



EB-2007-0905

OEB Application

for

Payment Amounts for OPG's Prescribed Facilities

Reply Argument

Ontario Power Generation Inc.

August 5, 2008

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1 **OVERVIEW**

2
3 OPG's reply argument focuses primarily on five issues:

- 4
- 5 1. Cost of capital, including capital structure, cost of debt and return on equity;
 - 6 2. The recovery of costs related to OPG's nuclear waste liabilities, including the Bruce
7 facilities and how the cost of OPG's nuclear liabilities flows into the relevant deferral
8 accounts;
 - 9 3. Nuclear OM&A, including the role of benchmarking;
 - 10 4. Corporate cost allocations and costs; and
 - 11 5. Other revenues, specifically the treatment of revenues from segregated mode of
12 operation transactions, water transactions, congestion management settlement credits
13 and Bruce lease revenues.

14
15 On the issue of cost of capital, the OEB must set OPG's returns fairly in relation to the
16 returns awarded to other public utilities and in recognition of the greater risk that OPG faces
17 as a nuclear generator. With relation to OPG's nuclear liabilities, the OEB should recognize
18 that the obligations reflected in these liabilities, including those for the Bruce facility, are an
19 integral part of owning nuclear assets and should command the same return as the assets
20 themselves. For nuclear OM&A, the OEB should approve the requested amounts which are
21 both reasonable and necessary for the safe and reliable operation of the prescribed nuclear
22 facilities. Similarly, the allocated amount of corporate costs is appropriate and should be
23 approved. Finally, OPG's proposed treatment of other revenues is fair and reasonable and
24 should be endorsed by the OEB.

25
26 On each of these issues, the evidence adduced in this proceeding supports OPG's position
27 and provides an appropriate basis for the OEB to set just and reasonable rates. In contrast,
28 the arguments advanced by intervenors generally are inconsistent with the bulk of the
29 evidence lack evidentiary support. In some instances, intervenor arguments are based on
30 calculations and numbers that are not in the record. In these cases, OPG takes the position
31 that intervenors have crossed the line from argument to evidence and that the OEB should

1 reject calculations which have not been put in evidence or tested in the hearing as
2 speculative and unproven.

3
4 In this reply, OPG responds directly to the intervenor arguments, but avoids repeating
5 arguments made in its argument-in-chief. Many intervenor arguments have already been
6 addressed in OPG's argument-in-chief and OPG has nothing further to add. In some cases, if
7 OPG views its argument-in-chief as a complete answer to an argument made by an
8 intervenor, this reply may refer to it but, in most cases, it does not. Therefore, the fact that
9 OPG does not specifically respond to an intervenor argument in this reply does not mean
10 OPG has no response.

11
12 OPG has tried to assemble similar intervenor arguments in one place or, where one
13 argument is clearly the lead argument, to respond to that argument but not to all the smaller
14 points that other intervenors may have introduced at the margins.

15
16 In some cases, intervenors have attributed positions or arguments to OPG which it does not
17 take or which it has not made. An example is CCC's attribution that OPG takes the position
18 that the OEB is bound by the Memorandum of Agreement between OPG and its shareholder,
19 the Province. OPG does not say the OEB is bound by this Agreement. OPG does say that
20 the terms of the Agreement are relevant to understanding OPG's costs or the meaning of
21 certain provisions in the Regulation. OPG does not respond to all of these misstatements of
22 its position. Failure to specifically respond to an intervenor characterization of this kind does
23 not mean OPG accepts that characterization. The OEB will see an accurate statement of
24 OPG's positions in its evidence and its argument-in-chief, not in the intervenor's attributions
25 or characterizations.

26
27 On many issues, intervenors have either said nothing or not taken issue with the relief sought
28 by OPG on that issue. In those cases, OPG presents no additional argument, as there is
29 nothing to respond to. In these instances, OPG relies on all of its evidence and the
30 argument-in-chief already presented to support the relief requested.

1 **1. RATE BASE**

2

3 **Issue 1.1**

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

6

7 No intervenors objected to OPG's calculation of its rate base, with the exception of
8 submissions on the inclusion of asset retirement costs ("ARC") in the nuclear rate base.
9 OPG's response to arguments on ARC is set out under Issue 7.1.

10

11 For all the reasons set out in its evidence and argument-in-chief, and in consideration of the
12 arguments provided under Issue 7.1, the rate base for the regulated hydroelectric and
13 nuclear facilities should be accepted by the OEB as filed.

14

1 **2. CAPITAL STRUCTURE AND COST OF CAPITAL**

2
3 **OVERVIEW**

4 The principal arguments against OPG's cost of capital requests, including a 42.5/57.5 debt
5 equity ratio and a return on equity of 10.5 percent are:

- 6
- 7 1. The government has already decided it is satisfied with a 55/45 debt equity ratio and
8 a 5 percent return on equity ("ROE");
 - 9 2. In any event, the government's "real" cost of equity is only 5.85 percent;
 - 10 3. OPG has little or no risk because of the likelihood of government intervention to
11 protect it (the stand-alone issue);
 - 12 4. Ms. McShane's recommendations are "too high" in relation to the other experts;
 - 13 5. An 'A' credit rating is unnecessary to ensure access to capital;
 - 14 6. OPG's cost of debt is "too high."
- 15

16 At the end of the day, while there is a range of recommendations in the evidence from 40
17 percent to 57.5 percent equity in the capital structure and, for ROE, from 5.85 percent to 10.5
18 percent, the OEB must set OPG's returns fairly and appropriately in relation to the returns
19 awarded to other public utilities in Canada. All the experts agree on one thing: OPG, as a
20 predominantly nuclear generator, faces greater risk than any transmission, distribution or
21 vertically integrated utility in Canada. OPG, therefore, as a matter of law, is entitled to a
22 capital structure and ROE which reflects that greater risk, that is, an equity ratio and ROE
23 which is greater than that granted to transmission, distribution *and* vertically integrated
24 utilities. The only real question for the OEB is, how much more should OPG's cost of capital
25 be?

26

27 To begin, however, OPG wishes to address one aspect of the AMPCO and CME arguments
28 relating to Ontario Hydro's 1999 restructuring. In trying to set a context for their punitive and
29 unrealistic recommendations on cost of capital, AMPCO and CME attempt to describe the
30 background to the province's decision to prescribe certain OPG assets and to set the price
31 for the output of those assets during the interim period. In short, it is OPG's submission that
32 the facts and circumstances of Ontario Hydro's 1999 restructuring are completely irrelevant

1 to the determination of OPG's payment amounts in 2008/2009. In any event, the "context"
2 presented by these intervenors is inaccurate and incomplete, as discussed below.

3
4 CME refers to the "profligate levels of spending that bankrupted OPG's predecessor, Ontario
5 Hydro" and AMPCO refers to "unsustainable Ontario Hydro generation investments" (CME
6 argument, para. 1; AMPCO argument, para. 10). The suggestion that Ontario Hydro was
7 bankrupt is nonsensical. Ontario Hydro was a state-owned, unregulated monopoly which
8 along with its owner, had the power to charge whatever was required to recover its costs. In
9 fact, on March 31, 1999 when Ontario Hydro ceased operation it was quite strong financially,
10 having paid down more than \$4B in debt during the 1994-99 period, even though its rates
11 were frozen (Ontario Hydro Final Annual Report, January 1998-March 1999, page 1).

12
13 The stranded debt arose from the transition to a competitive market, a transition urged on the
14 government of the day by AMPCO and its members. That stranded costs are a product of
15 electricity industry restructuring (not Ontario Hydro "bankruptcy") is made clear in the
16 *Electricity Act*, which defines stranded debt as debt that "cannot reasonably be serviced and
17 retired in a competitive electricity market" (*Electricity Act*, 1998, section 85.1). As Ms.
18 McShane indicated, this is debt that would have been recovered from consumers in any
19 event under the former regime. It became "stranded" only as a result of the move to a
20 competitive market (Tr. Vol. 10, page 66). In this regard, Ontario is largely the same as other
21 jurisdictions that have restructured their electricity industries and imposed transition charges
22 to recover their stranded costs (Tr. Vol. 10, page 76).

23
24 AMPCO and CME also quote selectively from the February 23, 2005, Ministry of Energy
25 Backgrounder that the province issued when announcing the regulation of the prescribed
26 facilities and the introduction of a new price cap and rebate mechanism for most of OPG's
27 non-regulated generation (CME argument, para. 2; AMPCO argument, paras. 15-16).
28 AMPCO's quotation omits the very first and most salient point the backgrounder makes, that
29 these prices are designed to "better reflect the true cost of producing electricity" (Ex. J1.1,
30 page 1).

31
32 Both AMPCO and CME also ignore the backgrounder's statements that:

- 1 • Since its inception, the Market Power Mitigation Agreement (“MPMA”) has cost OPG
2 approximately \$100M per month and approximately \$3.3B in total. As a result, OPG has
3 suffered poor financial performance over the last three years, and the government and
4 taxpayers have not been able to realize any financial benefit from OPG.
- 5 • Under the MPMA, all customers who use more than 250,000 kilowatt hours per year
6 receive a rebate if the annual average Ontario electricity price exceeds 3.8 cents per
7 kilowatt hour. This rebate applies to half of the electricity they consume.
- 8 • Due to the MPMA, electricity prices for consumers have been effectively subsidized by
9 taxpayers, and OPG has not been able to recover the cost of generating the electricity it
10 produces. This has severely compromised the company’s ability to improve its overall
11 financial performance.

12
13 These statements illustrate the government’s desire to improve OPG’s financial performance,
14 end electricity price subsidies and allow OPG to earn the revenues necessary to recover its
15 cost of producing electricity while providing a return to its shareholder (Ex. J1.1, page 4).

16
17 On the principal issues listed at the outset of this section, it will be OPG’s submission that:

- 18
19 1. The 55/45 debt/equity ratio and 5 percent return on equity which underpinned the
20 interim rates does not mean that the government has “already decided” what is
21 reasonable. No full cost of capital study was done to set interim rates. The interim
22 rates were a transitional measure to get OPG off the former MPMA, which was
23 seriously undermining OPG’s financial performance. By referring the matter to the
24 OEB post-April 2008, the government intended to complete the transition of OPG’s
25 prescribed assets to independent regulation.
- 26 2. For the purposes of determining utility ROE, the shareholder’s cost of raising funds is
27 not a relevant consideration, and for good reason. Under this argument, if the
28 shareholder’s “real” cost of equity is high then utility ratepayers would be saddled with
29 an unnecessarily high cost of capital. Customers cannot both benefit if the “real” cost
30 of equity for the shareholder is low and be insulated from the consequences of this
31 argument if the shareholder’s “real” cost is high. Economic and regulatory principles
32 require that the cost of capital must be determined on a stand-alone basis,

1 irrespective of the owner's own risk profile and cost of capital. Adopting a cost of
2 capital for OPG that is below the "real" cost will result in inefficient pricing for the
3 output from OPG's prescribed facilities and lead to inefficient use and allocation of
4 resources.

5 3. If OPG's assets are as important to the province as CCC, CME, AMPCO and other
6 intervenors say they are, the government would not let OPG fail whether it was the
7 shareholder or not. The government's ownership is therefore irrelevant. Further,
8 Hydro One Transmission is also critically important to the provincial economy. The
9 government would also surely intervene to prevent this utility from failing, yet it
10 receives a commercial cost of capital. As OPG, like Hydro One, is owned by the
11 Province of Ontario, and as OPG's business is necessarily riskier than transmission
12 and distribution, OPG's cost of capital must necessarily exceed that allowed to Hydro
13 One. Deferral and variance accounts like OPG's are common among most regulated
14 utilities and many of the accounts established for OPG are largely devoted to
15 preventing retroactive, hindsight reassessments of decisions made before OEB-
16 based regulation of OPG's payment amounts came about. The operational and
17 production risks of OPG's nuclear operations are very substantial and receive no
18 deferral or variance account "protections."

19 4. Ms. McShane's recommendations are not "too high." OPG's reply will examine why
20 this is so. It will also demonstrate that intervenors' cost of capital recommendations
21 are too low, even lower than that allowed Hydro One, and that Booth, Kryzanowski
22 and Roberts, and Schwartz all undervalue OPG's risks and arrive at an inappropriate
23 return.

24 5. Virtually every utility in Canada has an 'A' credit rating. Even those that do not have
25 'A' ratings have significant ROEs, without which they would not even enjoy 'BBB'
26 ratings. 'BBB' ratings expose OPG to both more limited, and more costly, markets for
27 debt financing. OPG should have financial metrics (i.e., capital structure and ROE)
28 that enable it to maintain an 'A' rating.

29 6. Intervenors, particularly AMPCO, have mis-characterized OPG's debt costs. By
30 attempting through argument to establish a record based on untested assertions, in
31 the form of new calculations, they have improperly and artificially overstated OPG's

1 actual cost of debt. OPG's cost of debt is reasonable; it is based on commercial,
2 independent, third party measures of the expected cost of borrowing.

3
4 **Issue 2.1**

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

9
10 **Issue 2.2**

11 **What is the appropriate return on equity (ROE) for OPG's regulated business for the**
12 **2008 and 2009 test years? Should the ROE be the same for both OPG's regulated**
13 **hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each**
14 **business?**

15
16 **1. The Implications of Cost of Capital Assumptions used to Establish Interim**
17 **Rates**

18 Intervenors, with AMPCO and CME leading the charge, argue that no change in the cost of
19 capital is warranted because the government, as shareholder, has already indicated its
20 willingness to accept a 55/45 debt/equity ratio and a 5 percent ROE. CME's position on ROE
21 is a moving target, however, in various places in its argument it says ROE should stay at 5
22 percent, ROE should reflect the government's so-called "real" cost of equity of 5.85 percent
23 and that OPG's ROE should be "no more than" that awarded to Hydro One Distribution of
24 8.57 percent. OPG will deal with all of these proposals in the course of this reply.

25
26 The central proposition of the AMPCO/CME argument, however, that the government has
27 already accepted the capital structure and ROE it wants, is unsustainable in logic and on the
28 facts. By O. Reg. 53/05, the government made the OEB the sole authority for the
29 determination of OPG's payment amounts. While the OEB's authority must be exercised in
30 accordance with certain rules stipulated in the Regulation, neither capital structure nor ROE
31 are prescribed. The OEB has a long history of determining both capital structure and ROE in
32 accordance with evolving principles of corporate finance and well-settled legal and regulatory

1 principles. It is inconceivable that the government, knowing of this history, and in a context
2 where a variety of other details are specified by regulation, would not have specified the
3 capital structure and ROE if it had been the government's intention to continue the 55/45
4 equity ratio and 5 percent ROE post-April 1, 2008. The very fact that the government did not
5 do so while conferring full authority on the OEB to determine OPG's payment amounts for
6 the prescribed facilities is a complete answer to the suggestion that the OEB should just
7 adopt what the government used for interim rates.

8
9 CME selectively cited passages from the government's announcement at the time it brought
10 OPG under the rate regulation but omitted the first and most important objective. The
11 government's first objective was to "better reflect the true cost of electricity."

12
13 As Mr. Goulding said in the hearing, "artificially suppressing what is recovered in rates for
14 OPG's cost of capital undermines the objective of designing rates that better reflect the true
15 cost of power" (Tr. Vol. 12, page 114). It is worth noting, as well, Mr. Goulding's opinion that
16 a ROE of 5 percent for the prescribed assets is "clearly inappropriate" (Tr. Vol. 12, page
17 112). The AMPCO/CME argument also ignores, for example, OPG's commercial mandate. It
18 also ignores the implications of referring the determination of OPG's payment amounts after
19 April 1, 2008 to the OEB when the government obviously knew that every other government-
20 owned utility in the province received a commercial rate of return.

21
22 CME also relies on the fact that the government's financial advisor in 2004, CIBC,
23 recommended a 55/45 debt equity ratio as the basis for OPG's capital structure in the interim
24 period. As OPG noted in the hearing, however, that number was not the product of a cost of
25 capital study but, rather, simply the result of a fairly cursory review of other existing utility
26 capital structures (Tr. Vol. 1, page 125). CME argues that OPG must show it has suffered a
27 change in business risk since 2005 to justify any change in its equity ratio. This is not correct.
28 CME's point might have had some traction if the 2005 equity ratio had been set by the OEB
29 after a full study of OPG's business risks and a full hearing on the matter. But that is not what
30 happened. The government adopted the interim equity ratio as a transition to full cost of
31 service rates established after an independent review by the OEB.

32

1 In addition, the evidence is clear that the government was well aware of this application and
2 what OPG was seeking (Ex. L-2-10). It would have been reasonable to expect the
3 government, as OPG's sole shareholder, to advise the company if OPG was seeking a
4 capital structure or ROE that was inconsistent with the government's intentions. Indeed, had
5 the government been resolved on the question of cost of capital as CME suggests, why
6 would the government have referred OPG's payment amounts to the OEB post-April 1, 2008
7 at all? The AMPCO/CME argument makes a mockery of the whole point of putting OPG's
8 payment amounts for the prescribed assets under the jurisdiction of an independent tribunal.
9

10 **2. The Shareholder's "Real" Cost of Capital**

11 CME (CME argument, para. 166) and AMPCO (AMPCO argument, para. 96) also argue that
12 the government's cost of capital should form the basis for determining the ROE for the
13 government's investment in OPG. This is a truly astonishing argument which, if adopted,
14 would herald a radical departure from all established principles of utility rate setting. What
15 CME is saying is that because the government's cost of capital for its equity investment is
16 allegedly 5.85 percent, that is what the ROE for the investment should be. But this principle,
17 if correct, must be applied equally whether the shareholder's own risk profile or cost of capital
18 is low or high. In other words, if ratepayers are to benefit from having a government
19 shareholder by enjoying a low cost of capital in rates, customers must equally be exposed to
20 higher costs of capital where other utility owners have a high cost of capital. That is not how
21 the OEB, or any other regulatory tribunal, has viewed the determination of an appropriate
22 ROE in any previous proceeding of which OPG is aware.
23

24 Besides violating the stand-alone principle (the stand-alone principle will be dealt with in the
25 next section of this reply, but is equally applicable here) and well-settled regulatory
26 principles, the CME/AMPCO contention violates a basic principle of finance - that the cost of
27 capital reflect the riskiness of the entity or the project in which the funds are invested, not the
28 source of the funds. The CME and AMPCO position reflects the "misconception that the cost
29 of raising capital to invest in a project (the financing decision) is the same as the cost of
30 capital (required return) of the project" (Ex. C2-T1-S1, page 11). Dr. Morin, author of *New*
31 *Regulatory Finance (2006)* says:
32

1 The fact that an operating utility is a wholly owned subsidiary of a
2 parent company is immaterial. The parent company, as the operating
3 company's sole shareholder, should not be discriminated against and
4 treated differently than any other shareholder. The only relevant concerns
5 should be the risk to which a common equity investment in the operating
6 utility subsidiary's rate base is exposed.
7

8 A utility operating company, segment, division, or line of business
9 must be treated as a separate stand-alone entity, distinct from its parent
10 company because it is the cost of capital for the division that we are
11 attempting to measure and not the cost of capital for the parent
12 company's consolidated activities. Financial theory clearly establishes
13 that the true cost of capital depends on the use to which the capital is put.
14 Both common sense and financial theory assert that risk-averse investors
15 require higher returns from high risk investments. This implies that the
16 expected return, or cost of capital, for a higher risk investment exceeds
17 that of a lower risk investment. The specific source of funding an
18 investment and the cost of funds to the investor are irrelevant
19 considerations.
20

21 The conclusion that the cost of equity is the same as the cost of debt would be the same as
22 saying the federal government should only expect a return on an investment in an oil and gas
23 exploration and development project equal to the cost of debt it could raise to invest in such
24 a project. CME and AMPCO miss the central point: that the return the government or any
25 other investor would expect from its investment is one that reflects the riskiness of the project
26 it is investing in, not the cost incurred to raise the capital for the investment (Ex. C2-T1-S1,
27 page 12). It is telling that AMPCO and CME's argument on this point has not been raised, or
28 even mentioned, by any finance expert who testified in this proceeding.
29

30 CME and AMPCO's suggestion that the Board set the ROE equal to the province's cost of
31 debt would require the OEB to ignore important regulatory principles. As Mr. Goulding stated:
32

33 As an *OBCA* corporation, OPG should be treated no differently from
34 any other entity that the OEB regulates. OPG should not be compelled by
35 the regulator to suppress what would otherwise be just and reasonable
36 equity returns to serve other policy objectives.
37

38 Owning and operating hydroelectric and nuclear generating assets is
39 clearly not risk free. As a result, a return of 5 percent for the prescribed
40 assets is 'clearly inappropriate' from a financial market and utility
41 perspective." (Tr. Vol. 12, pages 111-112)

1

2 He also said that, “provinces which sell power at less than full value lose out twice: first as
3 shareholders because they receive less revenue and lower profits than would otherwise be
4 achieved by their investments; and second, as policy makers, they lose again because
5 under-priced electricity encourages over-consumption and all of its attendant adverse
6 environmental impacts” (Tr. Vol. 12, page 143).

7

8 CME and AMPCO’s recommendation that the Board set the ROE equal to the province’s
9 cost of debt should be rejected by the Board.

10

11 **3. The Stand-alone Principle**

12 One of the principal arguments of CCC, AMPCO, CME and others is that the stand-alone
13 principle should not apply here because the shareholder also has legislative power and,
14 among other things, “would not let OPG fail.” From this allegation, CCC, for example,
15 concludes OPG has no risk and therefore should need minimal equity in its capital structure
16 and only an extremely low ROE.

17

18 OPG has relied on the stand-alone principle, as defined by Ms. McShane, in arriving at its
19 proposed capital structure for the prescribed assets. The cost of capital witnesses for Board
20 Staff and Pollution Probe (SEC also adopts the recommendations of Pollution Probe’s
21 witnesses) also call the stand-alone principle a “fundamental principle” and agreed with this
22 approach.

23

24 Contrary to the view expressed by the finance experts, CCC argues that the identity of the
25 shareholder cannot be ignored because: 1) the real owners of OPG are the residents of
26 Ontario and the government has a responsibility to ensure that they have an adequate
27 supply of electricity at reasonable prices; 2) the expressed objective of the shareholder is to
28 limit the risks to the taxpayers, and 3) the shareholder has the ability to determine the
29 sharing of risks between OPG and the ratepayers.

30

31 CCC’s first argument misses the key point that ratepayers’ interests must be kept separate
32 from taxpayers’ interests, as the OEB recognized in both H. R. 15 and H. R. 16 (OPG

1 argument-in-chief, page 17). In response to Ex. L-3-25, OPG noted that “While there is
2 clearly an overlap, Ontarians as taxpayers have different objectives (e.g., lower personal and
3 corporate taxes, increased social programs such as education) than Ontarians as electricity
4 consumers. Moreover, ratepayers do not necessarily consume electricity in proportion to
5 their contributions as taxpayers or consumers of social services,” and further, “Ontarians as
6 taxpayers and shareholders of OPG would in principle prefer to see a compensatory return
7 on their investment that could be used to fund reductions in personal and corporate taxes,
8 create new social programs or fund business development programs. While ratepayers may
9 prefer to see subsidized electricity prices, lower than full cost electricity prices encourage
10 ratepayers to over-consume electricity, with the resulting negative external costs, (e.g.,
11 over-building of infrastructure and negative impacts on the environment).”

12
13 CCC’s second reason for disregarding the stand-alone principle (i.e., the shareholder’s
14 alleged objective of limiting risks to the taxpayer) is also without merit. All shareholders have
15 an interest in limiting their risks. That is the fundamental basis of the corporate structure –
16 the limitation of liability. That does not mean that the sharing of risks between shareholder
17 and ratepayers through the established regulatory framework, including deferral and variance
18 accounts, is unreasonable. Why should, for example, the province as *shareholder* bear the
19 risk of OPG’s nuclear waste management obligations? It is the company’s risk, for which it
20 should be compensated in rates. No private investor would assume the unlimited nuclear
21 liabilities of the corporation. In this context, OPG notes the evidence of Mr. Goulding, who
22 concluded:

23
24 Bundling of generation with wires assets means that vertically integrated
25 utilities are, on par, less risky than the OPG prescribed assets; even
26 given the number of variance and deferral accounts proposed by OPG,
27 inclusion of the less risky wires asset class with generation makes
28 vertically integrated utilities less risky than OPG. Indeed, many vertically
29 integrated utilities have similar sets of variance and deferral accounts
30 associated with their generation assets. (Ex. M-T1, page 44)
31

32 In OPG’s submission, the proposed regulatory model, which includes the deferral and
33 variance account requirements of O. Reg. 53/05, appropriately shares the risks between

1 shareholder and ratepayers, is consistent with the approach taken by other utilities and
2 provides no basis for disregarding the stand-alone principle.

3
4 CCC also claims that the shareholder can control the sharing of risks between taxpayers and
5 ratepayers and would never allow OPG to fail. The fact that the government, as both energy
6 policy-maker and sole shareholder of OPG, may find it easier to use its legislative power to
7 make OPG (as opposed to a privately owned utility) an instrument of public policy should not
8 influence the determination of a reasonable return on investment. It is simply incorrect for
9 CCC and CME to claim that the government's legislative power has always been used to
10 protect or to benefit OPG. The price caps of the early 2000s (some of which, on OPG's
11 unregulated generation, continue in another form today), the original requirement to
12 decontrol a substantial portion of its assets, the 5 percent return on equity from 2005 to 2008,
13 and the requirement that OPG as the generator and owner of the nuclear assets take primary
14 responsibility for nuclear waste and decommissioning obligation with respect to those assets
15 are all examples of instances where the government has used its law making and ownership
16 prerogatives to effect policies which are not beneficial to OPG. It is the very fact that the
17 government can act both in ways to advantage and disadvantage OPG that creates
18 uncertainty – and therefore political risk – in the future. This is why Mr. Goulding says: “the
19 prescribed assets face a higher degree of political risk than either wires assets or merchant
20 generators” (Ex. M-T1, page 32) and why the bond rating agencies have highlighted political
21 risk. S&P noted:

22
23 Governments change, government policies change, views on
24 ownership change, economic circumstances change, and the financial
25 ability and willingness of the province to support its enterprises can
26 change also.

27
28 Fundamentally, it is not possible to predict the future political
29 willingness to support a separately incorporated entity. (S&P, FAQ:
30 Implied Government Support As A Rating Factor For Hydro One Inc. And
31 Ontario Power Generation Inc., October 20, 2005, Ex. L-12-44,
32 Attachment #2)
33

1 DBRS stated:

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Since the separation of the former Ontario Hydro into various independent operating entities in 1999, OPG has been the subject of significant government intervention, indecision and policy change. While it appears that the worst is now over as the government has begun to allow OPG more autonomy, the risk of further government intervention still exists. The most recent example of this type of political risk has been associated with the government's plan to close all of the coal-fired generating facilities in Ontario. The provincial government had targeted 2009 as the date for the closure of all coal-fired generation. However, in its most recent energy plan announcement in June 2006, the government has taken the recommendation of the IESO to extend the closure date indefinitely until adequate replacement generation is commissioned. Policy change such as this makes it more challenging for OPG to undertake long-term strategic planning. (DBRS, Rating Report: Ontario Power Generation Inc., August 3, 2006, Ex. L-3-13, Attachment 10)

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Further, if OPG's assets are as important to the province as CCC claims they are, the government would not let OPG fail whether it was the shareholder or not. Hydro One Transmission is also critical to the province, socially and economically. The government would surely not hesitate to intervene were Hydro One threatened with financial collapse, yet it recovers commercial costs of capital on a stand-alone basis, that is, independently of its shareholder's identity.

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CME's definition of stand-alone, that is, treating the regulated business as a separate entity from the unregulated business, is overly narrow and unsupported by any witness in this proceeding or any regulatory precedent. Indeed, regulatory precedent is all to the contrary. In addition to the argument-in-chief, OPG also relies on:

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- Applications by Union Gas Limited and Enbridge Gas Distribution for A Review of the Board's Guidelines for Establishing Their Respective Return On Equity 2007 NP General Rate Application – NP-CA-73; Decision and Order – January 16, 2004:

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A long standing regulatory principle espoused by the Ontario Energy Board, and by other regulators in North America, is the stand-alone principle. Applying this principle, the issue is what ought to be a prospective fair return on investment for a utility on a stand-alone basis, and not how a prospective return may compare or compete with other

1 business units of the parent company. Should it be the case that the
2 Ontario Gas utilities are unable to attract equity capital by virtue of
3 competition at the parent company level, whether the parent company is
4 foreign or domestic, this would be of great concern to the Board.
5

- 6 • Report of the Board in the Matter of Reference respecting the Unicorp Canada
7 Corporation Acquisition of Union Enterprises Ltd. – 15 February 1985:

8
9 The “stand alone” principle underscores all the Affiliated Interest rules.
10 This principle requires that the utility be operated and regulated as a
11 separate economic entity. Accordingly, the holding company owning or
12 controlling the utility maintains a debt and equity or capital structure which
13 is separate from that of the utility. Similarly, the Board regulates the utility
14 on the basis of a separate capital structure and with regard to an
15 independent evaluation of financial and business risks and returns (para.
16 106).
17

18 And even if OPG’s default risk is lower by virtue of its importance to the province’s well-
19 being, that does not mean that the company does not have material financial risks. OPG’s
20 high proportion of fixed costs and the potential for large negative returns on its segregated
21 funds (as we have seen this year) and on its pension fund, are just two examples of the
22 significant financial risks that OPG faces.
23

24 In addition, as Ms. McShane pointed out in cross-examination, all the background to OPG’s
25 regulatory circumstance suggests that the shareholder is “trying to create and maintain an
26 arm’s-length company” (Tr. Vol. 11, page 14). To proceed on the assumption that the
27 shareholder will intervene to protect OPG as an argument for ignoring the stand-alone
28 principle directly contradicts the province’s decision to place OPG’s prescribed assets under
29 the independent jurisdiction of the OEB. OPG also notes that the shareholder held that same
30 power in 1987 when Dr. Booth testified in respect of Ontario Hydro that:
31

32 Certainly, in terms of economic theory, if an entity controls \$5 billion in
33 resources and the opportunity cost is found to be 10%, then that entity
34 should earn \$500 million regardless of whether legally it is a privately
35 regulated firm or a Crown corporation. Resources do not suddenly cease
36 to be of value, simply because they are acquired by public-Crown
37 corporations, rather than by privately owned corporations. Hence, the
38 focus of this testimony is the same as in a rate of return hearing: What is
39 the appropriate rate base, i.e., the value of the resources controlled by

1 the entity and what is the entity's cost of capital, i.e., the opportunity cost
2 of those resources?" (Exhibit 12.3, Dr. Michael K. Berkowitz and Dr.
3 Laurence D. Booth, Estimation of a Fair Net Income for Ontario Hydro,
4 commissioned by Energy Probe for submission to Ontario Energy Board
5 H. R. 16 Hearings, June 1987)
6

7 Drs. Booth and Berkowitz's conclusion supports the application of the stand-alone principle,
8 is only made stronger by the province's decision to have OPG operate as a commercial
9 enterprise and to place independent oversight of the payment amounts for OPG's prescribed
10 assets in the hands of the OEB.
11

12 **4. The McShane Recommendation is not "Too High"**

13 Capital Structure

14 Most intervenors, while acknowledging OPG has certain operating or production risks,
15 minimize or downplay those risks on the basis, among other things, that they are all mitigated
16 by variance and deferral accounts. Intervenors, however, did not respond to or criticize the
17 important and unbiased evidence of Mr. Goulding on this issue.
18
19

20 It was Mr. Goulding's opinion, shared by Drs. Kryzanowski and Roberts, that OPG's nuclear
21 assets are far more exposed to potential loss of revenues due to operational risk than a
22 transmission or distribution network. The operational risk associated with OPG's prescribed
23 assets is, in fact, the principal risk that faces OPG (Tr. Vol. 12, pages 124-125). Notably,
24 none of OPG's nuclear production risk is mitigated by a deferral or variance account.
25

26 As Mr. Goulding agreed, identifying and correcting problems with older generating equipment
27 could require significant time and expense which would lead to lost revenue and increases in
28 OM&A expense (Ibid.). Generation assets entail significantly more complex operating
29 dynamics than transmission and distribution systems. Both the hydroelectric and nuclear
30 assets in OPG's prescribed portfolio face potential outage risk, particularly for the nuclear
31 units, for which such outages tend to be much longer and more involved than comparable
32 distribution or transmission outages (Tr. Vol. 12, page 124).
33

1 Another aspect of operating risk results from the fact that OPG is regulated by the Canadian
2 Nuclear Safety Commission (“CNSC”). OPG requires a licence from the CNSC to operate.
3 The CNSC has the power to order OPG to take measures that it thinks are necessary to
4 protect the environment, health or safety or national security. The CNSC has the power to
5 certify and decertify nuclear equipment and to issue, renew, suspend and revoke licenses. In
6 emergency situations, the CNSC has the power to make any order it deems necessary
7 without a hearing (Tr. Vol. 12, page 133).

8
9 Orders from the CNSC, or amended licence conditions, have the potential to cause
10 substantial increases in capital and operating costs for OPG (Tr. Vol. 12, page 134). Such
11 orders could have a significant adverse impact on OPG’s nuclear operations, financial
12 performance and liquidity. Indeed, even events at nuclear power plants in other jurisdictions
13 can cause the CNSC to initiate actions which affect the operations and costs of Canadian
14 nuclear generators. These powers are significant in the assessment of regulatory risk for
15 OPG (Tr. Vol. 12, page 135).

16
17 While Mr. Goulding did not make any specific recommendations with respect to capital
18 structure (or ROE), his analysis leads to the conclusion that OPG, even with the proposed
19 deferral and variance accounts, which are not dissimilar to the variance and deferral
20 accounts available to other regulated utilities, faces higher business risks than any of the
21 Canadian regulated utilities that he examined, with the exception of SaskPower and the coal-
22 and oil-based utilities in the Atlantic Provinces (Ex. M-T1, page 34), as well as higher
23 business risk than U.S. integrated electric utilities (Ex. M-T1, page 44). These views were
24 largely shared by Drs. Booth, Kryzanowski and Roberts as well. It follows logically that
25 OPG’s returns on capital must be set at a higher level than these entities to compensate for
26 its higher business risks.

27
28 Three cost of capital witnesses on behalf of intervenors recommended alternative capital
29 structures. However, in contrast to the business risk assessment of Ms. McShane, these
30 witnesses have underestimated the business risks faced by OPG and, as a result, have
31 underestimated the common equity ratio that reasonably reflects its business risks.

32

1 Pollution Probe recommends a capital structure for the prescribed assets containing 47
2 percent equity (in conjunction with their estimated ROEs for a benchmark utility), based on
3 the evidence of Drs. Kryzanowski and Roberts.

4
5 Drs. Kryzanowski and Roberts developed an analytical framework for this case to assess
6 utility business risk. They used three major categories of business risk: market risk,
7 operational risk and regulatory risk. By means of various subcategories, including operating
8 leverage risk, technology risk, capacity risk and asset retirement risk, they come up with nine
9 individual risks covering these three basic categories.

