from
17 operations. OPG is also developing plans to issue new corporate debt into the public markets
18 and intends to take steps to do so in 2009, provided it receives a positive decision from the
19 Board in respect of its ROE and capital structure (Ex. C1-T2-S2, page 3).

20
21 The interest rate associated with OEFC debt is determined prior to the date the funds are
22 advanced. It is based on the prevailing benchmark Government of Canada 10-year bond as
23 published by a verifiable market monitoring service (currently Bloomberg) on the day prior to
24 the date funds are advanced, plus a credit margin determined five business days before the
25 date funds are advanced. The credit margin is determined based on a sample of quotes for
26 OPG's credit margin as provided by a selected group of Canadian banks (Ex. C1-T2-S2,
27 page 4).

28
29 The forecast cost of planned new and refinanced corporate debt and project-related debt for
30 2008 and 2009 is based on the December 2007 Global Insight forecast of the 10-year Long
31 Canada Bond. An OPG credit margin of 130 basis points has been added to the Global
32 Insight interest rate forecasts for 2008 and 2009 to reflect the results of OPG's December 21,

1 2007 debt issue (Ex. C1-T2-S2, page 5). The market has continued to evolve from one
2 characterized by an abundance of capital being made available at low credit spreads to one
3 where corporate borrowers are seeing upward pressure on credit spreads as investors re-
4 price credit risk and reduce capital.

5
6 In accordance with approved risk management strategies, OPG entered into hedging
7 transactions with a number of AA-rated banks for planned debt issues. The effective debt
8 cost for each corporate debt issue reflects the impact of OPG's hedging activities (Ex. C1-T2-
9 S2, page 9).

10
11 OPG allocated its existing and planned corporate debt issues to regulated and unregulated
12 operations using the ratio of regulated net fixed assets at December 31, 2007 to the total net
13 fixed assets as per OPG's 2007 audited financial statements. The net fixed asset values
14 were adjusted to remove asset values that were financed pursuant to project specific
15 arrangements. The adjusted net fixed asset ratio was then applied to the existing and
16 planned corporate debt to determine the long-term debt component of the proposed capital
17 structure (Ex. C1-T1-S2, page 2).

18 19 **OTHER LONG-TERM DEBT PROVISION**

20 The other long-term debt provision is equal to the difference between the debt needed to
21 equate the proposed deemed capital structure to rate base and the project-related and
22 corporate long-term debt and short term debt assigned or allocated to OPG's regulated
23 operations. The well known finance and regulatory principle that the term of the debt should
24 be assumed to be similar to the life of the assets supports the use of a long-term debt rate for
25 this component of OPG's deemed capital structure. The average unhedged interest rate of
26 new and refinanced debt issued each year for both corporate and project-related borrowing
27 purposes is used to determine the interest rate attributable to the other long-term debt
28 provision (Ex. C1-T1-S2, page 5 and Ex. C1-T2-S2, pages 11-12).

29
30 In conclusion, OPG's short-term and long-term project-related and corporate financing
31 arrangements are reasonable. OPG's debt costs are market-based, its hedging activities are
32 prudent, appropriately supervised and have been accurately reflected in OPG's forecast debt

1 cost. The allocation of project-related, long-term corporate and short-term debt to regulated
2 operations reflects accepted regulatory cost allocation practices. The use of an “other long-
3 term debt provision” to balance OPG’s proposed rate base with its deemed capital structure
4 is a typical and appropriate regulatory practice.

5
6 **Issue 2.5**

7 **What are the implications of the deferral and variance accounts on OPG’s financial**
8 **risk? How should the implications be considered when determining the appropriate**
9 **return on equity?**

10
11 OPG has proposed that the OEB approve six deferral and variance accounts for the test
12 period beyond the four accounts that are mandated under the Regulation (see discussion of
13 Issues 9.1 through 9.7, below). The proposed accounts are intended, in part, to address
14 risks beyond OPG’s control.

15
16 Most of the accounts in the Regulation are in place to prevent retroactive rate making since
17 they allow for the recovery of costs associated with initiatives that were directed, authorized
18 or approved by the government before the introduction of rate regulation by the OEB. The
19 fact that OPG’s largest business risk, nuclear operations and production, is not covered by
20 any account underscores the fact that OPG retains significant risks even with the proposed
21 accounts.

22
23 Deferral and variance accounts are, in any event, a common feature of energy regulation -
24 OPG’s deferral and variance accounts are not out of step with the variance and deferral
25 accounts in place for other regulated entities (Tr. Vol. 12, pages 116-117).

26
27 Ms. McShane’s recommended capital structure and ROE reflect acceptance of OPG’s
28 proposals for variance and deferral accounts for the test period. Ms. McShane responded to
29 a number of undertaking and interrogatory requests relating to the impact on her
30 recommendations if certain of the proposed or mandated accounts were not approved.

1 Ms. McShane estimated the impact on the proposed ROE associated with the absence of
2 four specific accounts as: Ancillary Services (0.1 percent), Pension/OPEB (0.5 percent),
3 Water Conditions (0.7 percent), and Nuclear Fuel (0.4 percent) (Ex. KT1.6). She noted in
4 her response that these estimates assumed that the proposed capital structure was
5 approved. Acknowledging that there was no evidence that year-to-year variations in these
6 accounts were highly correlated, and increases in one account could be offset by decreases
7 in other accounts, she estimated that the absence of all four accounts would result in an
8 increase in her ROE recommendation of 25-50 basis points; or alternatively, an increase in
9 her proposed common equity ratio from 57.5 percent to 60 percent - 63 percent.

10
11 Ms. McShane also indicated that she viewed a denial of the recovery of costs incurred prior
12 to April 1, 2008 as a form of retroactive ratemaking which would have an enormous one-time
13 impact on OPG's net income and would likely be viewed by the investment community as
14 constituting a significant increase in regulatory risk and therefore the cost of capital (Ex.
15 J12.2). She went on to indicate that the absence of the nuclear liability, capacity
16 refurbishment and nuclear development accounts for the test period and beyond would also
17 likely have a significant impact on the cost of capital. However, she did not have sufficient
18 data to explicitly quantify that impact.

19
20 In summary, OPG's proposed capital structure and ROE assumes acceptance of the
21 proposed variance and deferral accounts. If certain of the proposed accounts are denied by
22 the OEB, then a corresponding increase in either the equity component of the capital
23 structure or the ROE will be required. If there is an impact on the recovery of prior period
24 costs then there would be a very significant increase in regulatory risk and the cost of capital.

25 26 **3. CAPITAL PROJECTS**

27 28 **OVERVIEW**

29 OPG is seeking three approvals with respect to its capital projects. The first is approval of
30 amounts that OPG has spent to increase capacity, as required by O. Reg. 53/05. The second
31 is for approval to include in rate base the fixed assets in OPG's 2007 audited financial
32 statements (also required by O. Reg. 53/05) together with forecast in-service additions in

1 2008 and 2009. Finally, OPG is seeking OEB approval of its forecast 2008 and 2009 capital
2 budgets.

3
4 Paragraph 6(2)4 of O. Reg. 53/05 provides that the Board shall ensure that OPG recovers
5 capital and non-capital costs incurred to increase the output of, refurbish or add operating
6 capacity to a regulated generation facility if the costs and financial commitments were within
7 the project budgets approved for that purpose by OPG's Board of Directors.

8
9 OPG has two projects associated with the regulated hydroelectric facilities and two projects
10 associated with the nuclear facilities that fall within the ambit of paragraph 6(2)4. These
11 projects and the associated approvals are discussed in detail under Issues 3.1 and 3.2.

12
13 The Niagara Tunnel Project has an approved project budget of \$985M and capital
14 expenditures of \$170.6M in 2008 and \$346.8M in 2009. None of these costs will enter rate
15 base during the test period. Sir Adam Beck I Generating Station - Unit G7 Frequency
16 Conversion Project has an approved project budget of \$35.2M and capital expenditures of
17 \$23.4M in 2008 and \$3.9M in 2009 and does enter rate base during the test period.

18
19 The Pickering B refurbishment has an approved project budget of \$54.7M OM&A and
20 \$340.7M capital to 2010, with forecast OM&A expenditures of \$6.2M in 2008 and \$5.1M in
21 2009, and capital expenditures of \$148.8M in 2009. The capital expenditures in 2009 do not
22 enter rate base in the test period and are contingent on a decision by OPG's Board of
23 Directors to proceed to Phase 2 of the project. The Darlington refurbishment has an
24 approved project budget of \$63.8M OM&A to 2010, with forecast OM&A expenditures of
25 \$18.5M in 2008 and \$22.7M in 2009. There are no rate base implications from this project in
26 the test period.

27
28 The total capital budget for which OPG is seeking approval includes the capital expenditures
29 associated with projects that fall under section 6(2)4 and the balance of the project portfolio.
30 The balance of the project portfolio represents capital expenditures of \$14.8M in 2008 and
31 \$44.9M in 2009 for regulated hydroelectric and \$189.0M in 2008 and \$182.1M in 2009 for
32 nuclear. In addition, there are corporate capital expenditures of \$23.9M in 2008 and \$22.0M

1 in 2009 that support the regulated facilities. These projects and the associated approvals are
2 discussed under Issue 3.5 below.

3
4 OPG's capitalization policy applies to all capital expenditures and is considered under Issue
5 3.6.

6
7 **Issue 3.1**

8 **Are the costs and financial commitments OPG is seeking to recover under section**
9 **6(2)4 incurred to increase the output of, refurbish or add operating capacity to a**
10 **prescribed facility?**

11
12 **Issue 3.2**

13 **If so, are the costs and financial commitments within project budgets approved for**
14 **that purpose by the board of directors of OPG?**

15
16 OPG has two projects associated with the regulated hydroelectric facilities and two projects
17 associated with the nuclear facilities that fall within the ambit of paragraph 6(2)4 (Ex. J2.6;
18 Ex. D2-T1-S3, page 11). These are:

- 19 • The Niagara Tunnel Project (capital)
20 • Sir Adam Beck I GS - Unit G7 Frequency Conversion Project (capital)
21 • Pickering B Refurbishment Project (OM&A and capital)
22 • Darlington Refurbishment Project (OM&A)

23 Although the OM&A portion of these costs is not part of the capital budget, they are
24 considered all in one place, here under Issues 3.1 and 3.2, for the sake of convenience.

25
26 Each of these projects will "increase the output of, refurbish or add operating capacity to a
27 prescribed facility" and the costs of the projects are "within project budgets approved for that
28 purpose by the board of directors of OPG", as detailed below. However, of these four
29 projects, only the G7 conversion project has capital expenditures that are being brought into
30 rate base in the test period. The OM&A expenditures on the nuclear refurbishment projects
31 also impact the test period revenue requirement.
32

REGULATED HYDROELECTRIC

The G7 conversion project will come into service during the test period. OPG is seeking to include the cost of the project, \$35.2M (Ex. D1-T1-S2, Attachment F) in the 2009 regulated hydroelectric in-service additions to rate base (Ex. B2-T3-S1, Table 2).

The purpose of the Unit G7 Conversion Project is to convert the existing 25Hz unit to a new 60Hz unit and return G7 to service. This increases the installed capacity of the Sir Adam Beck I facility by 61.5MW (Ex. D1-T1-S2, Attachment F). The G7 unit will allow for efficient use of the water available to the Beck complex, including water that will be available upon completion of the Niagara Tunnel Project. The G7 unit will also allow for increased use of the Sir Adam Beck Pump Generating Station, thereby increasing OPG's ability to shift energy production from off-peak periods to on-peak periods.

OPG's Board of Directors approved a project budget of \$35.2M for the G7 Conversion Project (Ex. D1-T1-S1, Attachment F). The project costs fall within that approved budget. Accordingly, OPG seeks recovery of these costs under section 6 (2) 4 of the regulation through their inclusion in the 2009 rate base.

The second capital project associated with the regulated hydroelectric facilities, which falls within the ambit of paragraph 6(2)4(i), is the Niagara Tunnel Project. The business case summary for the project is provided at Ex. D1-T1-S2, Attachment A. The Niagara Tunnel project, with a \$985M budget, will add substantially to OPG's water diversion capacity at the Beck complex. The effect of this new diversion capacity will be to increase the average annual generation output of the Beck complex by 1.6TWh. This project is currently scheduled to come into service after the test period. While no recovery of Niagara Tunnel Project costs is being sought for the test period, actual and planned costs for the years 2005 to 2009 are set out in OPG's response to Undertaking J2.6. These costs are expected at this time to remain within approved budget limits (Tr. Vol. 2, pages 34-35).

NUCLEAR

The costs that fall under section 6(2)4 of O. Reg. 53/05 for nuclear are related to the Pickering B and Darlington refurbishment projects. No capital costs of these projects are

1 proposed to enter rate base in the test period. The OM&A amounts for which OPG seeks
2 recovery are outlined in Ex. K6.2, Ex. D2-T1-S3, page 11, Chart 5 and J1-T1-S1, Tables 7
3 and 8. In addition to disposition of the interim variance account for Capacity Refurbishment
4 (a balance of \$16.2M as set out at Ex. J1-T1-S1, Tables 7 and 8 and Ex. K-6.2), OPG is
5 seeking approval for the following:

- 6 • Project Capital for Pickering B Refurbishment of \$148.8M in 2009
- 7 • Project OM&A for Pickering B Refurbishment of \$5.1M in 2009
- 8 • Base OM&A for Pickering B Refurbishment of \$6.2M in 2008
- 9 • Base OM&A for Darlington Refurbishment of \$18.5M in 2008 and \$22.7M in 2009

10
11 The Pickering B units are expected to reach the end of their production life over the 2014 -
12 2016 timeframe (Ex. D2-T1-S3, Section 2.0). A recommendation from management with
13 respect to whether to proceed with Pickering B refurbishment is expected to be provided to
14 the OPG Board no later than early 2009. The Phase 1 work that precedes the final
15 recommendation, and for which OPG seeks recovery in the test period, is predominantly for
16 the purposes of completing the requisite Environmental Assessment and the Integrated
17 Safety Review (Ex. D2-T1-S3, pages 4-6).

18
19 Darlington units are expected to reach the end of their production life over 2018 - 2020. No
20 final OPG Board decision with respect to whether to proceed with the Darlington
21 refurbishment are expected within the test period. Phase 1 work that is underway and will
22 occur in the test period, preceding a final decision and for which OPG seeks recovery (Ex.
23 D2-T1-S3, pages 6-7). This work includes a screening level economic assessment,
24 engineering studies, an Integrated Safety Review and some preliminary Environmental
25 Assessment work (Ibid.).

26
27 All Pickering B and Darlington refurbishment-related costs for which OPG seeks approval for
28 the fall within the budgets approved by the OPG's Board of Directors as part of the 2008 -
29 2010 Business Plan for Nuclear Generation Development and Services, dated December 13,
30 2007 (Ex. L-4-2, Attachment 3, an excerpt of which is contained in Ex. K6.1).

Issue 3.3

If the costs and financial commitments are not within project budgets approved by the board of directors of OPG, are the costs and financial commitments prudent?

OPG is not seeking in the test period recovery of any costs or financial commitments under section 6(2)4 that are not within the project budgets approved by OPG's Board of Directors.

Issue 3.4

In section 6(2)4, what is a "firm financial commitment" and a "pre-engineering commitment"?

OPG is not seeking recovery of any "firm financial commitments" or "pre-engineering commitments" in the test period (Tr. Vol. 6, page 131). As such, there is no need to make a determination of these terms at this point.

Issue 3.5

Is the additional capital spending (beyond the levels being recovered under section 6(2)4) appropriate?

OPG has capital spending on projects at the regulated hydroelectric facilities, the nuclear facilities and within corporate groups that support the regulated facilities that do not fall under section 6(2)4 (i.e., do not increase output, refurbish or add operating capacity to a prescribed facility) but that represent the acquisition or construction of new assets, rehabilitation or improvement of existing assets or replacement of assets. OPG seeks OEB approval of the capital budgets for nuclear and regulated hydroelectric facilities (Ex. A1-T2-S2, page 1).

All of the capital projects meet the requirements of OPG's robust business planning and investment approval processes (Ex. A2-T2-S1; Ex. D1-T1-S1, page 7; Ex. D2-T1-S1, page 1). In addition, the regulated hydroelectric and nuclear businesses have their own specific project management processes (Ex. D1-T1-S1, page 7; Ex. D2-T1-S1, page 1). Project approvals are at a level consistent with OPG's Organizational Authority Register (Ex. L-14-94, Attachment 1).

1 Information regarding these projects is provided separately for regulated hydroelectric (Ex.
2 D1-T1-S2), nuclear (Ex. D2-T1-S2) and corporate group (Ex. D3-T1-S2) capital projects. As
3 required in the filing guidelines, for all projects greater than \$10M, OPG has filed project
4 summary sheets that provide the project name, description, need, start date, in-service date
5 and project cost. In addition, OPG has also filed business case summaries for nuclear
6 projects coming into service in the test period with total project costs greater than \$10M (Ex.
7 J6.1). For projects between \$5M and \$10M, OPG has provided the project name, description
8 and cost as well as the total cost of all projects in this category. Finally, for projects less than
9 \$5M, OPG has provided the number of projects in this category, the total cost of all projects
10 in this category and the average cost of the projects.

11 12 **REGULATED HYDROELECTRIC**

13 OPG's capital plan involves a number of projects associated with its regulated hydroelectric
14 facilities. With the exception of the projects covered by O. Reg. 53/05, section 6(2)4
15 discussed above, all of these projects are "regulatory" or "sustaining" projects, i.e., they are
16 required to meet regulatory requirements or to maintain existing infrastructure and facilities at
17 their current performance level (Ex. A2-T2-S1, page 10).

18
19 OPG is seeking approval of the test period amounts associated with regulated hydroelectric
20 capital expenditures. Through approval of rate base, OPG is seeking approval of in-service
21 additions associated with regulated hydroelectric projects of \$46.2M in 2008 and \$48.5M in
22 2009 (Ex. B2-T3-S1, Table 2).

23
24 All regulated hydroelectric projects reflected in this category of additional capital spending
25 are identified and prioritized using a structured portfolio approach whereby engineering
26 reviews and periodic plant condition assessments are performed to determine the short-term
27 and long-term expenditures required to sustain or improve assets. Facility life cycle plans
28 may also be developed for certain assets where required expenditures are significant relative
29 to the value of the asset (Ex. A1-T4-S2, Section 4.1.1). After a project is initiated, a rigorous
30 project management process is in place to provide project oversight (Ex. D1-T1-S1, page 7).
31 Project closure reports are produced for all projects and post-implementation reviews are
32 conducted for all projects over \$200,000 (Ex. D1-T1-S1, Section 4.0; Tr. Vol. 2, page 45).