10
11 For each risk, Drs. Kryzanowski and Roberts rated OPG on a scale of one to five (Tr. Vol. 13,
12 pages 79-80). However, because Drs. Kryzanowski and Roberts have not used this
13 analytical framework before, it has never been applied to any other Canadian utility. Nor did
14 they attempt to apply it to other utilities for comparative purposes in this case. It is therefore
15 impossible to judge the robustness or the appropriateness of the analysis using this
16 framework for OPG in relation to any other utility (Tr. Vol. 13, page 81).

17
18 Drs. Kryzanowski and Roberts agreed that setting an appropriate equity ratio is a subjective
19 exercise, as is the assessment of the level of business risk (Tr. Vol. 13, page 82).
20 Accordingly, the decision to assign particular values to OPG in connection with a particular
21 prescribed asset in a particular risk category boils down to a subjective assessment involving
22 informed judgment (Tr. Vol. 13, pages 83-85).

23
24 In addition, although Drs. Kryzanowski and Roberts agreed that both the probability and
25 materiality of risk for OPG varied from one risk category to the next, they gave all nine risk
26 categories equal weight in conducting their analysis (Tr. Vol. 13, pages 86-87). Drs.
27 Kryzanowski and Roberts admitted that someone else conducting a risk analysis of OPG
28 might well not grant equal weight in terms of probability and materiality to all nine risk factors
29 and could come to different results (Tr. Vol. 13, page 87).

30
31 The central contradiction facing Drs. Kryzanowski and Roberts' business risk analysis is,
32 however, that, by their own admission, OPG's prescribed assets are riskier than any other

1 utility business in Canada. Yet, Drs. Kryzanowski and Roberts only assigned OPG a
2 business risk of 2.3 out of five. When asked to justify this low rating, given the scale of one to
3 five, Drs. Kryzanowski and Roberts claimed that they were reserving the upper half of their
4 business risk range for utilities that did not have risk mitigation available (i.e., deferral and
5 variance accounts) (Tr. Vol.13, pages 89-90). The problem with this explanation is that, again
6 by their own admission, this analytical framework was established to measure *utility* risk.
7 Variance and deferral accounts (risk mitigation measures) are, also by their own admission,
8 a common feature of Canadian utilities. Drs. Kryzanowski and Roberts are in effect,
9 therefore, reserving fully half of their range of risk for utilities that do not exist, that is,
10 hypothetical utilities with no access to deferral and variance account mechanisms.

11
12 With respect to operational risk, Drs. Kryzanowski and Roberts' claim that OPG performs
13 poorly against industry benchmarks and that this "strongly suggests" OPG's operational risks
14 are due to mismanagement (which, according to Drs. Kryzanowski and Roberts, are not a
15 risk to be recognized in regulation) is completely unsupported.

16
17 Drs. Kryzanowski and Roberts used a capacity factor benchmark of 91 percent taken from a
18 bond rating report as their standard for comparison. They conducted no analysis of what that
19 number was based on, what assets were in the database, where the underlying data came
20 from or how reliable or statistically relevant the results were. They merely assumed that
21 performance below 91 percent was evidence of mismanagement (Tr. Vol. 13, pages 99-101).

22
23 OPG's performance metrics are clearly tied to the age and stage of the particular technology.
24 Darlington, for example, tracks competitively against U.S. comparables and extremely well
25 against other CANDUs. The Pickering units are not top performers and are unlikely to
26 become top performers due to their design and age (Tr. Vol. 4, pages 131-132, and 152).
27 This, of itself, strongly suggests that OPG's benchmarking challenges are not management
28 but technology related (Tr. Vol. 13, pages 102-103).

29
30 The witnesses' mis-characterization of OPG's production risks in and of itself leads to the
31 conclusion that Drs. Kryzanowski and Roberts' business risk analysis is flawed and their
32 weighted combined 47 percent equity ratio is too low.

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Drs. Kryzanowski and Roberts showed that their recommendations would produce a 2.1 times interest coverage ratio. Their claim that a bond rating of 'BBB' could be maintained by OPG with this level of coverage, however, is not convincing.

OPG currently enjoys consolidated interest coverage ratios of three to four (Tr. Vol. 13, page 58). Drs. Kryzanowski and Roberts' sample of publicly traded holding companies had an average interest coverage ratio of 2.7 (Tr. Vol. 13, page 60). Drs. Kryzanowski and Roberts admitted that, of the companies in their sample, it was only those with the lowest ROEs (below the average of 12 percent) that were all 'BBB' rated (Tr. Vol. 13, pages 69-70). Emera, which owns Nova Scotia Power and which has one of the lowest ROEs at 10.93 percent, nevertheless requires that level of ROE to maintain even its 'BBB' rating (Tr. Vol. 13, page 71). This strongly suggests that a 7.35 percent ROE and 2.1 times interest coverage ratio would not support a 'BBB' rating.

CCC adopts the capital structure recommended by Dr. Booth containing 40 percent equity. Dr. Booth's business risk analysis simply discounts all of the business risks of OPG on the basis of government ownership and the existence of deferral and variance accounts. Conspicuously absent from his assessment of risk, however, is any analysis of operational and production risk. This was the central risk that virtually all the other cost of capital experts acknowledged was OPG's predominant risk. Production and operating risks are very significant for OPG due to the extremely high fixed costs of generation generally and the particularly acute risks of nuclear generation due to its technical complexity and harsh operating environment. There is simply no discussion of production risk at all in Dr. Booth's analysis.

Dr. Booth's categorical rejection of any material business risk due to deferral and variance accounts is also no explanation for his extreme position. Deferral and variance accounts are a common feature of utility regulation. Deferral and variance accounts are specifically irrelevant to the issue of nuclear production risk because OPG does not have, and is not seeking, deferral or variance account treatment of any nuclear production issues.

1 Dr. Booth also dismisses nuclear waste liabilities as a risk, again claiming that variance
2 account treatment for OPG's decommissioning and used fuel management obligations
3 eliminates this risk. However, Dr. Booth has not reviewed the ONFA and performed no
4 analysis of the actual extent of these liabilities (Tr. Vol. 13, page 154).

5
6 He did not consider, for example, that although the decommissioning fund is fully funded
7 based on today's projections, OPG bears the risk that these projections may turn out to be
8 wrong, resulting in residual unfunded liabilities that may not be recoverable through any
9 regulatory process. Moreover, he did not consider the fact that although a provincial
10 guarantee caps OPG's liability for used fuel management, the used fuel fund is significantly
11 less than fully funded (only 70 percent) and OPG's exposure up to the provincial cap remains
12 in excess of \$2B in 2007 dollars. Thus, as Mr. Goulding agreed, variance account treatment
13 of nuclear liabilities makes OPG less risky than with no variance account but OPG's ultimate
14 exposure to these liabilities is still a significant factor in assessing OPG's risk, particularly in
15 relation to utilities that have no responsibility for nuclear liabilities (i.e., almost all other
16 regulated utilities in Canada).

17
18 Dr. Booth also conveniently glosses over the fact that most of the deferral and variance
19 accounts are simply directed at preventing hindsight re-examinations of historical decisions
20 and commitments made long before the OEB acquired jurisdiction to determine payment
21 amounts for the prescribed assets.

22
23 Dr. Booth's claim that the risks of OPG's nuclear assets have been "largely removed" is
24 therefore a gross oversimplification and overstatement, unsupported by any facts or analysis
25 (Ex. M-T3, page 57).

26
27 Intervenors like CCC, AMPCO and CME point to amendments that were made to the
28 Regulation resulting in the creation of variance accounts to enable OPG to recover increases
29 in its nuclear decommissioning and waste management liabilities and costs associated with
30 developing new nuclear capacity. As the OEB did not have the authority to establish new
31 deferral and variance accounts during the interim period, OPG did not, unlike other regulated
32 utilities, have the option to apply for a change in payment amounts or for an accounting

1 order. Therefore the actions by the government in establishing the nuclear liability and new
2 nuclear variance accounts responded to the regulatory reality at the time. CCC placed
3 particular emphasis upon the fact that OPG has a deferral account to record developmental
4 costs preliminary to new generation, claiming that this was a level of protection that “no
5 private owner has.” With respect, CCC’s claim is incorrect. The un-contradicted and
6 unchallenged evidence in this hearing is that private nuclear generation companies will not
7 undertake new plant construction without the assurance of recovery of new generation
8 development costs (Tr. Vol. 12, pages 75-76).

9
10 Two intervenors (CCC, AMPCO) took issue with OPG’s argument that it faces higher
11 regulatory and political risk than the typical utility. Ms. McShane was not alone in the
12 assessment of the regulatory and political risk faced by OPG. On the issue of regulatory risk,
13 Board Staff’s witness, Mr. Goulding, agreed that the lack of clearly established rules and
14 procedures makes it difficult for OPG to assess the durability of the current regulatory
15 regime. Even with the best faith in the world in the OEB, no one can predict with certainty the
16 evolution of the way in which the prescribed assets will be regulated. Common sense tells us
17 that if you are doing something for the first time, the potential for making a mistake or getting
18 it wrong is simply higher. Regulation only becomes a mitigating factor with respect to
19 business risk, Mr. Goulding said, to the extent that the regulatory regime becomes
20 established and predictable (Tr. Vol. 12, pages 119-120). Mr. Goulding’s comments with
21 respect to regulatory risk are consistent with the conclusions drawn by Ms. McShane.
22 AMPCO completely mis-characterizes OPG’s argument on regulatory risk as an attack on
23 the OEB’s competence or integrity. This is nonsense. OPG is not impugning the OEB’s
24 competence or integrity at all. It is simply making the rather obvious point that because this is
25 brand new, regulatory risks will remain higher until there is an established track record.

26
27 Similar to Ms. McShane, Mr. Goulding also recognized the level of political risk to which OPG
28 is exposed. Mr. Goulding testified:

29
30 One of the biggest risks facing power sector investors in Ontario today is
31 the frequency with which government policies are changed, even during
32 the same administration. While all power sector assets in the province
33 face this risk, in some ways the risk is greater for the prescribed assets.
34 To the extent that OPG is viewed as a tool for keeping electricity prices

1 low, rather than as an investment of taxpayers' money which needs to
2 earn an appropriate commercial return, there is the potential for pricing of
3 output from the prescribed assets to be affected.(Ex. M-T1, pages 31-32)
4

5 Return on Equity

6 In its argument-in-chief, OPG noted that the opinions of Drs. Booth, Kryzanowski and
7 Roberts all suffered from a fundamental contradiction. Having all agreed with Ms. McShane
8 and Mr. Goulding that generation, and especially nuclear generation, was riskier than
9 transmission, distribution and vertically integrated utility services, and having acknowledged
10 the ROEs awarded by regulators to other utilities in Ontario and elsewhere, they still each
11 conclude with recommendations that put OPG's ROE substantially below that of any other
12 regulated utility in Canada. Neither CCC, the sponsor of Dr. Booth, nor Pollution Probe, the
13 sponsor of Drs. Kryzanowski and Roberts, responded to or explained this contradiction.
14

15 The CME proposal that OPG's return should not exceed Hydro One Distribution's 8.57
16 percent stands the issue on its head. The issue is not that OPG's ROE should be *no more*
17 than Hydro One Distribution, but that OPG's ROE *must be more* than Hydro One Distribution.
18

19 SEC's argument on ROE is another example of how intervenors struggled with this
20 contradiction and how often it led them to puzzling conclusions. After criticizing Dr. Booth's
21 view that the ROEs of all Canadian utilities are too high and concluding that Dr. Booth's
22 recommendation of 7.75 percent is "too low", SEC goes on to praise Drs. Kryzanowski and
23 Roberts' supposedly "unbiased"¹ approach and adopts their recommended ROEs of 7.35
24 percent and 7.40 percent for 2008 and 2009, respectively.
25

26 In the balance of this portion of the reply, OPG will respond to the various criticisms of Ms.
27 McShane's recommendations on ROE.
28

29 Capital Asset Pricing Model

30 All of the witnesses who provided explicit estimates of the cost of equity (Ms. McShane, Dr.
31 Booth, Drs. Kryzanowski and Roberts, and Dr. Schwartz) applied the Capital Asset Pricing
32 Model ("CAPM"). However, while Ms. McShane relied on the CAPM as one of five tests, the

¹ Drs. Kryzanowski and Roberts' opinion is not unbiased. Their market risk premium is downwardly biased as found by the NWT Public Utilities Commission.

1 others used CAPM either exclusively or gave it preponderant weight. The focus of the CAPM
2 [Risk-free Rate + Beta (Market Risk Premium)] is the minimum return that will allow a
3 company to attract capital (Ex. C2-T1-S1, page 25). Most intervenors, however, argued
4 against the use of any test other than the CAPM.

5
6 The conceptual and empirical problems with CAPM documented by well-known and
7 respected finance experts were summarized by Ms. McShane (Ex. C2-T1-S1, pages 152-
8 154). For example, “Empirical tests of the CAPM have, in retrospect, produced results that
9 are often at odds with the theory itself.”² “The attraction of the CAPM is that it offers powerful
10 and intuitively pleasing predictions about how to measure risk and the relation between
11 expected return and risk. Unfortunately, the empirical record of the model is poor – poor
12 enough to invalidate the way it is used in applications.”³ “Beta, the risk measure from the
13 capital-asset pricing model, looks nice on the surface. It is a simple, easy-to-understand
14 measure of market sensitivity. Alas, beta also has its warts. The actual relationship between
15 beta and rate of return has not corresponded to the relationship predicted in theory during
16 long periods of the twentieth century.”⁴ “Beta is not very useful for determining the expected
17 return on a stock, and it actually has nothing to say about the CAPM. For many years, we
18 have been under the illusion that the CAPM is the same as finding that beta and expected
19 returns are related to each other. That is true as a theoretical and philosophical tautology, but
20 pragmatically, they are miles apart.”⁵

21
22 Pollution Probe cites Drs. Kryzanowski and Roberts’ criticism of the analysis Ms. McShane
23 performed which showed that, over the long-term there was no relationship between beta
24 and market risk premium (Tr. Vol. 13, pages 51-55). OPG submits, however, that the results
25 of Ms. McShane’s analysis are clearly consistent with the concerns with CAPM cited by Dr.
26 Malkiel above. Further, even if some tests of the CAPM have shown there is a positive risk
27 premium above the risk-free rate (Tr. Vol. 13, page 55), the link between this very broad

² Diana R. Harrington, *Modern Portfolio Theory, The Capital Asset Pricing Model & Arbitrage Pricing Theory: A User’s Guide*, Second Edition, Prentice-Hall, Inc., 1987, page 188, cited at Ex. C2-T1-S1, page 152.

³ Fama and French, “The CAPM: Theory and Evidence”, *Journal of Economic Perspectives*, Volume 18, Number 3 (Summer 2004), pages 25-26, cited at Ex. C2-T1-S1, pages 152-153.

⁴ Burton Malkiel, *A Random Walk Down Wall Street*, New York: W. W. Norton & Co., 2003, page 240, cited at Ex. C2-T1-S1, page 153.

⁵ Dr. Stephen A. Ross, “Is Beta Useful?” *The CAPM Controversy: Policy and Strategy Implications for Investment Management*, AIMR, 1993, cited at Ex. C2-T1-S1, page 154.

1 conclusion and the specification of a market risk premium and beta that will produce a
2 compensatory ROE is tenuous at best.

3
4 Ms. McShane acknowledged that the CAPM was the most popular method for estimating the
5 cost of equity (Tr. Vol. 10, pages 152-153). This was indicated in an article cited by Drs.
6 Kryzanowski and Roberts and put to Ms. McShane by Mr. Klippenstein. Notably, the same
7 article also states, "While the CAPM is popular, we show later that it is not clear that the
8 model is applied properly in practice. Of course, even if it is applied properly, it is not clear
9 that the CAPM is a very good model." Ms. McShane also pointed out that most firms that use
10 CAPM use it for the purpose of evaluating potential investments and have the flexibility of
11 varying the inputs to test the sensitivity of the results (Tr. Vol. 10, pages 152-153).

12
13 OPG submits that, while CAPM is useful, the OEB should not place sole reliance on this
14 model. The recognized conceptual and empirical problems with the CAPM require that the
15 Board look both to other cost of equity models, as well as to less technical, but no less
16 informative, perspectives (e.g., the perspectives of capital market participants as discussed
17 in Ex. C2-T1-S1, pages 101-106) on a fair return when setting the allowed ROE for OPG.

18
19 Risk-Free Rate

20 Of the four witnesses who applied the CAPM or other risk-premium tests, only one, Dr.
21 Schwartz on behalf of Energy Probe, relied on a short-term (Treasury Bill) yield. All of the
22 others relied on the long-term Government of Canada bond yield. Dr. Booth agreed with Ms.
23 McShane with respect to use of the long-term rather than the short-term yield for the purpose
24 of establishing the allowed ROE. "Because what we're looking at here is an equity
25 investment, and the equity investment has a long maturity and you should be looking at a
26 risk-free rate that is not susceptible to short-run monetary policy" (Tr. Vol. 13, pages 173-
27 174).

28
29 With respect to the level of the long-term risk-free rate, three different forecasts were
30 provided: in her update, Ms. McShane used a single forecast rate of 4.5 percent (Tr. Vol.10,
31 pages 10-12); Dr. Booth used a single long-term rate of 4.75 percent; and Dr. Kryzanowski
32 and Roberts used separate forecasts for 2008 and 2009 of 4.10 percent and 4.40 percent,

1 respectively. OPG submits that Drs. Kryzanowski and Roberts' forecast is understated. Drs.
2 Kryzanowski and Roberts include in their forecast for 2008 months that are not even part of
3 OPG's test period (January to March 2008). Their 2009 forecast assumes that the full year
4 yield on 10-year Canada bonds will be equal to the Consensus Forecast of 3.9 percent for
5 May 2009. Their forecast for 2009 ignores the expectation that government bond yields will
6 rise during 2009. As Ms. McShane testified, the Consensus Forecast expects the 10-year
7 Canada bond yield to be 5 percent in 2010, which "means that there was an expectation that
8 10-year bond yields would be rising throughout 2009 in order to get to 5 percent in 2010."
9 (Tr. Vol. 10, page 11). Ms. McShane's evidence demonstrated that the forecasts of rising
10 rates would result in 10-year and 30-year Canada bond yield forecasts of 4.2 percent and 4.7
11 percent respectively in 2009. Ms. McShane's evidence on the forecast long-term Canada
12 bond yield as updated, which lies in the middle of the range of the experts' forecasts, was not
13 challenged. OPG submits that the OEB should accept Ms. McShane's forecast long-term
14 Canada bond yield of 4.5 percent for the test period in the application of the CAPM, as well
15 as for the application of the other two equity risk premium tests that she applied.

16
17 Market Risk Premium

18 Ms. McShane estimated the equity market risk premium at 6.5 percent; Dr. Booth and Drs.
19 Kryzanowski and Roberts estimated the market risk premium at five percent. All three of
20 these estimates were in relation to the long-term government bond yield.

21
22 CCC in final argument claims that Ms. McShane's 6.5 percent is derived predominantly from
23 U.S. data and that you have to go back to the early 1950s to get a risk premium above five
24 percent (CCC argument, para. 32). Pollution Probe cited the evidence of Drs. Kryzanowski
25 and Roberts, which "enumerates a number of adjustments made by Ms. McShane in her
26 CAPM tests that artificially inflate her rate of return estimate" (Pollution Probe argument,
27 page 5). Drs. Kryzanowski and Roberts claimed that Ms. McShane did not adjust her market
28 risk premium downward for the time series decline in risk premiums and the expectation that
29 the market risk premium will be lower in the future than in the past and that she chose an
30 inappropriate period over which to measure the risk premium (Ex. M-T12, pages 112-113).
31 Energy Probe indicates that Ms. McShane's 6.5 percent is too high because the long-term
32 observed premium over Treasury Bills was approximately equal to 6.5 percent and the

1 premium over long-term government bond yields has to be lower than the premium over
2 Treasury Bills (Energy Probe argument, paras.46 and 52).

3
4 CCC is incorrect when it claims that Ms. McShane's 6.5 percent market risk premium is
5 derived predominantly from U.S. data. The Canadian experience alone, when the risk and
6 return differences between the historic and current government bond market are
7 appropriately accounted for, supports Ms. McShane's 6.5 percent estimate of the market risk
8 premium.

9
10 Drs. Kryzanowski and Roberts demonstrate that, historically, stock returns in Canada have
11 been consistently in the range of 11.2 to 11.6 percent (Ex. M-T12, Schedule 4.3, page 112).
12 Ms. McShane's testimony showed a similar consistency in Canadian equity market returns
13 over time (Ex. C2-T1-S1, Appendix C, pages 145-148). Drs. Kryzanowski and Roberts'
14 Schedule 4.3 also shows increasing bond returns over shorter and shorter time series. This
15 too is consistent with Ms. McShane's data (Ex. C1-T1-S1, page 150).

16 The bond part of the measured market risk premium has been considerably higher than it is
17 expected to be in the future. However, on the equity market return side of the equation, there
18 has not been a downward or upward trend in the returns. The actual achieved equity returns
19 have remained relatively constant.

20
21 It is, therefore, the interplay of the consistent stock returns and increasing long Canada
22 returns that has tended to shrink the achieved market equity risk premium. However, forecast
23 long Canada yields are much lower than they have been in the recent past (Tr. Vol. 13, page
24 113). As a result, the Kryzanowski and Roberts estimated market equity risk premium is
25 downwardly biased. They have not given sufficient recognition to market equity risk premium
26 increases resulting from lower anticipated bond market returns. This was exactly the finding,
27 on identical evidence presented by Drs. Kryzanowski and Roberts, made by the Public
28 Utilities Board of the Northwest Territories (Tr. Vol.13, page 115). It said:

29
30 The Board considers Drs. Kryzanowski and Roberts estimated market
31 equity risk premium to be downwardly biased since the witnesses do not
32 appear to have given recognition to market equity risk premium increases

1 resulting from lower prospective bond market returns compared to the
2 historic. (Tr. Vol. 13, pages 115-116)

3
4 With Ms. McShane's updated forecast long-term Canada bond yield at 4.5 percent and no
5 evidence of a decline in stock returns over time, the Kryzanowski and Roberts' Canadian
6 stock market returns (11.2-11.6 percent) actually support an equity market risk premium over
7 long-term Canada bonds in excess of the 6.5 percent market risk premium estimated by Ms.
8 McShane.

9
10 The evidence of Dr. Booth pointed to the same factors as Ms. McShane. He testified that, in
11 his judgment, equity market risk has been relatively stable over time (Ex. M-T3, Appendix E,
12 page 9). This statement supports the conclusion that there has been no decline in the
13 expected equity market returns. Dr. Booth further stated that bond market risk increased over
14 the 1956-2007 period compared to earlier periods (Ex. M-T3, Appendix E, page 9), but that
15 over the last 10 years as governments have got their budgets under control, uncertainty in
16 the bond market has declined. Dr. Booth stated that "In my judgment with a current small
17 budget surplus and long Canada bond yields at the 4 percent level similar to where they
18 were in the late 1950s we have an economic scenario unlike any period since that time" (Ex.
19 M-T3, Appendix E, page 12). This statement supports the conclusion that bond returns going
20 forward are expected to be lower than they were historically.

21
22 Thus, Dr. Booth's evidence on this issue leads to a similar conclusion to Ms. McShane's: the
23 Canadian equity risk premium under current capital market conditions is higher than the
24 observed risk premium. The principal difference between the two is, 'how much higher?' Dr.
25 Booth says the market risk premium is five percent; Ms. McShane estimates it at 6.5 percent.
26 If equity risk and equity returns have been stable, future equity market returns should be in
27 their historic range, indicated above to be in the 11.2 percent to 11.6 percent range. If the
28 government bond market is less risky today than historically, then historic government bond
29 returns overstate the expected return. An expected bond return equal to the forecast yield
30 places the government bond return at approximately 4.5 percent. The conclusion that must
31 be drawn is that the equity risk premium is materially higher than the five percent Dr. Booth
32 estimated, and is at least 6.5 percent.

33

1 Pollution Probe also argues that Ms. McShane used an inappropriate period for the
2 estimation of the market risk premium, that is, she should not have included the period right
3 after World War II, due to pent-up demand and equity market exuberance. However, as Ms.
4 McShane noted in response to Ex. L-12-13, "On its own the economic activity of the first few
5 years after World War II and the impact on equity market returns is not necessarily more or
6 less representative of what may happen in the future as regards equity market performance
7 than any other sub-period dating from 1947. (The first five years of this period, 1947 to 1951,
8 also included three periods identified by the *Canadian Economic Observer* as recessions.)"
9 In cross-examination by Mr. Klippenstein, she indicated that most historic sub-periods have
10 some unique characteristics; she specifically pointed to 1974 to 1980, when there were very
11 high rates of inflation, the two very deep recessions in 1981-82 and 1991-1992, a secular
12 decline in the rate of inflation, starting in the early nineties, and a huge equity market bubble
13 which burst in 2000 (Tr. Vol. 10, page 149). Removing specific historic sub-periods either
14 because the equity returns may appear to "too high" or "too low" would, in OPG's
15 submission, amount to inappropriate cherry-picking.

16
17 Beta

18 Ms. McShane relied on a relative risk adjustment of 0.65-0.70 for a benchmark utility. Dr.
19 Booth and Drs. Kryzanowski and Roberts used a beta of 0.50.

20
21 Ms. McShane uses adjusted betas. CCC claims that that Dr. Booth also uses adjusted betas,
22 but concludes that Ms. McShane's adjustment is too large (CCC argument, para. 33).
23 Pollution Probe references Drs. Kryzanowski and Roberts' critique of Ms. McShane's CAPM
24 (Energy Probe argument, page. 5), which concluded that no adjustment to "raw" betas is
25 warranted (Ex. M-T12, page 112).

26
27 In OPG's submission, the betas used by Dr. Booth and Drs. Kryzanowski and Roberts are
28 too low and understate the equity return requirement for a benchmark utility. While Dr. Booth
29 describes the beta he uses as an adjusted beta, all he has done is rely on longer-term
30 averages of "raw beta" rather than the most recently observed lower "raw betas" (Ex. M-T3,
31 pages 64-70). Since Drs. Kryzanowski and Roberts also base their beta estimate on longer-

1 term average “raw betas” (Ex. M-T12, pages 86-87), it is no surprise that they end up with
2 the same beta as Dr. Booth of 0.50.

3
4 In arriving at the appropriate risk adjustment, the first step is to recognize the objective of the
5 exercise: to predict the investors’ required return. Raw betas are nothing more than a
6 calculated correlation between the stock price movements of a stock and the market index
7 (relative volatility) (Ex. C2-T1-S1, page 151). The body of evidence on CAPM leads to the
8 conclusion that, while betas do measure relative volatility, the proportionate relationship
9 between beta and return posited by the CAPM has not been established (Ex. C2-T1-S1,
10 page 152).

11
12 There is more to determining what specific return is required to induce an investor to invest
13 than just beta. Beta does not reveal the full risk of any particular investment. As Ms.
14 McShane said: “Gold stocks, for example, which are regarded as a quintessential counter-
15 cyclical investment, could reasonably be expected to exhibit negative betas. In that case, the
16 CAPM would posit that the cost of equity capital for a gold mining firm would be less than the
17 risk-free rate, despite the fact that, on a total risk basis, the company’s stock could be very
18 volatile” (Ex. C2-T1-S1, page 152). However, common sense tells us that investors in risky
19 gold mining stocks do not accept a return less than the risk-free rate simply because gold
20 mining stocks are counter-cyclical. No one invests in gold mining stocks in expectation of a
21 return below the risk free rate.

22
23 Use of adjusted betas implicitly recognizes that “raw” utility betas do not adequately explain
24 utility returns; their use mitigates the deficiencies in raw betas as a predictor of future returns
25 (Ex. C2-T1-S1, page 35). Moreover, Ms. McShane’s relative risk adjustment of 0.65-0.70
26 based on adjusted betas was supported by her analysis of relative total market risk
27 measured by the ratio of the standard deviation of the market returns of the S&P/TSX Utility
28 Index to the standard deviation of market returns of all the major industry sectors of the
29 Canadian equity market composite (Ex. C2-T1-S1, page 32).

30

1 It is also worth noting that Ex. K11.3, page 11, the CIBC Bruce Power fairness opinion,
2 estimated betas for operating companies with nuclear exposure in the 0.65 to 0.90 range,
3 higher than the 0.65-0.70 used by Ms. McShane to estimate the ROE for OPG.

4
5 Discounted Cash Flow Method

6 Pollution Probe stated that Ms. McShane appears not to have adjusted the DCF results for
7 optimism bias in analysts' forecasts. In fact, Ms. McShane did test for optimism bias in her
8 sample and found the utility forecasts not to be systematically optimistic. Thus, there was no
9 reason to adjust for optimism bias because there is no evidence that it exists, or that there is
10 even any reason for it to exist, in the utility context.

11
12 CCC concluded that "to accept Ms. McShane's DCF estimates would require the Board to
13 accept estimates known to be biased high" (CCC argument, para. 34). That is not the case.
14 There is no evidence that analysts' projections of utility stocks are upwardly biased.

15
16 Ms. McShane stated, in response to Ex. L-12-36, "optimism bias is least likely to impact
17 relatively stable industries and companies like utilities where the business model and
18 potential outcomes in terms of earnings are well understood. A relatively recent study entitled
19 "The Level and Persistence of Growth Rates", *Journal of Finance*, Vol. LVIII, No. 2, 2003 by
20 Chan, Louis C., Karceski, Jason and Lakonishok, Josef, which divided all U.S. stocks with
21 available I/B/E/S growth rates into value-weighted portfolios found that the companies with
22 the highest expected growth rates had actual growth rates in excess of the levels forecast
23 five years previously, but the lowest growth portfolio (where utilities would fall) did not exhibit
24 the same tendency."

25
26 In response to Ex. L-12-21, she noted that the "BCUC, in its March 2006 decision (Order No.
27 G-14-06) for Terasen Gas and Terasen Gas (Vancouver Island), concluded 'The major
28 criticism of the DCF method is that it relies on analysts' forecasts, which may be biased
29 upwards. The Commission Panel does not find Dr. Booth's comments helpful in that his
30 observations mostly cover U.S. technology analysts and the scandal on Wall Street
31 concerning inappropriate analyst behaviour in an investment banking milieu. The
32 Commission Panel finds that Dr. Booth's use of DCF estimates for U.S. utilities covered by

1 Standard & Poors, which included “multi-utilities” and energy marketing firms, should not be
2 used as representative of U.S. utility returns. The Commission Panel is more persuaded by
3 Ms. McShane’s evidence which compares Value Line and I/B/E/S forecasts and finds no
4 upward bias in the latter.’ Value Line is an independent research firm which neither buys nor
5 sells securities. It thus has no incentive to “inflate” its estimates of earnings growth in an
6 attempt to make stocks more attractive to investors.”

7
8 Ms. McShane also noted in response to Ex. L-12-36 that “the DCF model continues to be the
9 primary model relied upon by U.S. regulators, who presumably are aware of, and have
10 considered, the evidence as it specifically regards utilities and continue to find the DCF
11 evidence based on analysts’ forecasts compelling.”

12
13 OPG submits that Ms. McShane’s application of the DCF test is appropriate and the results
14 (10.0-10.5 percent inclusive of a 0.50 percent allowance for financing flexibility) are
15 reasonable and should be given weight by the Board.

16
17 Comparable Earnings Test

18 CCC and Pollution Probe contend that the OEB should not rely on the comparable earnings
19 test results. They raise a number of technical issues, all of which are addressed in the
20 evidence. At its core, however, the usefulness of this test is measured in the context of the
21 Fair Return Standard and the fact that none of the tests is perfect; they all have their warts.

22
23 For example, several of the critiques mentioned by Drs. Kryzanowski and Roberts are
24 equally applicable to the CAPM including their concerns that: 1) there is no agreement on
25 what time period should be used; 2) there is no agreement on how structural changes in the
26 economy or the number of economic sectors in the economy should be dealt with; and 3)
27 rates of return are backward looking.

28
29 Drs. Kryzanowski and Roberts also criticized the comparable earnings approach because, as
30 an accounting-based measure, the results will only coincide with the investor’s opportunity
31 cost (desired rate of return) by accident. Ms. McShane acknowledged that the comparable
32 earnings test does not measure the investor’s opportunity cost of attracting equity capital as

1 measured relative to market values. It does, however, provide a measure of the fair return
2 based on the concept of opportunity cost. Specifically, the test arises from the notion that
3 capital should not be committed to a venture unless it can earn a return commensurate with
4 that available prospectively in alternative ventures of comparable risk. Since regulation is a
5 surrogate for competition, the opportunity cost principle entails permitting utilities the
6 opportunity to earn a return commensurate with the levels achievable by competitive firms
7 facing similar risk.

8
9 Ms. McShane summed up her assessment of the comparable earnings test and its
10 importance in setting a fair return in her evidence-in-chief.

11
12 At the outset, the key, to me, is that -- the test is one which would only
13 apply in a regulated environment, and only apply in a regulated
14 environment where the regulatory construct is original cost.

15 I don't make the claim that comparable earnings is perfect. Indeed,
16 none of the tests that we tend to use to estimate the return are perfect.
17 Each of them has significant hurdles that have to be overcome. Drs.
18 Kryzanowski and Roberts list some of these hurdles.

19 A number of these hurdles are similar to the hurdles that are faced by
20 other tests, and I don't believe that the hurdles with respect to comparable
21 earnings are insurmountable.

22 Ultimately, I believe that each test, including comparable earnings
23 tests, should be given some weight to ensure that the allowed return rests
24 on a solid foundation and, indeed, is consistent with the fair return
25 standard. (Tr. Vol. 10, pages 22-23)

26
27 In addition, since most of the regulatory pronouncements relied upon by intervenors rejecting
28 the use of the comparable earning test were made, there has emerged a significant body of
29 research and commentary on the fact that the formula-based return methodology, which
30 drives off the CAPM approach, has produced returns which are too low as compared to the
31 U.S., where the formula and CAPM approach are not the dominant means of determining a
32 fair return (Ex. K12.3, Tabs 3-8). This at least raises questions about reliance solely on the
33 CAPM as the exclusive determinant of a fair return.

34
35 OPG agrees with Ms. McShane's approach and urges the Board to recognize the usefulness
36 of comparable earnings in establishing the fair return on equity. As noted in her testimony,

1 use of this test is consistent with the requirement to apply the fair return standard (OPG
2 argument-in-chief, pages 14-15).

3
4 Financing Flexibility

5 AMPCO (AMPCO argument, para. 86) and Energy Probe (Energy Probe argument, para. 58)
6 took the position that, because OPG will not be in the equity markets and may not be in the
7 debt markets, an allowance for financing flexibility is not warranted in this case. Ms.
8 McShane and Drs. Booth, Kryzanowski and Roberts, however, all recommend a 50 basis
9 point allowance for financing flexibility. The only witness who took issue with an allowance for
10 financing flexibility was Dr. Schwartz, an economist with no experience with deemed capital
11 structures or determining the cost of equity for rate regulated entities in Canada.

12
13 The 50 basis point allowance for financing flexibility does not turn on whether the utility is
14 actually forecast to enter the market or not. Appendix G to Ms. McShane's evidence (Ex. C2-
15 T1-S1, pages 181-186) discusses this issue in detail. Among other things, the financing
16 flexibility allowance is a margin for unanticipated market conditions.