1 Specific projects within this category of additional capital spending (i.e., outside of section
2 6(2)4 of O. Reg. 53/05) include:

- 3 • Rehabilitate Canal Lining Project at Niagara: A \$51M project to investigate and repair the
4 walls and liners of the aging open cut canal that services the Beck complex in order to
5 restore and maintain their integrity, prevent erosion and weathering, and improve water
6 flow (Ex. D1-T1-S1; Ex. D1-T1-S2, Attachment E)
7
- 8 • Unit G9 Upgrade Project at Beck I: A \$30M project to rehabilitate this aging unit for the
9 first time since 1974 to prevent unit failure, provide reliable long-term production,
10 overcome a 10MW de-rating and provide additional generation through improved turbine
11 runner efficiency (Ex. D1-T1-S1; Ex. D1-T1-S2, Attachment C)
12
- 13 • Unit G10 Upgrade Project at Beck I: A \$31M project to overhaul this aging unit that is
14 near the end of its useful life, prevent unit failure and achieve increased production
15 through improved turbine runner efficiency (Ex. D1-T1-S1; Ex. D1-T1-S2, Attachment D)
16
- 17 • Unit G3 Upgrade Project at Beck I: A \$31.5M project to overhaul this aging unit so as to
18 allow for reliable production in future, prevent unit failure and to achieve increased
19 capacity through improved turbine runner efficiency (Ex. D1-T1-S1; Ex. D1-T1-S2,
20 Attachment G)
21
- 22 ▪ Dyke Foundation Grouting Project at Beck PGS: A \$20M project to upgrade the protective
23 measures that are in place to prevent recurrence of the 1958 dyke failure due to sinkholes
24 and other phenomena on the bottom of the reservoir (Ex. D1-T1-S1; Ex. D1-T1-S2,
25 Attachment H)
26
- 27 ▪ Replace HVAC System Project at R.H. Saunders: An \$11.5M project to eliminate the
28 increasing costs of repairing this aging heating, ventilation and air conditioning system
29 that is original to the station, to eliminate the use of ozone-depleting refrigerants and to
30 eliminate health risks associated with exposure to lead and asbestos that are present in
31 the system (Ex. D1-T1-S1; Ex. D1-T1-S2, Attachment B)
32

1 Of the projects listed above, the HVAC System project at Saunders and the Sir Adam Beck I
2 – Unit G9 Upgrade project are included in the in-service additions to rate base. Other in-
3 service additions for regulated hydroelectric facilities are projects valued at less than \$10M.

4
5 **NUCLEAR**

6 Given the size and complexity of the nuclear technology and generating units, OPG has at
7 any given time a large portfolio of multi-year capital projects necessary for regulatory
8 compliance and maintenance purposes. With respect to these facilities, OPG seeks
9 approvals beyond the amounts referred to above under section 6(2)4 of the Regulation in two
10 categories, in-service additions (rate base) and capital budgets for 2008 and 2009.

11
12 OPG proposes to bring into service in 2008 new assets valued at \$225.8M and, in 2009,
13 assets valued at \$177.1M (Ex. K6.1, page 9). As discussed in Issue 1.1, Rate Base, OPG is
14 proposing to add these in-service additions to the fixed assets in the 2007 audited financial
15 statements to derive the nuclear generation rate base for the test period.

16
17 As noted in Ex. J6.5 and Ex. J2.7, the requirements of O. Reg. 53/05, that the OEB accept
18 the values in OPG's 2007 audited financial statements, means that, in any event, only a
19 portion of the in service additions (i.e., excluding pre-2008 CIP) are subject to OEB review.
20 Column (g) of Ex. J6.5 isolates the amount of the in-service additions for each project that is
21 not determined by OPG's 2007 audited financial statements.

22
23 OPG is also seeking approval of its capital spending plan for the test period of \$189M in
24 2008 and \$182M in 2009 (Ex. J2.6, Table 2, page 2). This represents a level of project
25 expenditures that has been approved by OPG's Board of Directors to support targeted
26 station performance and the "do-ability" of carrying out the work.

27
28 The portfolio management process for assessing and ultimately selecting the projects to be
29 executed using approved portfolio funding is a rigorous one. In addition to OPG's corporate
30 investment management processes (Ex. A2-T2-S1, Sections 4.0-6.0), there is a high level of
31 nuclear management involvement and oversight. The nuclear management oversight
32 includes a preliminary station level screening process; a station level project review and

1 approval process; a nuclear level asset investment screening and approval process; and,
2 ultimately, the appropriate level of management approval authority of the project business
3 case summary according to OPG's Organizational Authority Register (Tr. Vol. 6, pages 127-
4 128).

6 Project Management

7 A rigorous project management process is followed throughout the life cycle of each
8 individual project. This process, which is consistent with industry best practice, includes the
9 phases of project identification; project initiation; project definition; project execution; project
10 close-out and post implementation review (Ex. D2-T1-S1, pages 3-8).

12 As part of and at various stages of the project management process, OPG prepares
13 business case summaries that present the detailed analysis of alternatives, and the rationale
14 for the recommended alternative. OPG has provided business case summaries for projects
15 greater than \$10M with expenditures in the test period (Ex. J6.1). These demonstrate the
16 rigour applied and the level of oversight involved with all projects. The strength of this
17 underlying process supports the overall portfolio level budgets for Project OM&A and Capital
18 and the amounts for which OPG seeks recovery.

20 **CORPORATE**

21 OPG's capital expenditures for corporate groups include CIO projects and corporate real
22 estate projects. The level of capital spending is \$23.9M in 2008 and \$22.0M (Ex. D3-T1-S1,
23 Table 1). This represents the total spending on corporate projects that support the regulated
24 facilities. The projects, when completed, will have an impact on revenue requirement in one
25 of two ways. Projects that are directly associated with the prescribed facilities, such as an IT
26 project specific to the nuclear business, will enter the rate base of the relevant business unit.
27 For 2008 and 2009, in-service additions to rate base for corporate capital projects are \$1.8M
28 for the regulated hydroelectric facilities and \$17.2M for the nuclear facilities (Ex. L-6-17).
29 Completed corporate projects that provide benefits across OPG, such as an IT system that
30 supports corporate payroll administration, are reflected in the revenue requirement through
31 an increased asset service fee (Ex. KT1.1, pages 12-13)

1 The single project for corporate groups that is greater than \$10M is the OPG Clarington
2 Energy Park Development Project. The project has been undertaken to meet future nuclear
3 office space needs in the Clarington area (Ex. D3-1-2, page 4). This project will not come in
4 service during the test period and therefore has no impact on the revenue requirement.

5
6 Business case summaries and other supporting documentation for CIO and corporate real
7 estate capital projects less than \$10M demonstrate the need for these projects and their
8 prudence (Ex. L-3-62; Ex. L-3-63).

9
10 **Issue 3.6**

11 **Will OPG's accounting policies result in capitalization of an appropriate amount of**
12 **costs incurred in 2008 and 2009 with respect to the construction or acquisition of**
13 **capital assets?**

14
15 The capitalization policy, as set out in Ex. A2-T2-S1, Section 4.1, provides for the appropriate
16 capitalization of costs. Costs that are directly attributable to the acquisition or construction of
17 an asset are capitalized, consistent with Generally Accepted Accounting Principles (Ex. L-16-
18 7). Overhead costs that are not directly attributable, such as Board of Directors, executive
19 management and support functions such as Finance, Human Resources, Legal are
20 expensed (Ex. L-1-18).

21
22 Materiality thresholds for capitalization at the \$25,000 level are appropriate given the size
23 and complexity of OPG's business. OPG arrived at this threshold after considering other
24 capital intensive companies of similar size to OPG, the administrative burden and cost
25 effectiveness of different levels of capitalization, materiality for the purposes of the financial
26 statements and through consultation with its auditors (Ex. L-14-36).

27
28 The capitalization policy is regularly reviewed and updated (Ex. L-14-46) and is applied
29 consistently throughout the organization by the controllership groups (Tr. Vol. 8, page 38).

4. PRODUCTION FORECASTS

OVERVIEW

OPG's production forecast for the test period of 31.5 TWh for hydroelectric and 88.2 TWh for nuclear is based on sound methodology and experience with the units. It is OPG's best estimate (accepting the risk of unforeseen events) of forecast production from the prescribed facilities and should be accepted as reasonable.

The production forecasts for the regulated hydroelectric and the nuclear facilities are considered separately below.

Issue 4.1

Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Issue 4.2

Has the methodology been appropriately applied to create the production forecasts?

REGULATED HYDROELECTRIC

OPG is seeking approval of the test period regulated hydroelectric production forecast of 31.5 TWh¹² (Ex. K1-T2-S1, Table 1). OPG's production forecast for the regulated hydroelectric facilities is based on a robust forecasting methodology which has been appropriately applied to the test period.

OPG's hydroelectric production forecast is, to a significant extent, influenced by water availability. Water availability, in turn, is affected by meteorological conditions and other factors such as ice and weed retardation, that are outside of OPG's control and which are difficult to predict with accuracy (Ex. E1-T1-S1).

¹² This figure includes 12.9 TWh for 2008 (April 1, through December 31) and 18.5 TWh for 2009 (Ex. K1-T1-S1, Table 3 (numbers are rounded)).

1 OPG's water availability models use internal and external data. The forecasts produced by
2 these models are also compared against similar forecasts prepared by other companies and
3 agencies (Ex. E1-T1-S1, pages 1-4). These water availability forecasts are then fed into the
4 forecasting model for energy production (Ibid.).

5
6 The production forecast includes constraints at Niagara on OPG's capacity to divert all
7 available water for production purposes. These constraints will be somewhat alleviated by
8 completion of the Niagara Tunnel Project (Ex. D1-T1-S2, Attachment A, Section 3, bullet 3).
9 The hydroelectric production forecast also takes into account OPG's capacity to pump and
10 store water for the purpose of shifting energy production at the regulated facilities to periods
11 of high demand. The unit efficiency levels of the prescribed hydroelectric facilities also impact
12 the production forecast. Using these and other relevant factors, computer models are used
13 by OPG to derive the production forecasts for the regulated hydroelectric facilities (Ex. E1-
14 T1-S1).

15
16 OPG's hydroelectric forecasting methodology has an equal chance of over-forecasting or
17 under-forecasting (Tr. Vol. 2, page 16). Deviations from forecast in recent years are due to
18 unexpected natural variations in water levels and flows due to changing meteorological
19 conditions (Ex. E1-T1-S2, pages 3-6). In any event, OPG proposes to continue a variance
20 account to capture the impact of unexpected natural variations in water conditions during the
21 test period that are beyond OPG's control (see Issue 9.1 below).

22 23 **NUCLEAR**

24 OPG is seeking approval of the test period nuclear production forecast of 88.2 TWh¹³ (Ex.
25 K1-T3-S1, Table 1). The methodology used by OPG to generate the proposed nuclear
26 business production forecast uses a standard industry approach and produces OPG's best
27 estimate of nuclear production for the test period (Ex. E2-T1-S1, page 1). OPG is not seeking
28 a deferral or variance account to address variations in nuclear production from forecast.
29 Thus, OPG will be at risk for any variance between forecast and actual production during the
30 test period.

¹³ This figure includes 38.3 TWh for 2008 (April 1, through December 31) and 49.9 TWh for 2009 (Ex. K1-T1- S1, Table 3).

1 The nuclear production forecasting process is described in the evidence at Ex. E2-T1-S1,
2 pages 1-12 and at Tr. Vol. 5, pages 93-97. It starts with the capacity of the units. OPG then
3 factors in a forecast of scheduled planned outages, together with an estimated forced loss
4 rate to account for production losses due to unplanned outages or derates (Ex. E2-T1-S1,
5 page 1). To arrive at overall nuclear fleet production, a fleet level adjustment is also included
6 to account for unexpected events (Ex. E2-T1-S1, page 11; Tr. Vol. 5, page 106). The
7 production plan is reviewed by station management, the Chief Nuclear Officer and the
8 Nuclear Executive Committee and ultimately approved by OPG's Board of Directors (Ex. E2-
9 T1-S1, page 10).

10
11 The nuclear production forecast may appear challenging in light of recent experience (Ex.
12 E2-T1-S2, Tables 2a and 2b). However, the 2008 and 2009 production forecasts take into
13 account improvement initiatives, which OPG has already implemented or is currently
14 undertaking to improve planned and unplanned outage performance. OPG anticipates that
15 these initiatives will lead to more stable, reliable and predictable performance (Ex. E2-T1-S1,
16 pages 14-18; Ex. L-1-32). Improved material condition of the plants through reduced
17 maintenance backlogs, work done in previous outages and improvements in the outage
18 process are all factors that support OPG's production forecast (Tr. Vol. 5, pages 98-99).
19 Recent outage performance at Darlington also supports this conclusion (Tr. Vol. 5, pages 35-
20 36).

21
22 OPG's production forecast is based on a reasonable expectation that lost production due to
23 unplanned outages will be reduced due to the above noted improvement initiatives. The
24 forced loss rate for the combined fleet is expected to improve, with an anticipated drop from
25 11.7 percent in 2007 to a target of 4.2 percent by 2009 (Ex. E2-T1-S1, page 14, Tr. Vol. 5,
26 pages 134-135). In addition, several material unforeseen and unplanned events occurred in
27 the historical period that significantly reduced production in 2006 and 2007 (Ex. E2-T1-S2,
28 Appendix C). The causes of these unforeseen events have been addressed following a
29 thorough examination and they are not expected to recur (Tr. Vol. 5, pages 131-133).

5. OPERATING COSTS

This section addresses the reasonableness of the operating costs for OPG's regulated hydroelectric facilities, nuclear business unit and corporate support functions, including centrally held costs. For both the operating business units and the corporate groups, costs are determined through a rigorous business planning and budgeting process (Ex. A2-T1-S1). These plans are first reviewed by business unit management and then reviewed with OPG's President and CEO and CFO (Ex. A2-T1-S1, page 3). Based on these reviews, changes are made and the plans are submitted to OPG's Board of Directors for approval (Ibid.).

OM&A budgets (Issue 5.1) and human resource costs (Issue 5.3) are discussed in individual sub-sections covering regulated hydroelectric, nuclear and corporate. The nuclear sub-section also covers OPG's nuclear fuel cost forecasts (Issue 5.7) and the nuclear outage OM&A budgets and forecasting methodology (Issue 5.8). The corporate cost sub-section addresses OPG's depreciation cost (Issue 5.2), corporate cost allocation (Issue 5.4), asset service fee (Issue 5.5), other operating costs (Issue 5.6), and purchased service costs (Issue 5.9).

REGULATED HYDROELECTRIC

Issue 5.1

Are the Operation, Maintenance and Administration budgets for the prescribed hydroelectric and nuclear business appropriate?

The regulated hydroelectric OM&A costs include base and project OM&A, the asset service fee and the share of corporate support and centrally held costs attributable to the regulated hydroelectric facilities. The total OM&A budget is forecast to be stable at \$119.0M in both 2008 and 2009 (Ex. F1-T1-S1, Table 1).

Within the regulated hydroelectric business, OM&A costs represent the resources required to fund routine, day-to-day operations and maintenance activities and complete OM&A projects that support production of electricity and ancillary services from the regulated facilities. These

1 amounts are necessary to ensure the safe and reliable operation of these important
2 generation facilities. The output from the regulated hydroelectric facilities is also subject to
3 Gross Revenue Charges ("GRC"), which are budgeted at \$228.2M for 2008 and \$244.1M for
4 2009.

5
6 The budgeted amounts of base OM&A for the regulated hydroelectric facilities are \$56.1M for
7 2008 and \$57.9M for 2009 (Ex. F1-T1-S1, Table 1). Within these budgeted amounts, \$37.5M
8 in 2008 and \$39.2 million in 2009 are attributable to base OM&A labour costs, which are
9 subject to escalation in labour rates and changes in payroll burdens (Ex. F1-T2-S1, Table 1).
10 Labour costs are discussed further under Corporate Issue 5.3. The remaining components of
11 base OM&A are presented in Ex. F1-T2-S1, Table 2.

12
13 The largest single increase in forecast base OM&A is \$4.7M, or 9 percent, from 2007 to
14 2008. This forecast increase is due to the anticipated hiring of additional staff for the central
15 support groups and the regulated facilities, the timing of various projects and initiatives, and
16 the fact that 2007 costs were lowered by a one-time credit of \$1.6M from Hydro One for
17 certain work dating back to 1999 (Ex. F1-T2-S1, page 2; Ex. F1-T2-S2, pages 2-3).

18 The forecast project OM&A budgets for the regulated hydroelectric facilities are \$12.9M in
19 2008 and \$12.1M in 2009 (Ex. F1-T3-S1, Table 1). Project OM&A differs from base OM&A
20 owing to the non-recurring nature of the work, longer project timelines and the clearly defined
21 materiality thresholds that apply. These projects do not qualify for capitalization under OPG's
22 capitalization policy (Ex. A2-T2-S1, pages 4-7). OM&A projects are largely for the purpose of
23 sustaining the regulated assets through expenditures for the repair and maintenance of
24 production equipment and civil structures. OM&A projects are subject to the same project
25 management and oversight as capital project, as discussed under Issue 3.5.

26
27 As part of OPG's overall benchmarking efforts, the hydroelectric business benchmarks itself
28 on reliability, safety and cost. Though numerous factors, such as variations in plant design,
29 geography, water conditions and regulatory regimes, make direct cost comparisons between
30 individual stations inappropriate, benchmarking information is helpful as a guide in evaluating
31 plant performance and cost (Ex. A1-T4-S2, page 15).

1 Benchmarking helps to confirm that the OM&A budgets for the regulated facilities are
2 appropriate because, as a group, the regulated plants benchmark well, providing a high
3 degree of reliability at a competitive cost (Ex. A1-T4-S2, page 21). OM&A Unit Energy Cost
4 benchmarking prepared by Haddon Jackson Associates (now Navigant Consultants), is
5 summarized at Ex. A1-T4-S2, Chart 5, page 20. In each of 2005 and 2006, the aggregate
6 cost of the regulated hydroelectric facilities was in the top quartile (Ex. A1-T4-S2, Chart 5).

7
8 The support costs included in regulated hydroelectric OM&A include directly assigned and
9 allocated administration costs from OPG's corporate functions, hydroelectric central support
10 group costs and, for the Saunders facility only, which is part of the Ottawa-St. Lawrence
11 Plant Group, an allocated portion of that plant group's common support costs (Ex. F1-T2-S1,
12 Section 2.3)¹⁴. Finally, OM&A costs also include OPG's share of the operations and
13 maintenance costs for joint works that are shared with the New York Power Authority (Ex.
14 A1-T4-S2, pages 3-4).

15
16 OPG's methodology for allocating corporate support costs, hydroelectric central support and
17 plant group common support costs to the regulated facilities has been reviewed and
18 endorsed by independent cost allocation experts R.J. Rudden Associates (Ex. F3-T1-S1,
19 page 2). Allocations from the hydroelectric central support group cover departments that
20 provide oversight for senior hydroelectric management and specialized support to the plant
21 groups (Ex. A1-T4-S2, page 6). Allocations to R.H. Saunders from the Ottawa-St. Lawrence
22 Plant Group include costs associated with the common plant group departments such as
23 plant group management and business support (Ex. F1-T2-S1, page 3).

24
25 Another significant cost for the regulated hydroelectric facilities is the GRC. The GRC is
26 charged to owners of hydroelectric generating stations under Section 92.1 of the *Electricity*
27 *Act* and is comprised of a property tax component payable to the Ministry of Finance or
28 Ontario Electricity Financial Corporation, as well as a water rental component payable to the
29 Ministry of Finance for holders of water power leases (Ex. F1-T4-S1). O. Reg. 124/02

¹⁴ All of the costs of the Niagara Plant Group are included in hydroelectric OM&A because all of the plants in that group are prescribed facilities (Ex. F1-T2-S1, pages 2-3).

1 establishes the water rental component at 9.5 percent, while the property tax component is
2 tiered and dependent on annual production levels. (Ex. F1-T4-S1, Chart 1).

3
4 Each of the regulated hydroelectric facilities is subject to the property tax component of the
5 GRC and all except for the DeCew facilities, are subject to the water rental component (Ex.
6 F1-T4-S1, pages 2-4). OPG does not pay the water rental component for DeCew because it
7 does not hold a water power lease for that facility, but it does pay other amounts to the St.
8 Lawrence Seaway Management Company as compensation for conveying water through the
9 Welland Canal (Ex. F1-T4-S1, page 4).

11 **Issue 5.3**

12 **Are the 2008 and 2009 human resource related costs (wages, salaries, benefits,**
13 **incentive payments, FTEs and pension costs) appropriate?**

14
15 A general discussion of the reasonableness of OPG's labour costs is found under Corporate
16 Issue 5.3. For the regulated hydroelectric facilities, the FTEs that drive labour costs are
17 presented at Ex. F1-T2-S1, Tables 1 and 2. Table 1 shows that the total planned FTE levels
18 for the regulated hydroelectric business are 304 for 2008 and 301.5 for 2009. These levels
19 have remained relatively flat since 2005. OPG's evidence provides detailed descriptions of
20 each department and the corresponding number of staff (Ex. F1-T2-S1, page 4).

21
22 While staffing levels are expected to remain flat, total labour costs will increase over 2008
23 and 2009 primarily because of annual escalation for standard labour rates in the range of 3-4
24 percent (Ex. F3-T4-S1, pages 28-29).

26 **NUCLEAR**

28 **Issue 5.1**

29 **Are the Operation, Maintenance and Administration budgets for the prescribed**
30 **hydroelectric and nuclear business appropriate?**

1 Nuclear operating costs include base, project and outage OM&A, and the share of the
2 corporate support and centrally held costs attributable to the nuclear facilities (Ex. F2-T1-S1,
3 Table 1). The total costs budgeted for 2008 (\$2,184.6M) and 2009 (\$2,168.7M) are
4 necessary and appropriate for the safe and reliable operation of the nuclear facilities.

5
6 Base OM&A

7 OPG has forecast nuclear base OM&A amounts of \$1,360.8M for 2008 and \$1,368.0M for
8 2009 (Ex. F2-T2-S1, Tables 1 and 2). These amounts cover the costs of:

- 9 • The three nuclear stations (Pickering A; Pickering B and Darlington)
10 • Common nuclear support divisions including engineering, training and supply chain
11 • Nuclear Generation Development and Services
12 • Waste and transportation services (Ex. F2-T2-S1, Chart 1)

13
14 Base OM&A is presented in the evidence by station, division and operational function so that
15 the relative cost of each component and trends over time can be clearly understood.

16
17 The preliminary costs associated with the investigation into refurbishment and new
18 generation development projects have been budgeted in base OM&A. Because the
19 refurbishment activities are subject to section 6(2) of O. Reg. 53/05, OPG's argument with
20 respect to these costs is presented under Issues 3.1 through 3.4 (Capital Projects). Costs
21 associated with new nuclear build are discussed separately below.

22
23 Generally, base OM&A supports the ongoing production of electricity from operating nuclear
24 units, ensures safe operation, regulatory/legislative compliance, and maintenance or
25 improvement of station reliability for future production. In particular, base OM&A is used to
26 fund the cost of:

- 27 • Regular and non-regular staff labour (including overtime).
28 • Materials, CNSC license fees, purchased services and other costs in support of the base
29 program.
30 • Costs of forced outages.
31 • Indirect costs of commercial activities and inspection and maintenance services.

1 Key cost drivers for base OM&A include the nuclear safety requirements of the CNSC, the
2 complexity of the technology, training requirements for employees, material standards for
3 equipment that operates in a harsh environment, a work environment involving radiation, the
4 CANDU non-standard fleet, aging CANDU technology, evolving nuclear regulatory
5 standards, and advancements in nuclear technology (Ex. F2-T2-S1, pages 5-12; Ex. L-14-
6 13).

7
8 Base OM&A costs are forecast through a robust business planning process that establishes
9 performance targets and budgeted costs (Ex. A2-T2-S1). Mr. Pasquet explained that
10 business planning is an iterative process that develops operational performance and cost
11 targets for each of the nuclear units; assesses the resources and timeline required to achieve
12 such targets; and, following review and challenge, builds the performance targets and
13 associated resources into the nuclear business plan (Tr. Vol. 4, pages 153-54). Each nuclear
14 generating station sets targets for generation, production unit energy cost (PUEC), unit
15 capability factor; nuclear performance index and elective maintenance backlogs (Ex. A1-T4-
16 S3, pages 12-24, and in particular Chart 2).

17
18 Achieving the business plan targets may require performance improvement and cost
19 containment initiatives, such as the equipment performance improvement initiative,
20 discussed at Ex. F2-T2-S1, pages 23-29 and Appendices B-F. During the business planning
21 process, operational issues and limitations specific to each of the nuclear stations, as well as
22 a realistic estimation of their ultimate performance capability, are addressed. The business
23 planning process is concluded with successive management reviews and approvals,
24 ultimately leading to acceptance by the OPG Board of Directors (Ex. F2-T2-S1, pages 3-4;
25 Ex. L-4-2).

26
27 Performance targets in the business plan reflect benchmarking information obtained by OPG.
28 For its benchmarking, OPG uses the World Association of Nuclear Operators (WANO)
29 database, which allows for comparison of CANDU operational performance indicators, and
30 the Electric Utility Cost Group (EUCG) data, which allows for cost performance comparison
31 for non-CANDU reactors (Ex. A1-T4-S3, Chart 3, page 17; Ex. L-4-2, Attachment 3, pages 5-

1 8). OPG appropriately uses benchmarking information to develop performance targets and
2 verify its OM&A budgets.

3
4 OPG also uses benchmarking information to identify opportunities for improvement (Ex. A1-
5 T4-S3, pages 15-24). Mr. Robinson discussed this process as follows:

6
7 “From the standpoint of seeking continuous improvement, we do
8 that on a day-to-day basis. We do that through looking at other
9 stations in North America and how they do business and looking
10 for ways to improve our business. We do benchmark. As stated in
11 the evidence, we benchmark in two main areas because we’re
12 confident of the data in those two areas, and that is from WANO
13 and the other is the cost data from EUCG. And it is our priority, as
14 shown in the business plan, to improve performance at our
15 nuclear stations. The benchmarks that we do with WANO include
16 operational aspects as well as safety aspects of the business, and
17 the areas where we are focusing our attention, while safety is
18 always a number one priority, from a safety standpoint, we’re
19 doing very well. Where we are taking penalty points from the
20 nuclear performance index, which is the WANO indicator, is really
21 in the generation and forced loss rate area. The business plan
22 also shows the benchmarking that we do against other CANDU
23 units. So we are, in fact, fulfilling that requirement. Obviously, as
24 we have stated before, Darlington is, again, the better performer,
25 both from a generation standpoint and overall nuclear
26 performance index, and Darlington is in the top quartile of the
27 CANDU units from a nuclear performance index standpoint. (Tr.
28 Vol. 4, pages 43-44).”

29
30 Failure to achieve the performance targets has a direct impact on management
31 compensation. Mr. Pasquet explained that individual managers have bonuses which reflect
32 the targets set in the business plan and if these targets results are not achieved, there are
33 consequences for individual bonuses. (Tr. Vol. 5, pages 35-36).

34
35 Project OM&A

36 The forecast project OM&A budgets for the nuclear facilities are \$144.6M in 2008 (\$118.0M
37 portfolio, \$26.6M isolation project) and \$132.0M in 2009 (\$118.0M portfolio, \$14.0M isolation
38 project) (Ex. F2-T3-S1, Table 1). As discussed under Issue 3.5 for capital project, the level of
39 OM&A project expenditures is approved by OPG’s Board of Directors and managed through
40 the nuclear project management process. OM&A projects are largely for the purpose of

1 sustaining and maintaining the nuclear facilities or addressing regulatory requirements.
2 OM&A projects are subject to the same project management and oversight as capital
3 projects, as discussed under Issue 3.5.
4

5 New Nuclear Build

6 Section 6(2)4.1 of O. Reg. 53/05 requires that OPG recover the costs incurred in the course
7 of planning and preparation for the development of proposed new nuclear generation
8 facilities, subject to a review of prudence. Section 5.4(1) of the Regulation also provides for a
9 variance account to record differences between actual expenditures on new nuclear
10 generation and the amounts included in the payment amounts. With the recent
11 announcement by the Province that new nuclear will proceed at OPG's Darlington facility, it
12 is clear that OPG will have substantial expenditures relating to this initiative during the test
13 period. OPG has budgeted these expenditures at \$75.3M for 2008 and \$67.2M for 2009.
14 Therefore, inclusion of these amounts in the revenue requirement is appropriate.
15

16 Costs for the planning and assessment of new nuclear build are included in base OM&A (Tr.
17 Vol. 6, page 43). These costs are being properly captured, prudently incurred and are within
18 the scope of the June 2006 Directive from the Shareholder (Ex. D2-T1-S3, pages 7-10). Ms.
19 Swami described the new nuclear build work approved by OPG's Board of Directors for the
20 test period and explained that all of this work falls within the 2006 Shareholder Directive (Tr.
21 Vol. 6, pages 42-46).
22

23 Further evidence of the prudence of the new nuclear build is that they result from a detailed
24 and rigorous project management process with significant oversight. Ms. Swami explained
25 the project management approach being used for this work; the checks and balances in
26 place to ensure work is being carried out in a cost-effective manner; the level of management
27 review and oversight, up to and including OPG's Board of Directors; and, selective third party
28 review (Tr. Vol. 6, pages 44-45). To illustrate this point, Ms. Swami provided a specific
29 example: "We have started the environmental assessment as an example, by performing a
30 gap analysis against current information, so that we could limit the amount of new
31 information we needed to gather. And we have had several external bodies look at our work
32 to ensure it meets the tests of the Canadian Environmental Agency and the Canadian

1 Nuclear Safety Commission” (Tr. Vol. 6, page 45).

2
3 **Issue 5.3**

4 **Are the 2008 and 2009 human resource related costs (wages, salaries, benefits,**
5 **incentive payments, FTEs and pension costs) appropriate?**

6
7 Labour (including regular and non-regular staff) represents the majority of OPG’s base
8 OM&A budget. OPG has forecast labour costs for 2008 of \$987.0M and for 2009 of
9 \$1,014.0M (Ex. F2-T2-S1, Table 2, lines 1-2). OPG’s overall labour cost containment efforts
10 are discussed under Corporate Issue 5.3.

11
12 OPG’s labour costs track well against other comparable nuclear generators. For example,
13 comparison between OPG nuclear staff in the PWU and Bruce Power’s PWU staff shows
14 that OPG’s wages on a weighted average basis were 12.8 percent lower in 2006, a
15 difference which will grow to 13.3 percent in 2008 (Ex. F3-4-1, page 36). Exhibit L-14-15
16 indicates that OPG’s labour cost percentage, 73 percent of base OM&A, is comparable to
17 that of other U.S. nuclear utilities as reported by EUCG.

18
19 For nuclear, the trend reflecting increasing FTE numbers into 2008 is necessary for OPG’s
20 planned improvement programs. Subsequent reductions in 2009 are consistent with the
21 completion of these programs (Ex. F2-T2-S1, pages 20-21).

22
23 OPG engaged Navigant in 2006 to compare its staff levels to other Canadian CANDU plants
24 in order to identify potential improvement opportunities. The Navigant study did indicate that
25 in some instances OPG staff levels were higher than other Canadian CANDUs. OPG
26 reviewed these findings, and concluded that in certain cases the higher OPG staff levels
27 were justified by offsetting benefits. In other cases, opportunities for staff reductions existed,
28 which have since been undertaken.

29
30 For example, Mr. Robinson testified: “...that Darlington and the ops and maintenance area
31 was higher than the benchmark. We went back and looked at that, and we said, yes, that is
32 valid because of the increased resources we were applying to backlog reduction, and we see

1 through the evidence that, over time, those numbers will come down.” (Tr. Vol. 5, page 14).
2 Specifically, there was a plan in place to increase resources to improve the material condition
3 of Darlington, which partially accounts for the variance. In addition, although Darlington was
4 shown at a point in time to be over the benchmark staffing level, it was also outperforming
5 the other units in the study (Tr. Vol. 4, pages 169-170). Mr. Robinson testified that care must
6 be taken not to arrive at hasty or short-sighted conclusions that would drive performance in
7 the wrong direction (Ibid.).

8
9 Mr. Pasquet testified that as a result of input from the Navigant study some improvement
10 opportunities were identified in the station engineering function. These opportunities were
11 incorporated during business planning to reduce the engineering staff numbers over the
12 2005-2009 period (Tr. Vol. 5, pages 14-15).

13
14 The evidence also clearly shows that some ‘pre-hiring’ is required due to OPG’s aging
15 workforce demographics (Ex. F2-T2-S1, page 27, lines 21-30 and Appendix D). Incremental
16 costs associated with this requirement are \$20.1M in 2008 and \$22.5M in 2009 (Ex. F2-T2-
17 S1, Appendix D). As OPG’s evidence states: “OPG employs mostly unionized staff who are
18 highly skilled and have many years of experience. It is anticipated that OPG will experience a
19 significant staff shortfall by the year 2020 and, as a result, labour rates must be maintained at
20 a level that can retain existing highly skilled staff, attract replacement staff in advance of
21 anticipated shortfalls, and provide sufficient time to train new staff in order that the business
22 can continue to operate safely and effectively.” (Ex. F3-T4-S1, page 6).

23 24 **Issue 5.7**

25 **Is the forecast of nuclear fuel costs appropriate?**

26

27 OPG has forecast its nuclear fuel costs at \$162.4M for 2008 and \$204.2M for 2009 (Ex. F2-
28 T5-S1, Table 1). OPG’s nuclear fuel supply activities are designed to obtain a secure supply
29 of high quality fuel at the lowest cost that meets its quality and security objectives (Ex. F2-T5-
30 S1, page 1). OPG’s process for procuring fuel has three components: the purchase of
31 uranium concentrates, uranium conversion services and the manufacture of fuel bundles (Ex.

1 F2-T5-S1, pages 2-6). OPG's fuel purchasing process and the resulting forecast costs are
2 reasonable and should be accepted by the OEB.

3
4 OPG's forecast of nuclear fuel costs represents the cost of each finished fuel bundle as it is
5 loaded into the reactor (Ex. F2-T5-S1, page 8). OPG has appropriately forecast the nuclear
6 fuel cost, using the best available information including third party expert market forecasts
7 (UX Consulting) (Ex. F2-T5-S1, pages 8-9; Ex. L-1-65).

8
9 Uranium concentrate fuel prices are highly volatile (Ex. F2-T5-S1, Figure 1.0). OPG has
10 developed a risk management strategy to manage this price risk, by means of a supply
11 portfolio consisting of both market and indexed (base price escalated by economic indices)
12 supply contracts (Ex. F2-T5-S1, pages 6-7; Ex. L-1-65). A blend of market and indexed
13 supply ensures that if market prices rise, the indexed component will mitigate some of the
14 increase. Conversely, if market prices fall, the market-priced contracts in the portfolio will
15 work to lower the cost of nuclear fuel supply. OPG has proposed a nuclear fuel variance
16 account because the cost of nuclear fuel supply has been and will continue to be subject to
17 variability even after the effects of OPG's risk management strategy are considered (Ex. F2-
18 T5-S1, page 8).

19
20 **Issue 5.8**

21 **Is the methodology for deriving the nuclear outage OM&A budget and the forecast of**
22 **outage OM&A costs appropriate?**

23
24 OPG has forecast nuclear outage OM&A costs of \$192.2M for 2008 and \$207.9M for 2009
25 (Ex. F2-T4-S1, Table 1). Outage OM&A represents the incremental costs to complete
26 planned outages (including forced extensions of planned outages) and these amounts
27 include overtime, non-regular labour, augmented services, materials, other purchased
28 services (including the costs of the Inspection and Maintenance Services Division) (Ex. F2-
29 T4-S1, page 3).

30
31 The nuclear outage OM&A budget is accurately forecast and appropriately reviewed through
32 the business planning process (Ex. A2-T2-S1). Each station prepares its own five year

1 outage OM&A budget with reference to and in parallel with OPG's integrated nuclear outage
2 and generation plan (Ex. F2-T4-S1, page 2). The nuclear support groups also prepare five
3 year outage OM&A budgets at the same time as the stations to reflect the cost of their
4 required contribution to the planned outages. The process of preparing the plan is discussed
5 in Issues 4.1 and 4.2. The main drivers of outage OM&A cost are the number of planned
6 outages, the duration of the planned outages and their scope (Tr. Vol. 5, page 100). Thus,
7 outage OM&A varies from year to year as the number, scope and duration of planned
8 outages change (Ex. F2-T4-S1, Table 1).