17
18 As well, the adjustment for financing flexibility recognizes the basic principle of regulation,
19 that the market return derived from the equity risk premium test needs to be translated into a
20 return that is fair and reasonable when applied to book value. This premise was recognized
21 by the Independent Assessment Team ("IAT") retained by the Alberta Department of
22 Resource Development to determine cost parameters for power purchase agreements. The
23 holders of those agreements were also not actually in the financial markets but their implicit
24 cost of capital included an allowance for financing flexibility. The IAT said of this allowance
25 that:

26
27 This is sometimes associated with flotation costs but is more properly
28 regarded as providing a financial cushion which is particularly applicable
29 given the historic cost book value in rate of return regulation in Canada.

30
31 Hydro One and all of the municipal electric Local Distribution Companies ("LDCs") in Ontario
32 receive a 50 basis point allowance for financing flexibility. OPG's position is no different than
33 theirs and so should receive the same treatment. The same allowance was also awarded to

1 all utilities (including government-owned utilities that were not going to be entering the equity
2 markets) in the Alberta generic cost of capital decision.

3
4 In sum, OPG submits there is no evidence to support, and no justification for, denying to
5 OPG the allowance for financing flexibility awarded to every other regulated utility in Canada.

6
7 Technology-Specific Cost of Capital

8 The majority of intervenors take no position on the issue of technology-specific capital
9 structure, including VECC, CCC, Energy Probe, AMPCO and PWU. CME took the position
10 that it is unnecessary to set separate capital structures for the purposes of establishing
11 payments amounts. Only Pollution Probe and GEC submitted that the OEB should approve
12 technology-specific costs of capital. OPG's argument-in-chief has already set out its basic
13 position against the need for two capital structures.

14
15 GEC argued that four "benefits" would result from the application of a technology-specific
16 cost of capital. OPG submits that each of these purported benefits either do not exist or are
17 of little significance.

18
19 1. "Operating decisions can better reflect the high value of nuclear performance." GEC
20 is claiming that application of a higher cost of capital to the nuclear assets provides
21 an incentive to maximize nuclear production but provides no evidence to support its
22 conclusion that a higher nuclear payment amount would impact operating decisions.
23 OPG sets challenging production targets for its nuclear facilities and has placed
24 considerable emphasis on programs to enable it to meet those targets (Ex. L-1-32;
25 Ex. F2-T2-S1, page 26, Section 3.2; Ex. E2-T1-S1, page 14, Section 4.0). Both the
26 production targets and work programs are subject to scrutiny through OEB
27 proceedings, enabling stakeholders to assess OPG's "approach to maintenance"
28 (GEC argument, page 4). In any event, OPG has a strong incentive to maximize its
29 nuclear production with a payment amount based on single capital structure and a 25
30 percent fixed monthly payment (OPG argument-in-chief, page 90).

31

1 2. “Capital investment decisions (both routine and extraordinary) can reflect true costs
2 and risks.” OPG disagrees. Use of technology-specific discount rates will result in a
3 less precise assessment of project-specific risks than OPG’s methods (i.e., including
4 factoring project specific risks into the assessment of project cash flows). GEC
5 alleges that “OPG appears to be reluctant to be rigorous in its consideration of risk
6 when analyzing investments” (GEC argument, page 6). GEC offers no evidence to
7 support this accusation, because there is none. OPG takes the consideration of risk
8 very seriously. OPG’s approach reflects an appropriate balance between quantitative
9 and qualitative risk assessment and, in appropriate cases, incorporates a more
10 precise project-specific risk assessment in significant projects. This, in fact provides
11 more rigor than the technology-specific approach proposed by GEC. And in the case
12 where projects are regulatory or mandated by the CNSC a technology-specific
13 discount rate would have no effect on the investment decision.

14
15 3. “Electricity prices can be smoothed” by eliminating deferral and variance accounts.
16 This “benefit” is totally unrelated to the issue of whether a separate cost of capital
17 should be established by technology, and may result in unnecessarily high costs to
18 customers as the increased business risk would need to be factored into OPG’s cost
19 of capital and payment amounts.

20
21 4. “Regulatory efficiency” allegedly increases by providing for changes in the annual
22 cost of capital which will reflect the changing proportion of nuclear and hydroelectric
23 assets. OPG’s asset mix is forecast to remain stable during the test period; therefore
24 any adjustment to a single cost of capital would be inconsequential.

25
26 In summary, neither the rationale nor the empirical analysis in support of separate costs of
27 capital is adequate to depart from OPG’s proposal to set a single capital structure and ROE
28 for its prescribed assets.

29
30 **5. Importance of an ‘A’ Credit Rating**

31 Board Staff questioned the necessity of setting a capital structure which would allow OPG to
32 attain ratings in the ‘A’ category, suggesting that there is evidence to suggest that a lower

1 credit rating does not impair the ability of a company such as OPG to access capital (Board
2 Staff submission, pages 29-30). Of the intervenors, only Pollution Probe and PWU
3 addressed the issue of credit ratings. Pollution Probe concluded that little weight should be
4 accorded to the alleged requirement that OPG would require a rating above a 'BBB'
5 (Pollution Probe argument, page 6). The PWU argue the importance of an 'A' credit rating to
6 ensure OPG's ability to raise funds on reasonable terms and conditions (PWU argument,
7 paras. 21-28).

8
9 OPG makes three points in response to the submission of Board Staff. First, the fact that
10 there is no hard evidence of a 'BBB' rated company not being able to raise debt is hardly
11 surprising, since no company would issue a press release or make public the fact that its
12 proposal to raise debt had been declined. So it is simply not correct to conclude that the
13 absence of any articles in the Report on Business about 'BBB' rated companies' difficulties
14 raising debt means that it has not happened.

15
16 Second, the comparable utilities in Canada all have 'A' ratings. OPG submits that an 'A'
17 credit rating is a very material consideration in the determination of capital structure; the
18 determination of the capital structure consistent with an 'A' rating allows the ROE determined
19 by reference to 'A'-rated comparators to be applied to OPG. If the OEB sets a capital
20 structure with a higher debt ratio than recommended by OPG, that is, one consistent with a
21 'BBB' rating, then OPG will be a higher risk company. The cost of capital would thus need to
22 be higher than proposed, as the cost of capital reflects the total business and financial risk.
23 Ms. McShane's analysis demonstrated that the required cost of equity for OPG at a 45
24 percent common equity ratio would be approximately 1.5 percent higher than with the
25 proposed 57.5 percent common equity ratio (Ex. C2-T1-S1, page 95).

26
27 Ms. McShane's evidence (Ex. C2-T1-S1, Schedule 26), in which she provides the debt
28 ratings for 24 Canadian utilities, demonstrates that an 'A' rating is the rule and 'BBB' ratings
29 are the exception. Of the six utilities cited by Board Staff in their submission (page 29), all but
30 PNG have one rating in the 'A' category. Although access issues by individual Canadian
31 utilities may not be explicitly documented, the mere fact that 'A' ratings are the rule and 'BBB'
32 ratings the exception strongly suggests the importance of 'A' ratings to ensure continuous

1 access to capital on reasonable terms and conditions. Further, the small size of the 'BBB'
2 debt market in Canada referenced by Ms. McShane (Ex. C2-T1-S1, page 7; Tr. Vol. 10,
3 pages 15-16) and the smaller volume of 'BBB' issues for terms in excess of 10 years (Tr. Vol.
4 10, page 16) both support the conclusion that an 'A' rating is warranted to ensure access to
5 the long term debt markets. Drs. Kryzanowski and Roberts also admitted that the market for
6 'BBB' debt in Canada is very small and that 'BBB'-rated companies typically pay more for
7 debt than 'A'-rated companies (Tr. Vol. 13, pages 63-64).

8
9 Third, the 'BBB' market is more costly than the 'A' market in Canada. The cost of 'BBB'-rated
10 utility debt in Canada, as Ms. McShane testified, has been as much as 175 basis points more
11 than 'A'-rated utility debt (Ex. C2-T1-S1, page 80). To put this in perspective, for every
12 \$100M in 30-year debt, a 175 basis point premium for 'BBB' debt would cost ratepayers an
13 additional \$52.5M in debt costs, as that additional cost would be borne over the full term of
14 the debt. It must be emphasized as well that although OPG has obtained its required
15 borrowings to date from the Ontario Electricity Financial Corporation ("OEFC"), it may not
16 continue to do so in the future. In any event, the interest rate on OEFC debt is a market-
17 related estimate, established through an objective formula that incorporates independent
18 credit risk and long-term debt information based on notional "ratings" by commercial banks.

19
20 The conclusion that an 'A' rating is an appropriate target is strengthened by the potential
21 unprecedented capital expenditures that OPG may incur for regulated generation at the
22 same time as the electricity industry throughout North America needs to access massive
23 amounts of capital for infrastructure investment (Ex. C2-T1-S1, page 99). In that context, in
24 OPG's submission, taking the risk that a 'BBB' rating will be adequate for consistent access
25 to the debt markets on reasonable terms and conditions is unwarranted.

26 27 **Issue 2.3**

28 **Is it appropriate to establish a formula for an adjustment mechanism? Is the formula**
29 **proposed appropriate?**

30
31 Only two intervenors (CME and SEC) made submissions on this issue. Both supported use
32 of the adjustment mechanism.

1

2 CME made one additional comment. It stated that it did not see a need to predetermine that
3 the formula would need to be reviewed once long Canada bond yields reached a certain
4 level. While OPG endorsed Ms. McShane's view that the formula should be reviewed if
5 forecast bond yields were outside of the three to eight percent range, it accepts that there is
6 no immediate need to set out the circumstances under which it would be appropriate to
7 review the formula. As indicated in its argument-in-chief, OPG will seek a review of the
8 formula returns should its business risk or access to capital change materially. A change in
9 its ability to access capital could be triggered by significant changes in capital market
10 conditions.

11

12 For the reasons set out in its evidence and argument-in-chief, and in light of the fact that
13 there are no objections from intervenors, the Board should approve the future use of the
14 automatic adjustment mechanism for OPG.

15

16 **Issue 2.4**

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

19

20 Only four intervenors made submissions on this issue (AMPCO, CME, Energy Probe and
21 SEC). Their submissions are addressed below.

22

23 Short-Term Debt Rate

24 AMPCO argues that the rates for OPG's commercial paper and accounts receivable
25 securitization are too high. It proposes instead that the Board adopt a rate of four percent on
26 OPG's short term debt on the basis that this rate is "more consistent with current conditions
27 in financial markets" (AMPCO argument, paras. 72-73). CME and SEC support AMPCO's
28 submissions. None of AMPCO's submissions on this issue are compelling nor are they
29 substantiated by any reference to evidence on the record.

30

31 As explained in the evidence, OPG uses its commercial paper and A/R securitization
32 programs as its main source of short-term financing (Ex. C1-T2-S3, page 1). OPG also has a

1 bank credit facility which can be relied upon if it is unable to access the commercial paper
2 market and needs another source of short-term funds at reasonable rates. The bank credit
3 facility has a forecast \$1.4M fixed cost which is independent of the amount borrowed (OPG
4 argument-in-chief, page 34). This facility is both a necessary part of having a commercial
5 paper program, since it provides protection to investors, and a prudent form of “insurance.”

6
7 AMPCO has inappropriately calculated an “implicit cost rate” of 8.4 percent for the
8 commercial paper program by rolling in the fixed cost of the program’s credit facility with the
9 forecast interest costs on the commercial paper. This type of calculation ignores the financial
10 security benefits of having the credit facility in place. It is noteworthy that AMPCO does not
11 contest the need for the bank credit facility nor the \$1.4M annual fixed cost to purchase the
12 protection that it offers. Neither has AMPCO provided evidence on the forecast commercial
13 paper rates that would allow an “apples to apples” comparison with OPG’s forecast rate.

14
15 The actual rate for the commercial paper program is forecast to be 5.13 percent in 2008 and
16 5.32 percent in 2009 (Ex C1-T2-S3, Table 1, line 2). As the evidence makes clear, these
17 rates are market-based, comprised of a 10 basis point dealer fee and a corporate spread
18 over the forecast bankers’ acceptances rate. OPG has used the Global Insight forecast
19 (December 2007) as the basis for its forecast after adjusting for the spread between bankers’
20 acceptances and the yield on treasury securities.

21
22 AMPCO’s submissions on the A/R securitization rate are unsubstantiated by any reference to
23 a recognized third party source. It simply concludes that the costs for this source of financing
24 are above current short-term interest rates. Importantly, AMPCO does not dispute the
25 method of forecasting the banker’s acceptance interest rate, OPG’s corporate risk spread or
26 the dealer fee.

27
28 OPG’s proposed short-term debt rates are reasonable and are based on well known
29 independent forecasts that have been filed in this proceeding. They therefore should be
30 accepted by the Board.

1 Long-Term Debt Rate

2 AMPCO argues that the Board should adopt a rate of 5.50 percent for the cost of OPG's
3 long-term debt in the test period (AMPCO argument, para. 70). This rate appears to be
4 based on an acceptance of the rates associated with OPG's existing debt, and an assumed
5 10-year long Canada bond rate of 4.25 percent and a credit risk spread of 75 basis points for
6 new debt. There are a number of problems with AMPCO's "estimate" of the cost of new debt
7 during the test period which produces its proposed rate.

8

9 AMPCO has seized upon the 75 basis point credit risk spread realized by OPG on its
10 Niagara Tunnel project financing in June of 2007. However, AMPCO ignores the fact that the
11 credit spreads that were available in June 2007 are not expected to be available in the test
12 period due to changed market conditions. OPG's evidence on credit spreads, which was
13 essentially unchallenged in the proceeding, showed that spreads have widened considerably
14 since June 2007 and are expected to remain substantial during the test period. The actual
15 credit spread reflected in OPG's most recent long-term borrowing rate was 168 basis points
16 (April 22, 2008 as per Ex. J1.2). This is considerably higher than the 130 basis point spread
17 used to forecast OPG's long-term debt rate and more than twice the June, 2007 rate that
18 AMPCO would recommend to the Board. Ex. J1.2 also references a May, 2008 issue by
19 Suncor Energy, which has a similar credit rating to OPG that included a 210 basis point
20 spread. This is further evidence of the actual capital market conditions that OPG is likely to
21 face during the test period. Given the weight of actual data, there is clearly no basis to accept
22 AMPCO's extremely low proposal on credit spreads.

23

24 In terms of the underlying long term debt rate, AMPCO assumes an average 10-year Canada
25 bond rate for 2008 and 2009 of 4.25 percent. There is however no evidence to support this.
26 AMPCO merely relies on its observation that it is lower than the rate used by Ms. McShane.
27 In contrast, OPG's forecast was based on a recognized, independent source – Global
28 Insight.

29

30 AMPCO also argues that Ontario electricity distributors are only permitted to recoup the
31 lower of a negotiated rate or market rates with respect to affiliate borrowing. They suggest
32 that this principle should also apply to OPG. The evidence was clear that OPG's

1 arrangements with OEFC use an estimate of market rates established through a formula that
2 incorporates objective and independent information (as described in OPG's argument-in-
3 chief, page 36). OPG is not "partially shielded from market disruptions like the recent credit
4 crunch" as a result of its ability to borrow from the OEFC and its ownership by the Province
5 as alleged by London Economics (Ex M, Tab 1, page 19). Given that OPG's rates are
6 established using an objective formula for estimating a market rate, rather than a negotiated
7 rate, there is nothing to AMPCO's argument. It appears to be made without regard to the
8 evidence in the hearing and should be disregarded by the Board.

9
10 Other Long-Term Debt Provision

11 Dr. Schwartz, on behalf of Energy Probe, took the view that the other long-term debt
12 provision arises only as an accounting adjustment and therefore is not subject to a trust
13 indenture and will not be serviced. Dr. Schwartz concluded that this provision is more
14 accurately treated as equity and not debt. Energy Probe adopts this approach but
15 recommends that the Board consider this amount to be ratepayer supplied capital and gives
16 it a zero percent cost rate.

17
18 Dr. Schwartz is clearly unfamiliar with regulatory cost of capital concepts. The use of a debt
19 provision to equate the proposed deemed capital structure to rate base is common practice
20 before the OEB. Treating this provision as ratepayer supplied capital and assigning it a zero
21 cost makes no sense and should be rejected by the Board. OPG finances long-term assets
22 in its rate base with long-term financing; therefore it is reasonable to apply a long-term debt
23 rate to reconcile the debt component of OPG's regulated capital structure with the proposed
24 rate base that financing supports. OPG has used its forecast, unhedged, average long-term
25 debt rate for 2008 and 2009 for this purpose.

26
27 **Issue 2.5**

28 **What are the implications of the deferral and variance accounts on OPG's financial**
29 **risk? How should the implications be considered when determining the appropriate**
30 **return on equity?**

1 Only two intervenors made submissions on this specific issue (CME and SEC). Other
2 intervenors made related submissions under the general issue of risk and those are
3 addressed under Issues 2.1 and 2.2.

4
5 CME expressed the general proposition that if the Board broadens the scope of deferral and
6 variance account coverage beyond that provided for under the Regulation, then OPG's
7 allowed equity ratio should be reduced. SEC submits that other than the water variance
8 account none of the other accounts, in its view, would have a material impact on risk and
9 therefore on ROE or capital structure. In addition, in their summary of the evidence, Board
10 Staff misstated OPG's position on certain items under this issue.

11
12 Given that the OEB is in the process of determining the appropriate commercial ROE and
13 capital structure for OPG in this proceeding, there is no logical basis for CME's proposal. As
14 for SEC's submission, OPG would note that they have advanced no evidence or analysis to
15 support their conclusions. As such, their submissions should be disregarded by the Board in
16 preference for the analysis put forward by OPG's cost of capital expert, Ms. McShane.

17
18 Board Staff incorrectly states that OPG is of the view that its proposed variance and deferral
19 accounts should have no impact on its awarded ROE or capital structure. OPG's evidence is
20 absolutely clear that Ms. McShane's recommendations on ROE and capital, which OPG has
21 adopted, are based on approval of the deferral and variance accounts that OPG has
22 proposed. And to the extent that it is possible to quantify, OPG has provided through Ms.
23 McShane the increase in ROE or capital structure that should result from a denial of OPG's
24 proposed deferral and variance accounts. This evidence is summarized in OPG's argument-
25 in-chief from pages 38-39.

26
27 OPG's argument-in-chief highlights Ms. McShane's view that a denial of recovery of costs
28 incurred prior to April 1, 2008 is a form of retroactive ratemaking which would have an
29 enormous one-time impact on OPG's net income and would likely be viewed by the
30 investment community as constituting a significant increase in regulatory risk and therefore
31 would increase the cost of capital. An additional incremental risk is that a denial of accounts
32 mandated in the Regulation would likely have a significant impact on the cost of capital,

1 which Ms. McShane did not have the information to quantify (Ex. J12.2). The latter
2 incremental risk is not constrained to whether or not the account is accepted by the OEB; it
3 applies also to the scope covered by the approved account. Intervenors have challenged the
4 scope of OPG's Nuclear Liabilities Deferral Account with respect to the return on rate base
5 associated with the change in OPG's asset retirement obligations (discussed in Issue 9.5). "It
6 should also be noted that in making her recommendation regarding the composite cost of
7 capital for OPG's regulated facilities, Ms. McShane took into account OPG's rate base
8 treatment of the nuclear liability costs" (Ex. J1.3, page 3). If the Board accepts the
9 intervenors' arguments regarding the scope of the accounts, whether applied to nuclear
10 liabilities or the income tax accounts, this will result in incremental risks going forward that
11 are not reflected in Ms. McShane's cost of capital estimates.

12
13 As a general comment, OPG would note that the use of deferral and variance accounts and
14 the setting of an appropriate capital structure and ROE are the common methods for
15 addressing a regulated utility's financial and operating risks. None of the intervenors in this
16 hearing disputed this. Also, to the extent that risks are addressed by approved deferral or
17 variance accounts, such risks should not be considered in establishing a utility's capital
18 structure and ROE. Again, this is well known and accepted. Utilities apply for deferral or
19 variance accounts in response to a change in circumstance that is not reflected in the
20 approved capital structure or ROE. Such applications may or may not be granted. This
21 practice is common and should not be a consideration in establishing capital structure and
22 ROE. Capital structure and ROE should be set without speculating whether or not a utility will
23 apply for a specific deferral or variance account (or whether such an application will be
24 granted) subsequent to the proceeding. OPG's situation is no different.

25
26 OPG's proposed capital structure and ROE are based on the variance and deferral accounts
27 that it has proposed. To the extent that it was possible, Ms. McShane has quantified the
28 impacts on a denial of individual accounts. If the OEB, for any reason denies any of the
29 proposed variance and deferral accounts, it must take this into account in setting OPG's cost
30 of capital.

1 **3. CAPITAL PROJECTS**

2
3 **Issue 3.1**

4 **Are the costs and financial commitments OPG is seeking to recover under section**
5 **6(2)4 incurred to increase the output of, refurbish or add operating capacity to a**
6 **prescribed facility?**

7
8 **Issue 3.2**

9 **If so, are the costs and financial commitments within project budgets approved for**
10 **that purpose by the z of directors of OPG?**

11
12 OPG currently has two projects associated with the regulated hydroelectric facilities and two
13 projects associated with the nuclear facilities that fall within the ambit of paragraph 6(2)4 of
14 O. Reg. 53/05. These projects are considered in detail in OPG's argument-in-chief (page 40,
15 lines 9-26; page 41). No intervenor argued that these projects do not appropriately fall under
16 section 6(2)4 or that the costs are not within approved project budgets. OPG's capital and
17 OM&A costs for projects under section 6(2)4 should be approved as proposed.

18
19 Board Staff submits that the use of the past tense in section 6(2)4, i.e., "costs incurred," limits
20 recovery under this section to costs that have already been spent. This position is
21 inconsistent with Board Staff's statement that words are to be given their "plain meaning"
22 (Board Staff submission, page 7). While, as discussed below, OPG does not agree with
23 Board Staff's restrictive interpretation of section 6(2)4, neither Board Staff nor any intervenor
24 made any argument on OPG's requested recoveries in this application which turned on the
25 kind of distinction that Board Staff appears to be trying to make. Accordingly, nothing turns
26 on Board Staff's interpretation of section 6(2)4 in this case.

27
28 Though Board Staff would have the word "incurred" mean "expended", that is not what
29 incurred means. The operative portion of the definition of "incur" is "to become subject to"
30 (Compact Oxford English Dictionary). Thus the term "costs incurred" means "costs that OPG
31 has become subject to," not costs that OPG has expended.

32

1 Board Staff's interpretation is also inconsistent with its quoted rule of statutory interpretation
2 that "the words of an Act are to be read in their entire context" (Board Staff submission, page
3 3). The preamble to section 6(2) states "The following rules apply to the making of an order
4 by the OEB that determines payment amounts for the purpose of section 78.1 of the Act" and
5 the referenced order is for a future test period. The plain meaning of the words in section
6 6(2)4 better accords with a requirement to ensure OPG recovers the actual cost it incurs. To
7 address the potential that OPG's actual costs will be different from its forecast costs in the
8 test period, OPG has proposed continuation of the Capacity Refurbishment Variance
9 Account (Ex. J1-T3-S1, page 8, section 3.5.2).

10
11 **Issue 3.3**

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

14
15 As indicated in argument-in-chief, OPG is not seeking recovery of any costs or financial
16 commitments under section 6(2)4 in the test period that are not within the project budgets
17 approved by OPG's Board of Directors. No intervenors take issue with OPG's position. As
18 such, there is no need for the OEB to undertake any prudence review for this category of
19 costs.

20
21 **Issue 3.4**

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

24
25 As indicated in argument-in-chief, OPG is not seeking recovery of any "firm financial
26 commitments" or "pre-engineering commitments" in the test period. As such, there is no need
27 for the OEB to make a determination of these terms at this point in time. No intervenors
28 addressed this issue in their argument.

29
30 **Issue 3.5**

31 **Is the additional capital spending (beyond the levels being recovered under section**
32 **6(2)4) appropriate?**

1 No intervenors objected to OPG's forecast level of capital. As such, and for all the reasons
2 set out in its evidence and argument-in-chief, the capital budgets should be accepted by the
3 OEB as filed.

4
5 CCC recommends that the OEB require OPG to file an external review of its capital
6 budgeting process focusing on whether improvements need to be made to ensure that there
7 is a sufficient level of central control and accountability in the business planning and
8 budgetary processes (CCC argument, paras. 63-72).

9
10 OPG submits that there is no need for a costly external review and that the evidence is
11 persuasive that OPG has an effective capital budgeting process. CCC's submission that
12 there appears to be insufficient central control is without merit when assessed against the
13 evidence on the central controls that are in place. The annual business planning process has
14 a specific review of project portfolios and supporting documentation as described in Ex. A2-
15 T2-S1, page 8, section 4.3. This process requires a planning business case summary or, in
16 the case of nuclear, a project screening form for all capital projects with cash flows of at least
17 \$1M during the budget year and/or at least \$4M in future years of the business plan. This
18 process is described in greater detail in the business planning instructions issued to all
19 business units (Ex. L-14-45, Attachment 3, page 12, section 3.5). The business plans are
20 reviewed by the Chief Financial Officer and Chief Executive Officer prior to submission to the
21 OPG Board of Directors for approval.

22
23 For nuclear, the amount in the project portfolio for capital and OM&A projects were also
24 approved by the Chief Nuclear Officer and reviewed with committees of the OPG Board of
25 Directors (Tr. Vol. 6, pages 31-32).

26
27 There is significant corporate oversight in the release of funds to undertake project work.
28 Under OPG's Organizational Authority Register, in addition to the required line management
29 approval, all projects greater than \$10M for regulated hydroelectric and corporate groups and
30 \$15M for nuclear must be approved by the Vice President Corporate Investment Planning
31 (Ex. L-14-94, Attachment 1, page 10). In addition, projects greater than \$25M are approved
32 by the OPG Board of Directors (Tr. Vol. 6, page 107, line 13). Once initiated, controls are in

1 place such that if there is a forecast cost variance in a project, it must return to at least the
2 Vice President Corporate Investment Planning with a revised business case for re-approval
3 (Tr. Vol. 1, page 59, line 18). While these thresholds may seem large in comparison with
4 other utilities regulated by the OEB, they are reasonable in light of the cost of the facilities
5 operated by OPG and the size of OPG's capital budgets (\$208.8M in 2008 and \$395.6M in
6 2009 for regulated hydroelectric and \$189.0M in 2008 and \$330.9M in 2009 for nuclear) (Ex.
7 J2.6). OPG submits it has established the appropriate level for its corporate reviews and
8 approvals of capital projects.

9
10 Finally, there are two committees of the OPG Board of Directors that provide oversight for
11 major projects: the Major Projects Committee and the Nuclear Generation Projects
12 Committee (Ex. A1-T4-S1, page 4). These committees provide additional corporate oversight
13 for major supply projects including the Niagara Tunnel Project, refurbishment and new
14 nuclear build.

15
16 CCC questions the central control or oversight associated with reclassification of a capital
17 project as an OM&A project (CCC argument, para. 66). As described in the evidence (Ex.
18 A2-T2-S1, page 4, section 4.0), projects must meet OPG's corporate capitalization policy to
19 be classified as capital. If the scope of a project changes such that it no longer meets the
20 capitalization test, it must be classified as OM&A under OPG's corporate policy regardless of
21 the possible rate implications (Ex. A2-T2-S1, section 4.1). In fact, CCC submits that OPG's
22 accounting policies for capitalization are appropriate and notes that they are relatively
23 stringent (CCC argument, para 73).

24
25 The second area raised by CCC in support of its request for an external review is the historic
26 variance between actual and forecast capital expenditures during the 2005 to 2007 period.
27 These variances have been addressed within nuclear through recent improvements in its
28 project management process as explained in the evidence (Ex. D2-T1-S1, pages 1-3). Within
29 regulated hydroelectric, these variances arise almost entirely as a result of the delay in the
30 Niagara Tunnel Project, a project for which an external review would provide little benefit.
31 These two factors are considered separately below.

32

1 CCC's argument does not specifically address the recent improvements in the nuclear
2 project management process other than to acknowledge that OPG has indicated that
3 significant improvements have been made in project management processes but the
4 improvements "are not apparent in the evidence OPG has filed" (CCC argument, para 67).

5
6 There is significant evidence regarding the improvements in the nuclear project management
7 process. The process for developing the nuclear project portfolio in 2008 and 2009 was
8 different from previous years and OPG expects this change to reduce budget versus actual
9 variance. This expectation is supported in VECC's submission, which notes that project
10 spending forecast for 2008 and 2009 are aligned with the actual values in 2005, 2006 and
11 2007 (VECC argument, paras. 52 and 55).

12
13 OPG's past practice was to produce a nuclear project portfolio budget based on a specific list
14 of projects with cost estimates. OPG's experience was that the actual versus budgeted costs
15 were highly variable because the initial budget was based on very preliminary cost estimates
16 (Tr. Vol. 6, page 112). OPG improved the budgeting and approval processes by establishing
17 the concept of a capital and project OM&A portfolio (Tr. Vol. 6, pages 113-116).

18
19 The capital and project OM&A portfolio envelope of \$290M for budgeting was established
20 after extensive review in the nuclear business including an assessment of do-ability;
21 benchmarking to other utilities; and, assessing the amount of work required to maintain the
22 reliability of the nuclear fleet (Tr. Vol. 6, page 71).

23
24 OPG has a rigorous nuclear project portfolio management process to ensure that the
25 projects are properly prioritized and managed through to completion. This process includes
26 the Asset Investment Screening Committee which screens and conducts due diligence to
27 ensure appropriate projects are undertaken as well as the corporate requirements under the
28 Organizational Authority Register (Tr. Vol. 6, page 125; Ex. D1-T1-S1, page 5; L-14-94,
29 Attachment 1).

30
31 OPG provided evidence regarding the effectiveness of its new process to prioritize and
32 manage projects. The process has been benchmarked to industry project management

1 processes such as those of the Project Management Institute (Tr. Vol. 6, page 30). There is
2 increased governance and improved process for prioritization and selection of projects for
3 inclusion in the portfolio (Tr. Vol. 6, page 30; Ex. D2-T1-S1, pages 1-8).

4
5 The forecasts for 2008 and 2009 were the first to reflect the new project portfolio
6 management process (Tr. Vol. 6, page 114). OPG submits that the impact of these changes
7 on the variance between forecast and actual costs for 2008 should be reviewed in the
8 context of OPG's next application and that it is premature to require an external review of a
9 process that has just recently been benchmarked and is just beginning to operate.

10
11 The historical variance between forecast and budget capital expenditures for regulated
12 hydroelectric is almost entirely the result of delays in the Niagara Tunnel Project. If capital
13 expenditures on the Niagara Tunnel Project are excluded, the remaining aggregated
14 regulated hydroelectric capital budget variances have been below \$1M, and under 10
15 percent in each of 2005, 2006, and 2007 (Ex. L-16-4; Ex. D1-T1-S1, Table 2). OPG's
16 witnesses testified to the extensive ongoing oversight of the Niagara Tunnel Project starting
17 with direct on-site monitoring, including OPG's management review, and ending with weekly
18 reports to the Major Project Committee of OPG's Board of Directors (Tr. Vol. 2, pages 63-
19 64). Scheduling delays associated with the Niagara Tunnel Project are fully addressed in the
20 evidence and are a function of tunnel boring machine performance and sub-surface rock
21 conditions, not ineffective project controls (Ex. D1-T1-S1, page 3; Ex. L-1-14; Ex. L-6-39).

22
23 CCC suggests that the decision to proceed with the Niagara Tunnel Project was made
24 outside of the normal business planning process (CCC argument, para. 65). While OPG's
25 shareholder was involved in the decision making process (Tr. Vol. 1, page 49), this is
26 appropriate for a \$985M project of such strategic importance. Further, the testimony of Mr.
27 Long (Tr. Vol. 1, page 58) and Mr. Mazza (Tr. Vol. 2, page 64) demonstrate that OPG
28 followed its internal processes in approving the Niagara Tunnel business case (Ex. D1-T1-
29 S2, Attachment A).

30
31 Given the focus and priority OPG places on managing the Niagara Tunnel Project and the
32 unique nature of this project, it is hard to imagine what possible benefit would result from an

1 external review of capital budgeting processes in relation to this project. The remainder of the
2 regulated hydroelectric portfolio has shown excellent historical performance in terms of
3 tracking to forecast and therefore there is no demonstrated need to subject it to external
4 review.

5
6 **Issue 3.6**

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

10
11 No issues were raised by intervenors with respect to OPG's capitalization policy and further,
12 CCC notes that: "when compared with other OEB regulated utilities, OPG's accounting
13 policies are relatively stringent" (CCC argument, para 73).

14
15 CCC requests that the OEB direct OPG to provide evidence in the next proceeding that will
16 justify the capitalization and depreciation expense associated with the Pickering A Isolation
17 Project, specifically:

- 18 • why all costs should be attributed to refurbishing units 1 and 4 rather than placing units 2
19 and 3 in safe storage.
20 • why OPG cannot draw on the nuclear segregated funds to cover the costs of safe
21 storage for units 2 and 3.

22
23 Despite CCC's contention that "all costs" are being attributed to refurbishing units 1 and 4,
24 the reality is that the isolation costs are a minor component of the total safe storage costs.
25 They relate to work specifically associated with the ongoing operations of units 1 and 4, units
26 that are expected to operate over an extended period of time (Tr. Vol. 6, page 38). The costs
27 to place units 2 and 3 in safe storage were included in the ONFA reference plan and will be
28 funded through the Nuclear Liabilities Deferral Account (Tr. Vol. 7, pages 163-164).

29
30 A further review as to why OPG cannot draw on the nuclear segregated funds to cover the
31 costs of safe storage for units 2 and 3, as requested by CCC, is unnecessary as OPG
32 anticipates that safe storage costs will be paid through the segregated funds (Tr. Vol. 7, page

1 164). The units 2 and 3 safe storage costs are not in the revenue requirement, except as
2 they are reflected in the nuclear liabilities.

3
4 SEC recommends that OPG remove the \$190M costs associated with nuclear refurbishment
5 and new nuclear build in 2008 and 2009 from base OM&A and capitalize it. This
6 recommendation is based on their view that expenditures for the potential refurbishment of
7 Pickering B and Darlington and new build at the Darlington site are for capital improvement
8 projects, and are not operational costs.

9
10 Such a reclassification would be inconsistent with OPG's capitalization policy. Under this
11 policy, which is consistent with Generally Accepted Accounting Principles ("GAAP"), all costs
12 incurred prior to the date of the selection of the alternative to implement are charged to
13 OM&A (Ex. A2-T2-S1). Project development costs are capitalized once the preferred
14 alternative for a new capital asset or capital improvement to an existing asset is selected,
15 usually through the approval of the appropriate business case.

16
17 OPG does not yet have a preferred alternative for either of the Pickering B or the Darlington
18 refurbishment project or the nuclear new build project. Considering the three projects
19 separately, for Pickering B refurbishment a decision is expected no later than Q1 2009 and at
20 that time, if there is a decision to proceed, OPG will start to capitalize costs. This amount is
21 \$148.8M of capital in 2009 for Phase II of Pickering B refurbishment (Ex. D2-T1-S3, page
22 11). If there is a decision not to proceed, clearly it would have been inappropriate to have
23 capitalized expenditures prior to that decision and previously capitalized costs would be
24 charged to OM&A at that time.