10 **CORPORATE**

12 **Issue 5.2**

13 **Are the proposed depreciation rates and resulting expense appropriate?**

15 OPG has forecast depreciation expense for the prescribed hydroelectric facilities of \$62.7M
16 in 2008 and \$63.2M in 2009 (Ex. F3-T2-S1, Table 1). For the nuclear facilities, the
17 depreciation expense is forecast to be \$294.4M in 2008 and \$316.4M in 2009 (Ex. F3-T2-S1,
18 Table 4).¹⁵ The requested depreciation expense is reasonable because it is based on the
19 methodology that the OEB has accepted for other regulated utilities and uses appropriate
20 asset lives for the prescribed facilities.

22 OPG uses the group depreciation method, which is typical of other Ontario utilities (Ex. F3-
23 T2-S1, page 2, lines 1-5). Depreciation rates for the various classes of in-service fixed assets
24 are based on their estimated service lives. The estimated service lives are established by
25 technical and engineering personal. The service lives and calculation of depreciation
26 expense are reviewed by OPG's Depreciation Review Committee and ultimately approved by
27 senior management (Ex. F3-T2-S1, page 2, line 26 to page 4, line 4; Ex. L-1-45).

29 For the nuclear assets, one or two life-limiting factors determine the estimated service lives
30 for each station (Tr. Vol. 9, page 73). OPG has conducted significant technical analyses to

¹⁵ As explained in the discussion of Issue 5.5 below, the depreciation expense associated with corporate fixed assets which provide service to the prescribed facilities are collected through the asset service fee.

determine the anticipated service lives of these life-limiting components (Ex. L-1-47). Service lives for the hydroelectric assets are quite long (up to 100 years) and consistent with those used by other companies with hydroelectric assets (Tr. Vol. 9, page 73; Ex. L-1-44 and Ex. F3-T2-S1, Appendix A, page 10).

Gannett Fleming Inc., an independent consultant with substantial experience in evaluating depreciation calculations for regulated entities, reviewed the adequacy of OPG's depreciation review process and concluded that "OPG's current practices should result in a reasonable determination of average service lives and a reasonable and appropriate amount of depreciation expense to be included in OPG's revenue requirement request." (Ex. F4-T2-S1, pages 1-4). OPG also implemented changes to its depreciation review process in response to recommendations by Gannett Fleming (Ex. L-1-43).

Issue 5.3

Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

OPG's wages, salaries and benefits are appropriate for the scope and complexity of the regulated business. OPG requires highly skilled employees to operate its business, which contains a diverse mix of generation and three different vintages of nuclear plant. Attracting and retaining these employees is a significant challenge (Ex. F3-T4-S1, pages 3-4).

This challenge will increase as the demographic shift over the next few years requires OPG to hire and train employees to replace those who will retire (Tr. Vol. 8, pages 57, 60-61). For example, OPG expects some 47 percent of all Trades Supervisors and First Line Managers to retire between 2007 and 2011 (Ex. F3-T4-S1, Chart 2). OPG is facing increased competition for new employees to replace those who retire (Ex. L-14-50, Attachment 6, page 4). OPG remains committed to ensuring that its compensation will continue to attract, retain, and engage employees as required by the business.

OPG has relied on annual surveys by Towers Perrin, Mercer Human Resource Consulting, Watson Wyatt, and The Hay Group that show the overall salary increases of their client

1 companies. OPG has provided a summary of median 2006 actual salary increases from
2 these surveys (Ex. F3-T4-S1, Chart 12). Comparing the wage increases provided at OPG to
3 this summary data shows that OPG increases were in line with or below the external market
4 (Ibid.).

5
6 Over 90 percent of the employees working at the prescribed facilities are covered by
7 collective bargaining agreements which address wages, pension and benefits (Ex. F3-T4-S1,
8 page 3). OPG has also provided data comparing its annual wage adjustments to other
9 Ontario employers whose employees belong to the PWU and the Society (Ex. F3-T4-S1,
10 Charts 13 and 14). These charts demonstrate that OPG has been successful in negotiating
11 general wage increases that in total are below those of most of the former Ontario Hydro
12 successor companies and OPG's current competitors.

13
14 With respect to management employees, OPG retained Mercer Human Resource Consulting
15 to perform benchmarking studies covering both salaries and benefits (Ex. L-3-89). The study
16 by Mercer demonstrates that OPG is very close to both utility and non-utility benchmarks up
17 to the most senior levels of the organization (Ibid.). Above that level, OPG's compensation
18 for the top 21 executives is above that of the utility comparators, but below the compensation
19 provided by the non-utility comparators. This level of senior executive compensation is
20 appropriate given the size and complexity of OPG's operations when compared to those of
21 the utility comparators (Tr. Vol. 8, pages 86-87).

22
23 OPG has taken steps to control labour costs and improve productivity (Tr. Vol. 9, pages. 69-
24 70). OPG approaches each round of bargaining with cost containment as one of its goals (Tr.
25 Vol. 8, pages 160 -161).

26
27 OPG's performance incentives relate to activities that provide ratepayer benefits such as cost
28 reduction, production improvement, special initiatives and safety and environmental
29 performance. As Ms Irvine explained:

30
31 "Primarily, they're based on financial measure, which is reduced
32 cost, production measure, which will vary depending on the

1 technology in place. There will also be measures of specific site
2 initiatives, such as maintenance backlogs or other strategic
3 initiatives that the plant may be undertaking. There is usually an
4 index for both safety and for environment, and these are
5 calculated and if they are below the threshold, or above threshold,
6 I guess, in the case of safety and environment, they're then
7 deducted from the score for that particular plant." (TR Volume 8
8 pages 50-51).
9

10 Incentive payments are considered as part of total compensation. For executive nuclear
11 positions, these incentives are lower than those offered by nuclear operators in the U.S., with
12 whom OPG must compete for senior staff. (Tr. Vol. 8, page 56).
13

14 The licence retention bonus and the leadership allowance are necessary to attract and retain
15 qualified employees in the positions for which these payments are offered. The licence
16 retention bonus is part of OPG's collective agreement. This bonus compensates employees
17 for the substantial effort required to obtain and maintain these licences. Certain employees
18 (Authorized Shift Managers and Authorization Training Supervisors) who supervise and train
19 licensed employees also receive a bonus to ensure their compensation does not decline
20 when they enter a management position. Otherwise, it would be difficult to attract qualified
21 candidates into these positions (Tr. Vol. 8, pages 92-95 and pages 155-61; Ex. L-6-13).
22

23 The leadership allowance is a bonus paid to first level management employees to reflect the
24 fact that management employees are not paid overtime or shift differential (Tr. Vol. 8, pages
25 156-57; Ex. L-14-71). Again, it would be difficult to attract unionized employees who receive
26 these payments as part of the collective agreement into these management positions without
27 this allowance.
28

29 The rise in pension and OPEB costs from 2005 to 2007 was largely driven by changes in the
30 discount rate. (Ex. F3-T4-S1, Chart 6; Tr. Vol. 9, page 96). These changes are due to
31 changes in long term interest rates beyond OPG's control (Tr. Vol. 8, pages 66-67).
32 Nevertheless, OPG has taken a number of steps to control pension and benefit costs (Ex.
33 F3-T4-S1, pages 19-21). These include changing the pension for employees hired after 2000
34 at the manager level and above; increasing the employee pension contribution for all

employees and increasing the employee pension contribution for Society members and management employees again in 2006 (Ibid.).

In 2007, OPG's benefit payments rose an average of 3.1 percent as compared to an industry average figure of approximately 17 percent (Ex. F3-T4-S1, page 21). Benefit cost control measures include reduced vacation allowances for new management hires after July 2001; capped coverage for chiropractic and physiotherapy services and a new co-payment obligation; and terminated benefit coverage for future family members of a surviving spouse (Ibid.). As a result of these changes, OPG is experiencing less escalation in the costs of health and dental benefits than other employers.

Issue 5.4

Are the corporate costs allocated to the regulated hydroelectric and nuclear businesses appropriate?

The level of corporate costs is appropriate and they have been properly allocated to the regulated facilities. The forecast cost of the regulated hydroelectric and nuclear facilities includes an allocation of corporate support group and centrally-held costs of \$47.5M in 2008 and \$46.8M in 2009 for regulated hydroelectric and \$457.0M in 2008 and \$430.2M in 2009 for nuclear facilities (Ex. F3-T1-S1, Tables 2 and 3). These costs are reasonable and necessary to support the operation of the prescribed facilities.

These costs have been allocated to the regulated facilities using a robust allocation methodology that has been independently reviewed and found to meet current best practices, and which produces an appropriate allocation of costs to the regulated hydroelectric and nuclear business. The percentage of corporate support group and centrally held costs directly assigned or allocated to regulated facilities has remained stable since 2005 at about 70 percent (Ex. L-1-58). This is consistent with the regulated facilities share of OM&A costs and FTEs (Tr. Vol. 9, page 98).

The corporate support group costs are those of the centralized functions which support the regulated facilities including the Chief Information Office ("CIO"), Finance, Human

1 Resources, Corporate Affairs, Energy Markets, Real Estate, Executive Office, Corporate
2 Secretary and Law. (Ex. F3-T1-S1, page 1). Corporate costs are established through a
3 rigorous business planning process that includes challenges by the operating business units,
4 review by senior executives and use of prior year actual expenditures as the base line for
5 establishing budgets (Tr. Vol. 9, pages 63-64).

6
7 OPG's organization has the support groups report to a common functional head for efficiency
8 and effectiveness even though some employees in the groups directly support specific
9 business units and are located at plants (Ex. F3-T1-S1, page1; Ex. L-14-51). Centralization
10 of support group costs has helped lower costs through common processes and improved
11 reporting, which supports better decision making, and common use of specialized resources
12 (Ex. L-14-51).

13
14 The costs associated with the two largest corporate support groups, Finance and CIO,
15 benchmark well against comparators (Ex. J8.3; Ex. J8.15, page 3). Hackett Financial
16 Benchmarking found strong performance for Finance with both Effectiveness and Efficiency
17 scores in the 1st quartile (Ex. J8.3 Attachment, page 3).

18
19 In 2007, OPG initiated a review of support functions across the company. This review
20 focused on costs structure and work processes. Phase One of the review, completed last
21 year, focused on identifying cost saving opportunities, evaluating their associated risks, and
22 assessing the feasibility of implementing the identified opportunities. This application reflects
23 savings of approximately \$37M over 2008 and 2009 in nuclear and the corporate support
24 groups. Phase Two of the review, to be completed during 2008, will focus on assessing the
25 remaining opportunities. These generally carry a higher risk, will be more difficult to achieve
26 and some will require a longer time frame to implement (Ex. F3-T1-S1, pages 3-4; Ex. L-14-
27 45, Attachment 3, page 7).

28
29 In addition to allocating costs for corporate support groups, OPG allocates certain centrally
30 held costs. The major components of the centrally held costs are pension and other post
31 employment benefits ("OPEB") costs, insurance costs, and performance incentive plan costs
32 (Ibid.).

1 OPG allocates corporate support and centrally held costs to its regulated activities using
2 direct assignment when specific resources, both employees and non-labour resources, can
3 be reasonably linked to a specific business. Direct assignment of costs accounts for
4 approximately 45 to 50 percent of the corporate support and centrally held costs charged to
5 the regulated facilities (Ex. F3-T1-S1, page 1). The remaining costs are allocated based on
6 appropriate cost drivers, which reflect cost causation or benefits received.

7
8 OPG retained R.J. Rudden to review both the assignment and allocation of corporate support
9 and centrally held costs. (Ex. F3-T1-S1, page 1). Rudden found that OPG's approach and its
10 application were consistent with best practices and regulatory precedents.

11
12 Rudden also made certain recommendations to improve OPG's process. OPG has largely
13 implemented these recommendations (Ex. F3-T1-S1, pages 20-21; Ex. L-1-59).

14 15 **Issue 5.5**

16 **Are the asset service fee amounts charged to the regulated hydroelectric and nuclear** 17 **businesses appropriate?**

18
19 OPG seeks approval of the asset service fees included in the OM&A of both nuclear and
20 regulated hydroelectric. The asset service fee is a method of recovering the costs of the fixed
21 assets that are centrally held, but used to provide service for the regulated businesses. The
22 asset service fee is appropriately calculated and charged to the regulated businesses (Ex.
23 F3-T3-S1, page 1).

24
25 While approximately 90 percent of OPG's in-service fixed assets are directly associated with
26 specific generation facilities, the remaining assets are either directly associated with a
27 business unit, or are held centrally and are used by both regulated and unregulated
28 generation business units (Ibid.). The assets held centrally are not included in rate base and
29 the depreciation and amortization expense in the revenue requirement does not include any
30 costs related to these assets. Instead, the regulated business units (as well as unregulated
31 business units) are charged a service fee for the use of these assets, which is included in
32 their respective OM&A expenses in this application.

1 The calculation of the asset service fee follows appropriate ratemaking principles. For 2008
2 and 2009, the cost to the regulated business is the same under the asset service fee
3 treatment as it would be if the associated capital were allocated to the prescribed facility rate
4 base (Ex. J9.2).

5
6 Rudden reviewed the methodology for computing the asset service fees and concluded “the
7 assets for which Service Fees are charged are required and used by OPG’s generation
8 business units” and that “the methodology for determining the usage of the asset by the
9 generation business units for the purposes of allocating the Service Fee is based on cost
10 causation and consistent with the Centralized Support and Administrative Cost methodology
11 (Ex. F4-T1-S1, page 24).

12 13 **Issue 5.6**

14 **Are the amounts proposed to be included in 2008 and 2009 revenue requirements for**
15 **other operating cost items appropriate?**

16
17 Other operating cost includes depreciation expense and taxes as calculated for regulatory
18 purposes. OPG has forecast its other operating costs at \$71.4M in 2008 and \$71.9M in 2009
19 for regulated hydroelectric (Ex. F3-T2-S1, Table 1) and \$316.2M in 2008 and \$338.5M in
20 2009 for nuclear (Ex. F3-T2-S1, Table 4). The depreciation expense included in the revenue
21 requirement is discussed above under Issue 5.2.

22
23 Income and capital taxes are discussed below under Issue 10.1. In summary, OPG
24 calculates its regulatory income tax on a “stand alone” basis for the regulated facilities.
25 Regulatory taxable income is \$163.0M in 2008 and \$324.0M in 2009 (Ex. F3-T2-S1, pages
26 11-12). The income tax expense included in the revenue requirement has been reduced to
27 zero for 2008 and 2009 because of the use of tax losses from prior years in the regulated
28 business (Ibid.).

29
30 OPG is responsible for both the payment of municipal property taxes and a payment-in-lieu
31 of property tax to the Province. Municipal property taxes are regulated under the Assessment
32 Act, 1990 and are levied on the prescribed nuclear and hydroelectric lands and buildings

owned and operated by OPG and on the Bruce facilities (Ex. F3-T2-S1, pages 14-18; Ex. G2-T2-S1, page 12). Municipal property taxes incurred by OPG for the centrally held properties form part of the asset service fee (Ex. F3-T3-S1, pages 3-4). Payment-in-lieu of property tax is regulated through O. Reg. 224/00 and is paid to the OEFC. OPG forecast property taxes for Nuclear of \$13.9M and \$14.2M, in 2008 and 2009, respectively. OPG does not make payments-in-lieu of property tax on the regulated hydroelectric facilities; instead, OPG pays a Gross Revenue Charge.

Issue 5.9

Are the OM&A purchased services costs appropriate in the context of the OM&A budgets for the regulated facilities?

OPG has an effective corporate procurement policy that is applicable to purchases of goods and services by the nuclear and regulated hydroelectric businesses as well as to corporate group purchases (Ex F3-T5-S1, page 1). OPG relies on competitive procurement except when it is not possible or practical to obtain the required items or service competitively. Approval of single source procurement must occur in accordance with OPG's Organizational Authority Register (Ibid.). Supply chain acts as a single point of contact with potential suppliers and is involved in the negotiation and execution of purchase orders (Ex F3-T5-S1, page 2). A contract administrator ensures compliance with contracting standards.

Pursuant to the OEB's Filing Guidelines, OPG has described the purchases of products and services by the regulated hydroelectric business that represent at least one percent of the OM&A expense. Based on total regulated hydroelectric OM&A that ranged from a low of \$53.9M in 2005 to a high of \$85.6M in 2007, OPG conservatively calculated the 1 percent threshold at \$500K (Ex. F1-T5-S1, page 1). Ex. F1-T5-S1, Chart 1 shows all purchased products and services over this threshold amount along with the aggregate spending levels of \$4.1M in 2005, \$6.1M in 2006 and \$5.7M in 2007. The purchases that make up these amounts were made in accordance with OPG's corporate procurement policy.

The OM&A purchased services costs for nuclear also are made in accordance with corporate policy. Pursuant to the OEB's Filing Guidelines, OPG has described the purchases of

1 products and services by nuclear that represent at least one percent of the OM&A expense.
2 OPG established the one percent threshold at about \$15.0M (Ex. F2-T6-S1, page 1). Ex. F2-
3 T6-S1, Chart 1 shows all of the vendor contracts equal to or in excess of the \$15.0M
4 threshold and the total spending on these contracts for 2005 (\$414.6M), 2006 (\$436.1M),
5 and 2007 (\$346.3M).

6 In Ex. F3-T5-S2, page 1, OPG calculates the one percent of Corporate OM&A threshold
7 contained in the OEB's filing guidelines. Pursuant to this calculation, OPG has individually
8 shown all corporate purchase services worth \$5.0M or more (Ex. F3-T5-T2). All of the
9 contracts contained in this schedule were competitively sourced. The costs of these
10 contracts have been appropriately allocated to regulated activities using the methodology
11 discussed above under Issue 5.5.

12 13 **6. OTHER REVENUES**

14 15 **Issue 6.1**

16 **Are the proposals for the treatment of revenues from Segregated Mode of Operation,**
17 **Water Transactions and Congestion Management Settlement Credits appropriate?**

18
19 With IESO approval, R.H. Saunders Generating Station can segregate some of its
20 generation units from Ontario and reconnect them directly into Quebec such that the units
21 are no longer participating in the Ontario market, but instead receive revenues from Hydro
22 Quebec. This is known as segregated mode of operation ("SMO") (Ex. G1-T1-S1, Section
23 4.0). SMO provides several benefits including support for operations such as managing
24 excess baseload generation and indirect economic benefit to ratepayers by tending to reduce
25 market prices during on-peak hours in Ontario (Ex. G1-T1-S1, page 6, lines 7-20). In
26 providing these benefits, OPG incurs additional costs and risks for which it should be
27 appropriately compensated (Ex. G1-T1-S1, pages 8-9; Ex. L-1-68).

28
29 While O. Reg. 53/05 does not require the sharing of SMO revenues from the interim period¹⁶,
30 OPG believes that sharing of these revenues is appropriate. Accordingly, it is returning to
31 ratepayers \$11.5M plus interest as an offset to the test period revenue requirement (Ex. J1-

¹⁶ The OEB does not have jurisdiction over these revenues since they were earned prior to April 1, 2008.

1 T2-S1, Table 2 – updated June 18, 2008). The \$11.5M was calculated using a sharing
2 mechanism that was consistent with the design of the hydroelectric incentive mechanism.
3 OPG retains the market revenues from periods when production is above 1900 MWh in a
4 given hour. When OPG's production is less than 1900 MWh in a given hour, the sharing
5 mechanism as outlined in Ex. G1-T1-S1, pages 7-8 applies. The proposed 50/50 sharing is
6 of revenues net of costs to conduct the transactions.

7
8 OPG's share of the net revenues is necessary to cover incremental costs and risks
9 associated with the transaction. The evidence is clear that without the 50/50 sharing of SMO
10 net revenues, OPG would not engage in these transactions or would do so less frequently
11 (Tr. Vol., 3, page 13, lines 5-16). OPG's trading function has other commercial opportunities.
12 Without sufficient incentive to engage in SMO transactions, OPG will focus on these other
13 opportunities.

14
15 Forecasting revenues from SMO activities is very difficult, since SMO is highly dependent
16 upon hourly market conditions (Ex. G1-T1-S1, page 7, lines 14-20). For this reason, OPG
17 has not provided a forecast of SMO revenues and has instead proposed a variance account
18 to record the ratepayers' share (Ex. J1-T1-S1, Section 3.2.1) for the test period.

19
20 OPG proposal is that the treatment of SMO revenues during the test period be similar to the
21 treatment during the interim period, except that the 1900 MWh threshold would be replaced
22 with the proposed hourly average volume (Ex. I1-T1-S1, Section 5.2.2, page 12). This
23 change will maintain consistency between SMO operations and the proposed hydroelectric
24 incentive mechanism. It should be noted that SMO transactions are likely to decline in future
25 with the new high voltage transmission line between Ontario and Quebec (Ex. G1-T1-S1,
26 page 10, lines 2-6).

27
28 Revenues associated with Water Transactions ("WT") are proposed to be treated similarly to
29 those associated with SMO for many of the same reasons, during both the interim and test
30 periods (Ex. G1-T1-S1, Section 5.0). OPG is returning \$3M plus interest to ratepayers, as an
31 offset to the revenue requirement, representing their share from water transactions during
32 the interim period.

OPG proposes a different treatment for Congestion Management Settlement Credits ("CMSC"). CMSCs are fundamentally different than SMO and WT. CMSC payments are not incremental revenues but rather an offset to lost production/revenue and increased costs (Ex. G1-T1-S1, Section 6.0). Further, as indicated in Ex. J3.1:

"Constrained off situations (the majority of CMSCs) can result in wasted or inefficient use of water as the generator is dispatched to a level below its maximum efficiency point or may result in spill losses" (Ex. J3.1, page 2, lines 1-3).

Similarly:

"Constrained on situations typically require inefficient use of the hydroelectric generating units above the point of maximum efficiency or the inefficient operation of the Sir Adam Beck PGS when additional water needs to be withdrawn from storage" (Ex. J3.1, page 2, lines 17-19).

Both constrained off and constrained on situations result in lost efficiencies for OPG. The CMSC payments received by OPG may be less than the energy payments that would have been received if the same water had been used when OPG wanted to use it. If OPG is not permitted to retain CMSC payments, it will have no means of recovering its losses associated with constrained off and constrained on situations.

Issue 6.2

Are the forecasts of ancillary services revenues appropriate?

OPG has forecast ancillary services revenues of \$32.4M in 2008 and \$33.1M in 2009 for the regulated hydroelectric facilities (Ex. G1-T1-S1, Table 1), and \$3.0M in 2008 and \$3.1M in 2009 for the nuclear facilities (Ex. G2-T1-S1, Table 1). The revenues for ancillary services are used as an offset in calculating the revenue requirement. Differences between forecast and actual amounts will be reconciled in the proposed ancillary services variance account (Ex. J1-T3-S1, Section 3.4).

Issue 6.3

Are the forecasts of revenues from heavy water and tritium sales and services, radioisotope and nuclear inspection and maintenance services appropriate?

OPG has forecast revenues from heavy water and tritium sales and services, radioisotope and nuclear inspection and maintenance services at \$109.5M for 2008 and \$76.9M for 2009 (Ex. G2-T1-S1, Table 1). These forecast amounts are based on the best information available to OPG and are appropriate for use in setting the revenue requirement.

Non-energy revenues associated with OPG's nuclear facilities include revenues from heavy water sales and services, isotope sales (tritium and cobalt 60), as well as inspection and maintenance services. After deducting forecast direct costs associated with these revenues, the forecast net contribution margins are \$62.3M for 2008 and \$47.7M for 2009. OPG proposes to use the net margins from these businesses as an offset to the revenue requirement in the test period (Ex. G2-T1-S1, page 1, line 17).

For heavy water sales and services, forecast revenues are \$27.0M in 2008 and \$22.5M in 2009 (Ex. G2-T1-S1, Table 1). As explained at Ex. G2-T1-S1 Section 2.1, the bulk of these forecast revenues are for the provision of detritiation services to Bruce Power and are thereby driven by Bruce Power's needs. The 2008 forecast revenues drop slightly from 2007 actuals due to a one-time sale of heavy water to a nuclear energy company in China that occurred in 2007, which is offset in part by higher anticipated revenues for processing services. For 2009, the decline is the result of lower expected needs from Bruce Power.

Isotope sales include sales of tritium and cobalt-60. For cobalt-60 sales, annual revenues are generally driven by the timing of cobalt-60 harvests which, in turn, are driven by outage schedules for the Pickering units (Ex. G2-T1-S1, Section 2.2.1). For tritium sales, revenues have been relatively low and stable. The forecast revenues for tritium sales take into account increasing competition and the impacts of the higher Canadian dollar (Ex. G2-T1-S1, Section 2.2.2).

1 For inspection and maintenance services, the bulk of OPG's revenues are from Bruce Power
2 (Ex. G2-T1-S1, Section 2.3). As such, revenues are subject to variability in the work
3 programs planned for the Bruce facilities. Forecast revenues from services provided to Bruce
4 Power during the test period are forecast to decline in 2009 due, in large part, to a reduction
5 in outage days at Bruce and completion of the very large West Shift project (Ex. G2-T1-S1,
6 Table 1; Tr. Vol. 7, page 6, line 6).

7
8 **Issue 6.4**

9 **Are there revenues and related costs other than those included in the application, that**
10 **OPG earns or incurs from the prescribed assets that should be included in the**
11 **application?**

12
13 There are no revenues or related costs other than those included in the application that
14 should be considered. No evidence was brought forward by any party to suggest that there
15 are any such revenues or related costs.

16
17 **Issue 6.5**

18 **Are OPG's forecasts of costs related to the Bruce Nuclear Generating Station, and**
19 **costs and revenues related to the Bruce lease, accurate?**

20
21 OPG has provided an accurate forecast of the costs relating to the Bruce facility and the
22 revenues and costs relating to the lease. These forecasts should be used by the OEB in
23 setting the test period revenue requirement. This portion of OPG's argument should be read
24 in conjunction with OPG's argument on Issue 7.1 below.

25
26 The Bruce lease and associated agreements are described at Ex. G2-S2-T1. As discussed
27 under Issue 7.1, O. Reg. 53/05 provides that OPG recover all of the costs it incurs with
28 respect to the Bruce generating stations and that any revenues earned under the Bruce
29 lease agreement in excess of cost should be used to offset the revenue requirement for the
30 nuclear facilities (Ex. G2-T2-S1, page 1; O. Reg 53/05 paragraphs 6 (2) 9 and 6 (2) 10).
31 OPG's direct costs associated with the Bruce Nuclear Generating Station, for which OPG
32 seeks recovery, are forecast to be \$208.0M for 2008 and \$193.2M for 2009 (Ex. G2-T2-S1,

Table 3). When these forecast costs are deducted from the forecast revenues under the Bruce lease of \$277.1M for 2008 and \$275.8M for 2009 (Ex. G2-T2-S1, Table 1), the net amounts of \$69.1M in 2008 and \$82.6 M in 2009 are the amounts which offset the revenue requirement for OPG's regulated nuclear facilities. As such, the Bruce lease revenues in excess of costs provide a very significant reduction to the nuclear revenue requirement during the test period.

OPG's direct costs associated with the Bruce Nuclear Generating Station are broken down in Ex. G2-T2-S1, Table 3 and are discussed at Ex. G2-T2-S1, Section 4.1. Depreciation costs, which are forecast at \$77.5M for 2008 and \$66.7M for 2009 (Ex. G2-T2-S1, Table 3), are determined with reference to the fixed assets owned by OPG at the Bruce site, including those leased to Bruce Power and the fixed asset retirement costs associated with the nuclear liabilities relating to these stations. Depreciation expense is determined in accordance with the methodology applied to OPG's regulated facilities, as described under Issue 5.2.

The treatment of the fixed asset retirement cost associated with the nuclear liabilities relating to the Bruce stations is similar to the treatment proposed for other OPG-owned nuclear assets, as discussed under Issue 7.1, below. Return on equity costs related to the Bruce lease, based on the book values of the OPG-owned fixed assets, are \$70.1M for 2008 and \$66.2M for 2009, and are included as direct costs. These amounts reflect the same equity ratio and cost of equity as proposed for the prescribed facilities. Other direct costs include interest costs that reflect the same debt ratio and cost of debt proposed for the prescribed facilities applied to the net book value of OPG-owned fixed assets at the Bruce site (\$28.4M in 2008 and \$27.6M in 2009), as well as smaller amounts for property tax, capital tax and used fuel storage and management costs.

The treatment of Bruce lease costs is the same as that recommended by CIBC and incorporated in the 2005 to 2007 payment amounts. CIBC recommended that, "the revenues from the Bruce lease, net of OPG's cost, should be included as part of the regulated asset base," thus lowering the regulated rates for the use of OPG's assets (Ex. L-2-10, Attachment 1, page 20).

1 The composition of the Bruce lease revenues is set out at Ex. G2-T2-S1, Table 1. The bulk
2 of these revenues are for fixed (base) rent, supplemental rent and the amortization of pre-
3 paid rent. Together, these rent amounts total \$257.4M for 2008 and \$263.2M for 2009. The
4 largest portion of these amounts, supplemental rent, is currently in the range of \$28M per
5 operational unit per year, escalated annually by the consumer price index for Ontario (Tr.
6 Vol. 7, page 13). The test year forecasts for supplemental rent assume no revenue impacts
7 in 2008 or 2009 due to the return to service of the now non-operational Bruce units 1 or 2,
8 nor any impacts from the shutdown for refurbishment of Unit 3 (Ex. G2-T2-S1, page 3).

9
10 The balance of the revenues under the Bruce lease are associated with low and intermediate
11 level radioactive waste management services, as well as very small amounts for site services
12 and services associated with the interim storage and future disposal of spent cobalt-60 (Ex.
13 G2-T2-S1, page 4).

14 15 **7. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING**

16 17 **Issue 7.1**

18 **The proposed rate base includes the estimated net book value of OPG's nuclear fixed**
19 **assets, which in turn includes amounts related to OPG's obligations to decommission**
20 **the nuclear plants and manage nuclear waste. Do the amounts fall within the**
21 **parameters of O. Reg. 53/05? The proposed revenue requirement includes**
22 **depreciation of those nuclear fixed asset costs and a return on rate base. Is this**
23 **method of recovering nuclear fixed asset removal and nuclear waste management**
24 **costs appropriate? Or should alternative recovery mechanisms be considered?**

25
26 OPG is responsible for managing all radioactive waste resulting from the Pickering,
27 Darlington and Bruce Nuclear Generating Stations (Ex. H1-T1-S1, page 2). Radioactive
28 waste resulting from nuclear generation includes high level (used fuel), intermediate level
29 (reactor components) and low level (tools, cleaning equipment and protective clothing)
30 waste.

1 Used fuel is the most radioactive. Used fuel bundles are initially stored under water in used
2 fuel wet bays for a cooling off period of at least ten years. They are then transferred to above
3 ground concrete canisters. Interim storage of used fuel is maintained at each individual
4 generating station site.

5
6 The long term management of used fuel will be governed by the long term waste
7 management plans for all Canadian used fuel being developed under the auspices of the
8 federal *Nuclear Fuel Waste Act*. Ongoing day to day operations also produce low and
9 intermediate level waste ("LILW") which is currently stored at OPG's Western Waste
10 Management Facility located adjacent to the Bruce Nuclear Generating Station. OPG plans
11 to deal with the long-term management of this waste through the development of a deep
12 geologic repository close to the Western Waste Management Facility. OPG is also
13 responsible for the decommissioning of all its nuclear generating stations (including Bruce)
14 after the end of their useful lives (Ex. H1-T1-S1, page 4).

15
16 The *Nuclear Safety and Control Act* provides the Canadian Nuclear Safety Commission
17 ("CNSC") with authority over nuclear waste. The CNSC licenses all OPG's waste
18 management facilities. OPG is required to submit decommissioning plans to the CNSC on a
19 five year cycle, including estimates of the nuclear waste liabilities associated with these
20 plans. OPG must provide, as part of these plans, information on how the nuclear waste
21 liabilities will be discharged. OPG must also provide a financial guarantee to ensure that
22 these obligations are fulfilled.

23
24 OPG discharges its statutory obligation to provide for the management of nuclear waste, and
25 its financial guarantee, through the Ontario Nuclear Funds Agreement ("ONFA") (Ex. H1-T1-
26 S1, page 5). OPG submits to the CNSC annually a report on the status of the financial
27 guarantee, detailing amounts accumulated in the ONFA funds and any material changes in
28 waste management plans which may have an impact on OPG's financial obligations
29 concerning the management of nuclear waste.

30 Under the ONFA, OPG has established two funds: the decommissioning fund (which, based
31 on current estimates, is fully funded) and the used fuel fund (which is 70 percent funded) (Tr.
32 Vol. 7 pages 59-60). With respect to the liabilities to be covered by the decommissioning

1 fund, OPG is fully responsible for any residual unfunded liabilities if the estimated costs are
2 too low or if the returns on the funds are below target. For liabilities associated with the used
3 fuel fund, there is a provincial guarantee which caps OPG's liability. However, OPG's liability
4 could increase substantially (by over \$2B in 1999 present value terms) before the provincial
5 cap fully applies (Tr. Vol. 7 pages 66-67). The province also guarantees the return on the
6 used fuel fund. Both funds are largely made up of funds supplied by OPG or its shareholder
7 and earnings on those funds. At the beginning of 2005, the funds held approximately \$6B. By
8 June 2008 they were over \$9B (Tr. Vol. 7, page 46). This growth is the result of additional
9 contributions plus earnings on the funds. Since April 1, 2005, however, OPG has recovered,
10 on account of nuclear liabilities, less than \$1B through its interim payment amounts (Ex. H1-
11 T1-S3, page 2).

12
13 Under the CICA accounting rules, OPG is required to recognize in its audited financial
14 statements, as part of its fixed assets, the asset retirement costs associated with the
15 decommissioning of its nuclear generating stations and the management of used fuel and
16 low and intermediate waste (Ex. L-2-56).

17
18 OPG's 2007 audited financial statements show nuclear fixed assets of \$4,030M (Ex. A2-T1-
19 S1, Appendix A, Note 18, page 51). This was used as the starting point to determine OPG's
20 rate base for the test period (Ex. B1-T1-S1, page 8, Chart 1, line 1, column (b)). Embedded
21 in this \$4,030M are asset retirement costs for the Pickering, Darlington and Bruce generating
22 stations. The average of these asset retirement costs for Pickering/Darlington in 2008 (April
23 through December) is \$1,227M and for 2009 is \$1,121M. For Bruce, the average asset
24 retirement cost for 2008 (April through December) is \$1,099M and for 2009 is \$1,057M (Ex.
25 H1-T1-S3, page 2).

26
27 In keeping with the provisions of the Regulation, the CICA Handbook requirements and
28 OPG's own financial accounting policies, the asset retirement costs associated with OPG's
29 nuclear generating assets are required to be included in rate base. The weighted average
30 cost of capital recovered on these regulatory assets will be used to fund a portion of OPG's
31 nuclear waste management in the test period.

1 The recovery of OPG's total cost of nuclear waste obligations involves several components
2 (Ex. H1-T1-S3, page 2). The nuclear waste management revenue requirement total of
3 \$704M for the test period includes:

- 4 (a) The cost of capital on asset retirement costs in rate base (\$334M in the test period).
- 5 (b) Depreciation of the asset retirement cost (\$295M for the test period).
- 6 (c) The used fuel provision (\$61M for the test period).
- 7 (d) The low and intermediate level waste provision (\$13M for the test period) (Ex. H1-T1-
8 Section 3, page 2).

9
10 OPG's nuclear waste obligations include used fuel, station decommissioning and LILW
11 associated with the Bruce. These are "costs" associated with the Bruce in respect of which
12 the OEB must ensure that OPG recovers (O. Reg. 53/05, sections 6(2) 8 and 9).

13
14 OPG's proposed method of recovering the amounts needed to fund its nuclear waste
15 management obligations falls short of its actual cash obligations, both with respect to fund
16 contributions under the ONFA and the costs funded through cash from operations, which
17 total \$879M for the test period (Ex. H1-T1-S3, page 2). OPG will have to manage the cash
18 flow implications of this \$175M shortfall during the test period.

19
20 There are essentially three reasons why OPG's proposed method for recovering a significant
21 portion of these costs (the "rate base" method) is the right approach:

- 22 (a) The rate base method (including the Bruce) was the method employed by the
23 Province in setting interim 2005 to 2007 rates.
- 24 (b) O. Reg. 53/05 requires the OEB to allow OPG to recover these costs using the rate
25 base method.
- 26 (c) The rate base method is the best and most appropriate methodology to recover
27 OPG's nuclear waste management costs.