25
26 Work to assess the feasibility of Darlington refurbishment is scheduled to start in 2008, with
27 an expected decision on a refurbishment option in 2010 (Ex. D2-T1-S3, page 6). All test
28 period costs relating to Darlington refurbishment should be classified as OM&A because a
29 refurbishment alternative will not have been selected.

30
31 For new nuclear build, the forecast of base OM&A costs relates to work undertaken pursuant
32 to the June 26 directive as detailed in Ex. D2-T1-S3, page 9 and as further elaborated by Ms.

1 Swami (Tr. Vol. 6, pages 41-42 and 154-158). The classification of these costs as OM&A is
2 also consistent with OPG's capitalization policy. This assessment work (including vendor
3 selection) is largely for the purpose of the identification and approval of the preferred new
4 build alternative. Classification of these costs as OM&A is also consistent with the language
5 in section 5.4 of O. Reg. 53/05 which instructs OPG to establish a variance account for New
6 Generation Development to reflect the difference between the non-capital costs forecast in
7 OPG's rate application and the actual costs incurred. This account is to be established as of
8 the effective date of the OEB's first rate order.

9
10 On July 25, 2008, the Ministry of Energy and Infrastructure announced that a preferred
11 vendor for new nuclear build will be selected by the end of March 2009. To the extent that
12 the timing of a decision on the preferred alternative affects the total OM&A expenditures on
13 new nuclear build in 2009, the Nuclear Development Variance Account ensures that OPG
14 only recovers the OM&A costs that were actually spent.

15
16 SEC's recommendation circumvents OPG's project capitalization criteria. The specific criteria
17 in OPG's policy relating to the timing when capitalization begins apply to all projects equally.
18 Extending SEC's argument to other projects within the portfolio could result in significant
19 increases in capitalization. There is nothing to distinguish the refurbishment and new build
20 projects from other OPG projects except for size, and this factor does not justify departure
21 from the established capitalization policy. SEC's recommendation should be rejected by the
22 OEB.

23

1 **4. PRODUCTION FORECASTS**

2
3 **Issue 4.1**

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

6
7 **Issue 4.2**

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

9
10 No intervenors objected to OPG's forecast of regulated hydroelectric or nuclear production
11 for the test period. While Board Staff and Energy Probe commented on the nuclear fleet level
12 uncertainty adjustment and the forecast forced loss rate respectively, neither requested
13 changes to the nuclear production forecast for the test period. As such, and for all the
14 reasons set out in its evidence and argument-in-chief, the production forecasts for the
15 regulated hydroelectric and nuclear facilities should be accepted by the OEB as filed.

16
17 Board Staff states that the fleet level uncertainty adjustment factor for nuclear does not
18 appear to reflect historic performance. This submission stems from Board Staff's
19 misunderstanding of the fleet level uncertainty adjustment. Board Staff states: "Deviations of
20 actual production levels arise from unplanned outages or the extension of scheduled outages
21 beyond their planned duration. OPG labels this outage factor as a fleet level uncertainty
22 adjustment" (Board Staff submission, page 34). OPG's evidence is that unplanned outages
23 are properly captured by its forecast forced loss rate ("FLR"), not the fleet level uncertainty
24 adjustment, and that the FLR for the test period forecast appropriately takes into account
25 historical performance (Ex. E2-T1-S1, page 9, lines 14-15). The fleet level uncertainty
26 adjustment is a relatively small component of the overall nuclear production forecast (about
27 one percent) and reflects management's judgment of uncertainties in the nuclear fleet-wide
28 forecast that would not have been captured by the station-level forecasts (Ex. E2-T1-S1,
29 page 11; Tr. Vol. 5, page 106).

30
31 Energy Probe asserts that the OEB should be "skeptical" of OPG's forecast and its FLR
32 given past performance (Energy Probe argument, para. 70). However, Energy Probe does

1 not ask the OEB to reject any aspect of the application on this basis, nor did it put forward an
2 alternate production forecast. Energy Probe's argument seems to be that history must repeat
3 itself and OPG will thus not achieve forecast production levels (Energy Probe argument,
4 para. 72). OPG has given evidence specifically detailing measures taken to improve its
5 production performance, as well as evidence supporting the forecast nuclear production and
6 forecast FLR for the test period (Ex. E2-T1-S1, pages 14-18; Ex. E2-T2-S1, pages 3-5).

7 Examples of these measures include:

- 8
- 9 • Examination of the root cause of past forced outages and taking corrective actions
10 accordingly (Ex. E2-T1-S2, Appendix C; Tr. Vol. 5, pages 131-132).
 - 11 • Investing in the material condition of the station to improve reliability (Ex. E2-T1-S1, page
12 17, lines 6-19; Tr. Vol. 4, page 131; Tr. Vol. 5, pages 46-47, 98 and 135-136).
 - 13 • Factoring historical performance into its forecast of FLR (Ex. E2-T1-S1, page 9; Tr. Vol.
14 5, pages 149-150).

15

16 OPG sets challenging production forecasts to stretch the organization to achieve maximum
17 generation while ensuring safe and reliable operation (Ex. L-1-32). Energy Probe's argument
18 has been specifically refuted by OPG and therefore, should be completely disregarded.

19

1 **5. OPERATING COSTS**

2
3 This section replies to the arguments of intervenors addressing operating costs for OPG's
4 nuclear business unit and corporate support functions and related issues.

5
6 No arguments were raised that specifically addressed hydroelectric operating costs. As such,
7 and for all the reasons set out in OPG's evidence and argument-in-chief, these amounts
8 should be accepted by the OEB as filed.

9
10 No intervenors objected to OPG's forecast depreciation expense (Issue 5.2), asset service
11 fee amounts (Issue 5.5), other operating costs (Issue 5.6) or OM&A purchased service costs
12 (Issue 5.9). As such, and for all the reasons set out in its evidence and argument-in-chief,
13 these amounts should be accepted by the OEB as filed.

14
15 Nuclear OM&A budgets (Issue 5.1), OPG's nuclear fuel cost forecasts (Issue 5.7) and the
16 nuclear outage OM&A budgets and forecasting methodology (Issue 5.8) are considered in
17 the Nuclear sub-section. The corporate sub-section covers human resource costs (Issue 5.3)
18 and corporate cost allocation and corporate OM&A costs (Issue 5.4).

19 20 **NUCLEAR**

21 22 **Issue 5.1**

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

25
26 Board Staff question the reasonableness of increases in nuclear OM&A from 2005-2009
27 (Board Staff submission, page 38). SEC and CME also claim that these costs are too high
28 (SEC argument, para. 41; CME argument, paras. 194-95). OPG maintains that its proposed
29 nuclear OM&A spending is both reasonable and necessary for the safe and reliable
30 operation of the prescribed nuclear facilities and to achieve the performance levels specified
31 in the business plan. Funding at the levels proposed by SEC, or even with CME's lesser
32 decrease, would deny OPG the funds needed to continue with ongoing initiatives to reduce

1 elective and corrective maintenance backlogs, improve preventative maintenance, improve
2 outage planning and execution, and address demographic issues (Ex. A1-T4-S3, pages 11-
3 12). Neither would it provide the funds required to fulfill the direction from the Ontario
4 government to undertake work on refurbishment and new nuclear build (Ex. D2-T1-S3, page
5 11). Reducing these efforts would frustrate the performance improvements they are aimed at
6 achieving.

7
8 Excluding P2/P3 impairment charges and write-offs, total OM&A increases by 25.6 percent
9 (\$442.5M) from 2005 to 2009, or approximately 6.4 percent per year based on a simple
10 average. Compared to this average, actual year-over-year increases from 2005 to 2009 have
11 varied significantly [11.1 percent (2005 to 2006), 5.5 percent (2006 to 2007), 7.9 percent
12 (2007 to 2008) and -0.7 percent (2008 to 2009)] (Ex. F2-T1-S1, Table 1). These changes
13 vary from year to year primarily due to the impact of changing work programs and outage
14 requirements. For example, with completion of planned improvement initiatives and as a
15 result of cost containment initiatives outlined in the evidence, total OM&A for nuclear is
16 forecast to decrease in 2009 compared to 2008 even with an 8 percent increase in outage
17 OM&A (Ex. F2-T1-S1, Table 1).

18
19 The simplistic linear cost trend analyses offered by Board Staff, SEC and CME exclude any
20 consideration of the underlying cost drivers. OPG has outlined the work driving nuclear
21 OM&A trends, presenting drivers for changes in all OM&A cost components (base, outage,
22 and project) (Ex. L-1-35). With regard to base OM&A, of the \$331.6M increase between 2005
23 and 2009 (excluding one-time items), \$165M is attributable to labour escalation. Of the
24 remaining \$166M, \$88M is for new generation development, approximately \$39M is for
25 security and other programmatic improvements in nuclear programs and training, leaving
26 \$39M for other programmatic changes and improvements (Tr. Vol. 4, pages 5-6).

27
28 While recognizing these costs drivers, OPG has taken steps to minimize their impact. The
29 results of these efforts have been and will continue to be built into OPG's business plans (Ex.
30 F2-T2-S1, section 3.1). In addition to helping to offset escalation, cost containment initiatives
31 have helped to reduce the impact of significant cost pressures associated with an expanding
32 work program, which includes increasing security requirements mandated by the Canadian

1 Nuclear Safety Commission, vacuum building outage preparation at both Darlington and
2 Pickering (not included in 2005 costs) and new reliability improvement initiatives at Pickering
3 A (Tr. Vol. 5, pages 39-40). Neither Board Staff, nor SEC, appear to acknowledge that these
4 necessary activities have cost consequences.

5
6 SEC and CME propose that nuclear OM&A cost recovery be limited by an escalation factor.
7 VECC makes a general statement that OM&A cost increases should track inflation minus any
8 productivity increase, but makes no specific recommendation in this regard (VECC
9 argument, para. 60). SEC proposes a three percent annual increase for each year since
10 2005 using actual 2005 expenditures as the base (SEC argument, para. 44). These
11 proposals simply ignore OPG's unchallenged evidence that it is undertaking additional
12 activities that were not present in 2005. These represent substantial increases in costs
13 including an increase of about \$189M in OM&A expenditures between 2005 and the test
14 period related to nuclear new build and evaluating Pickering B refurbishment (Ex. D2-T1-S3,
15 page 11). These costs are being incurred at the direction of the Province and with a view to
16 increasing Ontario's electricity supply (Ex. A1-T4-S3, page 8).

17
18 CME proposes a total test period increase of 6 percent above 2007 OM&A costs, excluding
19 corporate costs allocation (CME argument, para. 194). No evidentiary support is provided to
20 justify this figure. Instead, CME mentions, but fails to cite, recent OEB-approved adjustment
21 mechanisms of less than 2 percent, for Union and EGD ("Enbridge") (CME argument, para.
22 192). CME provides no justification of why adjustment mechanisms for Union and EGD, two
23 natural gas distribution utilities with long histories of regulation, and which are operating
24 under voluntarily negotiated incentive rate mechanisms, are appropriate for a previously
25 unregulated electricity generator in a cost of service proceeding. There is no basis on the
26 record to conclude that the cost drivers for natural gas distributors are the same as those for
27 a nuclear generator and common sense suggests that they are different. For example, the
28 challenges associated with hiring, training and retaining skilled nuclear operators are
29 substantially greater than staffing a distribution call centre. As noted above, the use of 2007
30 as a base year ignores the significant cost impact from spending on Nuclear Generation
31 Development during the test period (\$100M in 2008, \$90M in 2009). Such extraordinary
32 expenses are typically "Z" factors under an incentive regulation regime.

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OPG submits that the nuclear revenue requirement resulting from these proposals would be insufficient to operate the nuclear facilities in a manner that would achieve business plan performance targets for reliability and production. Moreover, leaving aside their impacts on reliability and production, cuts of the magnitude suggested by SEC cannot be achieved over the test period. Labour costs constitute about 74 percent of OPG's nuclear base OM&A costs and some 90 percent of OPG's employees are covered by collective agreements (Ex. L.14-15; Ex. F3-T4-S1, page 2). As discussed more fully under Issue 5.3, for these employees, wages and benefits can only be changed through collective bargaining.

Finally, using an escalation approach, as advocated by these parties, has already been rejected by the OEB. In its determination of the appropriate methodology for OPG's first application, the OEB rejected an incentive regulation approach advocated by some intervenors. The OEB instead choose a cost-of-service approach, and stated

The Board finds that, instead of using the existing payments as a base payment for the incentive regulation formula, the Board will undertake a series of limited issues cost of service processes to set the base payment. The Board will extend the limited cost of service process over several payment orders until all relevant issues have been examined. The Board will implement an incentive regulation formula when it is satisfied that the base payment provides a robust starting point for that formula. (EB-2006-0064, page 11[emphasis added])

Despite this finding, SEC and CME continue to propose a formulaic approach to establishing nuclear OM&A costs. Neither SEC nor CME has offered any evidence to support the base years or escalation rates that they propose.

Board Staff questions whether the OEB should use an envelope approach to setting OM&A costs (Board staff submission, page 38). If by "envelope approach," Staff means that the OEB should establish and overall amount for OM&A in this proceeding and allow OPG to manage specific expenditures within this budget, then OPG agrees with this approach. OPG does not agree that its OM&A costs should be determined by benchmarking (Ibid.). Instead, the OEB should follow its decision to use a "cost of service" approach and base the approved OM&A budget on the detailed cost information that OPG has provided.

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SEC also proposes that costs related to nuclear new build (\$190M over the test period) should be capitalized rather than being included in base OM&A (SEC argument, para. 46). This proposal is addressed under Issue 3.6 Capitalization Policy.

Nuclear Benchmarking

AMPCO claims that OPG is “highly resistant to nuclear benchmarking” (AMPCO argument, para. 109). This claim is both untrue and unsupported. OPG has provided detailed descriptions of how it applies benchmarking and substantial benchmarking information (Tr. Vol. 4, pages 43-51; Ex. A1-T4-S3, pages 15-24, Appendix A; Ex. L-2-38; Ex. L-2-39; Ex. L-2-41; Ex. L-2-51; Ex. L-3-50; Ex. L-4-2, Attachment 3; Ex. L-6-42; Ex. L-12-52; Ex. L-14-15; Ex. KT1.10; Ex. J4.6; Ex. J4.7; Ex. J4.8; and Ex. J5.1).

AMPCO’s argument does not provide a single instance of an OPG witness stating that the company should not undertake benchmarking or that benchmarking is not necessary. It cannot, because no such statements were ever made. To the contrary, OPG’s witnesses discussed in detail how the company benchmarks and how that information is used (Tr. Vol. 4, pages 43-51). As support for its proposition that OPG is “highly resistant to nuclear benchmarking” AMPCO cites the testimony of OPG witnesses that explains the importance of understanding the way in which potential benchmarks are comparable and the ways in which they are not (AMPCO argument, paras. 114 and 119).

OPG has a strong commitment to benchmarking as part of its efforts to continuously improve performance (Tr. Vol. 4, page 43). OPG takes “benchmarking seriously and we apply the lessons that we learn to the way we do business.” (Tr. Vol. 4, page 44). OPG has provided benchmarking data from Electric Utility Cost Group (“EUCG”) and the World Association of Nuclear Operators and explained that these are the preferred sources of benchmarking because they use consistent data (Tr. Vol. 4, page 43). In addition, OPG retained Navigant to benchmark staffing levels on its own initiative (Tr. Vol. 5, page 12; Ex. L-3-50). All of these demonstrate that OPG is committed to benchmarking and has fully complied with the requirements of the Memorandum of Agreement, AMPCO’s suggestions to the contrary notwithstanding (AMPCO argument, para. 111).

1

2 AMPCO also argues that OPG's benchmarking demonstrates its costs are excessive
3 (AMPCO argument, para. 19). First AMPCO repeats the erroneous claim that the increases
4 in per unit costs between 2005 and 2007 demonstrate a lack of cost containment. For this
5 comparison AMPCO has selectively used data from the historical period rather than the test
6 period so as to show the largest possible percentage increase and has done the comparison
7 on a cost per unit of production basis so that any reductions in production increase the
8 percentage changes. In particular, the use of 2007 as the end-point skews the analysis
9 because production in that year was significantly impacted by a number of major one-time
10 events (Ex. E2-T1-S2, pages 4-5). As is shown below, comparing costs over the period 2005
11 to 2009 presents a more balanced view.

12

13 AMPCO also makes much of the comparison between OPG's CANDU plants and U.S.
14 reactors (AMPCO argument, para. 19). As OPG has explained, this comparison is influenced
15 by technology and accounting differences, and currency fluctuations (Ex. A1-T4-S3, pages
16 19-22). OPG explained the differences in technology as follows:

17

18 MR. ROBINSON: The benchmark that you are referring to there under the
19 cost is probably an appropriate benchmark for Darlington, and Darlington
20 is close in that area.

21 Pickering A and B, as we stated earlier, are very difficult to benchmark
22 against, especially in the U.S.

23 If you go to the comparison of plants, and I don't have that reference
24 very handy, but a 500 megawatt unit in the U.S. has significantly less
25 components.

26 If you go to Exhibit A1, tab 4, schedule 3, page 20, it shows you the --
27 you can see the differences in equipment.

28 Pickering A and Pickering B are first-generation CANDU plants, very,
29 very complicated, compared to a comparable-sized plant in the U.S.

30 For example, a 500-megawatt unit in the U.S. would have two steam
31 generators and two heat transport pumps. At Pickering A and Pickering
32 B, there are 12 steam generators, and 16 heat transport pumps.

33 If you multiply that with all of the attendant instrumentation and alarms
34 and controls associated with all of those components, you get a very, very
35 complex unit.

36 In addition to that, that single unit PWR in the U.S., 500 megawatts,
37 has one pressure vessel over which you do certain periodic inspections,
38 whereas the CANDU unit has 300-plus pressure tubes that have to be
39 inspected.

1 So it makes it very difficult to make that comparison between
2 Pickering A and Pickering B and a comparable U.S. plant, where it is
3 much easier to do a Darlington unit, because a Darlington unit, four steam
4 generators, four heat transport pumps, comparable to a comparable-sized
5 unit in the U.S. of nine to 1,200 megawatts that would have four steam
6 generators, four heat transport pumps. The only difference there is -- is
7 really the on-line refueling and the complexity of the reactor vessel itself,
8 if you will, the pressure tubes. (Tr. Vol. 4, pages 47-48)
9

10 AMPCO selectively highlights some of the performance benchmarks where OPG compares
11 unfavourably and omits any mention of those measures where OPG performs well (AMPCO
12 argument, para. 22).⁶ OPG fails to see the point of this exercise. As the company has
13 acknowledged, the Pickering units are not top performers and are unlikely to become top
14 performers for the many reasons that OPG has explained in detail related to their design and
15 age (Tr. Vol. 4 pages 131-32, and 152). But this does not mean that their performance
16 cannot improve; in fact, OPG expects performance to improve and costs to decrease (Tr.
17 Vol. 4, pages 108-109, and 152). In contrast, Darlington has generally performed well and
18 OPG expects that it will continue to perform well (Tr. Vol. 4, pages 44-45).

19
20 AMPCO presents a comparison between actual 2007 and forecast 2007 data and
21 recommends that in future filings OPG's benchmarking results be based on actual results
22 rather than business plan forecasts (AMPCO argument, para. 21). For historical information,
23 OPG uses actual results, but when presenting future information, OPG necessarily uses a
24 forecast. OPG's business plans represent the company's approved forecast.

25
26 In its analysis, SEC commingles production unit energy cost ("PUEC") values based on the
27 EUCG and OPG methods of calculation. As a result, SEC has presented distorted
28 information about the trend in PUEC for Darlington (SEC argument, para. 55). As OPG
29 explained, there are differences between the EUCG calculation of PUEC and OPG's internal
30 calculation (Tr. Vol. 4, pages 27-28). The major difference is that EUCG excludes other post
31 employment benefits ("OPEB") from the costs used in its calculation, while OPG includes
32 OPEB costs (Ibid.). SEC's chart uses the EUCG data for historic years and OPG data for the
33 test period. As a result, SEC shows a much larger increase in Darlington PUEC than is

⁶ For example, AMPCO fails to mention that Darlington as a whole is in the top quartile of world CANDU reactors in unit capability factor as is Darlington Unit 1 for Nuclear Performance Index (NPI) (Ex. J4-6, page 2).

1 actually forecast. The table below shows the Darlington PUEC on a consistent basis using
2 the OPG PUEC calculation (EUCG does not provide forecast data).

3
4 **Darlington PUEC using OPG Method (\$/MWh)**

5

	2005	2006	2007	2008	2009
Darlington	23.9	28.7	31.6	30	34

6 Source: Ex. L-2-41; Ex. A1-T4-S3, page 13.

7
8 SEC's views about the trend in Darlington's PUEC are based on inaccurate data as shown
9 above and ignore the drivers of changes in Darlington's PUEC that OPG has previously
10 explained (SEC argument, para. 57). As OPG has indicated, and as is acknowledged in
11 other parts of the SEC's argument (SEC argument, para.64), Darlington's PUEC increased
12 between 2006 and 2007 as OPG ramped up spending on maintenance as part of its
13 Equipment Performance Improvement Initiative to reduce maintenance backlogs (Ex. F2-T2-
14 S2, page 5). In addition, as explained below in detail for Pickering B, part of the apparent rise
15 in Darlington's PUEC in U.S. dollars is attributable to currency fluctuations. Finally, the
16 increase in OPEB and pension costs in 2006 caused a rise in PUEC when it is calculated
17 using the OPG method (Ex. F3-T1-S2, page 9).

18
19 SEC states that OPG attempted to explain the increase in Darlington's PUEC between 2005
20 and 2006 as being related to attempts to reduce elective maintenance backlogs but the
21 maintenance backlogs have not decreased (SEC argument, para. 58). However, the citation
22 that SEC provides ("Tr5:14") is to a discussion of Navigant benchmarking and not the change
23 in Darlington PUEC (Ibid.). The increase in Darlington PUEC between 2005 and 2006 is
24 largely attributable to increases in base OM&A unrelated to maintenance backlogs and
25 increased allocation of corporate costs as is fully explained in OPG's evidence (Ex. F2-T2-
26 S2, pages 8-11; Ex. L-1-35). Moreover, SEC's statement that Darlington's elective
27 maintenance backlogs decreased just slightly (from 400 to 373) is just wrong (SEC
28 argument, para. 58). In fact, Darlington's elective maintenance backlog decreased from 767
29 in 2005 to 584 in 2006 and further decreased to 373 in 2007 (Ex. F2-T2-S1, page 37, Chart
30 2).

31

1 SEC states that EUCG data shows that costs increased for all of OPG's units from 2005 to
2 2007 (SEC argument, para. 54). However, this statement illustrates OPG's point that care
3 must be taken in using EUCG benchmarking data (Ex. A1-T4-S3, page 19). For example, the
4 PUEC for Pickering B unit 5 in 2005 was C\$72.59 which equates to U.S.\$60.25, reflecting
5 the 2005 U.S./CDN\$ exchange rate of 0.83 (Ex. J.4.9, page 1). In 2007, the Pickering B unit
6 5 PUEC had declined to C\$67.05 which equates to U.S.\$62.42 using the 2007 U.S./CDN\$
7 exchange rate of 0.93 (Ibid.). Hence while the Unit 5 PUEC had actually declined in
8 Canadian dollars, it rose in U.S. dollars due to changes in the exchange rate. SEC also
9 ignores the impact of the Darlington vacuum building outage on its 2009 PUEC (Ex. J5.6).

10
11 SEC also comments that PUEC does not include stranded debt (SEC argument, para. 62).
12 As explained above, stranded debt is the legacy of the decision to move to a competitive
13 generation market (see Issue 2 above). Many U.S. jurisdictions made the same move and
14 also experienced "stranded debt" charges (Tr. Vol. 10, page 69, lines 13-25). The PUEC
15 shown for generators in those jurisdictions similarly do not include these charges.

16
17 Finally, Board Staff refer to a chart in Ex. L-1-34 as a source of comparative data between
18 OPG, Bruce Power and other nuclear generators. The chart is part of an interrogatory
19 *question* posed by Board Staff and not OPG's evidence. In its response to the interrogatory,
20 OPG states: "OPG does not know what is included in the Bruce Power OM&A cost shown in
21 the above chart," and

22
23 The data for the quoted NEI industry benchmarks is gathered from FERC
24 Form 1 filings. Not all generators are required to make this filing and for
25 some of the FERC Form 1 filings not all of the performance data fields are
26 completed. In order to arrive at industry benchmarks, there is a strong
27 reliance on using a) historical data (from past filings), for the missing data
28 fields or b) analytical models to interpolate missing data and missing utilities
29 based on best available information. In addition, the FERC data definitions
30 do not typically capture all relevant operating costs such as corporate
31 indirect costs.

32
33 When questioned about this chart during the hearing, Mr. Mauti reiterated OPG's concerns
34 regarding the use of the data in the chart for benchmarking (Tr. Vol. 4, pages 20-21).
35 Ultimately, there was a Board Staff undertaking to explain the source of the data in the chart

1 relating to Bruce Power (Ex. J5.5). This undertaking generated a multi-page response that
2 was neither adopted by any witness nor subject to cross examination. OPG notes that the
3 Bruce Power data submitted in the undertaking response as the source of the data in the
4 chart is not data from an audited financial report. OPG submits that given the lack of an
5 opportunity to test the data presented in this chart during the hearing, the OEB should give
6 no weight to it in coming to its determination on the appropriateness of OPG's nuclear OM&A
7 costs.

8 9 The Navigant Study

10 A number of parties criticized OPG's response to the Navigant Study and misinterpreted how
11 its results were intended to be used (SEC argument, paras. 63-71; VEC argument, para. 62;
12 CME argument, para 192). In fact, OPG's response to the study has been appropriate and is
13 entirely consistent with the purpose for which it was undertaken. OPG commissioned the
14 Navigant Study to obtain a high level view of staffing at other Canadian CANDU plants for
15 use in assessing OPG's staff levels in various functions (Tr. Vol. 5, page 12). OPG intended
16 to use the information produced to review staffing in those areas where the Navigant study
17 indicated opportunities for reductions (Tr. Vol. 5, pages 13-15). These areas have been
18 reviewed and, based on these reviews, OPG has reduced staff in certain areas where
19 reductions were appropriate (Tr. Vol. 5, pages 14-16).

20
21 CME claims "Navigant indicates that OPG labour costs are 12 percent above benchmark,
22 and that impact should be considered in disallowing OM&A costs for the test period. CME
23 estimates this impact to be approximately \$123M/yr over the test period" (CME argument,
24 para. 192). OPG rejects CME's conclusion that the Navigant study results can be used to
25 establish the overall reasonableness of OPG staffing levels (TR Vol. 5, pages 37-38). As
26 noted above, the purpose of the Navigant study was to examine comparative staffing levels
27 for different functions, not to look at overall labour costs.

28
29 VECC states that the Navigant study "other things being equal, implies total labour costs
30 being 12 percent above benchmark levels" (VECC argument, para. 62). This is exactly the
31 type of conclusion that cannot be drawn from the Navigant study. The Navigant study is a
32 snapshot of relative staffing levels by function at a single point in time and is not

1 representative of staffing levels in the test period (Tr. Vol. 4, page 169) or their relative cost.
2 Moreover, this conclusion ignores the previously discussed staff reductions and OPG's
3 actions to maintain staff at a constant level in the face of increasing workloads. Finally, in
4 assessing appropriate staff levels, it is crucial to assess the performance of the comparator
5 so that the functioning of a well performing unit is not undercut by reducing its staffing level to
6 that of a lower performing comparator (Tr. Vol. 4, pages 169-70). VECC's conclusion simply
7 ignores this consideration.

8
9 SEC suggests that OPG has done nothing with the Navigant results except for staff
10 reductions in Supply Chain, and argues that Supply Chain comprises only a small
11 percentage of base OM&A (SEC argument, para. 66). This assertion ignores OPG's
12 response to the Navigant study in other areas and incorrectly minimizes the importance of
13 the Supply Chain improvements. As noted above, OPG provided a number of examples of
14 staff reduction undertaken as a result of the Navigant study (Tr. Vol. 5, pages 14-16). For
15 example, OPG's evidence shows that Darlington operations and maintenance full-time
16 equivalents ("FTEs") decrease in 2009 and engineering FTEs decrease in 2008 and 2009
17 (Ex. F2-T2-S1, Table 3). Issue 5.3 below discusses OPG's projected staffing levels in the
18 face of increasing workload.

19
20 For Supply Chain, staffing declines from an actual headcount of 469 at the end of 2006 to a
21 planned FTE complement of 377 in 2009 (Ex. F2-T2-S1, pages 41-42). SEC is also incorrect
22 when it states that despite these reductions in staff, Supply Chain costs are rising (SEC
23 argument, para. 66). Supply Chain costs were \$63.8M in 2007 and are forecast to decrease
24 to \$60.4M in 2008 and to further decrease to \$56.3M in 2009 (Ex. F2-T2-S1, page 42).
25 Moreover, as a result of the Supply Chain Improvement project, overall savings of \$25.4M
26 have been incorporated into the business plan for 2008-09 (Ibid.).

27
28 SEC also asserts that OPG did not respond to the question of whether it intended to proceed
29 with subsequent phases of the Navigant study (SEC argument, para. 67). As the following
30 exchange makes clear however, this assertion is untrue:

31

1 MR. BOGUSKI: My understanding is they were hired to do phase 1,
2 which is benchmark the staffing levels at OPG versus CANDU
3 equivalents.

4 MR. KAISER: So phase 2, 3 and 4 they weren't asked to do?

5 MR. ROBINSON: That's correct. That's ours.

6 MR. KAISER: And when are you going to do phase 2, 3 and 4?

7 MR. ROBINSON: We have been working on those phases, although not
8 specifically laid out and designed according to the Navigant study, but
9 things like operating processes, practices and behaviours, driving the
10 level of performance that we want, we do that through benchmarking that
11 we do on the common practices that we see in the fleet and the industry.

12 I gave you -- one example of that is in the process around control
13 of work activities. So we go out and look at how the best people do that,
14 and we then look at how we're doing it and make changes to do that.

15 And so this is -- this really is a continuous improvement program
16 that we take the elements of and practice on a routine basis.

17 MR. KAISER: But I take it you agree that the task described in this report
18 as phase 2, "What level of costs and operational performance
19 improvement is justified?", is an important question.

20 Do you think you have answered it satisfactorily at this point? I
21 mean, do you have a clear idea of what the goal is?

22 MR. ROBINSON: I believe we have --

23 MR. KAISER: Or are you still working on the goal?

24 MR. ROBINSON: No. I believe we have a clear goal. We set out an
25 improvement program on Pickering B. It was called 85/5, and the reason
26 it was called 85/5, because we were targeting an 85 percent capacity
27 factor and a 5 percent forced loss rate.

28 At Darlington, obviously we're targeting higher than that, because
29 we believe that capability at Darlington is better than that, and we're
30 demonstrating that on a day-to-day basis.

31 If you look at forced loss rate at Darlington, again, over the 2007
32 period, it was less than one, which is a very good performance. (Tr. Vol.
33 4, pages 160-61)

34 35 The Future of Pickering A and B

36 Several parties have questioned the economic viability of Pickering A and B and proposed
37 that the OEB take various actions on this issue (AMPCO, Energy Probe, SEC). AMPCO asks
38 the OEB to "provide clear direction to OPG that it must operate Pickering A well enough to
39 justify continued recovery of forecast costs" and to require that OPG file an assessment of
40 Pickering A's long-term viability in its next application (AMPCO argument, paras. 138-39).
41 Energy Probe asks the OEB to withhold payment to "any generator that is likely, or virtually
42 certain, to raise the cost of power to Ontario's electricity customers, compared to the case
43 where that generator simply does not operate" (Energy Probe argument, para. 77). SEC asks

1 the OEB to order OPG to produce a “clear plan to have Pickering A and B operate at a level
2 that is at least reasonably approximate to other nuclear generators” (SEC argument, para.
3 74). These requests ignore both the OEB’s jurisdiction under section 78.1 of the Act and
4 OPG’s evidence on its performance improvement initiatives that will lead to lower cost per
5 unit of output, and misapprehend the purpose of this hearing.

6
7 OPG believes that the continued operation of Pickering A is economic and throughout the
8 course of this proceeding has demonstrated the actions that the company is taking to
9 improve the operation of the plant. In any event, however, in deciding this application, the
10 role of the OEB is to review the costs of Pickering A, and, based on these costs, to set just
11 and reasonable payment amounts. It is not for the OEB to decide the ultimate viability of
12 Pickering A. Such a review is beyond the scope of section 78.1 of the Act and would
13 necessarily involve matters such as the ability to meet provincial electricity demand without
14 Pickering A, particularly given the Province’s off-coal policy. More generally, considerations
15 of system planning are part of the Integrated Power System Plan process.

16
17 With respect to Pickering A performance, the Return to Service (“RTS”) analysis anticipated
18 that the initial years would be challenging as the units were brought back from extended lay-
19 up (Ex. A1-T4-S3, page 10).

20
21 MR. ROBINSON: The Pickering A units have just come out of a very
22 extended shutdown, and a lot of the unplanned capability there is
23 discovery work coming out of those long shutdowns, and so even though
24 the elective backlogs are lower than Pickering B, there was some
25 expectation when we brought those units back that their capability would
26 not be as good over the short-term, but would improve over time. (Tr. Vol.
27 4, page 130)
28

29 The average capacity factor assumed for Pickering A Unit 1 in the OPG Review Committee
30 report that recommended the units return to service was 75 percent to 90 percent over the
31 multi-year service life (Ex. L-6-32). The average capacity factor forecast for Unit 4 was 85
32 percent with a range of 70 percent to 90 percent tested as part of the sensitivity analysis. The
33 combined target forecast unit capability factory for Pickering A in 2009 is 81.4 percent, which
34 is within the 75 to 90 percent range (Ex. A1-T4-S3, page 13, Chart 2). Achievement of
35 performance in this range will significantly improve Pickering A’s per unit costs.

1

2 AMPCO and Energy Probe suggest comparing Pickering A costs to Hourly Ontario Energy
3 Price (“HOEP”) to determine if Pickering A is economic (AMPCO argument, para. 133;
4 Energy Probe argument, para. 76). This comparison is fallacious. Nearly all generators in
5 Ontario receive supplementary payments from contracts administered by the Ontario Power
6 Authority (“OPA”), which add to the revenues they receive from the market (Tr. Vol. 15,
7 pages 95-96).

8

9 AMPCO also incorrectly states that the forecast incremental cost of Pickering A production
10 averages 8.1 cents/kWh over the test period (AMPCO argument, para. 135). The correct
11 figures are 7.6 cents/kWh in 2008 and 7.7 cents/kWh in 2009 (Tr. Vol. 4, pages 161-62).

12

13 SEC claims that OPG has no plan to improve production at Pickering, but this too is wrong
14 (SEC argument, paras. 72-74). OPG’s written and oral evidence clearly describes how OPG
15 intends to improve performance (Ex. F2-T2-S1, pages 26-27, lines 34-38; Ex. L-1-32; Tr. Vol.
16 4, pages 160-62).