28
29 It is clear from Mr. Long's testimony and from Ex. L-2-10 Attachment 1, page 19, that the
30 2005 to 2007 interim rates established by the Lieutenant Governor in Council in O. Reg.
31 53/05 were based on, among other things, the rate base approach to nuclear waste

1 management cost recovery (including the Bruce assets) (Tr. Vol. 1 pages 78 and 81; Vol. 7
2 pages 27-28, 30, 34-36, 43-45, 48-50, 53-54 and 97).

3
4 The CIBC report which was used in setting the interim payment amounts considered two
5 options for recovering nuclear obligations and ultimately recommended the rate base method
6 that OPG proposes to continue in the test period (Ex. L-2-10 Attachment 1, page 19). CIBC
7 noted that under neither of the two options being considered would OPG recover in regulated
8 payment amounts the amount required to make its cash contributions to the segregated
9 funds. Rather, OPG would need to fund this cash shortfall through operations (Ibid.). CIBC
10 also noted that, in contrast to the U.S. where the federal government assumes the liability for
11 long term disposal of used fuel for a fee, OPG bears the responsibility for its nuclear waste.

12
13 The second reason why the rate base approach is the right approach is that it is required by
14 O. Reg. 53/05. Section 6(2)5(i) provides that the OEB "shall accept" the amounts set out in
15 OPG's 2007 audited financial statements for assets and liabilities. Section 6(2)6(ii) further
16 provides that the OEB "shall accept" values in OPG's 2007 audited financial statements
17 relating to "the revenue requirement impact of accounting and tax policy decisions."

18
19 These sections make it clear that asset values resulting from accounting policy decisions
20 approved by OPG's auditors and OPG's Board of Directors must be accepted by the OEB in
21 making its first order. The 2007 audited financial statements approved by OPG's auditors
22 and Board of Directors contain, within the \$4,030M fixed asset value, asset retirement costs
23 on account of nuclear waste management obligations (Ex. B1-T1-S1, Chart 1, page 8; Ex.
24 H1-T1-S3, page 2). The average of these asset retirement costs for 2007 amount to
25 \$2,528M. According to O. Reg. 53/05, the OEB must accept into rate base OPG's prescribed
26 fixed asset values. Any other interpretation of sections 6(2)5 and 6 would render them
27 meaningless and totally ineffective. Accepting the asset retirement cost into rate base, but
28 attaching a different cost of capital to this element of rate base would similarly contravene the
29 clear intent of these sections.

30
31 The matter does not end there. O. Reg. 53/05 also requires OPG, in sections 5.1 and 5.2, to
32 establish deferral accounts to record changes to OPG's ONFA obligations which are not

1 already reflected in the payment amounts. Section 6(2)8 requires the OEB to ensure that
2 OPG recovers the revenue requirement impact of its nuclear decommissioning liabilities. The
3 revenue requirement impact of those liabilities includes the \$334M OPG seeks by way of its
4 cost of capital on the fixed assets associated with the nuclear waste obligations.

5
6 The regulation goes even further, however, in section 6(2)7, by requiring the OEB to ensure
7 recovery of any balances recorded in the sections 5.1 and 5.2 deferral accounts, to the
8 extent that the OEB is satisfied that the revenue requirement impacts “are accurately
9 recorded in the accounts based on,” among other things, “return on rate base.” There would
10 be absolutely no need for, or even meaning to, this provision if it had not been the LGIC’s
11 intention that payment amounts reflect the revenue requirement impact of the rate base
12 approach to recovering the cost of OPG’s nuclear waste management obligations. Further, it
13 would be entirely capricious and arbitrary to employ one method for recovering balances in a
14 deferral account resulting from *changes* to the ONFA obligations and an entirely different
15 method to recover the cost of existing obligations from the current ONFA reference plan
16 *itself*.

17
18 Finally, OPG submits that the rate base approach is, in any event, the more appropriate
19 method of recovering the nuclear waste management costs. The CICA accounting rules
20 require OPG to recognize asset retirement costs of its nuclear generating stations as part of
21 the fixed assets associated with those stations. The asset retirement costs included as part
22 of fixed assets represents the present value of the asset retirement obligations at the time
23 they are recognized. For OPG, they were initially recognized in 1999 and subsequently
24 adjusted in 2003 and 2006. The rate base approach represents a rational allocation of these
25 costs over the useful life of the underlying assets in a parallel manner to the way the
26 acquisition cost is allocated through depreciation.

27
28 The rate base approach also recognizes and accommodates the reality that an investor,
29 who, in addition to acquiring an asset, must also fund a large asset retirement obligation at
30 the same time, will require recovery of the cost of capital associated with both the generating
31 asset and the asset retirement obligation. If no consideration is given to the capital required

1 to finance the asset retirement obligation as well as the asset itself, no investor would ever
2 invest in nuclear generation (Ex. J1.3; Tr. Vol. 7, page 48).

3
4 It is appropriate for the investor to earn a return on the funds posted to satisfy that long term
5 obligation. In fact, when OPG was first established, the cost of satisfying its asset retirement
6 obligations was taken into account in capitalizing OPG using the weighted average cost of
7 capital (Tr. Vol. 7, page 48). This approach was, as noted above, continued by the
8 government in establishing the interim 2005 - 2007 nuclear payment amount of \$ 49.50.

9
10 As CIBC noted, the rate base approach is also consistent with traditional regulatory practice
11 for rate base methodology (i.e., the avoidance of "streaming" particular costs to particular
12 assets), requires a lower level of analysis and administration and represents a more
13 transparent financial presentation in OPG's audited financial statements (Ex. L-2-10
14 Attachment 1, page 19). Ms. McShane also endorsed the rate base approach as being
15 consistent with regulatory practice and appropriate for OPG's circumstances (Ex. J1.3
16 Addendum).

17
18 Since the rate base method is not tied directly to the level or pace of cash funding required, it
19 also avoids the potential for significant volatility in the year to year evaluation of cost recovery
20 due to, for example, the impact of market conditions on fund earnings. As Mr. Long pointed
21 out, at the end of Q1 of 2008, earnings on the decommissioning fund alone were running
22 close to \$170M below plan. Forecasting the performance of the funds would be a difficult
23 task (Tr. Vol. 7, page 46).

24
25 Bruce Lease - Cost Of Equity

26 OPG's proposed recovery of nuclear waste management cost includes all nuclear waste
27 management costs associated with the Bruce Nuclear Generating Station (Ex. G2-T2-S1).
28 OPG is the owner of the Bruce and retains all residual decommissioning obligations for that
29 site. OPG also has contractual obligations to manage all used fuel and LILW from the Bruce.
30 OPG is proposing to recover the cost associated with these obligations through the proposed
31 rate base method (Ex. H1-T1-S3, page 2). CIBC also included a return on a fixed asset

1 including asset retirement cost, associated with the Bruce in its recommended 2005 - 2007
2 interim rates (Ex. L-2-10, pages 10 and 20).

3
4 CIBC specifically addressed the issue of whether OPG's payment amount should include
5 revenue from the lease of the Bruce assets, net of cost (Ex. L-2-10, Attachment, page 20).
6 CIBC recognized that the inclusion of this offset to nuclear revenue requirement was a
7 government policy decision rather than one that can be guided by regulatory precedent.
8 Based on this analysis and the objectives of the province, CIBC recommended that, "the
9 revenues from the Bruce lease, net of OPG's cost for these assets, should be included as
10 part of the regulated asset base," thus lowering the regulated rates for the use of OPG's
11 assets.

12
13 Mr. Long also testified that the Bruce fixed assets (largely consisting of asset requirement
14 costs) were included in the interim regulated rate in the manner and at the level
15 recommended by the CIBC (save for a 5 percent ROE rather than the CIBC recommended
16 10 percent) (Tr. Vol. 7, pages 27-28). OPG submits that the policy question of the level of
17 offset to the nuclear revenue requirement that the LGIC intended to derive from the Bruce
18 lease is made clear from the government's decision to include the Bruce fixed assets in
19 OPG's rate base during the interim rate period.

20
21 In any event, section 6(2)8 of O. Reg. 53/05 requires the OEB to ensure that OPG "recovers
22 the revenue requirement impact of its nuclear decommissioning liability using the current
23 reference plan." The current reference plan includes provision for the nuclear
24 decommissioning liabilities associated with the Bruce (Ex. H1-T1-S1, pages 2 and 7).

25
26 Section 6(2)9 requires the OEB to "ensure" that OPG recovers "all the cost it incurs" with
27 respect to the Bruce NGS. One of the costs OPG incurs with respect to the Bruce is the cost
28 of capital to cover decommissioning liabilities associated with the Bruce.

29
30 The fact that the cost of capital associated with the Bruce was considered by the government
31 to be a cost "incurred" is made plainly obvious by the fact that Bruce fixed assets were
32 included in OPG's rate base for purposes of determining the 2005 - 2007 interim payment

1 amounts. This is strong evidence that the cost arising from the “rate base” approach to
2 recovering nuclear waste management was intended to qualify as a “cost” which OPG
3 “incurs” with respect to the Bruce under section 6(2)9. In addition, Ms. McShane indicated
4 that in her view the equity supporting the Bruce assets does have a cost associated with it
5 (Tr. Vol. 10, pages 9-10).

6
7 Further, section 6(1)10 provides that OPG’s revenues, net of the costs OPG incurs with
8 respect to the Bruce lease, are a credit to the revenue requirement. Under OPG’s approach,
9 the net revenue which constitutes an offset to the revenue requirement is \$134.4M (Ex. K1-
10 T1-S1, Tables 1 and 2). It would be profoundly unfair and contrary to the provisions of
11 section 6(2) as discussed above, to provide rate payers with the benefits of the Bruce lease
12 revenues while denying OPG “recovery” (i.e., the “cost” offset) of the legitimate, and very
13 real, cost of its nuclear waste decommissioning obligations associated with the Bruce. If, for
14 example, the Bruce NGS had been financed by OPG with 100 percent debt, it could not be
15 credibly argued that the interest cost of servicing that debt was not a “cost incurred” with
16 respect to the Bruce which would represent an offset to revenues under section 6(2)10.

17
18 For all these reasons, OPG submits that the OEB should (and must) adopt the rate base
19 approach to recovery of OPG’s nuclear waste management costs, as set out in Ex. H1-T1-
20 S3, page 2.

21 22 **8. DESIGN OF PAYMENT AMOUNTS**

23 24 **Issue 8.1**

25 **Are OPG’s suggested changes to the hydroelectric incentive payment system**
26 **appropriate?**

27
28 OPG is proposing a new hydroelectric incentive mechanism that facilitates more efficient
29 peaking operations while fairly balancing risks between ratepayers and the company. As
30 such, the proposed hydroelectric incentive mechanism is entirely appropriate and should be
31 approved.

THE EXISTING INCENTIVE MECHANISM

OPG's regulated hydroelectric facilities are primarily baseload. However, they do have some ability to increase production to meet peak demand. This peaking capability is primarily provided through the Sir Adam Beck complex, largely because of the integrated operations of the Sir Adam Beck Pump Generating Station ("PGS") within the complex. R.H. Saunders and DeCew Falls Generating Stations also provide small amounts of peaking capability (Ex. I1-T1-S1, pages 1-2).

The peaking capability provided by the prescribed hydroelectric assets is important to the Ontario electrical system. Providing this peaking capability at the right time improves overall system reliability and helps temper market prices.

OPG's regulated hydroelectric facilities currently receive an incentive to provide peaking supply in response to demand (Ex. I1-T1-S1, page 3). Section 4(2) of O. Reg. 53/05 provides that, if the total combined output of the prescribed hydroelectric generation facilities exceeds 1900 megawatt hours of output in any hour, OPG receives the regulated rate of \$33 for the first 1900 megawatts and the market price for production above 1900 megawatts. This creates an incentive for OPG to produce more energy in periods of high demand when prices are typically higher. Consumers benefit by having a peaking resource available to offset what typically would otherwise be higher cost generation (Ibid.).

Experience since 2005 has shown that there were situations when the current mechanism did not provide the right market signal (Ex. I1-T1-S1, page 7). Accordingly, OPG, with the benefit of three years experience, is proposing a refined hydroelectric incentive mechanism (Tr. Vol. 15, page 199).

PROPOSED CHANGES

The proposed changes to the hydroelectric incentive mechanism are described Ex. I1-T1-S1, Section 5.1. Under the new mechanism, OPG will be financially obligated to supply a given quantity ("hourly volume") in all hours and will receive the regulated rate for this hourly volume. If OPG produces more than the hourly volume in a given hour, it will receive the regulated payment amount up to the hourly volume and market prices for the incremental

1 energy above this hourly volume. If OPG fails to produce the hourly volume in a given hour,
2 then the amount payable to OPG will be reduced by the production shortfall multiplied by the
3 market price. This notionally results in OPG “purchasing” the difference between the actual
4 energy produced and the hourly volume from the market. OPG proposes that the hourly
5 volume be equal to the actual average hourly net energy production over the month.

6
7 The key change to the current methodology involves the modification of the threshold at
8 which market prices begin to apply. The setting of this threshold is an important
9 consideration. If it is set too low then OPG will earn market prices on a larger portion of its
10 regulated output. If it is set too high, then OPG will effectively have to purchase from the
11 market in many hours when the price is well in excess of the regulated hydroelectric rate,
12 resulting in a financial loss to OPG. OPG’s proposal to base this threshold on the actual
13 monthly average mitigates the risk of the former for ratepayers and the risk of the latter for
14 OPG (Ex. I1-T1-S1, Section 5.2.2).

15
16 The proposed changes to the mechanism come with increased risk to OPG (Ex. I1-T1-S1,
17 pages 13-14). To compensate for this risk, and to provide OPG with a financial incentive to
18 operate the facilities in an economically efficient manner, it is appropriate that OPG receive
19 reasonable compensation under the mechanism. The net revenues associated with the
20 proposed incentive mechanism are detailed in Ex. L-1-90. They are significantly less than the
21 net revenues associated with the existing mechanism (Ex. L-1-90, page 2). The proposed
22 mechanism, although less profitable to OPG, results in better operational drivers and is
23 therefore preferred (Tr. Vol. 15, pages 127-128).

24
25 Consumers benefit from OPG’s peaking operations having the right market drivers. By time-
26 shifting water to displace more expensive generation, the forecast reduction in the hourly
27 market price is \$0.4/MWh to \$1.20/MWh with an annual estimated savings ranging between
28 \$80M and \$270M for consumers. Given this projected benefit (Ex. I1-T1-S1, Chart 1, page
29 15; Ex. L-1-91), the amount that OPG expects to receive, estimated at \$12M, is entirely
30 reasonable.

31
32 **Issue 8.2**

Is the fixed payment of 25 percent of revenue requirement an appropriate design for the nuclear facilities?

OPG is seeking approval of payment amounts for its nuclear facilities consisting of a \$58.2M/month fixed amount, a variable amount of \$41.50/MWh and a rate rider of \$1.45/MWh related to the recovery of the test period amortization of nuclear deferral and variance account balances (Ex. K1-T3-S1; Ex. J1-T2-S1).

The fixed monthly payment is designed to recover 25 percent of the nuclear revenue requirement, net of the test period amortization for deferral and variance account balances. The variable charge is designed to recover the remaining 75 percent based on OPG's forecast nuclear production.

The significant variable component of the proposed payment amount design provides a strong incentive for OPG to maximize its nuclear unit availability, avoid outages and to bring units back as quickly as possible. The smaller, fixed component of the payment amount allows for partial recovery of fixed costs (Tr. Vol. 15, pages 138-139).

OPG submits that the 25 percent fixed component in the payment amounts is appropriate for the following reasons:

- Over 90 percent of the costs associated with OPG's nuclear facilities are fixed.
- Generators in Ontario and other jurisdictions receive a form of fixed payment.
- Rate structures approved by the OEB for other regulated entities typically include both a fixed and variable component.
- A fixed payment amount reduces risk, so there is a corresponding reduction in the cost of capital.

OPG's evidence indicates that over 90 percent of its nuclear costs are fixed (Ex. I1-T2-S1, Chart 1, page 6). Given the high degree of fixed costs, reliance on an energy-only payment exposes OPG to a significant amount of risk. A partially fixed payment is a better approach

1 as it recognizes the principle of cost causality while providing a degree of risk mitigation (Tr.
2 Vol. 15, pages 138-139).

3
4 Second, many North American electricity generators receive fixed payments, in some form,
5 to ensure recovery of fixed costs. Mr. Goulding noted that some form of fixed payment is
6 common among regulated energy utilities (Tr. Vol. 12, page 116, line 11). Integrated utilities
7 typically have fixed customer charges, some portion of which is associated with the
8 generation component of their operations. Within Ontario's hybrid market structure, many
9 generators have contracts which provide for fixed cost recovery. For example, the contract
10 structure for Ontario's clean energy supply contracts includes a monthly contingent support
11 payment which is the monthly net revenue requirement less the imputed net revenue, where
12 the imputed net revenue represents the expected net revenue from energy sales.

13
14 Third, the provision of fixed charges is also common among utilities regulated by the OEB.
15 Union Gas recovers approximately 50 percent of its approved non-commodity revenue
16 requirement through charges that do not vary with throughput. Enbridge recovers
17 approximately 20 percent of its non-commodity revenue requirement through fixed charges.
18 Similarly, Hydro One collects about 50 percent of its revenues from distribution customers
19 through fixed charges (Ex. I1-T2-S1, page 8).

20
21 Finally, another benefit of the 25 percent fixed payment is the risk mitigation effect on the
22 cost of capital. The existence of a fixed payment allows for a reduction in the requested
23 ROE. Ms. McShane indicated that if OPG's fixed payment proposal was not accepted by the
24 OEB, then either the required ROE or the equity component of the capital structure would
25 have to be increased by approximately 25 basis points (Ex. L-12-1).

26
27 Rate design is typically a balancing of competing objectives. OPG's proposed nuclear
28 payment design achieves this balance. It maintains a strong incentive for maximizing nuclear
29 production while also recognizing cost causality, existing precedents from other generators
30 and current OEB regulatory practice for other utilities. Ratepayers also benefit from a lower

cost of capital, reflecting OPG's reduced financial risk associated with the fixed component of the nuclear payment amount.

9. DEFERRAL AND VARIANCE ACCOUNTS

OPG is seeking recovery of the test period amortization of the balances in its existing variance and deferral accounts. The total balance of these variance and deferral accounts was \$339.3M (Ex. J1-T1-S1, Table, June 18, 2008). These balances have all been appropriately calculated and recorded according to the terms of O. Reg. 53/05. OPG's proposed methods of recovering these balances and the recovery periods proposed are fair and consistent with the provisions of the Regulation.