17

18 SEC also submits that investments in performance improvement should have been made in
19 the past (SEC argument, para. 73). OPG’s evidence clearly shows that such investments
20 have been made over the past few years, but that additional investments are needed to
21 achieve sustained performance improvements (Ex. A1-T4-S3, pages 8-11). As the benefits
22 of these additional investments will accrue to ratepayers in the form of increased production
23 and lower cost per unit of output, it is appropriate that they bear the costs of these
24 investments (Tr. Vol. 4, pages 167-68). The projected improvements can be seen in OPG’s
25 performance targets for 2008 and 2009⁷ (Ex. A1-T4-S3, page 13).

26

27 With respect to Pickering B, OPG is currently assessing the possibility of refurbishment with
28 a recommendation expected to go to OPG’s Board of Directors by early 2009 (Ex. D2-T1-S3,
29 page 4). This assessment work will include analyzing the anticipated future performance of
30 the facility (Tr. Vol. 4, page 131). Given that OPG’s plans for Pickering B will be presented in

⁷ The apparent decline in Darlington’s performance for 2009 is attributable to the mandated vacuum building outage that will require all four units being out of service for approximately 4 weeks (Ex. E2-T1-S2, page 3).

1 the next payments amounts proceeding, there is no reason for the OEB to make any
2 pronouncement with respect to its future operations in this proceeding and the OEB should
3 decline intervenors' invitation to do so.

4
5 Simply put, it is not the OEB's role in this proceeding to decide whether Pickering A and B
6 should continue to operate. Those decisions are for OPG's Board of Directors in the first
7 instance, and ultimately for OPG's shareholder, the Province.

8 More generally, OPG would make the observation that a number of intervenor arguments
9 refer back to decisions made in the past, before OPG even existed, and seek to assign
10 "blame" or to justify non-recovery of costs today for alleged prior failings of management.

11
12 Leaving aside the OEB's jurisdiction to consider such arguments, given the language of
13 section 78.1 and O. Reg. 53/05 (OPG would submit that the OEB's jurisdiction does not
14 extend to the reconciliation of any historical decisions). There is a complete absence of any
15 evidence on the record that any historical decisions of Ontario Hydro's management (or of
16 OPG's for that matter) were imprudent having regard to information that was reasonably
17 available at the time those decisions were made. As OPG noted in its argument-in-chief,
18 hindsight may not be used to evaluate prudence. The broad, vague allegations of historical
19 mismanagement made by intervenors rely 100 percent on hindsight and do not even come
20 close to establishing any basis upon which the denial of costs today could be justified.

21
22 **Issue 5.3**

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

25
26 **NUCLEAR**

27 OPG's wages, salaries, benefits, incentive payments and pension costs are discussed below
28 in the section on Corporate operating costs. This section addresses the FTEs necessary to
29 operate OPG's prescribed nuclear facilities safely and efficiently.

30
31 Staffing levels since 2006 have been under pressure due to changes in work programs for
32 matters such as security, new generation development; Pickering B refurbishment, and the

1 isolation and safe storage of Pickering A units 2 and 3, preparation for vacuum building
2 outages at both Darlington and Pickering and maintenance backlog reductions (Tr. Vol. 5,
3 pages 39-40). OPG has been able to find efficiencies to offset these pressures on staff levels
4 and maintain these levels with a slight decline in 2009 (Ex. F2-T2-S1, Table 3).

5
6 OPG's evidence that it has found efficiencies is borne out by review of staffing levels in
7 specific areas. While overall staffing has experienced an absolute increase from 7,482 to
8 7,934 over the 2005 to 2009 period (an increase of 452), a review of the underlying drivers
9 reveals that new initiatives, not inefficiency, are driving this increase. Indeed, as noted
10 above, OPG is finding efficiencies in operations.

11
12 As shown in Ex. F2-T2-S1 (pages 20-21 and Table 3), the initiatives requiring additional staff
13 are:

- 14 • New generation development and Pickering B refurbishment (net increase of 185 staff).
- 15 • Inspection and Maintenance Services is increasing staff from 440 to 669 as part of its
16 initiative to move from contracting staff to full time staff. This will make Inspection and
17 Maintenance Services more efficient and ensure better performance (Ex. G2-T1-S1,
18 pages 6-7).
- 19 • Pickering A safe storage project has increased from 107 in 2005 to 168 in 2009 (a
20 decline from 205 in 2008).
- 21 • Programs and Training has increased by 150 staff driven by demographics need (Ex. F2-
22 T2-S1, Appendix D) and significant changes to security requirements as mandated by the
23 Canadian Nuclear Safety Commission (Tr. Vol. 5, page 39).

24
25 The above four drivers representing new work activities, regulatory requirements or
26 Inspection and Maintenance Services productivity enhancements, total 655 FTEs, yet total
27 OPG staff over the period increases by only 452 FTEs. This demonstrates the effectiveness
28 of measures taken by OPG to find efficiencies and reduce staffing levels.

29
30 VECC asks the OEB to disallow \$20.6M in labour cost because, in VECC's view, they are
31 excessive (VECC argument, paras. 68-69). In making this proposal VECC fails to realize that
32 OPG's average increases in labour are made of individual annual increases that are above

1 and below the average. General wage escalation rates (excluding any staff movement,
2 progressions, and promotions) average less than 3 percent for the Power Workers' Union
3 and Society represented employees who comprise about 90 percent of OPG's workforce
4 (Ex.F3-T4-S1, pages 2 and 38). Including staff movement, progressions and promotions, the
5 average annual escalation rate is about 4 percent for represented staff (Ex. F3-T4-S1, page
6 29). Given that there is variability in staff movement, progressions and promotions across
7 years, it is possible to have years that are below and years that are above the average. For
8 example, while the Nuclear chart in Ex. J2.4 shows a 6.5 percent increase in 2008, the Hydro
9 chart shows an increase of only 1.6 percent in 2006.

10
11 Moreover, contrary to VECC's claim, OPG did not indicate that the 2008 increase in nuclear
12 costs for 2008 in Ex. J2.4 could not be explained. Instead, OPG stated a number of factors
13 that could contribute to the increase including changes to the burden factors included in base
14 labour costs, and indicated that in the time available to prepare the undertaking response,
15 which OPG developed to correct the errors in VECC's Ex. K2.1, there was insufficient time to
16 fully analyze the increase (Tr. Vol. 4, pages 55-56).

17
18 **Issue 5.7**

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

20
21 OPG's forecast of nuclear fuel costs should be adopted by the OEB. No intervenor opposed
22 the forecast or proposed an alternative forecast. Board Staff states that increased use of
23 market-based contracts increases the risk that OPG's forecast does not accurately reflect the
24 nuclear fuel costs it will incur, but that this risk can be eliminated by OPG's proposed nuclear
25 fuel price variance account (Board Staff submission, page 41). OPG does not agree that its
26 nuclear fuel forecast is inaccurate, but does agree that its proposed nuclear fuel variance
27 account will address the risk that Board Staff sees in this area.

28
29 **Issue 5.8**

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

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No party specifically commented on OPG's proposed outage OM&A expenditures. As such, and for all the reasons set out in its evidence and argument-in-chief, these amounts should be accepted by the OEB as filed. General comments on OM&A levels are addressed above under Issue 5.3.

CORPORATE

Issue 5.3

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

Wages and Salaries

OPG uses an array of tools to determine its wages and salaries relative to market. OPG undertakes separate comparisons for its management and unionized positions with management positions being compared against both utility and non-utility comparator groups (Ex. F3-T4-S1, section 9.0). These comparisons demonstrate that OPG's labour costs are reasonable and appropriate, as summarized in OPG's argument-in-chief (pages 65-66).

SEC argues that Bruce Power's labour costs are not a meaningful comparator suggesting that "OPG and Bruce Power have a common problem" due to "legacy collective agreements and labour costs" (SEC argument, para. 97). It has been approximately seven years since the employees in question became the employees of Bruce Power, and thus SEC's attempt at painting Bruce Power essentially as a "sister" company to OPG rings false. Moreover, OPG has never stated that Bruce Power is a perfect comparator. In fact, OPG noted that Bruce Power's collective agreements have changed since 2001 and that Bruce Power's private ownership affects its negotiating stance and, ultimately, its collective agreements (Tr. Vol. 8, page 69; Tr. Vol. 9, page 93). Finally, OPG notes that a comparison against Bruce Power is only one of a number of tools that OPG has made available to the OEB and intervenors in the course of this hearing to support the reasonableness of OPG's labour costs. This comparison shows that in OPG's wages for 2008 are more than 13 percent below those of Bruce Power (Ex. F3-T4-S1, page 36).

1

2 SEC's argument applies the results of the Mercer Compensation Review inappropriately and
3 thus draws erroneous conclusions regarding the reasonableness of OPG's overall labour
4 costs (SEC argument, paras. 98-99). First, OPG reiterates that the Mercer study is for
5 management employees only, which represent only 10 percent of OPG's workforce (Ex. F3-
6 T4-S1, page 2). Second, in the non-utility comparison data presented by SEC, OPG is below
7 market in Bands A, B, C, E and F, slightly above market in Bands G and K, and above
8 market in Bands D, H, I, J, L and M. However, SEC's analysis fails to consider the actual
9 number of management employees in each band. This information is clearly necessary for
10 any meaningful conclusion with respect to OPG's overall management labour cost levels.

11

12 OPG notes that the vast majority of management employees are in bands F, G and H.
13 Among these bands, only band H is significantly above the non-utility average; Band G is
14 similarly above the utility average. Bands H and G exceed these comparators as a result of
15 compression issues relative to the unionized wages of the subordinates of these employees,
16 who are generally first-level managers (Ex. F3-T4-S1, page 31, lines 4-6). In order to
17 address demographic and succession planning pressures, OPG must provide appropriate
18 incentives to get staff to move up into these entry-level management positions. SEC
19 appeared to understand this issue of compression in the context of the discussion of shift
20 premiums, but that understanding has not carried over to the need to establish appropriate
21 salaries for first-level supervisors in Bands H and G (Tr. Vol. 8, page 157).

22

23 SEC notes that while Band A compensation is well below the non-utility comparators, it is
24 200 percent above the utility comparators (SEC argument, para. 98). OPG's single Band A
25 employee is the Chief Executive Officer and his compensation is appropriate given the state
26 of the labour market, the experience and talent of the incumbent, and the scope of the Chief
27 Executive Officer's job at OPG in light of the complexity and diversity of OPG's operations
28 when compared to other utilities (Tr. Vol. 8, page 86-87).

29

30 SEC also questions OPG's conclusion that the Tower's Perrin Study shows that the company
31 is slightly above market for the positions surveyed (SEC argument, paras. 100-104). As SEC
32 notes, following standard compensation practice, a position is considered to be on market if it

1 is within 10 percent of the market comparator (Ex. L-1-53). Without any evidence
2 whatsoever, SEC concludes from this statement that “a threshold of 10% above the 75th
3 percentile would likely mean OPG’s salaries could be above the 80th percentile of the
4 market” (SEC argument, para. 102). This is pure speculation unsupported by the record.

5
6 Rather than looking only at positions that are above market as SEC does, OPG submits that
7 a more appropriate way to put the variances shown by the Towers Perrin study in
8 perspective is to determine the simple average of the positive and negative variances greater
9 than 10 percent (SEC argument, page 103). Out of a total of 34 positions (rather than figure
10 of 33 cited by SEC), there are 21 positions meeting the 10 percent threshold (19 with positive
11 and 2 with negative variance). The simple average of these variances is approximately 14.5
12 percent, which means that OPG’s positions, on average, are approximately 4.5 percent
13 above the “on market” threshold.

14
15 SEC erroneously contends that because licence retention bonuses and leadership
16 allowances received by some OPG staff are not included in the wage comparisons presented
17 in the Towers Perrin study, the comparison to the market benchmarks is in reality even less
18 favourable to OPG. Given that payments of this type are not included in either the OPG or
19 the comparator data, OPG fails to see how they influence the comparison (Tr. Vol. 8, pages
20 158-159). In other words, it is entirely possible that other members of the comparator group
21 offer their employees different types of incentive compensation that OPG does not, and that
22 inclusion of this compensation would actually make the comparison more favourable to OPG.

23
24 OPG also disagrees with SEC’s submission that “there is no point in doing a benchmark
25 comparison if your attitude appears to be that your results are acceptable even if you’re near
26 the top of the market” (SEC argument, para. 102). By definition, comparisons are made
27 against the market benchmark that one is trying to match. OPG explicitly selected the 75th
28 percentile of the market as its market benchmark in order to take into account the “additional
29 complexity in OPG that does not exist in other utilities” and “OPG having unique and diverse
30 assets that are not found in other utilities” (Ex. F3-T4-S1, pages 12 and 31). Factors
31 evidencing this complexity include having the largest nuclear fleet in Canada, the first (and
32 oldest) large-scale CANDU reactor units ever built, some of the oldest hydroelectric

1 generating assets which are also subject to complex international agreements and water flow
2 management requirements, as well as diverse requirements in corporate support areas such
3 as risk management, compliance with legislative requirements, labour relations, and real
4 estate portfolio management, among others (Ex. L-6-11).

5
6 Performance Incentives

7 SEC and AMPCO argue that OPG's incentive plan, particularly with respect to nuclear
8 operations, is not properly aligned with achieving "cost efficiencies" (SEC argument, para.
9 108) and "improved operational performance and cost control" (AMPCO argument, para.
10 145). These arguments are inaccurate and rely on a selective presentation of the evidence.
11 Rather than demonstrating flaws in OPG's performance incentive plan, these arguments
12 demonstrate a lack of understanding regarding the plan's operation. OPG's incentive plan is
13 robust and clearly aligns with ratepayer interests, including cost efficiencies and operational
14 performance. This is true both from a plan design and actual plan payout perspective as
15 demonstrated below.

16
17 The crux of the argument advanced by AMPCO and SEC is that nuclear incentive levels do
18 not appear to correlate well with nuclear production cost per unit of output (AMPCO
19 argument, para. 143; SEC argument, para. 105). This argument ignores the fact that OM&A
20 cost levels and production together comprise 50 percent of OPG's nuclear business unit
21 objectives in the 2007 incentive plan (30 percent for production against budget and 20
22 percent for financial performance expressed as OM&A against budget), (Ex. L-14-70,
23 Attachment 7 - Nuclear Business Unit Scorecard). Similarly, OM&A cost levels and
24 production targets represent 70 percent of the 2007 OPG's corporate objectives for the
25 incentive plan (20 percent for nuclear production, 15 percent for non-nuclear production, and
26 35 percent for reductions in OM&A costs) (Ex. L-14-71, page 5).

27
28 As both costs and production clearly represent the dominant components of the business
29 unit and corporate-wide incentive plan scorecards, it is not necessary to introduce an actual
30 measure of "cost / unit of production" because both the numerator and denominator of such a
31 measure are already included in the scorecards. They are simply separated into two distinct
32 objectives rather than being combined. Production and cost reduction are the only financial

1 measures present in corporate-wide and business unit scorecards. Profit is not a component
2 of the incentive payments (Tr. Vol. 9, page 57).

3
4 SEC's statement that OM&A cost control could represent "only about 18 percent for
5 employees in the corporate function and as little as 8 percent for other employees" is wrong
6 (SEC argument, para. 107). All OPG employees are subject to three levels of scorecards
7 with various weightings: corporate (25 percent), business unit (50 percent) and individual (25
8 percent), except for senior corporate executives who are rated only on overall corporate
9 score (Ex. F3-T4-S1, page 14). Given that OM&A cost control accounts for 35 percent of the
10 corporate scorecard and 20 percent of the nuclear business unit scorecard in 2007, a
11 production unit employee has a minimum 19 percent ($35\% \times 25\% + 20\% \times 50\%$) of his or her
12 performance incentive tied to cost control (Ex. L-14-70). In addition, SEC's claim that this
13 percentage cannot be calculated from information on the record is wrong (SEC argument,
14 page 107).

15
16 If the score does not meet the threshold value (usually at a 5 percent variance from target),
17 no incentive is awarded. Conversely the incentive awarded increases if the target for a
18 measure is exceeded, until the maximum payout is reached, typically at 5 percent above
19 target (Tr. Vol. 9, page 59). Therefore, the incentive plan clearly encourages OPG's
20 management to strive to meet and exceed the targets related to production and cost control,
21 both of which are in ratepayers' interest.

22
23 AMPCO errs when it claims that OPG's incentive plans are "clearly disconnected" from
24 "economic performance" based on a comparison of the change in nuclear unit production
25 costs relative to incentive pay levels year over year (AMPCO argument, para. 143). Incentive
26 awards are based on performance relative to the business plan in each year. Evaluating
27 performance against annual business plan targets is superior to comparing results against
28 prior year performance because business planning takes into account more than just what
29 happened last in the previous year. For example, the business planning process sets
30 production targets for the year taking into account planned outages and the forecast forced
31 loss rate. This was explained as follows:

32

1 MR. RODGER: What we see happening is that the performance
2 incentives increased from 24.6 million in 2005 to 29 million in 2007. So
3 the 19 percent nuclear cost increases, our conclusion is that they were
4 not significant enough to result in reductions in incentives being paid; is
5 that correct?

6 MS. IRVINE: I believe what you are trying to draw a parallel from is not
7 necessarily correct. The incentives are based on the business planning
8 for the year, and costs aren't necessarily going to go down if you have
9 bigger projects planned in a certain year, or so on, of if you have higher or
10 lower production targets because of outages. So I don't think you can
11 draw a line between those two numbers (Tr. Vol. 8, pages 52-53)
12

13 There are significant flaws in AMPCO's analysis of the incentive pay allocated to nuclear
14 (AMPCO argument, para.143). The analysis does not recognize that of the \$4.4M increase
15 from 2005 to 2007 (from \$24.6M to \$29.0M), approximately \$4.1M relates to the introduction
16 of a new performance recognition system for staff represented by the Society of Energy
17 Professionals starting in 2006 in order to improve productivity and encourage increased
18 personal performance (Ex. F3-T4-S1, page 10). Also management incentives are determined
19 as a percentage of base pay (Ex. F3-T4-S1, Chart 4). Thus, as base pay increases, so does
20 the absolute dollar value of incentive payouts even when the percentage payout remains the
21 same. The escalation rate for management pay was approximately 1.5 percent in 2006 and 3
22 percent in 2007 (Ex. F3-T4-S1, page 29). Therefore, after adjusting for the Society
23 performance recognition system and the two years of salary escalation, the level of
24 incentives has actually decreased from \$24.6M to \$23.8M.
25

26 A clear example of the operation the incentive plan can be further found upon the
27 examination of results and incentive plan scores in 2007. On the corporate-wide scorecard,
28 the nuclear production component received a very low score of 0.6, well below the score of
29 1.0 which represents achievement of target (Ex. L-14-71, page 5). The same score of 0.6
30 was given to the production component of the nuclear business unit scorecard for that year.
31

32 These scores demonstrate that the lower than planned nuclear production in 2007 reduced
33 payments under OPG's incentive plan. Furthermore, this reduction not only affects staff in
34 the nuclear business unit but it affects all other staff within the organization (including
35 regulated hydroelectric and corporate support groups) by virtue of the fact that nuclear
36 production is given a 20 percent weight on the corporate-wide scorecard, in addition to its 30

1 percent weight on the nuclear business unit scorecard (Ex. L-14-71; Ex. L-14-70, Attachment
2 7).

3
4 Finally, the elements of the incentive award formula not directly related to cost control or
5 production also produce clear benefits for ratepayers. For example, for the nuclear business
6 unit, 21 percent of the score is related to the clearing of elective and corrective backlogs as
7 well as achieving planned duration of outages and performing the planned scope of work
8 during these outages (Ex. L-14-70, Attachment 7). These goals are clearly an integral part of
9 efficient and reliable operation of nuclear stations. The nuclear business unit scorecard also
10 included measures that relate to project execution and completion of service milestones
11 (ibid.). These activities are all necessary to ensure continued safe and reliable operation of
12 nuclear facilities. They fully meet AMPCO's suggestion that incentives be linked to "improved
13 operational performance and cost control" and SEC's submission that incentives be tied to
14 efficient day to day operations (AMPCO argument, para. 145; SEC argument, para. 108).

15
16 Licence Retention

17 SEC asks the OEB to find that OPG's licence retention bonuses are *per se* imprudent and
18 uses these bonuses to exemplify what it regards as OPG's lack of discipline in collective
19 bargaining (SEC argument, para. 112). Once the facts underlying the licence retention
20 bonuses are presented, and they are viewed in their proper context, however, OPG believes
21 that the OEB will come to see them for what they are – reasonable provisions in a negotiated
22 collective agreement.

23
24 The Canadian Nuclear Safety Commission ("CNSC") licensing process is challenging and
25 requires employees to devote their personal time and effort to obtaining and retaining a
26 licence (Ex. F3-T4-S1, page 17). Contrary to SEC's view, positions that require a licence do
27 not attract a higher salary than that paid to other similarly graded positions (SEC argument,
28 para. 110). As a result, in the rare case that an employee fails to maintain his or her licence,
29 the employee would move to another similarly graded position that did not require a licence
30 (Tr. Vol. 8, page 156). That is, they would do work that OPG has determined to be at the
31 same level, but which can be performed without a licence from the CNSC. Practically,
32 however, this is of minimal concern because OPG's evidence establishes that for each year

1 between 2005 and 2007 less than one percent of the employees who receive these bonuses
2 have let their licences lapse (Ex. L-6-13, Part D). This evidence demonstrates that the
3 bonuses are working for their intended purpose.

4
5 Ms. Irvine testified that nuclear operators typically include a portion of Licence Retention
6 Bonuses and Leadership Allowances in pensionable earnings (Tr. Vol. 8, p. 161-62). Ms.
7 Irvine agreed that that this practice is not common in the private sector but reiterated that it is
8 common in the nuclear industry (Ibid.). This is not a public versus private issue. A private
9 company like Bruce Power is still a nuclear company. For nuclear companies there is a
10 unique need to attract and retain qualified employees, particularly those who possess the
11 skill and ambition necessary to acquire and maintain a CNSC licence (Ex. F3-T4-S1, page
12 17).

13
14 The Licence Retention Bonus is a single provision in OPG's collective agreement. To isolate
15 it and say "this by itself" is unreasonable is to misunderstand the collective bargaining
16 process. In a negotiated agreement, no provision stands by itself. Instead each forms part of
17 a collective whole that is acceptable to both parties. OPG's Licence Retention Bonuses help
18 address its crucial business need for authorized nuclear operators and are a reasonable and
19 prudent part of OPG's collective agreement.

20
21 Collective Bargaining

22 SEC argues that OPG has not been diligent in controlling either labour or retiree benefits
23 costs because it has had the ability to pass these costs through to customers. It suggests
24 that if OPG is to receive a commercial rate of return, it must act like a commercial company.
25 This argument is wrong on a number of levels. OPG's costs are not today and never were a
26 "flow through to ratepayers." Up until April 1, 2005, OPG received revenues that were limited
27 by the Market Power Mitigation Agreement ("MPMA") that capped the price OPG could
28 receive for the majority of its output (Ex. A2-T1-S1, Appendix A, 2005 Annual Report, pages
29 14-15). Since April 1, 2005, the bulk of OPG's output (i.e., the production from the prescribed
30 facilities) has received a fixed rate set by the Province; the majority of the non-regulated
31 production is subject to the OPG non-prescribed assets rebate ("ONPA"), a new cap and
32 rebate mechanism (Ibid.).

1

2 As this brief recitation indicates, since its inception, OPG's revenues have been limited by
3 various rebate and regulatory mechanisms. In response to them, OPG, acting as any
4 commercial company would, has attempted to control costs, including labour and retiree
5 costs, to maximize the return to its shareholder. The fact that OPG has acted like any other
6 commercial company undercuts SEC's claim that it should not receive a commercial rate of
7 return (SEC argument, para. 118).

8

9 SEC's argument implies, without any evidence, that OPG engages in collective bargaining
10 with different objectives than those of a private unionized enterprise (SEC argument, paras.
11 118-119). SEC provides no evidence for this assertion because none exists. In fact, all of the
12 evidence in this proceeding points to the opposite conclusion. OPG has taken steps to
13 control labour costs and improve productivity in each round of collective bargaining (Tr. Vol.
14 9, pages 69-70). OPG has been successful in negotiating general wage increases for its
15 unionized employees that in total are below those achieved by most of the former Ontario
16 Hydro successor companies and OPG's current competitors who employ staff represented
17 by these unions (Ex. F3-T4-S1, Charts 13 and 14). OPG has also taken a number of steps
18 with respect to managing its pension and benefit costs (OPG argument-in-chief, pages 67-
19 68). In short, the evidence in this proceeding overwhelmingly demonstrates OPG's prudence
20 in conducting labour negotiations and exercising control over labour cost.

21

22 Like any organization with a heavily-unionized workforce (whether public or private; regulated
23 or unregulated), OPG must "balance the business requirements and long-term company
24 interest related to working in a competitive, unionized environment with unions, who, in most
25 cases (e.g., the Power Workers' Union), have the right to strike." (Ex. F3-T4-S1, pg. 6) In
26 protecting consumers and promoting the public interest, the OEB should recognize the
27 negative consequences of OPG having an adversarial relationship with its unions and the
28 severe consequences of a potential labour disruption (both in terms of financial cost to
29 consumers as well as the broader social, economic and human costs). The OEB should
30 review the prudence of OPG's management decisions and actions in labour negotiations with
31 these considerations in mind.

32

1 **Issue 5.4**

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

4

5 Several intervenors have contested the allocation of OPG's corporate costs to the regulated
6 businesses and, in certain specific areas (i.e., information technology and parts of Corporate
7 Affairs), the costs themselves. As OPG will demonstrate below, these claims fail when
8 viewed against the evidence as a whole.

9

10 Corporate Cost Allocation

11 CME claims that OPG has failed to meet its burden of proof on the issue of corporate cost
12 allocation because the R.J. Rudden study that OPG supplied to independently validate its
13 corporate cost allocation methodology was based on 2006 data and is therefore, in CME's
14 view, out of date (CME argument, para. 196). This claim is wrong on several counts. OPG's
15 allocation methodology is fully explained in OPG's evidence (Ex. F3-T1-S1; Ex. F3-T1-S2).
16 This evidence stands on its own merits and meets OPG's burden of proving that the
17 proposed allocation of corporate common costs and centrally held assets in the test period is
18 fair and reasonable. There was no requirement in the OEB's Filing Guidelines that OPG file
19 an independent review of its cost allocation methodology; OPG commissioned an
20 independent review and filed the resulting report on its own initiative.

21

22 OPG voluntarily engaged R.J. Rudden so as to provide the OEB and intervenors with
23 additional evidence that OPG's corporate cost allocation methodology is appropriate (Ex. F4-
24 T1-S1). Rudden used 2006 data in conducting its analysis because that was the most recent
25 data available when OPG filed its application in November 2007. Based on its review,
26 Rudden concluded that OPG's allocation methodology uses direct allocation where possible
27 and appropriate allocators where direction allocation is not possible; and is consistent with
28 best practices and applicable regulatory precedents (Ex. F4-T1-S1, page 4). No party
29 challenged Rudden's conclusion; nor did anyone challenge Rudden's independence,
30 objectivity or expertise in this area.

31

1 OPG's sworn testimony confirms that the methodology endorsed by Rudden in its 2006 study
2 has been consistently applied to the forecast 2008-2009 costs at issue in the current
3 application (Tr. Vol. 9, page 20, lines 17-18). Moreover, OPG's auditors have confirmed that
4 the 2007 costs are based on the application of the company's cost allocation methodology
5 (Tr. Vol. 9, page 23). Thus, CME's proposed disallowance of \$40M related to this issue is
6 completely without merit (CME argument, para 197).

7
8 VECC also claims that OPG has failed to provide an independent evaluation for the test
9 period corporate cost allocation and urges the OEB to order OPG to produce an independent
10 evaluation in its next application (VECC argument, paras.72-74). Board Staff also raises
11 questions about the need for an independent cost allocation review in the next rate hearing
12 (Board Staff submission, page 40). OPG will submit an independent evaluation of its
13 corporate cost allocation methodology and the use of that methodology to allocate costs in
14 the test period as part of its next application for payment amounts.

15
16 The growth in the allocation of corporate costs to the regulated businesses, particularly the
17 regulated hydroelectric business, relative to the allocation to OPG's unregulated businesses,
18 has been fully explained in OPG's pre-filed evidence, interrogatory responses and oral
19 testimony. In raising this issue in argument, intervenors have not refuted these explanations,
20 just ignored them and substituted crude and arbitrary analyses for facts. In addition, OPG
21 has fully explained the necessity for growth in certain corporate costs areas in ways that fully
22 address all of the points raised by intervenors. Again, intervenors have not challenged these
23 explanations.

24
25 AMPCO states that it is "concerned by the evidence that indicates that OPG's corporate
26 central O&M associated with its regulated assets are increasing at a significantly higher rate
27 than the costs associated with OPG's unregulated assets." In support of this assertion,
28 AMPCO offers only a comparison of increases from 2005 to 2007, the historical period
29 covered by the interim rates established by the Province. The more relevant comparison (i.e.,
30 one that actually encompasses the test period costs at issue in this proceeding) is the
31 increase from 2005 to 2009 (Ex. K8.1, page 5). That comparison shows a much lower
32 number. Costs allocated to unregulated operations increase by 17 percent rather than 6.5

1 percent as claimed by AMPCO (AMPCO argument, para. 103). This increase is much more
2 consistent with the increase in total corporate costs of 22 percent and the 21 percent
3 increase in cost allocated to the nuclear business for that same period. The costs allocated
4 to the hydroelectric business did increase quite substantially during this period, due to factors
5 unique to the growing hydroelectric business, as discussed below.

6
7 The increased costs allocated to the hydroelectric business between 2005 and 2009 are
8 primarily due to the relatively higher increase in capital spending for hydroelectric projects,
9 primarily the Niagara Tunnel project (Ex. L-1-36, Part C). That hydroelectric capital spending
10 is growing faster than spending in the unregulated parts of OPG makes perfect sense.
11 Hydroelectric capital spending is increasing due to the Niagara Tunnel project and other
12 refurbishment projects, growing from about \$85M in 2005 to almost \$396M in 2009. (Ex. D1-
13 T1-S1, Table 1). In contrast, no increases in capital spending for unregulated facilities are
14 forecast (Tr. Vol. 8, page 150). This is to be expected given that the coal plants, which make
15 up a large portion of the unregulated generation facilities, are due to be shut down by 2014.

16
17 Higher capital spending for regulated hydroelectric impacts the allocation of corporate costs
18 in two ways. First, a number of corporate costs are allocated based on a blend of OM&A and
19 capital spending (Tr. Vol. 8, page 151). As a result, the relatively higher amounts of
20 hydroelectric capital spending increases the costs allocated to hydroelectric. Second, the
21 greater amount of capital work in the regulated hydroelectric area due to the Niagara Tunnel
22 was a major driver in the establishment of a separate Finance controllership group for
23 hydroelectric which increased the corporate costs directly assigned to regulated hydroelectric
24 (Ex. L-14-54, Part (A) and Tr. Vol. 8, page 148).

25
26 Further, the intervenors' claims regarding the increase in costs allocated to regulated
27 business ignore the fact that the overall level of costs allocated to the regulated operations,
28 as a percentage of OPG's total corporate costs, has ranged between 68 and 71 percent
29 over the 2005-2009 period and is moving toward the lower end of that range during the test
30 period (2005 Actual – 67.7 percent, 2006 Actual – 70.0 percent, 2007 Actual – 71.3 percent,
31 2008 Plan – 69.6 percent, 2009 Plan – 68.9 percent) (Ex. L-1-58). The allocations to
32 regulated hydroelectric business specifically have grown only marginally from 4.9 percent to

1 6.8 percent over the same period (Ex. J8.7) – small growth that is consistent with reasons
2 outlined above related to the expansion and refurbishment of OPG’s regulated hydroelectric
3 production.

4
5 SEC claims that the percentage of corporate and centrally-held costs allocated to the
6 regulated business is higher than is warranted by the percentage of generation capacity or
7 revenues represented by the prescribed facilities (SEC argument, para. 125). As OPG
8 pointed out during the hearing, revenues are not particularly relevant to allocating corporate
9 costs because the revenues of the prescribed facilities are baseload facilities constrained by
10 the regulated payment amounts while the non-regulated facilities include peaking facilities
11 whose revenues are impacted by the generally higher market price during peak periods (Tr.
12 Vol. 9, page 97). Similarly, capacity is not a relevant comparator because the prescribed
13 facilities are dominated by the nuclear plants, which are significantly more complex and
14 require more employees than the non-regulated facilities. The percentages of the relevant
15 comparators (FTEs, OM&A spending and capital expenditures) attributable to the prescribed
16 facilities are equal to or greater than the 70 percent of corporate costs allocated to them (Tr.
17 Vol. 9, page 98).

18
19 SEC also makes the curious submission that because some of the corporate OM&A costs
20 are being allocated to the prescribed facilities using an allocator that includes a blend of
21 OM&A and capital costs, these costs should be capitalized (SEC argument, para. 130). This
22 argument confuses the allocation of costs and the nature of those costs. Costs are allocated
23 using appropriate cost drivers, whose primary purpose is to reflect cost causation (Ex. F4-T1-
24 S1, page 7). Costs are capitalized based on OPG’s capitalization policy, which capitalizes
25 those support costs that are directly attributable to the capital work being performed
26 consistent with GAAP (Ex. L-1-18). Thus, it is entirely appropriate that capital expenditures
27 would form part of an allocator for OM&A costs that are related to the level of capital work,
28 but are themselves not eligible for capitalization.

29
30 AMPCO and SEC ask the OEB to apply some unspecified form of affiliate relationships code
31 to OPG (AMPCO argument, paras. 105-06; SEC argument, paras. 122-23). OPG submits the
32 application of such a code to OPG would not produce any additional benefits for consumers,

1 would impose additional cost, and would be inconsistent with OPG's corporate structure and
2 operations.

3
4 OPG is a single company with a single business, the generation of electricity. It has no
5 affiliates that engage in other businesses. The operations of the prescribed facilities are part
6 of OPG's overall operations all of which are directed to maximizing value for OPG's
7 shareholder, the Province of Ontario. All of OPG's generation, which must be offered into the
8 market pursuant to the OPG's Generation Licence and in accordance with the IESO Market
9 Rules, is operated in an integrated fashion. The only difference between the regulated and
10 unregulated units from this perspective is the price that they receive from the IESO. Thus,
11 OPG's situation is substantially different from that of the electric and gas distributors that can
12 have multiple businesses in a variety of areas, some of which are competitive but have
13 substantial interactions with the regulated utility (e.g., a local distribution company with an
14 energy services affiliate). Nor is this a situation where a new owner has come in wanting to
15 centralize many operations and lines of business out of a corporate head office in another
16 country or jurisdiction.

17
18 Many of the functions necessary for the prescribed facilities are performed centrally and
19 many of the assets used by the prescribed facilities are centrally held for reasons of
20 efficiency and effectiveness. In addition, the prescribed hydroelectric facilities are integrated
21 within the Hydroelectric business unit and attempting to extract them also would increase
22 cost and reduce efficiency. Thus applying an affiliate relationships code would just add
23 additional cost without producing additional benefit.

24
25 In addition, a number of constraints found in affiliate relationships code for electric
26 distributors and transmitters could not be applied to OPG. For example, conditions related to
27 financial separation or the sharing of employees or information services could not be applied
28 under OPG's current structure. Many of the affiliate relationships code provisions do not
29 make sense in the context of a single company with a single function (e.g., Affiliate
30 Relationships Code for Electricity Distributors and Transmitters, Ontario Energy Board, May
31 16, 2008, sections 2.4 "Financial Transactions" or 2.5 "Equal Access to Services").

32

1 There is no need to apply an affiliate relationships code to OPG. OPG has developed and
2 implemented a fair and reasonable methodology for allocating the costs of common
3 corporate services and centrally held assets. This methodology is fully consistent with the
4 electric distribution affiliate relationships code requirement that shared corporate services
5 pricing be based on fully allocated cost (Affiliate Relationships Code for Electricity
6 Distributors and Transmitters, Ontario Energy Board, May 16, 2008, section 2.3.5). As
7 discussed above, both the methodology and its implementation have been independently
8 reviewed and found to comply with OEB precedent and OPG has stated that it will obtain
9 another independent review for its next rate hearing.

10
11 Introduction of affiliate relationship-type requirements will introduce overlap and duplication
12 and increase costs. Applying the requirements for competitive sourcing of services would
13 necessarily raise costs, as OPG would lose the economies of scope and scale and would
14 incur the transaction costs associated with implementing an affiliate relationship type code
15 and the development of service agreements.

16
17 AMPCO urges the OEB to go further and order OPG to work toward structural separation of
18 the regulated nuclear and hydroelectric businesses, “ideally the two would be separate
19 companies” (AMPCO argument, para. 23). This request is just the latest manifestation of
20 AMPCO’s longstanding agenda to break up OPG. The OEB should reject it as inconsistent
21 with Provincial policy and beyond the jurisdiction provided to the OEB with respect to
22 establishing payment amounts for the prescribed facilities.

23
24 The OPG Review Committee looked at a number of options for OPG including both
25 separation into two independent operating companies and structural separation under a
26 holding company (Report of the OPG Review Committee, pages 28-33). Ultimately, the
27 Committee recommended a model with two operating divisions and a central management
28 function that is similar to the way OPG operates today (the major difference being the
29 subsequent separation of the fossil and hydroelectric facilities into separate operating
30 divisions) (Ibid.). Thus, AMPCO’s proposal has already been considered and rejected.

1 More recently, the government-appointed Agency Review Panel in its November 30, 2007
2 Phase II Review Report identified concerns with overlap and duplication among five
3 provincially-owned agencies in Ontario. Any requirement to structurally separate OPG's
4 regulated and unregulated operations would increase overlap and duplication.

5
6 In any event, the OEB's authority to set payment amounts cannot reasonably be read to
7 confer jurisdiction to order the restructuring of OPG. The OEB's authority with respect to
8 OPG is limited to setting payment amounts for the prescribed facilities. While the OEB may
9 impose conditions, classifications or practices as part of its order (pursuant to OEB Act
10 section 78.1(4)), these can only relate to setting payment amounts for the prescribed facilities
11 not to the overall corporate organization of OPG as a whole, which includes both prescribed
12 and non-prescribed facilities.

13
14 Corporate Costs

15 SEC questions the amount of corporate costs for the Chief Information Officer ("CIO")
16 function (information technology) and parts of Corporate Affairs including regulatory affairs
17 and nuclear advertising and human resource costs including salaries, wages and benefits.
18 CCC also questions the regulatory affairs budget, while Energy Probe challenges the nuclear
19 advertising spending. OPG addresses these issues below and shows that the proposed
20 spending is reasonable and necessary for the operation of the prescribed facilities.

21
22 CCC has proposed that OPG should "continue benchmarking all corporate support and
23 administrative departments" (CCC argument, para. 80). OPG generally agrees that
24 benchmarking is valuable, but wishes to clarify that it does not currently benchmark all
25 corporate support groups. It benchmarks the major groups that have comparable and
26 controllable costs. These groups are CIO, Finance and Human Resources, which represent
27 approximately 73 percent of the corporate costs allocated to the prescribed facilities (Ex. F3-
28 T1-S1, Tables 2 and 3). It is OPG's intention to continue this benchmarking in the normal
29 course of business and to provide those completed benchmarking studies that are available
30 in time for its next OEB application, subject to addressing any confidentially concerns.

1 CCC also requests that the OEB direct OPG to undertake benchmarking on terms
2 acceptable to intervenors (CCC argument, para.80). While OPG is planning on conducting
3 stakeholdering in advance of its next application, as it did with this application, it is not
4 appropriate for intervenors to set the terms of OPG's benchmarking. OPG has the obligation
5 to manage its business effectively and efficiently and is doing so. This is the company's
6 obligation, not that of the intervenors. OPG also has the burden of establishing the
7 reasonableness of the corporate costs allocated to the regulated business, not the
8 intervenors. On this basis the Board should reject CCC's proposal.

9
10 In support of intervenor involvement in benchmarking, CCC cites the collaborative process
11 used by Enbridge Gas Distribution Inc. ("EGD") in the acquisition of its replacement customer
12 information system ("CIS") (CCC argument, para. 81). The context of the EGD case cited by
13 CCC is significantly different from that for benchmarking of OPG's corporate function costs.
14 The EGD consultative process arose after the OEB rejected EGD's proposal to sign a 12-
15 year CIS replacement contract with an affiliate, which had been considered in a 40-day
16 hearing (EB-2005-0001, Decision with Reasons, pages 54-62). The OEB cited deficiencies,
17 in EGD's evidence and concluded that EGD had disregarded the OEB's prior comments on
18 competitive tendering and that the contract's fee structure was not just and reasonable. In
19 contrast, OPG has not disregarded any prior OEB comments and no party has criticized the
20 terms under which OPG has undertaken previous benchmarking studies. Also, the long-term
21 nature of the EGD CIS contract means that it impacts revenue requirement for many years.
22 In contrast, benchmarking is a tool employed by a utility to assess its operations and it does
23 not have a direct or long-term impact on revenue requirement.

24
25 Intervenor interest in OPG's corporate cost benchmarking studies (the list of which was
26 provided in response to interrogatory Ex. L-6-42) during this proceeding was limited. In fact,
27 CCC was the only intervenor to ask about the benchmarking studies and, when CCC was
28 asked by OPG whether it was interested in reviewing all the corporate cost studies listed in
29 Ex. L-6-42, CCC declined and asked only for the Finance benchmarking study (Tr. Vol. 8,
30 pages 18-19; Ex. J8.3). Based on these facts, OPG submits that the current circumstances
31 do not warrant such an extraordinary step as ordering OPG to obtain intervenor agreement
32 to terms and methodologies of corporate cost benchmarking studies.

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OPG's management recognizes the value of benchmarking and, consistent with its Memorandum of Agreement with its shareholder, has used benchmarking as one tool in its pursuit of efficiency improvements. Ultimately, however, management is in the best position to make final decisions on benchmarking and the OEB should not micro-manage this effort or cede to intervenors responsibilities that rest with management.

CCC also requests that OPG be ordered to undertake an "independent end-to-end review of its internal corporate processes to ensure that: Services are not duplicated with the OPG's operating divisions; and processes for review, reporting and approval are effective" (CCC argument, para. 78).

OPG has fully described its corporate support business planning process (Ex. F3-T1-S1, page 3; Tr. Vol. 9, pages 63-65). During this process corporate groups are challenged by their leaders to identify cost savings each year. OPG's senior executives, including the Chief Financial Officer and Chief Executive Officer, challenge the business units during the budgeting process as to the necessity of proposed expenditures and the efficiency of spending. Finally, the level of costs being allocated to production businesses is challenged by the production business unit leaders who evaluate the level of support they receive from corporate groups and ask the corporate groups to justify how corporate costs help them to generate electricity (Tr. Vol. 8, page 72; Ex. L-14-53, Part A).

OPG also has recently concluded Phase I of the Support Function Review (Ex. F3-T1-S1, pages 3-4; Ex. L-14-53, Part B). That examination "consisted of a review of both corporate and business unit support groups' cost structure and work programs" and specifically focused on "how OPG can be more effective and efficient, especially in supporting its work priorities" (Ex. F3-T1-S1, page 3). It also considered "opportunities to optimize OPG's support function resources." (Ex. L-14-53, page 2). This application reflects savings of approximately \$37M over 2008 and 2009 in nuclear and the corporate support groups resulting from Phase I of this review. In light of the Support Function Review, the additional study suggested by CCC would appear to duplicate work already undertaken by OPG in 2007.

1

2 CCC raised no concerns with regard to OPG's organization structure nor has it identified
3 duplicated services that would justify its requested study. In fact, CCC has acknowledged
4 that centralization of support functions has helped to decrease costs (CCC argument, para.
5 78). Nor is there any evidence to suggest that OPG corporate services are duplicative or that
6 its processes are ineffective. Finally, CCC has not explained what such a study would
7 actually add, given the recently completed Support Function Review. For these reasons, the
8 OEB should reject CCC's request.

9

10 Information Technology

11 SEC challenges certain aspects of OPG's CIO costs (SEC argument, paras. 92-94). OPG's
12 evidence resolves the issues raised by SEC and more generally demonstrates that OPG's
13 CIO costs benchmark favourably against a peer group of Canadian and U.S. energy
14 companies (Ex. J8.15, page 3).

15

16 While SEC correctly calculates that OPG's overall budgeted CIO costs including CIO OM&A
17 projects are increasing by \$18.3M or 10 percent in 2008, it mistakenly concludes that this
18 increase is unjustified (SEC argument, paras. 92-94). While SEC appears to concede the
19 reasonableness of cost increases related to new initiatives, it erroneously claims that "much
20 of the NHSS increases are in areas unrelated to new initiatives," (SEC argument, para. 93).
21 In fact, most areas of the New Horizon System Solutions ("NHSS") contract expense show
22 relatively small increases or decreases (Ex. J8.15). The two areas that show material
23 increases are Enhancements and Variable Demand, and Infrastructure Management. The
24 increase in Enhancements and Variable Demand is largely due to the "transfer in the
25 management of third party contracts for expenditures related to telecommunications and
26 certain hardware purchasing from OPG's internal CIO departments to NHSS" (Ex. J8.15).
27 These are entirely offset by a reduction in internal CIO costs (Ibid.). For Infrastructure
28 Management, 79 percent of the increase between 2007 and 2008 relates to new initiatives
29 including the relocation of data centres and the re-engineering of the IT Help Desk (Ibid.)

30

31 With respect to the status of the IT Help Desk re-engineering initiative, the initiative is subject
32 to a final proposal being received from NHSS (Ex. J8.16). OPG's evidence also shows that of

1 the \$7.0M cost for this initiative, only \$3.7M is included in OPG's proposed revenue
2 requirement (all in 2008), and that offsetting cost savings from this planned initiative of \$2.1M
3 also have been included in the 2009 revenue requirement (Ibid.). Thus, the net impact of the
4 inclusion of this initiative in the revenue requirement over the test period is \$1.6M.

5
6 SEC questions why the 2009 budget for Infrastructure Management is at the same level as
7 the 2008 budget (SEC argument, para. 94). In fact, the 2009 budget is \$3M less than the
8 2008 budget (Ex. J8.15). The reason that the 2009 budget for Infrastructure Management
9 does not reflect a reduction equal to the full \$7M cost of the one-time help desk re-
10 engineering initiative is that the cost of the data centre relocation initiative increases from
11 \$5M in 2008 to \$10M in 2009 (Ibid.).

12 13 Corporate Affairs

14 For Corporate Affairs costs, CCC accepts the proposed Regulatory Affairs budget for 2008,
15 but argues that while the Regulatory Affairs budget is the same in both 2008 and 2009, the
16 2009 figure is excessive because a "rates proceeding is not scheduled for 2009" (CCC
17 argument, para. 83). CCC's argument is based on a false premise. The OEB has already
18 stated that "OPG will be required to file in early 2009 to support a new payment setting for
19 2010" (A Regulatory Methodology for Setting Payment Amounts for the Prescribed
20 Generation Assets of Ontario Power Generation Inc., EB-2006-0064, November 30, 2006 –
21 page 13). Of the \$10.8M in 2009 Regulatory Affairs budget allocated to the prescribed
22 facilities, \$6.5M is for OEB fees and intervenor cost awards budgeted for the hearing to be
23 conducted during 2009 (Ex. J8.13).

24
25 SEC recommends that a deferral account be created for Regulatory Affairs costs related to
26 consultants and purchased services "given the fact that many of these fees (in particular
27 OEB fees and intervenor cost awards are not under OPG's control," and are uncertain (SEC
28 argument, para. 82). CCC also suggest that the OEB consider a variance account for
29 Regulatory Affairs costs (CCC argument, para. 85). OPG opposes such a variance account
30 because it would not meet the standards for materiality in the context of OPG's total
31 operating costs. Moreover, OPG notes that both these parties have opposed variance
32 account treatment for pension and other post employment benefit costs due to changes in

1 the discount rate. This proposed pension and OPEB variance account addresses a matter
2 that is equally beyond OPG's control and by the terms of the proposed account, which is not
3 effective until a \$75M threshold is achieved, necessarily would involve amounts that are an
4 order of magnitude greater than OPG's Regulatory Affairs costs (SEC argument, para. 243;
5 CCC argument, para. 141).

6
7 Both Energy Probe and SEC argue for a reduction in the Corporate Affairs budget to
8 eliminate spending on nuclear advertisement (Energy Probe, paras. 80-90; SEC, paras. 83-
9 91). SEC argues that \$6M be disallowed over the 21-month test period; Energy Probe
10 appears to request about the same amount of disallowance, but its argument is vague on the
11 precise amounts it wants cut (SEC, para 83; Energy Probe, para. 90).

12
13 Both intervenors cite selected excerpts from OPG and Canadian Nuclear Association
14 materials to argue that this spending is an inappropriate attempt to influence the public
15 debate on the future of nuclear power, particularly in the context of the Integrated Power
16 System Plan. This is incorrect. OPG's nuclear advertising activities inform the residents of
17 site communities about its nuclear activities in those communities and provide information
18 across the Province about nuclear generation; they have absolutely nothing to do with the
19 Integrated Power System Plan (Ex. J4.2, page 1, lines 37-42).

20
21 OPG explained the reason why it engages in advertising and other communication about
22 nuclear energy as follows:

23
24 OPG is different than other regulated utilities in Ontario with respect to
25 the issue of advertising. Operating a nuclear plant in a community or
26 planning to construct a nuclear plant in a community requires OPG to
27 maintain the long-term support of the community.

28 In effect, OPG would not be able to operate its plants, or construct a
29 new plant, without a supportive local community. In the case of nuclear
30 power, it is also important to be open and transparent in communications
31 across the province since nuclear power is responsible for close to half of
32 Ontario's power supply now and will continue to supply more than any
33 other form of generation into the future. Because of these business
34 imperatives, OPG invests considerable effort in reaching out to its site
35 communities and provincial residents to keep them informed about its
36 operations and plans for the future.

1 Without strong local and provincial support OPG would have more
2 difficulty in securing licenses with acceptable conditions from the CNSC
3 and the Canadian Environment Assessment Agency. OPG also relies on
4 the local communities for back up fire, police and health services. Without
5 a supportive community, OPG would not be able to count on the level of
6 support for these services that it presently enjoys.

7 In addition, OPG is required under its Mandate from the Province to
8 "...operate in Ontario in accordance with the highest corporate standards,
9 including but not limited to the areas of corporate governance, social
10 responsibility and corporate citizenship" and to maintain "...a high level of
11 accountability and transparency". OPG's advertising expenditures are
12 consistent with these requirements.

13 Finally, OPG is currently conducting environmental assessments and
14 public consultations for new nuclear development at the Darlington
15 nuclear site and the potential refurbishment of the Pickering B nuclear
16 station. This work is being undertaken in response to a June 2006
17 directive from the Province. Responding to these directives requires OPG
18 to reach out to the local and broader community to inform them of its
19 plans and proposals and endeavour to obtain their input. (Ex. J4.2, pages
20 1-2)
21

22 OPG undertakes its own advertising and communication efforts and, as a member of the
23 Canadian Nuclear Association funds a portion of that organization's advertising efforts. For
24 the 21-month test period, OPG forecasts spending \$3.7M on its own efforts and \$2.3M on
25 Canadian Nuclear Association advertising efforts (Ex. JT1.2, Chart 2; Ex. J-8-10). Examples
26 of OPG's efforts include the Quarterly Update to the Pickering Community, OPG's billboard,
27 advertisements and posters for Durham region, and a Pickering community event poster (Ex.
28 J4-2, Attachments 4-8). A description of the Canadian Nuclear Association advertising
29 materials are included in the Canadian Nuclear Association's presentation on 2006 Creative
30 & Media Recommendations (Ex. J4.2, Attachment 3).

31
32 Before responding to the specifics of Energy Probe's arguments, OPG notes that many of
33 these arguments appear to rest on characterizations that Mr. Rubin made in the course of
34 questioning OPG witnesses (Energy Probe argument, paras. 86, 89, and 90). As much as
35 Energy Probe seems to rely on them, these statements are not evidence, and the OEB
36 should not treat them as such.
37

1 Also SEC expressed doubt about whether the typographical error that OPG identified in
2 Attachment 3 of Ex. J4.2 was really an error at all (SEC argument, para. 88). OPG stated in
3 J8.12:

4

5 The second bullet contains a typographical error – the word “against”
6 should be read as “among,” i.e., “To increase support among
7 Stakeholders”. The phrase as it currently appears in Attachment 3 to Ex.
8 J4.2 is not logical, as organizations work with their stakeholders, not
9 against them.

10

11 Despite SEC’s doubts, OPG stands by this statement and has confirmed with the Canadian
12 Nuclear Association that the bullet contains the error stated above.

13

14 OPG submits that the materials provided in this case show that its nuclear advertising efforts
15 are an education and communication exercise that is entirely consistent with OPG’s mandate
16 from the Province to maintain a high level of transparency (Ex. A1-T4-S1, Appendix B). In
17 fact, under cross-examination by Energy Probe, OPG testified to this very fact:

18

19 MR RUBIN: Do we not agree that one of the purposes of your advertising
20 is to change public opinion, to change the opinions of voters and
21 ratepayers?

22 MR. STAINES: I think it is more to make them aware of what goes on
23 within OPG. (TR Vol. 8, pg. 113)

24

25 Energy Probe (Energy Probe argument, para. 82) and SEC’s (SEC argument, para. 87)
26 arguments selectively cite objectives of OPG’s nuclear advertising. Other equally, if not
27 more, important objectives of OPG’s nuclear public relations initiatives that are omitted from
28 the two interveners’ argument include:

- 29
- 30 • “Access to Information and Education” (Ex. J8.11, Attachment 1, page 2)
 - 31 • “Communication to employees for issue management and employee education:
32 o Better engagement / Our ambassadors in our communities” (Ex. J8.11, Attachment 1,
33 page 3)
 - 34 • “Station Relicence Support” (Ex. J8.11, Attachment 1, page 4)
 - 35 • “Nuclear Security Communications” (Ex. J8.11, Attachment 1, page 4)
 - “Site Community Outreach and Programming” (Ex. J8.11, Attachment 1, page 4)

- 1 • “Continued focus on community, educational and environmental initiatives” (Ex. J8.11,
2 Attachment 1, page 6)
- 3 • “Continued excellence in employee communications...” (Ex. J8.11, Attachment 1, page
4 11)

5

6 The above cited objectives indicate that OPG’s nuclear public relations initiatives clearly
7 relate to the education of Ontarians in the area of nuclear generation, engagement of
8 stakeholders in discussions related to OPG’s existing and potential future nuclear generation
9 in their communities (i.e., access to information), ensuring appropriate security around
10 nuclear plants, and boosting employee engagement and thus productivity. All of these aims
11 are clearly to the benefit of the ratepayers, and are consistent with OPG’s mandate, but have
12 been ignored by Energy Probe and SEC. These purposes are integrated throughout OPG’s
13 communications. Thus Energy Probe’s suggestion that certain communication expenditures
14 should be linked to new generation and captured in the nuclear development deferral
15 account is without merit (Energy Probe argument, para.89).

16

17 OPG further notes that Energy Probe itself has stated that it supports open communication
18 with stakeholders, which are precisely what above cited objectives represent: “In this regard,
19 it is certainly not Energy Probe’s intent to hinder OPG’s efforts to share, reveal, or publish
20 factual information about its nuclear activities, or to communicate openly with its many
21 stakeholders” (Energy Probe argument, para. 87).

22

23 Energy Probe cites a number of statutes and regulations from various U.S. jurisdictions
24 limiting ratepayer funding of promotional, political or institutional advertising by utilities.
25 However, it also fails to cite the rules from other U.S. jurisdictions that explicitly recognize
26 that advertising may benefit customers and more precisely define “political” and “institutional”
27 advertising. Some examples follow.

28

29 The Oregon Administrative Rules categorize various types of advertising and states which
30 categories can be included in rates (OAR 860-026-0022 “Presumptions of Reasonableness
31 of Advertising Expenses in Utility Rate Cases” found at:
32 http://arcweb.sos.state.or.us/rules/OARS_800/OAR_860/860_026.html). It contains the

1 following definitions of institutional and political and utility informational advertising and
2 includes the limits on what categories of advertising can be included in rates:

3 c) "Institutional Advertising Expenses" means advertising expenses, the
4 primary purpose of which is not to convey information, but to enhance the
5 credibility, reputation, character, or image of an entity or institution;

6 (e) "Political Advertising Expenses" means advertising expenses, the
7 primary purpose of which is to state or imply that persons should take a
8 specific political action;

9

10 ...
11 (g) "Utility Information Advertising Expenses" means advertising
12 expenses, the primary purpose of which is to increase customer
13 understanding of utility systems and the function of those systems, and to
14 discuss generation and transmission methods, utility expenses, rate
15 structures, rate increases, load forecasting, environmental considerations,
16 and other contemporary items of customer interest;

16

17 2) For the purposes of this rule, advertising expenses are categorized as
18 follows:

19

20 (a) Category "A" – Energy efficiency or conservation advertising expenses
21 that do not relate to a Commission-approved program, utility service
22 advertising expenses, and utility information advertising expenses;

23 (b) Category "B" – Legally mandated advertising expenses;

24 (c) Category "C" – Institutional advertising expenses, promotional
25 advertising expenses and any other advertising expenses not fitting into
26 Category "A," "B," or "D";

27 (d) Category "D" – Political advertising expenses and nonutility
28 advertising expenses; and

29 (e) Category "E" – Energy efficiency or conservation advertising expenses
30 that relate to a Commission-approved program.

31

32 (3) For rate-making purposes:

33

34 (a) Advertising expenses in Category "A" are presumed to be just and
35 reasonable in a rate proceeding to the extent that expenses are twelve
36 and one-half hundredths of 1 percent (0.125 percent) or less of the gross
37 retail operating revenues determined in that proceeding;

38 (b) Advertising expenses in Category "B" are presumed to be just and
39 reasonable for rate-making purposes;

40 (c) The energy or large telecommunications utility shall carry the burden
41 of showing that any advertising expenses in Category "C" are just and
42 reasonable for rate-making purposes. In any rate filing under ORS
43 757.210 and ORS 759.180, the utility shall separately state the amount of
44 advertising expenses in Category "C";

45 (d) Advertising expenses in Category "D" are presumed to be not just and
46 reasonable for rate-making purposes; and

1 (e) With Commission approval, advertising expenses in Category "E" may
2 be capitalized. The Commission will review the prudence of such
3 expenses in a general rate proceeding pursuant to ORS 756.500, ORS
4 757.210, or ORS 759.180.

5
6 (4) The presumptions in section (3) of this rule are rebuttable. An energy
7 or large telecommunications utility seeking to include expenditures in
8 excess of amounts in section (3) of this rule shall have the burden of
9 showing that the expenditures are just and reasonable. Parties
10 challenging expenditures which are equal to or less than the amounts in
11 section (3) of this rule have the burden of showing that the expenditures
12 are not just and reasonable.
13

14 Oregon allows "utility informational advertising," as defined above, to be included in rates but
15 limits spending to 0.125 percent or less of a utility's gross retail operating revenues (OAR
16 860-026-0022 (2) (a) and (3) (a)). The utility has the burden of proving why "institutional
17 advertising," as defined above, is just and reasonable (OAR 860-026-0022 (2) (c) and (3)
18 (c)). "Political advertising," as defined above, is presumed not to be just and reasonable
19 (OAR 860-026-0022 (2) (d) and (3) (d)).
20

21 Using the Oregon definitions, OPG's nuclear advertising clearly would be classified as "utility
22 informational advertising" and be presumed to be just and reasonable. It is not "political
23 advertising" in that it nowhere advocates that any person take any political action
24 whatsoever. Neither is it institutional advertising because its primary purpose is to provide
25 information on nuclear energy rather than enhancing OPG's corporate image.
26

27 With respect to "political" advertising, the New Mexico Administrative Code allows advertising
28 that "results in reduction of operating cost and more efficient utility service to ratepayers"
29 except where that advertising "advocates a position rather than providing factual
30 information." (New Mexico Administrative Code 17.3.350.9 (b) and (c) found at:
31 <http://www.nmcpr.state.nm.us/NMAC/parts/title17/17.003.0350.htm>). OPG's nuclear
32 advertising provides factual information and helps reduce the cost of licensing its plants and
33 operating in its host communities. This benefit is achieved because advertising initiatives
34 educate host communities on OPG's activities and thus garner a level of support within them
35 (see, for example, Ex. J4.2, Attachment 6).
36

1 The Texas Public Utilities Commission rules for electric utilities permit some advertising and
2 contain a focused definition of political advertising. The rules state that: “The actual
3 expenditures for ordinary advertising, contributions, and donations may be allowed as a cost
4 of service provided that the total sum of all such items allowed in the cost of service shall not
5 exceed three-tenths of 1.0% (0.3%) of the gross receipts of the electric utility for services
6 rendered to the public.” (TX PUC Rules §25.231 (b) (1) (E) found at:
7 <http://www.puc.state.tx.us/rules/subrules/electric/25.231/25.231.pdf>). The rules also contain
8 the following prohibition on political advertising:

9 (2) **Expenses not allowed.** The following expenses shall never be
10 allowed as a component of cost of service:

11 (A) legislative advocacy expenses, whether made directly or indirectly,
12 including, but not limited to, legislative advocacy expenses included in
13 professional or trade association dues;

14 (B) funds expended in support of political candidates;

15 (C) funds expended in support of any political movement;

16 (D) funds expended promoting political or religious causes;

17 ...

18 (J) any expenditure found by the commission to be unreasonable,
19 unnecessary, or not in the public interest, including but not limited to
20 executive salaries, advertising expenses, legal expenses, penalties and
21 interest on overdue taxes, criminal penalties or fines, and civil penalties or
22 fines.
23

24 Again, under the Texas rules, OPG’s nuclear advertising would not constitute “political”
25 advertising as it does not advocate any legislation or support any political candidate or
26 movement.

27
28 Energy Probe’s main claim appears to be that OPG’s nuclear advertising is “political” rather
29 than “institutional” since it provides no explanation of how it believes that OPG’s materials
30 are intended to enhance OPG’s corporate image. SEC makes a similar argument that these
31 materials are political advertising. Even using the broad definition of “political” advertising
32 found in the jurisdictions cited by Energy Probe, OPG’s nuclear advertising does not meet
33 the definition of “political advertising” commonly used in these statutes.

34
35 For example, Utah Rule R746-406-1 (Energy Probe argument, pages 27-28) provides the
36 following definition: “The term “political advertising” means advertising for the purpose of

1 influencing public opinion with respect to legislative, administrative, or electoral matters, or
2 with respect to an issue of public dispute” Energy Probe argument para. 85). Neither Energy
3 Probe nor SEC has supplied a shred of evidence that OPG’s activities are aimed at
4 “influencing public opinion with respect to legislative, administrative, or electoral matters, or
5 with respect to an issue of public dispute.”

6
7 Both Energy Probe and SEC offer the OEB’s ongoing Integrated Power System Plan review
8 as an example of a matter that nuclear advertising is intended to influence.

9
10 OPG certainly does not share the view implicit in Energy Probe’s and SEC’s argument that
11 the OEB panel reviewing the Integrated Power System Plan is susceptible to advertising or
12 public pressure resulting from advertising (Tr. Vol. 8, page 110). In any event, this argument
13 could not possibly be correct because in the context of the Integrated Power System Plan,
14 the Province has already decided the role of nuclear energy; it is no longer a matter of public
15 dispute.

16
17 As the OEB is well aware, the Minister of Energy in June of 2006 directed the OPA to: “Plan
18 for nuclear capacity to meet base-load electricity requirements but limit the installed in-
19 service capacity of nuclear power over the life of the plan to 14,000 MW” (Ministerial
20 Directive to the OPA, June 13, 2006). Consistent with this directive, the Integrated Power
21 System Plan, which the OPA has filed for OEB review, includes existing and new/refurbished
22 nuclear power plants. In reviewing the Integrated Power System Plan, the OEB must, among
23 other things, “ensure it complies with any directions issued by the Minister” (*Electricity Act*
24 section 25.30 (4)). Furthermore, on June 16 of this year the Province announced that it had
25 chosen Darlington as the site for constructing two new nuclear reactors and OPG as the
26 operator of these plants. The Province already signed a contract for the refurbishment of the
27 Bruce A units in October 2005. Thus, contrary to Energy Probe’s and SEC’s claims, the
28 Integrated Power System Plan proceeding is not a debate about the role of nuclear energy.
29 Ontario has moved past the debating stage with respect to the future of nuclear energy and
30 has entered the implementation stage.

1 The Board itself has recognized these decisions in rejecting suggestions by Energy Probe
2 and SEC that the Integrated Power System Plan include a broad review of nuclear energy:

3
4 As noted above, several parties, particularly Energy Probe and SEC,
5 urged the Board to take a very broad view of its scope for the review of
6 nuclear issues. ...

7
8 The Board recognizes the enormity of the implications of the nuclear
9 decisions that face the province. However, many of the most significant
10 decisions regarding nuclear power have been made, or will be made,
11 outside this proceeding. The government of the province directed the
12 OPA to “plan for nuclear capacity to meet base-load electricity
13 requirements” and set a limit on the installed in-service capacity over the
14 life of the Plan. It is not within the Board’s mandate in this proceeding to
15 review general provincial policy regarding nuclear power. (EB-2007-0707,
16 Decision with Reasons, March 26, 2008, pages 23-24).
17

18 Energy Probe also fails to acknowledge that some of the U.S. rules it cites include
19 exceptions or “tests” that make advertising expenditures allowable for recovery when they
20 are found to be in the public interest. For example, the Utah rule allows promotional and
21 institutional advertising to be recovered in rates if found to be in the public interest (Utah Rule
22 R746-406-1 C.). OPG submits that is in the public interest for Ontarians to be informed about
23 OPG’s nuclear generation and the operation of nuclear plants in their communities.

24
25 Energy Probe urges the OEB to avoid compelling Ontarians who oppose nuclear energy to
26 provide funding for OPG’s nuclear advertising. In making this plea, Energy Probe ignores its
27 own request that the OEB compel Ontarians who support nuclear energy to fund Energy
28 Probe’s anti-nuclear efforts. Energy Probe has requested recovery of 100 percent of its costs
29 in this proceeding. The funding of any costs awarded will come from ratepayers, some who
30 fully support nuclear energy and others who strongly oppose it. As Energy Probe aptly
31 points out, nobody who attended the hearing in this matter could doubt that one of Energy
32 Probe’s goals was to use its participation in this hearing to continue its longstanding
33 advocacy against nuclear power (Energy Probe argument, para. 84).

34
35 OPG submits that a full discussion regarding nuclear energy, including communications by
36 both proponents and opponents, is in the public interest. Such communication is required to

1 ensure that Ontarians, particularly those who live in nuclear communities, receive complete
2 and accurate information about nuclear power. If OPG's communications are not funded as a
3 legitimate cost of the prescribed nuclear facilities, then it is less likely that Ontario citizens will
4 be presented with the full spectrum of information and perspectives on this issue.

5

1 **6. OTHER REVENUES**

2
3 **Issue 6.1**

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

6
7 Segregated Mode of Operation

8 Several intervenors proposed that the sharing of Segregated Mode of Operation (“SMO”)
9 revenues be more heavily weighted in favour of consumers than that proposed by OPG
10 (AMPCO argument, para. 152; CCC argument, para. 91; CME argument, para. 181; Energy
11 Probe argument, para. 109; SEC argument, para. 141; VECC argument, para. 87). This
12 would have the undesirable effect disincenting economic SMO transactions, as OPG’s
13 trading function will pursue other, more lucrative, opportunities. While OPG would still
14 transact to manage excess baseload generation and to minimize hydroelectric spill, it would
15 reduce other economic transactions that currently benefit Ontario consumers (OPG
16 argument-in-chief, page 74; Tr. Vol. 3, pages 67-68).

17
18 SEC compares SMO transactions to the transactional services associated with excess
19 storage and transportation capacity marketed by the natural gas utilities (SEC argument,
20 paras. 148-150). The fundamental difference that SEC neglects, is that the staff within OPG
21 that engages in SMO transactions has other transactional activity available to them. This is
22 not the case for the transactional services offered by the natural gas utilities.

23
24 OPG’s proposal to share 50 percent of SMO net revenues when production is less than the
25 threshold for the hydroelectric incentive mechanism is appropriate given the economic
26 benefits associated with SMO transactions. AMPCO questions the value of these benefits,
27 stating that they have not been quantified (AMPCO argument, para. 148). As OPG has
28 indicated in its evidence, the benefits are extremely difficult to quantify given the fact that the
29 additional supply that is available during peak hours from outside Ontario is not contractually
30 linked to the volume of SMO sold during off-peak hours. However, it is known that Hydro
31 Quebec has significant capacity to store water to use for energy production when it is most
32 valuable (Tr. Vol. 3, page 51). Economic theory indicates that additional supply will increase

1 competition and this will tend to reduce Ontario prices during peak periods when additional
2 supply is very costly. SMO transactions mainly occur during off-peak hours when prices are
3 low and the supply curve is relatively flat. Not only are peak prices indirectly reduced as a
4 result of SMO activities, but experience during the interim period was that consumers also
5 benefited from a positive balance in the SMO variance sub-account (Ex. J1-T1-S1, Table 3,
6 line 19). Accordingly, OPG submits that the 50/50 sharing mechanism, as proposed, is
7 reasonable.

8
9 AMPCO states that OPG recommends continuing to use the 1900 MWh (that was present in
10 the interim period) threshold for calculating SMO variance account entries during the test
11 period (AMPCO argument, para. 151). This is simply incorrect. OPG has clearly stated that
12 the threshold to be used for SMO transactions during the test period is consistent with the
13 value which is to be used for the incentive mechanism⁸ (Ex. G1-T1-S1, page 9, lines 21-28;
14 OPG argument-in-chief, page 74, lines 20-24).