OPG is seeking approval for the continuation of certain existing accounts and the establishment of new accounts for the test period. The accounts mandated by regulation are the PARTS Deferral Account, the Capacity Refurbishment Variance Account, the Nuclear Liability Deferral Account and the Nuclear Development Variance Account. In addition, OPG proposes continuing the Water Conditions and Ancillary Services accounts and the Segregated Mode of Operation and Water Transactions account. OPG also proposes establishing a Nuclear Fuel Cost Variance Account, a Pension/Other Post Employment Benefit ("OPEB") Cost Variance Account and a Changes in Tax Rates, Rules, and Assessments Variance Account.

Issue 9.1

Are the costs and revenues recorded in the variance account established under section 5(1) (the "forecast variance account") due to deviations from the forecast set out in "Forecast Information for Facilities Prescribed under Ontario Regulation 53/05"? Were the costs incurred and the revenues earned or foregone on or after April 1, 2005?

Issue 9.2

Do the costs and revenues recorded in the forecast variance account conform to the requirements of section 5(1)?

Issue 9.3

Were the revenues recorded in the forecast variance account earned or foregone; were the costs prudently incurred; and were the revenues and costs accurately recorded as required in section 6(2)1?

Subsection 5(1) of the Regulation required OPG to establish a variance account – referred to in OPG’s evidence as the Interim Variance Account or IVA - for the interim period to record the capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecasts set out in the document “Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05”, as posted on the OEB website. Specifically, this variance account records deviations from forecasts for the five matters discussed below, each of which has been tracked in a sub-account. The amounts recorded in the sub-accounts include the application of interest at a rate of 6 percent. The December 31, 2007 balance in this account is included in OPG’s audited financial statements (Ex. J2.7, Note F).

(a) Sub-account for deviations from forecasts arising from differences in hydroelectric electricity production due to differences between forecast and actual water conditions

This sub-account is referred to in the evidence by OPG as the “Hydroelectric Water Conditions Sub-Account” and is discussed at Ex. J1-T1-S1, Section 3.1.1. The interim hydroelectric rate is based on a forecast of the total production and the total costs for the regulated hydroelectric facilities over the interim period as set out in the “Forecast Information.” The production forecast in turn is based largely on a forecast of water availability. As discussed in the context of hydroelectric production forecasting under Issue 4.1, a number of meteorological and geographic variables beyond OPG’s control influence water availability (Ex. E1-T1-S1). The forecast of water availability is in turn used as an input into computer models to determine forecast energy production. To determine the production impact of changes in water conditions, the actual flow values are entered into the same production models, holding all other variables the same. The resulting production based on

1 actual flows is then compared with the original energy production forecast in order to
2 determine the deviations from forecast.

3
4 The revenues earned or foregone that are associated with the deviation from forecast were
5 determined in accordance with Section 5 of the Regulation. Specifically, the deviations from
6 forecast beginning April 1, 2005 were multiplied by the interim hydroelectric payment amount
7 of \$33/MWh, net of changes in gross revenue charges and conveyance payments, as
8 presented at Ex. J1-T1-S1, Table 3. The closing balance of this sub-account as at the end of
9 2007 is \$6.7M (Ex. J1-T1-S1, Table 2).

10
11 *(b) Sub-account for deviations from forecasts arising from unforeseen changes to nuclear*
12 *regulatory requirements or unforeseen technological changes*

13
14 OPG did not record any amounts in this sub-account as there were no events that fell within
15 the scope of this account during the interim period.

16
17 *(c) Sub-account for deviations from forecast arising from ancillary service revenues*
18

19 For this sub-account, consistent with O. Reg 53/05, Section 5(1)(c), OPG recorded the
20 difference between actual ancillary service revenues earned by the regulated facilities during
21 the interim period and the forecast amounts provided to the Province for use in determining
22 the interim payments. For each month since April 1, 2005, the difference between these
23 numbers has been recorded in the sub-account. Ancillary services are provided either by
24 contract with the IESO or through markets operated by the IESO. The amount of ancillary
25 service revenue in any period is beyond OPG's control given that it is driven by demands
26 from the IESO or the Ontario market. For a full discussion of ancillary service revenues in the
27 hydroelectric context, see Ex. G1-T1-S1 and Ex. J1-T1-S1, Section 3.1.2. Ancillary services
28 in the nuclear context are discussed at Ex. J1-T1-S1, Section 4.4.1. Exhibit J1-T1-S1, Tables
29 3 and 10 summarize the ancillary services variances for 2005, 2006, and 2007 for
30 hydroelectric and nuclear, respectively. The closing balance of this sub-account as at the end
31 of 2007 is \$6.7M for hydroelectric and (\$1.7M) for nuclear (Ex. J1-T1-S1, Tables 2 and 4).

1 *(d) Sub-account for deviations from forecast arising from acts of God*

2
3 OPG did not record any amounts in this sub-account as there were no events that fell within
4 the scope of this account during the interim period.

5
6 *(e) Sub-account for deviations from forecast arising from costs associated with transmission*
7 *outages and restrictions not otherwise recovered*

8
9 This sub-account is referred to in the evidence as the Transmission Outages and
10 Restrictions Variance Sub-Account (Ex. J1-T1-S1, Section 4.4.2). When OPG's generation
11 facilities are de-rated or constrained-off due to a transmission outage or restriction, OPG
12 tracks the details for posting to this sub-account. While these situations can apply to any of
13 the regulated facilities, the amounts recorded in this sub-account during the interim period
14 have only been associated with the nuclear facilities.

15
16 The amount of lost production was determined as the variance between actual production
17 and the hourly capability of the facility for the duration of the transmission related event (Tr.
18 Vol. 14, pages 189-190), multiplied by the nuclear rate during the interim period of
19 \$49.50/MWh. The duration of the outage is equal to the length of time that the grid is not
20 available, plus the length of time that it takes for a facility to return to full production following
21 the transmission outage. As required by the subsection 5(1)(e) of the Regulation, OPG
22 reduced the financial impact of a transmission outage/restriction by any congestion
23 management settlement credits payments that were received from the IESO. OPG has
24 recorded amounts for three transmission outages that affected the Darlington Nuclear
25 Generating Station on December 12, 2005, April 25-26, 2006 and June 17-18, 2006. The
26 closing balance at the end of 2007 was \$1.6M (Ex. J1-T1-S1, Table 11; Tr. Vol. 14, page 96).

27
28 *(f) Segregated Mode of Operations Sub-account*

29
30 In addition to the variance accounts required under subsection 5(1) of the Regulation, OPG
31 has established a Segregated Mode and Water Transactions (discussed in subsection g
32 below) Net Revenue Account to support its proposal to voluntarily share a portion of the

1 profits from these activities during the interim period. Each activity is tracked using a sub-
2 account, described below, similar to those described for subsection 5(1) of the Regulation.
3 The total balance to be returned to ratepayers from these accounts is \$16.2M, which is an
4 offset to the test period revenue requirement (Tr. Vol. 14, page 130). Unlike the sub-accounts
5 required under subsection 5(1) of the Regulation, the balance in this account is not subject to
6 review by the Board since it accumulated during the interim period (Ex. J14.1). There was no
7 obligation on OPG to record or track these amounts and no obligation to share with or credit
8 any amounts to ratepayers.

9
10 OPG believes that it is appropriate to share with ratepayers a portion of the net revenues
11 earned from segregated mode of operation (SMO) during the interim period because the
12 revenues were earned through the use of the regulated facilities, supported by OPG's
13 unregulated trading function that identifies and executes appropriate SMO transactions (see
14 Issue 6.1 above for a description of SMO). To facilitate this sharing, OPG created this sub-
15 account (Tr. Vol. 14, pages 84-85). The closing balance at the end of 2007 is (\$11.5M) (Ex.
16 J1-T1-S1, Table 2, line 3, June 18, 2008).

17
18 *(g) Water Transactions Net Revenue Sub-Account*

19
20 OPG's regulated hydroelectric facilities earn revenues when a portion of its water
21 entitlement, as dictated by international treaty, is used at the New York Power Authority
22 generating facilities in the United States pursuant to a water transaction (Ex. G1-T1-S1,
23 Section 5.0). Occasionally, water transactions occur where a portion of the New York Power
24 Authority's water entitlement is used by OPG. Similar to SMO, there was no obligation to
25 record or track these amounts or to credit any amount to rate payers. Nevertheless, OPG
26 believes that it is appropriate to share with ratepayers a portion of the profits earned from
27 water transactions during the interim period. This sub-account was established in support of
28 that proposal. The closing balance on this sub-account at the end of 2007 is (\$3.0M) (Ex. J1-
29 T1-S1, Table 2, June 18, 2008).

30
31 **Issue 9.4**

1 **Are all of the non-capital costs recorded in the deferral account established under**
2 **section 5(4) incurred after January 1, 2005 and associated with either the planned**
3 **return to service of all of the units at the Pickering A Nuclear Generating Station or**
4 **units the board of directors of OPG determined should be placed into safe storage?**

5
6 Subsection 5(4) of the Regulation requires OPG to establish a deferral account to record the
7 non-capital costs incurred on or after January 1, 2005 that are associated with the planned
8 return to service of all units at Pickering A, including those units that OPG's Board of
9 Directors has determined should be placed in safe storage. Examples of costs that may go
10 into this account and the manner for calculating interest costs on this account for the period
11 prior to the effective date of the OEB's first order are set out at subsection 5(5) of the
12 Regulation.

13
14 Paragraph 6(2)5 of the Regulation requires the OEB to accept the balances in OPG's audited
15 financial statements, which includes the PARTS Deferral Account balance in the financial
16 statement note associated with regulatory assets and liabilities (Ex. J2.7, Attachment 2, Note
17 F). The PARTS Deferral Account balance, net of accumulated amortization, was \$183.8M on
18 December 31, 2007 (Ex. J1-T1-S1, page 8). This balance reflects actual production during
19 the interim period. Using actual production ensures that the actual amount of amortization
20 received during the interim period was used to reduce the balance in the account (Tr. Vol.
21 14, page 171). Effective January 1, 2005, OPG deferred all of its non-capital costs related to
22 the PARTS project. These costs were tracked by OPG and audited as part of OPG's financial
23 statement audit process to ensure that only costs related to the PARTS project were included
24 in the deferral account (Ex. J1-T1-S1, page 8).

25
26 **Issue 9.5**

27 **Are the revenue requirement impacts of any change in OPG's nuclear**
28 **decommissioning liability, arising from an approved reference plan approved after**
29 **April 1, 2005, accurately recorded in the nuclear liability deferral account established**
30 **under subsection 5.1(1), as required by section 6(2)7?**

1 Subsection 5.1(1) of O. Reg 53/05 requires OPG to establish a deferral account to record for
2 the period up to the effective date of the Board's first order the revenue requirement impact
3 of any change in its nuclear decommissioning liability arising from a reference plan, approved
4 after April 1, 2005, as reflected in the audited financial statements approved by the Board of
5 Directors of OPG.

6
7 On December 31, 2006, OPG recorded in its financial statements an increase of
8 approximately \$1,386M to its nuclear decommissioning, nuclear used fuel management, and
9 nuclear low and intermediate level waste management liabilities (together the "nuclear
10 decommissioning liabilities") and correspondingly increased the nuclear fixed asset balance.
11 This increase in nuclear decommissioning liabilities is the result of a new reference plan
12 approved by the Province on December 13, 2006 which was not contemplated when interim
13 payment amounts were set (Ex. H1-T1-S1, page 7). OPG's accounting and regulatory
14 treatment of nuclear liabilities is discussed further in Ex. H1-T1-S2.

15
16 As required under section 5.1(1) of the Regulation, OPG has recorded the revenue
17 requirement impacts of this new reference plan in the nuclear liability deferral account. These
18 revenue requirement impacts are based paragraph 6(2)7 of the Regulation and consist of the
19 return on rate base, depreciation expense, capital tax and fuel expense (Ex. J1-T1-S1, page
20 12). Additionally, OPG has recorded simple interest on the monthly opening balance of the
21 account at an annual rate of six percent applied to the monthly opening balance in the
22 account, compounded annually as required by subsection 5.1(2) of the Regulation (Ibid.).
23 The Nuclear Liability Deferral Account (Transition) balance as at December 31, 2007 was
24 \$130.5M as set out in OPG's audited financial statements (Ex. J2.7, Note F; Ex. J1-T1-S1,
25 page 12). Based on this evidence, the Board can be satisfied that the balance in this account
26 has been accurately recorded.

27 28 Other Variance and Deferral Accounts

29 The following sections address accounts not specifically contemplated by the OEB-approved
30 issues list, yet which are important elements of the variance and deferral account component
31 of OPG's application.

1 *Capacity Refurbishment Variance Account*

2 Paragraph 6(2)4 of the Regulation requires the OEB to ensure that OPG recovers the capital
3 and non-capital costs incurred, and firm financial commitments made to increase the output
4 of, refurbish or add operating capacity to a regulated facility.

5
6 OPG has incurred costs in carrying out assessments of the feasibility of refurbishing units at
7 Pickering B and Darlington, pursuant to the June 16, 2006 directive from the Province (Ex.
8 J1-T1-S1, page 14). The work has included assessments of the physical condition of the
9 plants, consideration of environmental and regulatory requirements, and timing for
10 completing the work. The costs associated with this work are covered by subsection 6(2)4(i)
11 of the Regulation. These costs are within the project budgets approved by the OPG Board of
12 Directors and are therefore not subject to a prudence review (Ex. D2-T1-S3, pages 6-7).

13
14 The amounts in the account for the Pickering B and Darlington refurbishment work reflect
15 differences between actual costs incurred and the amounts included in the information
16 provided by OPG to the Province for the purposes of establishing the interim payment
17 amount. The balance in this account on December 31, 2007 is summarized in Ex. J1-T1-S1,
18 Table 8. OPG's 2007 audited financial statements include the Capacity Refurbishment
19 Variance Account balance within the regulatory asset that is described as Nuclear
20 Generation Development Costs in financial statement Note 7 (Ex. 2.7, Note F). OPG has
21 applied interest to this account in a manner consistent with the other nuclear variance
22 accounts.

23
24 While there are two hydroelectric projects covered by this account - the Niagara Tunnel
25 Project and the G7 Refurbishment at Beck - there are no entries in this account for these
26 projects.

27
28 *Nuclear Development Deferral Account (Transition)*

29 During the interim period, OPG incurred costs associated with initiating the approvals
30 process for new nuclear capacity at an existing site. This work is being undertaken pursuant
31 to a directive that OPG received on June 16, 2006 from the Province (Ex J1-T1-S1, page
32 14).

Subsection 5.3(1) of the Regulation requires OPG to establish a deferral account that records, for the period up to the effective date of the Board's first order, the costs incurred and firm financial commitments made on or after June 13, 2006, in the course of planning and preparation for the development of proposed new nuclear generation facilities that are associated with any one or more of the activities listed therein. Subsection 5.3(2) requires OPG to record simple interest on the monthly opening balance of the account at an annual rate of six percent applied to the monthly opening balance in the account, compounded annually. OPG's 2007 audited financial statements include the Nuclear Development Deferral Account (Transition) balance in the regulatory asset described as Nuclear Generation Development Costs in financial statement at Note 7 (Ex. J2.7, Attachment 2, page 4).

OPG has incurred costs associated with developing new nuclear capacity at Darlington. No costs for new nuclear development were included in the information provided to the Province for the purposes of establishing the interim payment amount. OPG's costs for developing new capacity at Darlington, including budgets and other supporting information, are discussed in Ex. D2-T1-S3. OPG's balance in this account on December 31, 2007 is summarized in Ex. J1-T1-S1, Table 8. In all respects, OPG has followed the requirements of the Regulation in recording amounts into this account. The amounts are accurately recorded and fall within the definition of the account and should therefore be accepted by the Board (Ex. J1-T1-S1, pages 14-15).

Issue 9.6

Are OPG's proposed recovery methods including periods of recovery for the deferral and variance account balances consistent with the requirements of O. Reg. 53/05 sections 6(2)1, 6(2)3, and 6(2)7 and otherwise appropriate?

OPG's recovery proposals are based on the deferral and variance account balances as at December 31, 2007, as reflected in its 2007 audited financial statements. The proposed recovery periods are tied to the end of OPG's fiscal year. This provides a validation of the account balance through OPG's financial statement audit process.

1
2 With respect to the balances in the hydroelectric accounts, due to their small size OPG
3 proposes to recover these balances during the test period as a reduction in OPG's proposed
4 hydroelectric revenue requirement, as indicated at Ex. J1-T2-S1, page 1. With respect to the
5 nuclear accounts, with one exception OPG proposes to clear the deferral and variance
6 account balances by December 31, 2010, consistent with paragraphs 6(2)1 and 6(2)7 of the
7 Regulation. The one exception is the PARTS Deferral Account balance, which OPG
8 proposes to recover by December 31, 2019, consistent with paragraph 6(2)3 of the
9 Regulation. OPG proposes to apply a payment rider (\$1.45/MWh) on its test period nuclear
10 production to recover the test period portion of the December 31, 2007 nuclear variance and
11 deferral account balances. The use of such a rate rider is consistent with Board practice as is
12 discussed below (Ex. J1-T2-S1, Section 3.0).

13
14 Differences between the amounts reflected in its interim payment amounts and OPG's actual
15 costs/revenues incurred after December 31, 2007 will continue to be recorded in the deferral
16 and variance accounts until the effective date of the OEB's first payment order. These post-
17 December 31, 2007 balances will be brought forward for disposition in OPG's next payment
18 amounts application (Tr. Vol. 14, pages 158-159). OPG also proposes to continue to apply
19 interest to the opening monthly balance of these accounts until the balances are fully
20 recovered. OPG will record in its deferral and variance accounts the actual interest costs at
21 the rates approved by the OEB for the test period. OPG will seek to recover these costs in its
22 next payment application as well.

23
24 As the nuclear payment rider is based upon forecast production, any differences between
25 forecast and actual production during the test period will cause a variance. This variance will
26 be carried forward to OPG's next payment application. This approach is consistent with the
27 requirements of the Regulation, which provides that the OEB shall ensure recovery of the
28 specific deferral and variance account balances. In addition, it is fair both to consumers and
29 to OPG as the balances approved by the OEB would not be over- or under-recovered. The
30 nuclear payment rider calculation is shown in Ex. J1-T2-S1, Table 3.

31
32 OPG proposes that the forecast recovery period for its PARTS Deferral Account end

December 31, 2019, consistent with paragraph 6(2)3 of the Regulation, because this account is associated with a long-term asset and the extended service life of Pickering A will provide benefits in the form of nuclear electricity production that will be received by future ratepayers. The test period amortization is calculated on a straight line basis commencing April 1, 2008 and ending December 31, 2019, consistent with paragraph 6(2)3 of the Regulation.