15
16 Further, while AMPCO “accepts that OPG needs some incentive to pursue SMO
17 transactions,” it submits that the incentive should not be a function of the amount of output at
18 a particular point in time (AMPCO argument, paras. 151-152). OPG disagrees with this
19 submission. In order to drive appropriate SMO decisions, they need to be integrated with
20 decisions on peaking under the hydroelectric incentive mechanism and tied to market
21 signals. Removing consideration of the threshold from SMO decisions effectively eliminates
22 the necessary integration between SMO and the hydroelectric incentive mechanism.

23
24 SEC submits that OPG should use the average of its SMO revenues for the last three years
25 as the basis for a revenue requirement offset (SEC argument, para. 144). This simplistic
26 forecasting approach will not work. The data from 2005-2007 shows the significant variability
27 in SMO revenues and demonstrates why they are so difficult to forecast. SMO revenues in
28 2006 represent 123 percent of the 2007 revenues and the 2005 revenues represent 225
29 percent of the 2007 revenues (Ex. G1-T1-S1, Table 1, line 2). Using a three year historical
30 average as a revenue requirement offset should more appropriately be referred to as a

⁸ Further discussion of the proposed average value can be found in Issue 8.1 on the Hydroelectric Incentive Mechanism.

1 “guess”, not a “forecast”. Further, SMO transactions are expected to decline in future with the
2 new high voltage transmission line between Ontario and Quebec which comes into service in
3 May 2009 (Ex. G1-T1-S1, page 10, lines 2-6). SEC’s proposal to forecast SMO revenues
4 based on a historical average is inconsistent with the nature of these revenues and should
5 not be adopted.

6
7 Both CCC and Board Staff address the potential for negative balances in the SMO variance
8 account. CCC states that if OPG enters into uneconomic transactions, then OPG should bear
9 the consequences, not the consumer (CCC argument, para. 91). Board Staff questions both
10 individual transactions that result in a loss and the possibility of a negative account balance
11 at the end of the year (Board Staff submission, page 43). These submissions do not
12 acknowledge the risks associated with SMO transactions. Transactions are economic when
13 entered into; if they become uneconomic, it is due to changing market conditions and prices
14 (Ex. G1-T1-S1, page 8). Transactions to manage excess baseload generation may result in a
15 negative sub-account entry but have associated social and environmental benefits (Ex. G1-
16 T1-S1, page 6). OPG submits that it would not represent an appropriate balance of risks and
17 benefits between OPG and consumers if negative entries were not allowed on individual
18 transactions. On an annual basis, however, OPG accepts the proposition that its transactions
19 should result in a net benefit to consumers. It therefore accepts the Board Staff’s suggestion
20 that OPG would not seek recovery of any negative balance at the end of a fiscal year.

21
22 Water Transactions

23 OPG proposed to treat the revenues associated with water transactions in a manner similar
24 to those associated with SMO for many of the same reasons, during both the interim and test
25 periods (Ex. G1-T1-S1, Section 5.0; OPG argument-in-chief, page 74, lines 28-32). No
26 intervenor raised arguments about water transactions that were distinct from those for SMO,
27 which OPG has responded to already. Again, OPG submits that its sharing proposal for
28 water transaction revenues be adopted as filed.

29
30 Congestion Management Settlement Credits

31 OPG’s proposal for the treatment of congestion management settlement credits (“CMSC”) is
32 different than that for SMO or water transactions, because CMSCs are fundamentally

1 different. CMSC revenues are not a “windfall” – they are an offset to lost revenue and
2 increased costs (Ex. G1-T1-S1, section 6.0).

3
4 Both AMPCO and SEC propose that significant portions of CMSC revenues be returned to
5 ratepayers, either as an offset to the revenue requirement or through a deferral account.
6 AMPCO, in acknowledging that there is significant forecasting uncertainty in these revenues,
7 proposes to create a deferral account for CMSC net revenues. SEC, on the other hand,
8 considers all CMSC revenues to be incremental and as such, proposes they be included as
9 an offset to revenue requirement (SEC argument, para. 158).

10
11 The fact that CMSC payments are designed to keep a market participant whole is
12 made clear in the following excerpt from a presentation made by the IESO⁹:

13
14 Working definition of CMSC:

- 15 • Restores participant to the operating profit they would have received
16 in the absence of Ontario constraints (based on unconstrained
17 schedule)
- 18 • Usually means payment to bring profit back up to the level based on
19 the unconstrained schedule
- 20 • If profit from unconstrained schedule would have been lower than
21 what happened based on the constrained schedule, CMSC is a
22 negative settlement amount. Returns participant to the unconstrained
23 profit.

24
25 CMSCs are intended to keep market participants whole, up to the operating profit they would
26 have otherwise received, had they not been constrained-on or off by system conditions
27 beyond their control (Ex. G1-T1-S1, pages 13-14).

28
29 OPG’s regulated facilities are obligated to comply with the IESO market rules and therefore
30 are subject to exactly the same dispatch schedules as other market participants which give
31 rise to constrained-on and off situations (Ex. A1-T6-S1, page 3). There is no regulatory
32 construct which protects them from the consequences of uneconomic dispatch resulting from
33 constraints. If OPG is not permitted to retain constrained-off payments, it will have no means

⁹ June 13, 2006 presentation entitled “CMSC Background”, <http://www.ieso.ca/imoweb/pubs/tp2006/tp187-7a-Presentation-CMSC-Background.pdf> Additional information can be found in the IESO Market Rules Appendix 7.6 and Market Manual 2.12.

1 of recovering losses associated with spilled or inefficient use of water when constrained-off,
2 which, as shown in Undertaking J3.1, form the majority of annual CMSC payments (Ex. L-3-
3 96).

4
5 With respect to constrained-on operation, OPG's proposal means that it has the same
6 financial outcome whether it gets CMSC payment or an energy payment for its peaking
7 operations (Tr. Vol. 3, page 65, lines 12-23). In these situations, the water that is
8 constrained-on is usually water that has been pumped into the Sir Adam Beck PGS storage
9 reservoir for peaking activities later in the day. If OPG is not permitted to retain the CMSCs in
10 this situation it will have no means of recovering its losses associated with pumping. Viewed
11 another way, had OPG operated when it had planned to based on its offers, it would not be
12 required to share its energy revenues under its proposed hydroelectric incentive mechanism.
13 It thus makes no sense for OPG to share (or give up altogether) its CMSC payments.

14
15 Both SEC and AMPCO argue that OPG has failed to quantify the incremental costs
16 associated with constrained situations (SEC argument, para. 154; AMPCO argument, para.
17 154). That is quite simply because the complexity associated with tracking such data makes
18 it prohibitive (Ex. L-3-96, lines 19-20). There may be situations where the CMSC payments
19 were either slightly greater than or slightly less than the energy payment that OPG would
20 have received had it not been constrained. These situations depend on the relative value of
21 the regulated payment amount and the market price. On average, however, the CMSC
22 payments over the year are a reasonable approximation of the impact on OPG's revenue
23 associated with constrained operation.

24
25 CMSC payments are also subject to review by the Market Assessment and Compliance
26 Department of the IESO (Ex. G1-T1-S1, page 14). These reviews, which follow a process
27 defined in the market rules and market manuals, result in the return of any inappropriate
28 CMSC payments. The reviews are based on the costs, including opportunity costs,
29 associated with a constrained event (IESO Market Rules, Appendix 7.6 Local Market Power
30 and Market Manual, section 2.12 Treatment of Local Market Power).

31

1 To disallow in whole or in part OPG's retention of CMSC payments, is inappropriate as it
2 imposes a financial penalty on OPG due to market conditions which are beyond its control –
3 the very situation that CMSCs were created to guard against. Congestion management
4 settlement credits are not “windfalls” but rather are an integral part of the IESO markets in
5 which OPG's prescribed facilities operate. They simply provide payments to keep market
6 participants financially whole.

7

8 **Issue 6.2**

9 **Are the forecasts of ancillary services revenues appropriate?**

10

11 There were no arguments from intervenors with respect to OPG's forecast of ancillary
12 services revenues. As such, and for all the reasons set out in its evidence and argument-in-
13 chief, these amounts should be accepted by the Board as filed.

14

15 **Issue 6.3**

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

18

19 There were no arguments from intervenors with respect to OPG's forecast of revenues from
20 heavy water or tritium sales and services, radioisotope sales or nuclear inspection and
21 maintenance services. As such, and for all the reasons set out in its evidence and argument-
22 in-chief, these amounts should be accepted by the Board as filed.

23

24 **Issue 6.4**

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

28

29 As indicated in OPG's argument-in-chief, there are no revenues or related costs other than
30 those included in the application that should be considered. Moreover, there has been
31 neither evidence nor argument from any party to suggest anything to the contrary.

32

1 **Issue 6.5**

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

4

5 This issue resolves around three main questions:

6

7 1. Is the cost of capital associated with the Bruce Nuclear Generating Stations ("NGS")
8 fixed assets of \$1,194.6M, comprised predominantly of the asset retirement cost
9 related to the nuclear and waste decommissioning liabilities associated with this
10 station, a cost OPG incurs (O. Reg. 53/05 section 6(2)9)? OPG submits that it is.

11

12 2. Do the nuclear waste and decommissioning liabilities associated with the Bruce
13 facilities arise from an approved reference plan (sections 5.1, 5.2 and 6(2)7 and 8)?
14 OPG submits that they do.

15

16 3. If the answer to either or both of questions 1 and 2 is yes, how should the revenue
17 requirement impact of nuclear waste and decommissioning liabilities associated with
18 the Bruce facilities be calculated? OPG submits that it should be in accordance with
19 the "rate base method."

20

21 Questions 1 and 2 will be discussed below in this section of the Reply Argument. Question 3
22 will largely be dealt with under Issue 7.1. Accordingly, OPG's Reply Argument on this issue
23 should be read in conjunction with its Reply Argument dealing with Issue 7.1.

24

25 On the general point of whether return on equity is a cost, Ms. McShane testified that equity
26 has a "cost" associated with it and that this basic economic principle has been well accepted
27 by the OEB in relation to regulated assets (Tr. Vol. 10, pages 9-10). She went on to explain
28 that this principle would apply equally to unregulated assets or operations (Ibid.). She also
29 agreed with the rates of return that OPG is proposing for the Bruce NGS assets, as they
30 represent a fair measure of OPG's opportunity cost of capital (Ibid.).

31

1 Common sense and common regulatory practice also supports the conclusion that return on
2 equity is a “cost” in this context. The “cost” of service approved for utilities regulated by the
3 OEB always includes an amount for return on capital. The Board's Affiliate Relationships
4 Code for Electric Distributors and Transmitters (“Affiliate Relationships Code”) requires that
5 when a utility provides a service to an affiliate it must charge fully allocated cost. “The fully
6 allocated cost shall include a return on the utility’s invested capital. The return on invested
7 capital shall be no less than the utility’s approved weighted average cost of capital.” (Affiliate
8 Relationships Code, section 2.3.4.2). Finally, the Board has historically recognized the need
9 for a return on capital for non-utility programs such as water heaters and natural gas vehicle
10 programs run by Ontario gas utilities. In relation to these programs, the revenue requirement
11 was reduced by the surplus revenues from these programs after the program costs, including
12 a return on equity, were covered. This is similar to the model proposed for the Bruce NGS
13 assets. Given Ms. McShane’s unchallenged testimony and the common use of the term,
14 OPG submits that it is only reasonable to conclude that capital has a cost and that return on
15 equity is that “cost” as identified in the Regulation.

16
17 For the period ending December 31, 2007, Board Staff takes the position that, as return on
18 equity for the Bruce facilities is not included as a “cost” in OPG’s 2007 audited financial
19 statements, it is not an amount that the OEB must accept under section 6(2)5(iii) of O. Reg.
20 53/05 (Board Staff submission, page 10). For the period after December 31, 2007, Board
21 Staff takes the position that section 6(2)9 requires the OEB to permit recovery of “ongoing”
22 costs associated with the Bruce facilities. However, they are unclear as to whether a return
23 on equity for the Bruce-related assets after April 1, 2008 would qualify as an ongoing 6(2)9
24 cost.

25
26 Board Staff also argue that section 6(2)8 does not apply to the Bruce facilities because they
27 are not “prescribed” assets (Board Staff submission, pages 14-15). Board Staff makes the
28 same argument with respect to the nuclear liability deferral accounts referred to in sections
29 5.1 and 5.2 and the recovery the OEB must ensure under section 6(2)7 (Board Staff
30 submission, page 23).

1 CME and VECC make the similar argument that: return on equity for the Bruce facilities is
2 not a “cost” under section 6(2)9; and that OPG has no right to any recovery of the cost of
3 nuclear liabilities, however calculated, with respect to the Bruce facilities.

4
5 In OPG’s submission, these arguments proceed from a profound and patently unreasonable
6 misinterpretation of the Regulation which, if adopted, would constitute clear grounds for
7 reversible error on a matter of law. Accepting these submissions also raises the prospect of
8 OPG having to take an impairment charge against the value of its Bruce NGS asset if it is
9 unable to recover the costs associated with its Bruce NGS nuclear liabilities. This potential
10 outcome only highlights the unreasonableness of the submissions of these parties.

11
12 By way of background, Ex. J2.7 shows that OPG’s 2007 audited financial statements
13 contain, in Note 7, Regulatory Assets and Liabilities and Summary of Rate Regulated
14 Accounting, include an entry for “Nuclear liabilities deferral account” of \$131M. The Bruce
15 NGS facilities account for \$54M of this amount, which includes a return on the asset
16 retirement cost associated with the Bruce facilities (Tr. Vol. 15, pages 84-86). Exhibit J2.7
17 and Ex. G2-T2-S1, Table 2 also show that the value of the net fixed assets associated with
18 the Bruce facilities at \$1,194.6M. As can be seen by comparing the asset retirement cost
19 associated with the Bruce facilities in Ex. H1-T1-S3, almost all (90 percent) of the Bruce NGS
20 “asset” on OPG’s books is the nuclear decommissioning liabilities associated with these
21 facilities.

22
23 OPG owns the Bruce facilities. OPG derives revenues from the Bruce facilities through the
24 lease with Bruce Power. That lease, however, also provides that OPG is responsible for all
25 nuclear waste and decommissioning liabilities associated with the Bruce facilities. OPG does
26 not get the revenues without the liabilities (costs). To the extent revenues benefit ratepayers,
27 therefore, the same proposition must be true: ratepayers do not get the benefit of any
28 revenue associated with the Bruce facilities without taking account of the costs (including the
29 nuclear liabilities). And as the evidence makes clear, ratepayers do get a very substantial net
30 benefit from the lease, even after providing for OPG’s legitimate costs. The ratepayer
31 benefits amount to \$69.1M in 2008 and \$82.6M in 2009.

32

1 The concept of ratepayers only getting the benefit of Bruce revenues net of all costs is given
2 explicit recognition in the Regulation in a number of ways and was the basis of the interim
3 rates fixed by the Province in 2005. The Province knew what was embedded in the interim
4 rates when it issued O. Reg. 53/05. That circumstance must inform the proper interpretation
5 of the meaning and intent of that Regulation.

6
7 Under section 5.1 of the Regulation, OPG must establish a deferral account that records the
8 revenue requirement impact of any change in its nuclear decommissioning liability “arising
9 from an approved reference plan” approved after April 1, 2005 and before the effective date
10 of the OEB’s first order. Section 6(2)7 provides that the OEB “shall ensure” that the balance
11 recorded in this deferral account is recovered on a straight line basis over a period not to
12 exceed three years to the extent that the OEB is satisfied that revenue requirement impacts
13 have been accurately recorded in the account, based on return on rate base, depreciation
14 expense, income and capital taxes and fuel expense. OPG’s obligations for used fuel,
15 nuclear waste and decommissioning under the Ontario Nuclear Funds Agreement cover
16 Bruce A, Bruce B, Pickering A, Pickering B, and Darlington (Exhibit J14.2, Schedule 1.1,
17 page 25). Accordingly, it was well known to the Province when the Regulation was
18 promulgated, providing for the recovery of all costs associated with the Bruce facilities and
19 the recovery of all costs associated with a change in the approved reference plan under the
20 Ontario Nuclear Funds Agreement, that the Bruce NGS facilities were included in the then
21 current reference plan as well as any future approved reference plan.

22
23 Further, it was well known to the Province that the interim rates that it approved for the 2005
24 to 2008 period reflected costs associated with Bruce A and B nuclear liabilities (OPG’s
25 argument-in-chief, pages 77-79 and 85-87). Not only did the Province assume that “costs
26 incurred” with respect to the Bruce facilities included nuclear liabilities associated with the
27 Bruce facilities, it also assumed, for the purposes of interim rates, that the proxy for recovery
28 of that cost was the return on the value of the Bruce NGS fixed asset, i.e., the “rate base
29 method”. As will be discussed in more detail under Issue 7.1, the fact that interim rates
30 employed the rate base method for the recovery of nuclear liability costs and the fact that the
31 Province was aware, before the application was made, of what OPG was seeking in this
32 case, while not binding on the OEB after April 1, 2008, are powerful evidence of surrounding

1 circumstances, which must be considered in determining the intent and meaning of sections
2 6(2)7 to 10 of the Regulation. The only available conclusion is that return on rate base (i.e.,
3 the fixed asset value of the Bruce NGS facilities), as well as the other components of the
4 revenue requirement impacts specified in section 6(2)7, are “costs” OPG incurs with respect
5 to those facilities.

6
7 Further, the Board Staff and CME arguments fly in the face of the plain language of the
8 Regulation and, in fact, stand the Regulation on its head. Board staff further complicates their
9 analysis by implying fundamentally different legislative intents for the periods before and after
10 December 31, 2007. No reasonable interpretation of the Regulation could produce the
11 conclusions of Board Staff and CME on this issue.

12
13 Section 5.1 of the Regulation is abundantly clear, in referring to “any change” in OPG’s
14 nuclear decommissioning liability arising from an approved reference plan, that *all* such
15 liabilities are to be included in the deferral account. Section 5.1 does not exclude the Bruce
16 facilities. Where special treatment of the Bruce facilities was intended in the Regulation, the
17 Regulation specifically provides for such special treatment. If the Province had intended to
18 restrict the deferral account only to the prescribed facilities, it would have specified this in the
19 Regulation. Similarly, section 6(2)8 is of general application. It provides that the OEB must
20 ensure that OPG recovers the revenue requirement impact of *any* nuclear decommissioning
21 liability arising from an approved reference plan, not just nuclear decommissioning liabilities
22 arising from particular stations. Accordingly, OPG submits that an interpretation of the
23 obligation to record *any* change in OPG nuclear decommissioning liabilities arising from an
24 approved reference plan which excludes nuclear liabilities associated with the Bruce facilities
25 is unsustainable and directly contradicts the plain words of the Regulation.

26
27 Board Staff argues that because some provisions of O. Reg. 53/05 deal specifically with the
28 Bruce facilities (sections 6(2)5, 9 and 10), if the government had intended sections 5.1 and
29 6(2)8 to apply to the Bruce facilities, the Regulation “would have referred to those facilities *in*
30 *the same manner* as it does in sections 6(2)5, 9 and 10” [emphasis added]. This argument
31 stands the logic of these provisions on its head. Section 6(2)5, 9 and 10 contain provisions
32 that apply specifically and exclusively to the Bruce Nuclear Generating Stations. If sections

1 5.1 and 6(2) had referred to the Bruce facilities “in the same manner” as 6(2)5, 9 and 10,
2 they would have *excluded* the facilities specifically prescribed in O. Reg. 53/05. The whole
3 point of sections 5.1 and 6(2)8 is that they are of general application. They were clearly not
4 intended to exclude the prescribed facilities and it is equally clear that they also were not
5 intended to exclude the Bruce facilities because both are included in the approved reference
6 plan.

7
8 Board Staff’s general summary of the principles of statutory interpretation is essentially
9 correct. First among those principles is the legislative text itself. Legislative intent is derived
10 principally from the words used in the enactment. Legislative purpose, as Board Staff argues,
11 should be adopted only “insofar as the language of the text permits”. Nothing about the
12 legislative purpose of O. Reg. 53/05 demands excluding Bruce nuclear waste and
13 decommissioning liabilities from the determination of OPG’s revenue requirement. Indeed,
14 given that ratepayers are deriving the substantial benefit of net revenues from the Bruce
15 facilities (i.e., revenues *net of costs*), legislative purpose rather suggests the opposite. Most
16 importantly, however, the plain language of sections 5.1 and 6(2)8 apply to *any* nuclear
17 liabilities arising from *any* change to the approved reference plan.

18
19 Further, the evidence clearly shows that the Bruce lease revenues include a profit and allow
20 OPG to cover the cost of its Bruce nuclear liabilities. Altogether apart from the plain words of
21 sections 5.1, 6(2)8, 9 and 10, it would be grossly unfair to give the ratepayers the benefit of
22 *revenues* which include a provision for recovery of nuclear liabilities, but not credit the cost of
23 those liabilities against those revenues.

24
25 Further, the revenue requirement impact associated with the Bruce NGS portion of the 2006
26 approved reference plan must be recorded in the Nuclear Liability Transition Deferral
27 Account because the interim rates included nuclear liability costs related to the Bruce
28 facilities. The deferral account was clearly intended to capture the difference between
29 forecast and actual costs associated with nuclear waste and decommissioning liabilities
30 resulting from a change in the approved reference plan.

1 It is also OPG's submission that the approach used to calculate the amounts in the deferral
2 account should be consistent with the method used to calculate the revenue requirement in
3 interim rates. This is precisely because the intent of this deferral account is to provide OPG
4 with the rates it would have received if the adjustment to the reference plan in 2006 had been
5 known when interim rates were originally established. In other words, the record is clear that
6 had the government approved the new reference plan incorporating increased liabilities
7 associated with the Bruce refurbishment before approving O. Reg. 53/05, those new
8 liabilities would have been embedded in the interim rates in accordance with the "rate base
9 method" adopted for the recovery of those costs.

10
11 The CME argument that "nuclear liability costs attributable to Bruce are only recoverable to
12 the extent that Bruce costs exceed Bruce revenues" is just dead wrong. Section 6(2)9 of the
13 Regulations could not be clearer in providing that the OEB is required to ensure that OPG
14 recovers "all the costs it incurs" with respect to the Bruce facilities. It is only when revenues
15 exceed costs, and not the other way around, that any benefit accrues to ratepayers. Sections
16 6(2)9 and 10 can only be read to mean that any credit to the revenue requirement arising
17 from the Bruce facilities is after recovery of *all costs incurred* with respect to those facilities.
18 The evidence is absolutely clear, and unchallenged, that nuclear waste and
19 decommissioning liabilities related to the Bruce facilities are a cost OPG incurs with respect
20 to those facilities.

21
22 The only question remaining, therefore, dealt within Issue 7.1 below, is how to quantify the
23 cost, both for the deferral accounts and the test period. As discussed in OPG's argument-in-
24 chief and under Issue 7.1 below, OPG believes that the Regulation requires use of the rate
25 base method.

26
27 It should also be noted that one consequence of excluding Bruce nuclear waste and
28 decommissioning costs associated with the Bruce facilities from the determination of
29 payment amounts, as urged by Board Staff and CME et al, would be a significant reduction in
30 the tax loss carry-forwards that OPG has voluntarily made available to mitigate test period
31 rate impacts. If the costs of nuclear liabilities with respect to the Bruce facilities are excluded
32 from the determination of payment amounts, there would be no logical basis for giving, and

1 OPG would not give, ratepayers the benefit of tax deductions associated with OPG's
2 segregated fund contributions related to the Bruce facilities. In the 2005 to 2009 period, OPG
3 will have made segregated fund contributions of some \$2.5B (Ex. J15.11) of which
4 approximately \$1.5B is associated with the Bruce facilities. The withdrawal of these
5 contributions from the "regulatory account" would cause a significant reduction of available
6 accumulated tax losses from 2005 to 2009 (Ex. J8.1, Note 5).

7

8 In summary, it is clear that return on equity in respect of the Bruce NGS is a cost incurred by
9 OPG. The argument that nuclear liabilities associated with Bruce NGS are not recoverable as
10 part of the approved reference plan is not sustainable on the plain wording of O. Reg. 53/05.
11 Ratepayers cannot get the benefit of Bruce revenues without taking full account of all
12 associated costs, which includes the cost of OPG's obligations with respect to nuclear
13 liabilities associated with the Bruce facilities. The Regulation, and the surrounding
14 circumstances when the Regulation was passed, make clear that the rate base approach is
15 the correct way to value the cost of these liabilities.

16

1 **7. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING**

2
3 **Issue 7.1**

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

11
12 The lead argument on nuclear waste and decommissioning liabilities has been made by
13 CME. Others adopted or supplemented CME's arguments. OPG's reply will, therefore,
14 primarily address the arguments of CME and respond to particular issues raised by others
15 where they depart materially from CME.

16
17 The CME argument depends heavily on many complex calculations in which CME has
18 "estimated" values based on a combination of existing evidence, understandings,
19 misunderstandings and speculations. OPG submits that CME has improperly crossed the
20 threshold from argument to evidence on this issue. Much of CME's "argument" purports to
21 put new formulations, calculations and values on the record. However, while it may be
22 appropriate to derive new numbers from simple calculations based on information already on
23 the record, it is not appropriate to introduce new calculations based on entirely new
24 interpretations of the evidence which appear nowhere in the record and which have not been
25 put into evidence or tested through cross examination. CME is entitled to and did elicit
26 evidence during the interrogatory phase, the technical conference and through cross-
27 examination on this issue. It was also entitled to tender evidence of its own through a
28 qualified witness but did not do so. CME is not entitled to create a new record at this stage in
29 the proceedings in the guise of argument.

30

1 OPG therefore submits that the OEB should disregard CME's arguments which are based on
2 CME's new calculations of what CME thinks the revenue requirement associated with
3 nuclear liabilities should be. Most of CME's assumptions, claimed facts and calculations have
4 not been put into evidence or tested in the hearing and, as is shown below, many of them are
5 wrong.

6
7 In a related vein, CME, SEC and VECC have recommended that the OEB resolve this matter
8 on an interim basis so that it can be revisited during OPG's next rate case. They base this
9 recommendation on allegations that the record contains insufficient evidence for the OEB to
10 make an appropriate determination of the "right" amounts required to discharge OPG's
11 nuclear waste obligations.

12
13 OPG opposes interim treatment and disagrees that the record contains insufficient evidence
14 on which to decide this matter. OPG's proposal has been articulated clearly from the outset.
15 Dozens of interrogatories were asked about it. The issue of nuclear liabilities was covered
16 during the technical conference and literally days were spent on it during cross-examination.
17 If intervenors believe that there is inadequate evidence on alternative approaches, the
18 responsibility lies with them alone.

19
20 Intervenor Positions

21 CME asks the OEB to reject OPG's rate base method, and in particular to reject any return
22 on the asset retirement cost ("ARC") component of rate base. CME and others argue that the
23 ARC should be removed from rate base on the grounds that ratepayers should not pay a
24 return on capital that, they claim, has not been raised. VECC suggests that consideration be
25 given to a funding strategy similar to a sinking fund provision and submits that one way to
26 apply this approach would be to adopt the recommendations of CME. For "interim" purposes
27 SEC accepts OPG's submitted revenue requirement impact in the areas of depreciation, fuel
28 and tax but proposes that the return component should be based on a 4.6 percent cost rather
29 than the weighted average cost of capital. CME also proposes an analogous approach on an
30 interim basis, until the OEB's further review of nuclear liability related costs is complete. CCC
31 submits that the OEB should include ARC in rate base but distinguish between the "funded"

1 component, which should earn a return, and the “unfunded” component, which should
2 receive zero return.

3
4 These arguments, however, continue to display significant confusion around the meaning of
5 ARC and asset retirement obligations (“ARO”) and around what various representations of
6 OPG’s nuclear waste and decommissioning liabilities actually mean.

7
8 The “Cost of Service Supplement to Depreciation”

9 CME concedes, at paragraph 74 of its argument, that ARC depreciation alone over the
10 remaining life of the nuclear assets, will be insufficient to provide the total fund that is needed
11 at the end of the economic life of the asset, to discharge OPG’s undiscounted total nuclear
12 liability associated with that asset. In OPG’s submission, the proposition conceded by CME is
13 correct.

14
15 CME then argues that the question to be determined is “what is the additional amount that
16 needs to be recovered from ratepayers, over and above ARC depreciation, to produce a fund
17 at the end of the economic life of the assets in an amount which equals the shortfall?” (CME
18 argument, paras. 72, 77, 87, 91). CME refers to this as the “cost of service supplement to
19 ARC depreciation method.

20
21 As CME describes the approach, essentially one starts with ARC depreciation amounts for
22 each station and then, using the appropriate discount rate, calculates the additional amount
23 that would be needed in rates over the remaining economic life of each station to provide
24 OPG, together with the segregated funds existing to date (and earnings on those funds), with
25 an amount that is sufficient to cover the entire cost of managing the used fuel, nuclear waste
26 and decommissioning liabilities associated with these assets (CME argument, paras. 68-72).

27
28 Leaving aside OPG’s position that Regulation 53/05 requires the OEB to adopt the rate base
29 method, CME has failed to correctly calculate the cost of its proposed methodology. CME
30 incorrectly calculates the necessary amounts that still must be collected by the end of each
31 station’s economic life to fully address decommissioning, used fuel and nuclear waste costs.

32

1 CME's major error involves its argument based on the \$24B ARO figure discussed in Ex. L-
2 1-84 and in Ex. J15.1, Addendum 2. This error goes to the heart of all CME's attempts to
3 quantify this approach to funding OPG's nuclear liabilities. CME seems to think this \$24B
4 amount represents the total amount OPG requires to fulfill its nuclear waste and
5 decommissioning obligations at the end of the various stations' lives. What CME has chosen
6 to disregard, or misunderstands is that the \$24B figure is both undiscounted *and unescalated*
7 for future inflation and does not include costs for incremental used fuel and low and
8 intermediate level wastes that will be generated in the future, and that need to be managed
9 and disposed of. This is clearly stated in Ex. L-1-84 and Ex. J15.1, Addendum 2. In other
10 words, this figure is stated in constant 2007 dollars as if OPG had to pay for its nuclear waste
11 and decommissioning obligations all at once in 2007, at 2007 rates for labor, equipment,
12 materials and all other costs. The *escalated* and undiscounted liability is far in excess of
13 \$24B, in the order of \$100B, because these expenditures will not be made for a very long
14 time and will continue to be made far out into the future.

15
16 Accordingly, CME's \$5B "estimate" of unfunded, undiscounted ARO is not correct. \$5B is not
17 the appropriate target amount which must be collected over the remaining life of the nuclear
18 stations in order to satisfy OPG's obligations. The correct amount will depend on future
19 inflation rates and other considerations and OPG's current estimate is approximately \$17B.
20 In order to apply the CME approach properly, that is, to determine how much is actually
21 needed for each station's share of the total nuclear waste and decommissioning obligation at
22 the end of that station's life, each station's share of the \$24B constant dollar estimate would
23 need to be escalated to the year in which the funds are to be spent and then present valued
24 to the end of station life.

25
26 Thus, the amounts yet to be funded by the end of station lives under the CME proposal is not
27 21 percent of the \$24B constant dollar figure (or \$5B) but, rather, the difference between the
28 amounts actually required at the end of each station's life less the projected amount in the
29 funds at that time (Tr. Vol. 7, pages 151-52).

30
31 Another error in the CME calculation is the application of a discount rate of 4.6 percent (CME
32 argument, paras. 75-76). The accounting discount rate of 4.6 percent is used for accretion

1 and applies only to the increase in liability recognized in December 2006. The blended
 2 accretion rate for the total liability is 5.6 percent (Ex. J12.1). The target rate of return on the
 3 ONFA fund is 5.15 percent (Tr. Vol. 7, pages 151-152). It is unclear what discount rate CME
 4 intended to apply in its calculation.

5
 6 As noted earlier, the amounts required to be set aside in the funds each year to fulfill the
 7 nuclear waste management and decommissioning obligations are the ONFA fund
 8 contributions plus the amounts funded internally from operating cash flows (Ex. J15.11). For
 9 the test period, these amounts are summarized as follows (from Ex. H1-T1-S3 and Ex.
 10 J15.11):

11 **Cash Requirements (\$M)**

	2008 (9 months)	2009	Test Period
ONFA contributions	341	339*	
Internally funded	88	100	
Total	429	439	868

*2009 contribution is shown as \$350M in Ex. H1-T1-S3 but this is updated in Ex. J15.11 as a result of the Bruce Extraordinary Payment made in December, 2007.

12
 13 Given the errors made in CME's calculations, the only reliable determination of the revenue
 14 requirement impact of the approach proposed by CME that is in evidence are the amounts
 15 shown in the table above; that is, a revenue requirement impact of \$868M rather than the
 16 alternative estimates of \$481M or \$550M proposed by CME (CME argument, paras. 93, 95
 17 and 98).

18
 19 The ONFA contribution schedule is recognized to be somewhat front-end loaded. This is
 20 partly the result, however, of the fact that funds need to be contributed for all stations until
 21 2014 when the first of them reaches the end of its useful life. In the early years, all stations
 22 are in-service and the total contribution amounts reflect contributions for each. As stations
 23 retire from service, contributions associated with these stations, assuming no changes in the
 24 approved reference plan, will come to an end, so the total contribution amount steps down.
 25 Additional front-end loading results from specific ONFA prescriptions which limit the pace of
 26 reductions in fund contributions, even though they may be warranted by changes in

1 reference plan, such as life extensions. These restrictions ensure that the funding of these
2 eventual liabilities remains robust (ONFA Agreement; Ex. J14.2, Article 3.6.2(e), pages 25-
3 26).

4
5 Other Calculation Errors in CME's Summary

6 CME's "Summary of Recommended Revenue Deficiency Reductions" contains several other
7 errors related to nuclear liabilities (CME argument, para. 199). CME "recommends" excluding
8 ARC from rate base for a so-called net reduction of \$153M. CME also "recommends" an
9 adjustment for a claimed "understatement" of Bruce revenues resulting from CME's exclusion
10 of any offset for Bruce nuclear liability costs of \$171M. These two figures result in almost
11 complete double counting because the cost of capital associated with the Bruce nuclear
12 liabilities is removed twice. The starting point for the \$153M reduction, the exclusion of the
13 \$334M cost of capital, is for all nuclear stations, including the Bruce facilities. The \$171M
14 reduction is also for cost of capital on the Bruce facilities. Since over 90 percent of the Bruce
15 fixed asset is ARC, almost all of the \$171M reduction is already included in the earlier
16 reduction of \$334M.

17
18 Another example of CME errors arises from the "recommended" nuclear liability deferral
19 account reduction of \$53M in the same summary. The \$53M represents the amount of this
20 deferral account that relates to the Bruce facilities. OPG proposed to recover this amount
21 over three years (i.e., one third of the proposed recovery falls outside the test period) yet
22 CME incorrectly proposes to eliminate the entire \$53M from the test period revenue
23 requirement.

24
25 Once again, these are examples of serious, material errors that result from advancing
26 complex, untested calculations and proposals for the first time in argument. The OEB should
27 reject all of CME's calculations. The important issues are the issues of principle, whereas
28 CME has focused only on trying to advance arguments which reduce the revenue
29 requirement.