OPG proposes to include the test period amortization of its December 31, 2007 non-PARTS account balances in the nuclear payment rider. These amounts are calculated on a straight line basis commencing April 1, 2008 and ending December 31, 2010, consistent with paragraphs 6(2)1 and 6(2)7 of the Regulation, which specify that recovery must be over a period not to exceed three years.

In addition, paragraph 6(2)4.1 entitles OPG to recover the balance in the Nuclear Development Deferral Account to the extent the Board is satisfied that the costs were prudently incurred and the financial commitments were prudently made, with such balance to be recovered on a straight line basis over a period not to exceed three years, consistent with paragraph 6(2)7.1 of the Regulation.

Issue 9.7

What deferral and variance accounts, other than those mandated by Reg. 53/05, should be established for 2008 and 2009?

For the test period, the Regulation mandates the following:

- To continue the PARTS Deferral Account per subsection 5(4).
- To establish the Nuclear Liability Deferral Account per subsection 5.2(1).
- To establish the Nuclear Development Variance Account per subsection 5.4(1).
- To continue the Capacity Refurbishment Variance Account per paragraph 6(2)4.

Other than these mandated accounts, OPG is proposing the continuation of the Water Conditions and Ancillary Services accounts, which the Regulation required as part of the Interim Variance Account during the interim period (Ex. J1-T3-S1, page 2). OPG is also

1 proposing the continuation in the test period of the SMO and Water Transactions account
2 that were established for the purpose of sharing revenues during the interim period, as
3 described earlier. In addition, for the test period OPG is proposing the establishment of three
4 new accounts to deal with uncertainties associated with nuclear fuel costs, pension and
5 OPEB costs and tax rate and rule changes. Each of these is discussed below.

6
7 Non-Mandated Accounts That OPG Proposes To Continue

8
9 *Hydroelectric Water Conditions Variance Account*

10 OPG proposes to continue the variance account for water conditions that was established for
11 the interim period pursuant to subsection 5(1)(a) of the Regulation in order to address the
12 risk of production varying from forecast due to factors that are beyond OPG's ability to
13 manage or control, such as meteorological conditions (Ex. J1-T3-S1, pages 4-5). The
14 volatility of actual water flows is illustrated in Chart 1 of Ex. J1-T3-S1 at page 5, which shows
15 that variances from forecast are highly likely based on historical experience. Without this
16 account ratepayers would be exposed to the risk of OPG earning additional revenues and
17 OPG would be exposed to the risk of foregone revenues due to favourable or unfavourable
18 deviations from forecasted water conditions in the test period. These outcomes could unduly
19 penalize or reward either OPG or consumers. This variance account ensures that this will not
20 occur.

21
22 *Ancillary Services Variance Account*

23 OPG proposes to continue the variance account that was established pursuant to subsection
24 5(1)(c) of the Regulation during the interim period, which captures the impact of changes to
25 revenues from ancillary services from the regulated facilities (Ex. J1-T3-S1, page 6).
26 Variances in forecast revenues for ancillary services are highly likely due to their
27 unpredictability. Moreover, the underlying circumstances that give rise to these revenues are
28 beyond OPG's ability to manage or control. OPG has a limited ability to influence the
29 revenues from these services as they are a function of changing demand and system/grid
30 operating requirements and the emergence of other service providers (Ibid.). These factors
31 also reduce the predictability and increase the potential variability of these revenues. While

1 the total variance to date has not been significant, the use of a variance account would
2 alleviate any stakeholder concerns about forecast risk/error.

3
4 *Segregated Mode and Water Transactions Net Revenue Variance Account*

5 OPG proposes to continue the Segregated Mode and Water Transactions Net Revenue
6 Variance Account (Ex. J1-T3-S1, pages 10-12). This account is for the purpose of recording
7 the ratepayer share of revenues from segregated mode transactions negotiated from time to
8 time for electricity generated at Saunders, as well as the ratepayer share of revenues from
9 water transactions between OPG and the New York Power Authority. Continuing this account
10 will allow the continued sharing of net revenues earned from these activities during the test
11 period. OPG does not forecast SMO revenues as they are a function of market
12 circumstances that are not predictable. Water transaction revenues are also very difficult to
13 forecast because the transactions are a function of operating circumstances and water and
14 ice conditions. The transactions are also subject to acceptance by the New York Power
15 Authority.

16
17 Non-Mandated Accounts That OPG Proposes To Establish

18
19 *Nuclear Fuel Cost Variance Account*

20 OPG proposes to establish a Nuclear Fuel Cost Variance Account to record the difference
21 between forecast and actual costs of nuclear fuel expensed during the test period (Ex. J1-T3-
22 S1, page 10). The uranium market has moved from a contract market towards a commodity
23 market and, as a result, prices have become significantly more volatile and fuel purchasing
24 costs have become increasingly difficult to predict. While OPG has implemented some risk
25 mitigation measures, nuclear fuel cost volatility remains a significant business risk for OPG
26 and the probability of a material cost variance is high. OPG's nuclear fuel procurement
27 forecast and the potential variability associated with the forecast cost for the test period is
28 discussed in Ex. F2-T5-S1.

29
30 Given that the cost of the uranium concentrate is the largest component of the full bundle
31 cost and given that the remaining components are expected to remain relatively stable, the
32 variability in the total cost of the nuclear fuel is essentially the same as the variability in the

1 cost of the uranium concentrate (Ibid.). As a result, OPG is proposing to determine the
2 variance based on the variance in the total cost of the fuel bundles. The nuclear fuel cost and
3 production forecast approved by the OEB will be used to determine the \$/MWh rate for the
4 test period. The difference between this amount and OPG's actual cost of nuclear fuel on a
5 \$/MWh basis will be applied to OPG's actual nuclear production during the test period. The
6 resulting amount will be recorded as the cost variance.

7
8 *Pension/Other Post Employment Benefit ("OPEB") Cost Variance Account*

9 OPG proposes to establish a Pension/OPEB Cost Variance Account to record the impact of
10 changes in the discount rate used to determine pension and OPEB cost for OPG's regulated
11 operations (Ex. J1-T3-S1, pages 12-14). A change in this discount rate will cause a variance
12 between the pension and OPEB costs included in the revenue requirement and OPG's actual
13 pension and OPEB cost.

14
15 OPG proposes only to seek clearance of the account if the accumulated actual variance plus
16 the forecast variance to the end of the bridge year (excluding interest) exceeds a trigger
17 amount of \$75M. OPG would propose to recover/refund this forecast balance during that test
18 period. This clearance mechanism would apply to both positive and negative variances (Tr.
19 Vol. 14, page 115).

20
21 In order to project pension and OPEB costs, it is necessary for OPG to estimate the value of
22 the obligations and the pension fund assets at the end of each year. This requires making
23 projections of actual pension fund performance and of economic, demographic and other key
24 assumptions, such as the discount rate, that will be used to determine the costs. Relatively
25 small changes in this discount rate can have significant impacts on pension and OPEB costs
26 actually recorded for a given year. For example, for 2007 a 50 basis point increase in the
27 discount rate produces a \$110M increase in pension/OPEB costs while a 50 basis point
28 decrease produces a corresponding decrease in these costs (Ex. J15.3).

29
30 In most instances, the discount rate will only be available after payment amounts have been
31 set by the OEB. To calculate the pension and OPEB costs to be recorded in a given year,
32 OPG must use a year-end discount rate from the prior year to meet GAAP requirements (Ex.

1 J1-T3-S1, page 13). As such, the change in the discount rate and the resulting impact on
2 pension and OPEB costs in any given test period is not within OPG's control (Tr. Vol. 14,
3 pages 115-116).

4
5 Establishing this account and clearing balances that exceed the trigger provisions will
6 address the underlying risk of cost recovery and provide rate stability. Ms. McShane
7 estimated that a potential shortfall of 0.5 percent in ROE could result from the absence of this
8 account (Ex. KT1.6). The proposed variance account also reduces forecast risk for OPG and
9 assessment risk for ratepayers associated with material variances in these costs. This will
10 contribute to a rate review process that is less contentious and is fair to both OPG and
11 ratepayers.

12
13 *Changes in Tax Rates, Rules, and Assessments Variance Account*

14 OPG proposes to establish a Changes in Tax Rates, Rules, and Assessments Variance
15 Account to capture the potential impact on the revenue requirement of changes in tax rates
16 and rules, assessment or administrative policies and interpretation bulletins, court decisions,
17 tax assessments or re-assessments (Ex. J1-T3-S1, pages 14-16).

18
19 As noted in the evidence, OPG is currently being audited by the Provincial Tax Auditors for
20 1999 (Ex. F3-T2-S1, page 12). While OPG has incorporated the results of the 1999 audit in
21 its estimate of tax losses from the 2005 – 2007 period and tax expense for the test period,
22 there is a risk that these estimates could be impacted by audits of the 2000 taxation year and
23 later years. The results of these subsequent audits have the potential to cause a material
24 impact on the tax losses that OPG has forecast and used to reduce income tax expense and
25 mitigate the consumer impact of this application in the test period (Ex. F3-T2-S1; Ex. K).

26
27 OPG notes that in December 2005, the OEB authorized the regulated electric distributors to
28 use Account 1592, 2006 Payments in Lieu and Taxes Variances, to capture many of the
29 same tax impacts that it is seeking in its account. OPG forecasts taxes and payments in lieu
30 of taxes (where applicable) for the test period based on the tax rates and laws currently in
31 effect. While the impact of an announced or anticipated tax change is generally known in
32 advance of its effective date, typically the timing and implementation requirements

1 associated with the change are uncertain, making it difficult to define the financial impact.
2 Such a change is beyond OPG's ability to control.

3
4 In addition, tax reassessments or appeal settlements can take place when OPG is not before
5 the OEB for a revenue requirement determination. Such processes can have significant
6 impacts on the tax provisions included in the payment amounts in effect at the time. These
7 impacts are also beyond the control of OPG.

9 **10. DETERMINATION OF PAYMENT AMOUNTS**

11 **Issue 10.1**

12 **Are regulatory income and capital taxes appropriately determined in accordance with**
13 **regulatory and tax legislation requirements?**

14
15 OPG has calculated its regulatory income and capital taxes in accordance with applicable
16 regulatory and legislative requirements using the stand alone principle (Ex. F3-T2-S1, pages
17 7-8; Tr. Vol. 9, page 43). OPG is not seeking to recover any income tax expense in the test
18 period. For the regulated hydroelectric facilities, OPG is seeking to recover capital taxes of
19 \$8.7M in each of 2008 and 2009. For the nuclear facilities, OPG is seeking to recover capital
20 taxes of \$7.9M and \$7.8M in 2008 and 2009, respectively (Ex. F3-T2-S1, Table 4). OPG also
21 pays capital and property taxes on the Bruce facilities that are included in the Bruce Lease
22 costs (Ex. G2-T2-S1, Table 3).

23
24 Under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate
25 income and capital taxes to the Ontario Electricity Financial Corporation ("OEFC") and to file
26 federal and provincial income tax returns with the Ontario Ministry of Finance. The tax
27 payments are calculated in accordance with the *Income Tax Act* (Canada) and the
28 *Corporations Tax Act* (Ontario) and are modified by the *Electricity Act, 1998* and related
29 regulations. This effectively results in OPG paying taxes similar to what would be imposed
30 under federal and Ontario tax legislation (Ex. F3-T2-S1, page 7).

1 On April 1, 2005, OPG adopted the taxes payable method for income taxes for its regulated
2 operations because this is the method approved by the OEB for the utilities it regulates.
3 Under the taxes payable method, only the current tax expense is recorded in the financial
4 statements; future taxes are not recorded to the extent that they are recovered or refunded
5 through regulated payment amounts (Ex. F3-T2-S1, pages 7-8).

6
7 For the test period, regulatory income taxes are determined by applying the statutory tax rate
8 to regulatory taxable income of the combined nuclear and regulated hydroelectric operations
9 as well as taxable income associated with the Bruce facilities. Regulatory taxable income is
10 computed by making adjustments to the regulatory earnings before tax for items with
11 different accounting and tax treatment. The most significant adjustments are discussed in the
12 evidence (Ex. F3-T2-S1, pages 9-11 and Tables 7 and 8).

13
14 OPG is subject to the Ontario capital tax. For regulatory purposes, the rate base in excess of
15 the general capital tax deduction is used as a proxy for the taxable capital used for
16 calculating Ontario capital tax. The full capital tax deduction was attributed to regulated
17 operations, consistent with the determination of regulatory income taxes on a stand-alone
18 basis (Ex. F3-T2-S1, Tables 2 and 5).

19
20 **Issue 10.2**

21 **Is the proposed treatment of OPG's loss carry forwards for the regulated business**
22 **appropriate?**

23
24 For the years 2005 – 2007, OPG had tax losses in its regulated business (Ex. F3-T2-S1,
25 Tables 7, 8 and 9). The cumulative losses at the end of 2007 that are available to be carried
26 forward are \$990.2M. These tax losses were generated mainly due to OPG's contributions to
27 segregated funds, which are deductible for tax purposes. The segregated funds cover all
28 OPG owned nuclear facilities including Bruce (Ex. H1-T1 S1, page 2). OPG made annual
29 contributions of \$454M from 2005 to 2007 as well as a one-time additional payment of
30 \$334M in 2007 in accordance with the Ontario Nuclear Funds Agreement.

1 While an argument could be made that these tax losses belong to OPG and not to
2 ratepayers since they arose in a period prior to Board regulation, OPG has decided that it is
3 appropriate that they be returned to ratepayers. Therefore, OPG has applied its total
4 cumulative tax losses at the end of 2007 to reduce the projected regulatory taxable income in
5 2008 and 2009 of \$163.0M and \$324.0M, respectively, to nil in accordance with standard
6 regulatory practice. In addition, the remaining projected tax losses are used to mitigate the
7 customer bill impact of OPG's payment amount and deferral/variance account recovery
8 proposals (Ex. K1-T2-S1, Table 1; Ex. K1-T3-S1, Table 1).

9
10 As noted in the evidence, OPG is currently being audited by the Provincial Tax Auditors for
11 1999 (Ex. F3-T2-S1, page 12). While OPG has incorporated the results of this audit in its
12 estimate of tax losses for 2005 – 2007 and in determining tax expense for the test period,
13 OPG remains subject to audit for the years after 1999. As a result, there is a degree of
14 uncertainty as to the final tax losses available to return to ratepayers and the tax expense for
15 the test year. However, OPG proposes that the payment amounts for the test period be set
16 on the basis of currently calculated tax losses as this represents the best information
17 available, and any impact of audits for taxation years after 1999 be addressed through a tax
18 variance account as discussed under Issue 9.7 (Ex. J1-T3-S1, page 14).

19
20 **Issue 10.3**

21 **Are OPG's methods for removing Q1 2008 costs, revenues and production**
22 **appropriate?**

23
24 Since the OEB's jurisdiction to set payment amounts did not begin until April 1, 2008, Q1,
25 2008 costs, revenues and production must be removed from the annual data provided in the
26 application (Ex. K1-T1-S1, page 1). The application uses annual forecasts for 2008 to allow
27 for comparisons of year-over-year trends and to provide information consistent with OPG's
28 business planning process and fiscal year.

29
30 The Q1 adjustments are based on an analysis of the trending of forecast information for 2008
31 (Ex. L-1-123). This analysis took into account matters such as the pattern of outage costs,

1 the design of the gross revenue charge rates and the build up of depreciation to calculate the
2 appropriate Q1 adjustment (Ex. K1-T1-S1, Table 1).

3
4 **Implementation of New Payment Amounts**

5 OPG is seeking new payment amounts that allow for the full recovery of the test period
6 revenue requirement. Accordingly, OPG requests recovery of the difference between the
7 current payment amounts, declared interim on February 7, 2008, and the final payment
8 amounts determined by the OEB for the period from April 1, 2008 to the implementation date
9 of the OEB's order setting final payment amounts (Ex. K1-T1-S4, page 1).

10
11 OPG proposes that the retrospective amounts back to April 1, 2008, be recovered over the
12 balance of the test period through the monthly payments OPG receives from the IESO in
13 respect of its regulated assets (Ex. K1-T1-S4, page 1). For example, if the OEB decision is
14 issued in September and includes an effective date of April 1, 2008, the IESO would make
15 monthly payments beginning in October reflecting the new payment amounts for the balance
16 of the test period plus the recovery of the difference between the existing payments as set
17 out in O. Reg. 53/05 and the new payment amounts established by the Board.

18
19 The amount to be recovered for the retrospective period (in this example April 1, 2008 to
20 October 1, 2008) would be equal to the difference between the new payments approved by
21 the Board multiplied by actual production from the regulated facilities during that period and
22 the actual revenues received by OPG under the existing payment amounts set out in O. Reg.
23 53/05, excluding any hydroelectric incentive revenues. The revenues calculated at the new
24 payment amounts for the retrospective period would include revenues from the proposed
25 nuclear rate rider but not from the proposed hydroelectric incentive mechanism. This total
26 difference in revenues for the retrospective period would then be recovered through equal
27 monthly payments over the remaining 15 months in the test period. This monthly
28 retrospective payment would be in addition to the new payment amounts established by the
29 OEB order for the balance of the test period. OPG's deferral and variance account balances
30 will be adjusted as appropriate to reflect the recovery rate in the new payment amounts.

1 OPG has confirmed with the IESO that the difference between existing and new payment
2 amounts can be calculated for each wholesale customer based on historical actual load
3 consumption for the period between April 1, 2008 and the date of implementation of new
4 payment amounts and can be recovered through the IESO's settlement system (i.e.,
5 reconciliation would be carried out on the basis of historical customer actual consumption)
6 (Tr. Vol. 15, pages 150-53; Ex. J15.9).

7
8 OPG has also had discussions with the IESO regarding its proposals for the hydroelectric
9 (i.e., new incentive mechanism) and nuclear payment amounts (i.e., fixed monthly amount
10 and rate rider). The IESO has indicated that it is capable of developing an approach to
11 quickly implement the proposed structures (i.e., within one settlement period), pursuant to an
12 Order from the Board (Tr. Vol. 15, page 150). The new hydroelectric incentive mechanism
13 can only be implemented prospectively with the issuance of the Board's final order. For the
14 period up to the issuance of the Board's final order, the current incentive mechanism would
15 remain in effect.

16
17 To assist the IESO, OPG requests that the OEB's order specify the process to be used for
18 recovery of the retrospective amount.