1 The “Not Really an Asset” Argument

2 One of the principal criticisms by CME, CCC, VECC, SEC and others of OPG’s rate base
3 approach to recovering the cost of nuclear liabilities is the allegation that no debt or equity
4 have been raised to acquire this asset (CME argument, para 70; CCC argument, para. 106;
5 VECC argument, para. 21; SEC argument, para. 213). Rather, they say, because it is
6 unfunded, by definition it cannot have been financed by debt or equity. There are at least two
7 problems with this argument.

8

9 First, as has been pointed out by OPG and by Board Staff in argument, accounting standards
10 state that upon recognition of a liability for an asset retirement obligation, OPG must
11 recognize an asset retirement cost “by increasing the carrying cost of the related long-lived
12 asset by the same amount as the liability.” (Canadian Institute of Chartered Accountants
13 Handbook section 3110, Asset Retirement Obligations, para. 13). There is an asset - it is the
14 nuclear facilities that generate electricity and revenue. The waste and decommissioning
15 liability does not exist independent and apart from these assets, rather it is integral to them.

16

17 The second and related problem with this argument is that it ignores the fact that the
18 segregated funds that exist today were largely funded by investor-supplied capital, not cost
19 of service recovery from electricity consumers through regulated payment amounts. Most of
20 the existing funds, at this point, have been contributed by the shareholder, either directly or
21 indirectly, through dividends foregone because OPG made contributions to the segregated
22 nuclear funds instead. Investor-supplied capital which is used to fulfill obligations associated
23 with fixed assets that are used in supplying utility service is entitled to a return. Even CCC
24 admits this in principle (CCC argument, para. 107). There is no principled reason why the
25 return on capital required to fulfill ARO should be any different than the return on capital used
26 to acquire other useful assets for the provision of service.

27

28 CME tries to dodge this issue by claiming that the “income earned on invested funds, in
29 theory, should equal or exceed any Costs of Capital the investor incurs to raise the funds.”
30 (CME argument, paras. 83-90). This argument seems to treat the equation as if the
31 shareholder is receiving the benefit of the earnings on the segregated funds, akin to a
32 dividend. This is clearly wrong. The Province receives nothing from the segregated funds

1 (unless, in the case of the used fuel fund, it is clearly in an overfunded position). The
2 fulfillment of the ARO, in fact, depends in large measure upon the earnings on the funds
3 remaining in the funds. Thus, these earnings, far from being a credit to the shareholder, are
4 an important and necessary component of raising the amount of money required to satisfy
5 OPG's nuclear waste and decommissioning obligations as they come due.

6
7 It is for this reason that intervenors' reliance on the example of deferred taxes as a form of no
8 cost capital is inapt. In the case of deferred taxes, ratepayers are, in effect, getting back
9 amounts in respect of the cost of prepaid taxes which they contributed through rates. That is
10 clearly not the case with the funded portion of ARO. To date, OPG and its shareholder have
11 contributed most of the amounts in the segregated funds (Tr. Vol. 7, page 139).

12
13 SEC argues for "streaming" the financing cost of the ARC at the 4.6 percent discount rate on
14 the similar basis that investors have not provided funds to finance ARC (SEC argument,
15 paras. 218, 220). Like CCC and CME, SEC simply ignores the fact that very substantial
16 contributions to the segregated funds have already been made by the shareholder (OPG
17 argument-in-chief, page 81). On the other hand, CCC agrees that while the "funded" portion
18 of ARC should earn the WACC, there should be zero return on the remaining portion. As
19 OPG has said repeatedly, it makes no sense to talk about funded and unfunded ARC.
20 Further, CCC's approach ignores the fact that simply collecting depreciation on the ARC and
21 investing those amounts will not result in sufficient contributions to the funds by end of station
22 life to satisfy the ARO at that time.

23
24 O. Reg. 53/05 Requires the Rate Base Approach

25 As noted in connection with Issue 6.5, Bruce nuclear liability costs, the Province clearly
26 knew, when approving O. Reg. 53/05, that the interim rates it approved in that Regulation
27 were based on the rate base methodology for recovery of the cost of OPG's nuclear waste
28 and decommissioning liabilities. While this, of itself, may not be dispositive of the recovery
29 method post April 1, 2008, it is compelling evidence of the facts known to the Province when
30 the Regulation was passed. As such, it is an important factor to be considered in the
31 interpretation of sections 6(2)5 to 8 of the Regulation.

1 To similar effect is the fact that the Province is aware of what OPG is seeking in this
2 application. As the sole shareholder, if OPG's request was out of line with the intent of O.
3 Reg. 53/05, it would be reasonable to expect that the Province would have so advised the
4 company.

5
6 SEC argues that if the rate base method produces just and reasonable rates, then OPG
7 would not need to argue that the rate base method is required under O. Reg. 53/05 and was
8 used by the Province to set interim rates (SEC argument, paras. 173-74). This is mere
9 sophistry. That O. Reg. 53/05 requires the rate base method and that the government used
10 this method during the interim period are not inconsistent with the conclusion that the method
11 produces just and reasonable rates. In fact, they support this conclusion.

12
13 CME argues that, while it agrees the OEB must accept the assets and liabilities contained in
14 OPG's 2007 audited financial statements, the "revenue requirement" impact of costs
15 associated with nuclear liabilities is a matter of the OEB's discretion. The basis for this
16 argument is unclear. If the OEB must accept the ARC as a fixed asset but is free to assign it
17 a zero cost, how has the OEB "accepted" anything? CME's approach makes a complete
18 mockery of sections 6(2)5 and 6 of the Regulation. Furthermore, section 6(2)5 does not even
19 use the words "revenue requirement impact" so the OEB's prima facie obligation to accept
20 the assets and liabilities as recorded in the 2007 audited financial statements is not impacted
21 by that expression.

22
23 More importantly, however, CME vastly overstates the implications of that phrase as it
24 appears, for example, in 6(2)6(ii) or 6(2)7 and 8 of the Regulation. CME seems to think that
25 the phrase "revenue requirement impact" leaves entirely to the OEB the determination of
26 whether, through what means and in what amount the cost of OPG's nuclear liabilities may
27 be recovered. This cannot be and is not correct.

28
29 The only reasonable interpretation of the phrase "revenue requirement impact" as it is used
30 in O. Reg. 53/05 is that it distinguishes between "costs" at large and the impact that costs
31 have on the payment amounts in the test period. It is simply a way of ensuring that OPG
32 does not recover more than the revenue requirement impact of a particular cost; for example,

1 a long-term capital cost is not recoverable during the test period, only depreciation, cost of
2 capital and related taxes are recoverable, because those are the “revenue requirement
3 impacts” of that cost. The revenue requirement impact would also operate, for example, to
4 restrict recovery of costs to the test period, because out of period costs (e.g., the Niagara
5 Tunnel) would not exert a revenue requirement impact in 2008/2009.

6
7 The phrase “revenue requirement impact” does not convey total discretion to the OEB, as
8 CME would have it. All this expression does is restrict OPG to recovery of a certain category
9 of costs, that is, those costs which have an impact on the test period revenue requirement.
10 The addition of the phrase “to the extent are accurately recorded in the accounts” (O. Reg.
11 53/05, section 6(2)7) does nothing to change this conclusion. Instead, that phrase obligates
12 the OEB to ensure that OPG has accurately calculated the “revenue requirement impacts”
13 and recorded the correct figures in the deferral account; it has nothing to do with the
14 methodology that the OEB must follow for determining the “revenue requirement impacts.”

15
16 Further, as noted above, the government was well aware of how these costs were being
17 treated and recovered in the interim rates. The rate base method was used to determine the
18 “revenue requirement impact” of OPG’s nuclear liabilities from April, 2005 to April, 2008. Why
19 would the Regulation have made a point of requiring the OEB to accept values relating to the
20 revenue requirement impact of accounting policy decisions embedded in OPG’s audited
21 financial statements or required recovery of nuclear liability deferral account balances based
22 on “return on rate base” or the “revenue requirement impact” of OPG’s nuclear liabilities
23 arising from an approved reference plan, if it was not to authorize the continuation of the
24 treatment afforded these costs in interim rates? In referring to “revenue requirement impact,”
25 therefore, the Regulation is not conferring *jurisdiction* on the OEB, it is merely confirming
26 continuation of the status quo.

27
28 CME, in paragraph 50, argues that OPG disregards GAAP in determining its nuclear costs.
29 This is simply not so. Note 2 to OPG’s audited financial statements for the year ended
30 December 31, 2007 states that OPG’s consolidated financial statement were prepared in
31 accordance with GAAP in connection with nuclear liabilities, which includes its accounting for
32 asset retirement obligations and asset retirement costs. OPG has reflected the ARC of its

1 nuclear liabilities as part of the fixed assets giving rise to those liabilities correctly and in
2 accordance with the clear dictates of the CICA Handbook, section 3110. As Board Staff in its
3 argument concedes, this means that those fixed assets must be accepted into rate base if
4 section 6(2)5 is to have any meaning.

5
6 CCC makes the further argument that the OEB is not required to adopt accounting
7 assumptions embedded in OPG's audited financial statements. In fact, O. Reg. 53/05,
8 section 6(2)6(ii), clearly and unambiguously requires the OEB to accept the revenue
9 requirement impact of accounting and tax policy decisions reflected in the 2007 audited
10 financial statements. This is recognized by Board Staff in its argument.

11
12 In paragraph 25 of its argument, VECC suggests that the rate base treatment is a hedge
13 against the performance of the segregated funds by assuming that if the funds perform
14 poorly, this will result in an increase in the ARC in the following year, which will result in
15 higher rates to ratepayers. This is clearly not the case. As has been stated repeatedly, the
16 ARC has nothing to do with the amount in the segregated funds (Ex. J15.1, Addendums 1
17 and 2).

18 19 Interim Amounts and Further Consideration

20 In support of their proposals for interim treatment, CME and SEC argue for various interim
21 amounts pending a further review of the appropriate methodology for recovering nuclear
22 liabilities. CME, in attempting to justify a test period amount of only \$181M, again puts
23 entirely new evidence on the record in the guise of argument, and again falls into the error
24 noted above (e.g., using \$24B as the ultimate value for ARO and selectively adopting the
25 post 2006 accounting discount rate of 4.6 percent). Even if there were any merit to the
26 \$2,251M figure referred to in paragraphs 95 and 96 of CME's argument (which there is not),
27 4.6 percent is not the right discount rate. OPG's evidence is that only the incremental liability
28 arising from the December 2006 approved reference plan is discounted at 4.6 percent. For
29 the much larger portion of the liability, which arose before 2006, the discount rate is 5.75
30 percent (Ex. L-1-81). At the very least, therefore, the discount rate to be applied would have
31 to be the blended rate of 5.6 percent, rather than the conveniently lower rate of 4.6 percent.

1 A similar selective error is made by SEC in its argument proposing interim rates pending
2 further OEB review.

3

4 In making her recommendation regarding the composite cost of capital for OPG's regulated
5 facilities, Ms. McShane took into account OPG's rate base treatment of the nuclear liability
6 costs (Ex. J1.3). In addition, as stated under Issue 2.5, the treatment of costs in the nuclear
7 liability deferral account also has an impact on the cost of capital. Deferring the final decision
8 on the methodology for recovering the nuclear liability will, therefore, leave a significant risk
9 factor for OPG and would require further consideration of the cost of capital when the final
10 nuclear waste methodology is determined.

11

12 OPG does not believe there is anything to be gained by postponing the determination of
13 recovery of nuclear waste and decommissioning liabilities because the method for doing so
14 is prescribed by Regulation. More study, further alternatives, more evidence and conflicting
15 expert opinions will not change that.

16

1 **8. DESIGN OF PAYMENT AMOUNTS**

2
3 **Issue 8.1**

4 **Are OPG's suggested changes to the hydroelectric incentive payment system**
5 **appropriate?**

6
7 Many intervenors expressed support for the concept of a hydroelectric incentive mechanism,
8 recognizing the need for efficient peaking and a link between OPG's financial interests and
9 the interests of ratepayers (AMPCO argument, para. 160; Energy Probe argument, para. 92;
10 PWU argument, para. 96).

11
12 Board Staff expresses uncertainty about whether OPG's proposed incentive mechanism
13 constitutes an improvement over the existing mechanism (Board Staff submission, page 49).
14 This uncertainty is misplaced. The proposed mechanism is clearly a significant improvement
15 since it establishes the correct price signals for all periods. Because the existing mechanism
16 relied, in part, on consideration of the regulated rate, the signals it provided were not optimal,
17 resulting in less pumping than system economics would have dictated. The proposed
18 mechanism provides the correct signals for peaking operations since it drives the decision to
19 pump on the spread between forecast on-peak and off-peak prices (Ex. I1-T1-S1, page 8,
20 lines 2-13; Tr. Vol. 15, pages 111 and 128).

21
22 One feature of the proposed incentive mechanism was opposed by some intervenors – the
23 means by which the threshold energy volume (“threshold”) is set. OPG has proposed an
24 hourly average value (the “hourly volume”) calculated for each month based on actual net
25 energy production in that month (i.e., energy production net of load including Sir Adam Beck
26 PGS pump load and including SMO production). The benefits of setting the threshold on the
27 basis of actual production are twofold. The first is that it allows for the threshold to be rooted
28 in reality – since it is based on actual production for the month in question as opposed to
29 some predetermined value that is unrelated to the actual water conditions in that month. The
30 second benefit is that using actual production allows for a higher volume of energy at the
31 regulated payment amount than would be the case with a predetermined volume because
32 the volume can be established without the need to incorporate a risk premium to account for

1 forecast uncertainty. A higher threshold volume benefits consumers (Tr. Vol. 15, page 101).

2
3 SEC questions why OPG should be rewarded for "...simply exceeding its own average
4 production..." (SEC argument, para. 231). This grossly oversimplifies the nature of OPG's
5 proposal. An alternative, such as choosing a higher target that would be difficult to meet will
6 not result in efficient peaking operations and does not represent a just and reasonable
7 approach. If the threshold is too high, OPG will be driven to maximize energy production at
8 the expense of pumping for peaking purposes, since pumping reduces total energy output.
9 The objective is not to maximize OPG's production at the regulated hydroelectric facilities but
10 to optimize economically efficient production based on market signals, which represent the
11 value of production at various times.

12
13 SEC submits that the existing mechanism should be continued on an interim basis (SEC
14 argument, paras. 232-233). This would not be in the best interest of ratepayers as the
15 existing mechanism does not provide the correct signals for pumping at the PGS. Moreover,
16 the proposed mechanism is forecast to yield net revenues that are a small fraction of the net
17 revenues produced by the existing mechanism (Ex. L-1-90, pages 1-2).

18
19 In their submissions, both AMPCO and SEC state that the volumes associated with SMO are
20 excluded from the monthly average, thereby artificially reducing the hourly volume. This is
21 incorrect as Ex. I1-T1-S1, Section 5.2.2 clearly states:

22
23 The **hourly volume** would be calculated as the sum of the net energy
24 production (i.e., energy production net of load including Sir Adam Beck
25 PGS pump load) from the prescribed assets for that month (in MWh)
26 divided by the number of hours in the month. At the end of each month,
27 the **actual net energy production** supplied into the IESO market only
28 (i.e., segregated mode of operation production is not included) for each
29 hour of the month would be reconciled against the hourly volume for that
30 month. (Emphasis added)
31

32 The hourly volume (i.e., the threshold) includes all net energy produced from the prescribed
33 facilities including SMO volumes. It is only the actual net energy production (the amount
34 compared against the threshold volume for settlement purposes), that does not include SMO
35 volumes. AMPCO submits that including SMO production in the calculation of the monthly

1 average production (i.e., the hourly volume) is appropriate (AMPCO argument, para. 167).
2 OPG agrees, since that is exactly how the proposed mechanism is structured.

3
4 The second concern with respect to the threshold energy volume relates to the treatment of
5 pump energy. Energy Probe is concerned that pumping lowers the average hourly volume,
6 resulting in OPG earning market prices, on a greater portion of its output. This is the case, as
7 shown in Ex. J15.6. However, Energy Probe goes on to suggest that this will create a
8 perverse incentive for OPG to “over-use the PGS” (Energy Probe argument, para. 102). This
9 is incorrect for two reasons. First, the decision to pump is based solely on the price
10 differential between the peak and off-peak prices at a point in time, less the associated costs.
11 It is not based on any plan to lower the average hourly volume. (Tr. Vol. 15, page 111, lines
12 12-21).

13
14 Second, and perhaps more compelling, is OPG’s evidence on the estimated benefits
15 associated with Beck operations to consumers (Ex. I1-T1-S1, page 15, Chart 1). The annual
16 average benefit to consumers ranges from \$80M to \$270M and increases with increasing
17 pump usage. So while OPG’s revenues will increase as a result of more pumping, so will the
18 benefits that will accrue to consumers, and by a much greater amount. OPG submits that
19 Energy Probe’s concern about over-use of the PGS is unfounded.

20
21 Energy Probe offers two proposals to address concerns regarding energy consumption
22 during pumping and its impact on the threshold (Energy Probe argument, para 108). Under
23 Proposal “A”, Energy Probe would use the average of the last three years of energy
24 production on a monthly basis to establish the threshold. The problem with this approach is
25 the same problem as with any predetermined value, that is, it disconnects the threshold from
26 the actual water available to the regulated facilities. This is clearly inappropriate since the
27 evidence has shown that history is a poor predictor of future water volumes.

28
29 Proposal “B” adjusts the hourly volume by adding in pump energy losses. AMPCO proposes
30 a similar adjustment (AMPCO argument, para. 164). While Proposal “B” is grounded in actual
31 water availability, it is punitive in that it sets an energy threshold higher than what OPG has

1 actually achieved in a given month. Setting an unreasonably high threshold is unwarranted in
2 light of the consumer benefits associated with OPG's proposal as outlined above.

3
4 Energy Probe spends more than two pages of argument trying, unsuccessfully, to show that
5 the proposed incentive can be "gamed" through overuse of the Sir Adam Beck PGS (Energy
6 Probe argument, paras. 103-108). As OPG has demonstrated, this is not a significant impact
7 (Ex. J15.6). Even under the extreme and highly unrealistic scenario proposed by Energy
8 Probe, the benefits to OPG are miniscule. As elements of reality are introduced to the
9 analysis, however, Energy Probe's concerns are shown to be baseless. While Energy
10 Probe's formulation assumes flat out pumping regardless of forecast prices, the Sir Adam
11 Beck PGS cannot physically accommodate that amount of pumping because pumping must
12 account for automatic generation control ("AGC") requirements, physical storage
13 characteristics of the storage reservoir and hydrologic conditions (Ibid.). Also, OPG must
14 base pumping decisions on the forecast spread between on- and off-peak prices or risk
15 being unable to recoup its pumping costs (Ibid.).

16
17 The Energy Probe/AMPCO proposal to add back pump energy losses to the threshold is
18 illogical because it would decrease OPG's incentive to use the PGS to increase on-peak
19 generation, but this is the very action that will benefit ratepayers. As OPG has demonstrated
20 through uncontroverted evidence, time shifting water and thereby displacing more expensive
21 peak generation is estimated to produce annual savings ranging from a low of \$80M to a
22 high of \$270M (Ex. I1-T1-S1, Chart 1; Ex. L-1-91). The OEB and consumers should be
23 looking for ways to encourage OPG to maximize this benefit, but the Energy Probe/AMPCO
24 proposal will have the opposite effect.

25
26 AMPCO also recommends that the Board order an independent review of the hydroelectric
27 incentive mechanism (AMPCO argument, para. 108). While OPG agrees that it is appropriate
28 to review the operation of the mechanism in a subsequent application to the Board, OPG
29 does not believe an independent review is feasible or necessary. The incentive mechanism
30 will be put in place with the implementation of the OEB's decision, likely in Q4 2008. With
31 OPG's next application targeted for early 2009, there would not be sufficient time for an
32 independent review. More importantly, it is far from clear that an independent review would

1 add anything. In its next filing, OPG will provide a review of the incentive's effect on its
2 operating decisions, based on information available to OPG, so the impact of the new
3 mechanism can be readily observed. This analysis will provide ample information to evaluate
4 the mechanism.

5
6 VECC proposes that the Board order OPG to track the operation of the mechanism in a
7 deferral account with clearance subject to Board review (VECC argument, para. 105). A
8 deferral account is not warranted given the significant consumer benefits that result from
9 time-shifting production to peak hours. Its existence will also negate the incentive power of
10 the mechanism since OPG won't know the disposition of the account balance at the time it is
11 making operating decisions.

12
13 **Issue 8.2**

14 **Is the fixed payment of 25% of revenue requirement an appropriate design for the**
15 **nuclear facilities?**

16
17 Intervenors were split on OPG's proposal for a fixed charge equivalent to 25 percent of the
18 nuclear revenue requirement, net of the test period amortization for deferral and variance
19 account balances. Four intervenors supported the proposal for a fixed charge (CCC
20 argument, para. 124; VECC argument, para. 108; PWU argument, para. 97; SEC argument,
21 para. 234). While three of these parties supported OPG's 25 percent figure, CCC would go
22 further and set the fixed charge set at the 50 percent (CCC argument, para. 124). Three
23 intervenors objected to any fixed charge (AMPCO argument, para. 179; Energy Probe
24 argument, para. 112; GEC argument, page 7). CME's argument was confused on this point,
25 stating: "We support AMPCO's detailed submissions in support of the proposition that 25
26 percent of the nuclear revenue requirement be recovered in a fixed charge" (CME argument,
27 para. 207).

28
29 The four intervenors who supported the proposal variously cited the rate-making principle of
30 cost causality with reference to the high proportion of nuclear fixed costs (approximately 90
31 percent), the need for consistency with other utilities regulated by the OEB and the risk
32 mitigation benefits of the proposal. Ms. McShane was the only expert witness to provide a

1 quantification of the impact of the 25 percent fixed payment proposal on OPG's cost of
2 capital. Ms. McShane indicated that if OPG's fixed payment proposal was not accepted by
3 the OEB, then either the required ROE or the equity component of the capital structure would
4 have to be increased by approximately 25 basis points since she had assumed that it would
5 be approved when she made her recommendation (Ex. L-12-1). The supporting intervenors
6 also accepted OPG's evidence that the 75 percent variable charge would provide a very
7 strong incentive to maximize nuclear production.

8
9 The objecting intervenors raised a number of points, none of which is particularly compelling.
10 Before addressing their points below, it is worth noting that none of the objecting intervenors
11 challenged OPG's cost analysis or submissions on the principle of cost causality nor did they
12 challenge Ms. McShane's estimate of the ROE adjustment that would be necessary if OPG's
13 proposal is not approved.

14
15 Energy Probe suggested that the fixed charge proposal for nuclear was not needed because
16 OPG did not have a similar proposal for its hydroelectric assets which also have a relatively
17 high proportion of fixed costs (67 percent). This submission ignores OPG's clear evidence on
18 the key differences between the production risk for nuclear and hydroelectric facilities. The
19 main production risk for hydroelectric facilities is the availability of water which OPG has
20 proposed to address through a water conditions variance account.

21
22 The main argument by the objecting intervenors was that they did not want any possible
23 diminution of the production incentive that comes with a 100 percent variable payment
24 amount. In making their submissions, they ignored OPG's evidence that given the amount of
25 money involved, a 75 percent variable structure would provide a very strong incentive to
26 maximize production and that OPG would do nothing different, in terms of maximizing
27 production, if it had a 100 percent variable rate (Tr. Vol. 15, page 138). This simple, singular
28 focus on one issue ignores the reality that rate design is by its nature complex and that it is
29 the task of the regulator to balance competing interests. Board Staff has articulated this view
30 as follows: "Board Staff believes that the Board's statutory responsibility is best fulfilled, and
31 its statutory objectives in relation to electricity distribution are best promoted, using
32 distribution rates that are designed on the basis of a number of guiding principles" These

1 principles can be conflicting, and “it is the task of the regulator to balance competing
2 interests.”¹⁰

3
4 In casting about for support for its position, AMPCO misrepresents part of Ms. McShane’s
5 evidence on this issue. AMPCO says that Ms. McShane “...acknowledged that no other
6 entity in the Ontario market gets paid irrespective of its ability to produce – no one else gets
7 this benefit (Tr. Vol. 12, page 69, lines 2-25).” (AMPCO argument, para. 175). OPG has
8 reproduced that section of the transcript below and it is quite clear that Ms. McShane’s
9 evidence (see underlined section) was that she had not examined this point and therefore did
10 not know whether or not anyone in Ontario market gets paid even when they have units on
11 outage.

12
13 MR. RUPERT: Okay. One maybe related question. You have had a lot
14 of questions over today and earlier about the proposal from the company
15 to have a quarter of the revenue required for nuclear fixed, unrelated to
16 generation.

17 I wondered if you are aware of any company in Ontario that operates
18 in this market that has a similar arrangement, where it would be paid,
19 irrespective of its ability to produce?

20 MS. McSHANE: I don't know whether or not that is true in this province,
21 because I haven't studied the contractual arrangements for contracts,
22 say, with the OPA. And I am not aware that they're publicly available. I
23 mean I understand, from discussions I have had, that the contracts are
24 fairly -- give the generators a fair amount of protection.

25 I would say that when you look at the restructuring that occurred in
26 Alberta before the PPAs, in the interim period, the arrangement was that
27 the distributors paid the full cost of the capital costs of the existing plants,
28 irrespective of whether or not they produced.

29 MR. RUPERT: Okay. But I guess the answer is in terms of Ontario,
30 you're not aware of --

31 MS. McSHANE: No.

32 MR. RUPERT: -- any company that has an arrangement, with a
33 government contract or otherwise, that would compensate it in the event
34 that it is unable to produce?

35 MS. McSHANE: I am not specifically familiar with that.

¹⁰ EB-2007-0031, Staff Discussion Paper, Rate Design for Electricity Distributors: Overview and Scoping. March 30, 2007, page 9: “Building upon the legislative foundation, Board staff believes that the Board’s statutory responsibility is best fulfilled, and its statutory objectives in relation to electricity distribution are best promoted, using distribution rates that are designed on the basis of a number of guiding principles set out below.” and continued on page 10: “These principles can be conflicting, and it is the task of the regulator to balance competing interests.”

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Finally, CME suggested that if the fixed rate proposal is accepted then OPG's equity ratio should be reduced (CME argument, para. 208). No basis for this submission is offered and there is no acknowledgement that Ms. McShane's recommended capital structure assumes approval of the 25 percent fixed charge for nuclear. On this basis alone, the submission should be rejected by the Board.

GEC and AMPCO suggested that there are no precedents for such a fixed charge (GEC argument, page 7; AMPCO argument, para. 175). OPG has acknowledged that there are no precedents for regulating stand alone generation assets, however there is considerable precedent for regulated utilities and contract generators receiving fixed cost recovery.

AMPCO claims that approving OPG's fixed payment is inconsistent with a potential future move to incentive regulation (AMPCO argument, para. 176). AMPCO does not provide any basis for this claim and does not reconcile it with the fact that the OEB has both promoted incentive regulation and approved fixed charges for electricity distributors. AMPCO also quotes selectively from OPG's cross examination responses, ignoring the examples that Mr. Barrett provided of fixed payments to generators (Tr. Vol. 15, pages 95-96 and 186-188).

In conclusion, the Board should accept OPG's proposal for a 25 percent fixed charge for nuclear since it represents an appropriate balancing of competing objectives. It maintains a strong incentive for maximizing nuclear production while also recognizing cost causality, existing precedents from other generators 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. The merits of OPG's proposal have been recognized and supported by intervenors representing numerous ratepayers in Ontario.

1 **9. DEFERRAL AND VARIANCE ACCOUNTS**

2
3 **Issue 9.1**

4 **Are the costs and revenues recorded in the variance account established under**
5 **section 5(1) (the “forecast variance account”) due to deviations from the forecast set**
6 **out in “Forecast Information for Facilities Prescribed under Ontario Regulation**
7 **53/05”?** **Were the costs incurred and the revenues earned or foregone on or after April**
8 **1, 2005?**

9
10 **Issue 9.2**

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

13
14 **Issue 9.3**

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

18
19 No intervenors took issue with the balances in the variance account established under
20 section 5(1) or OPG’s proposals for clearing these balances. Accordingly, and for the
21 reasons set out in OPG’s evidence and argument-in-chief, the OEB should accept both the
22 December 31, 2007 account balances and OPG’s proposed methods for disposing of the
23 balances in this account.

24
25 In addition, OPG established a Segregated Mode of Operations and Water Transactions Net
26 Revenue Deferral Account to voluntarily share a portion of the profits of these activities
27 during the interim period. Again, no intervenors took issue with OPG’s evidence or proposals
28 related to this account. Accordingly, and for the reasons set out in OPG’s evidence and
29 argument-in-chief, the OEB should accept both the December 31, 2007 account balance and
30 OPG’s proposed methods for disposing of the balance in this account.

1 **Issue 9.4**

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

6

7 No intervenors objected to OPG's evidence on this issue. Accordingly, and for the reasons
8 set out in OPG's evidence and argument-in-chief, the OEB should find that all of the non-
9 capital costs recorded in this account are associated with either the planned return-to-service
10 of all of the units at the Pickering A Nuclear Generating Station or units the Board of
11 Directors of OPG determined should be placed in safe storage and are therefore eligible for
12 recovery by OPG.

13

14 **Issue 9.5**

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

19

20 The Capacity Refurbishment Variance Account and the Nuclear Development Deferral
21 Account (Transition), as well as the Nuclear Liabilities Deferral Account are addressed in this
22 section.

23

24 Capacity Refurbishment Variance and Nuclear Development Deferral Accounts

25 The Capacity Refurbishment Variance Account and the Nuclear Development Deferral
26 Account (Transition) were not specifically identified on the Issues List, yet they are important
27 variance and deferral accounts in OPG's application. No intervenors objected to OPG's
28 proposals relating to these accounts. While Board Staff suggested that the balances in these
29 accounts may be subject to a prudence review by the OEB in certain circumstances; no
30 intervenors contested the prudence of the balances recorded in these accounts. Accordingly,
31 and for the reasons set out in OPG's evidence and argument-in-chief, the OEB should

1 accept both the December 31, 2007 balances in these accounts and OPG's proposed
2 method for recovering these balances in a nuclear rate rider.

3
4 Nuclear Liabilities Deferral Account

5 A number of intervenors contested the inclusion of nuclear liabilities relating to Bruce NGS
6 assets in this account as well as the manner in which OPG has calculated the rate base
7 impact of the liabilities. OPG's response to the arguments of intervenors on the calculation of
8 the balance in this account can be found under Issues 6.5 and 7.1. There were no objections
9 to OPG's proposed clearance methodology for this account.

10
11 For the reasons set out in OPG's evidence, argument-in-chief and reply argument under
12 Issues 6.5 and 7.1, the OEB should accept both the December 31, 2007 balances in this
13 account and OPG's proposed method for recovering this balance in the nuclear rate rider.

14
15 **Issue 9.6**

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

19
20 Other than the interest rates to be applied to the deferral and variance account balances
21 after April 1, 2008, intervenors did not contest OPG's proposals with respect to the recovery
22 of deferral and variance balances.

23
24 With respect to the issue of interest rates, four intervenors (CME argument, para. 204; VECC
25 argument, para. 81; AMPCO argument, para. 183 and CCC argument, para. 134) argue that
26 the OEB's generic interest rate methodology should apply to OPG's accounts.

27
28 CCC argues that OPG had not demonstrated that its accounts are sufficiently unique to
29 warrant a different treatment. Further, they argue that departing from the standard treatment
30 would set a regulatory precedent, resulting in inequitable treatment of the entities regulated
31 by the OEB (CCC argument, para. 134). Finally, CCC argued that OPG has not established
32 criteria for the application of long term rates or WACC and that absent such criteria, OPG

1 has provided no support that its balances are big enough or that the duration of recovery is
2 long enough to warrant the use of such rates.

3
4 SEC said that OPG's claims that its balances were larger and will be paid out over a longer
5 period than the accounts held by other distributors were unsubstantiated, speculative and
6 irrelevant (SEC argument, para. 251). SEC, AMPCO and VECC also reference Board Staff's
7 comment that large balances had been accumulated over several years by electricity
8 distributors and conclude that OPG should not be treated differently.

9
10 The issue here is whether a generic approach should be applied even when evidence is
11 readily available on the specific balances, durations and actual interest costs. OPG submits
12 that its circumstances support the treatments that it has proposed and that it makes no sense
13 to ignore these circumstances in favour of rules that were developed for other utilities. Far
14 from being inequitable and establishing an inappropriate precedent, it would be inequitable
15 not to acknowledge OPG's substantially different circumstances in terms of the size of the
16 balances and the duration before recovery of these balances. The only precedent being
17 established is that the OEB will consider justifiable exceptions from a generic methodology.
18 OPG encourages the OEB to support this precedent.

19
20 Focusing first on the comparison of OPG's proposals to the manner in which the transitional
21 regulatory assets held by the electricity LDCs were treated. Board staff suggested that the
22 balances in these accounts were substantial, like OPG's balances, but that these accounts
23 received carrying charges very different from those proposed by OPG. A closer review of the
24 history of these accounts, at least for four larger LDCs, shows something different.

25
26 In response to applications by four large electricity LDCs (Hydro One, Toronto Hydro,
27 Enersource, and London Hydro), the OEB set the carrying charges for their regulatory assets
28 accounts at their individual deemed long-term debt rates. The OEB rejected the use of the
29 utilities' annual debt rate (i.e., a short-term rate) and instead endorsed the use of the
30 individual long-term debt rates that were used to set each distributor's authorized rates (RP-
31 2004-0117/0118; RP-2004-0118; RP-2004-0100; RP-2004-0069; RP-2004-0064 Decision
32 with Reasons, December 09, 2004, page 18).

1

2 As Board Staff pointed out in the hearing, these transitional regulatory asset balances were
3 accumulated and recovered over a relatively long duration. However, for the vast majority of
4 this period the carrying cost on these balances was a long-term debt rate, as OPG is
5 proposing for most of its accounts. The long-term rate applied to the regulatory assets of
6 these utilities over a four year period (2002, 2003, 2004, 2005 and part of 2006). It was only
7 starting on May 1, 2006 that the OEB applied a short-term rate.

8

9 The second point raised by intervenors was the duration that the account balances would
10 have to be carried before they could be recovered. Here again OPG's situation is different
11 than those LDCs covered by the generic methodology. Under the OEB Act, the OEB must
12 make an order at least once every 12 months (every three months for commodity accounts)
13 that determines whether and how amounts recorded in the account shall be reflected in rates
14 (section 36, parts 4.1 and 4.2; section 78, parts 6.1 and 6.2). These sections do not apply to
15 OPG. Given that OPG is on a two year review cycle, it will be carrying its account balances
16 for at least three to four years – a much longer duration than the gas and electric LDCs
17 covered by the generic methodology.

18

19 With respect to the issue of account size that was raised by intervenors, OPG notes that the
20 total regulatory asset balance as at December 31, 2002 for all 92 electricity LDCs filings, for
21 recovery in rates effective April 1, 2004, was \$550.5M (March 1, 2004 Rate Adjustments /
22 Regulatory Asset Recovery / Amounts Filed in Applications found at:
23 http://www.oeb.gov.on.ca/documents/regassets_200204.xls). OPG's total balance is
24 \$339.3M (Ex. J1-T1-S1, Table 1 (updated June 18, 2008)). The asset balance that OPG is
25 carrying is therefore about 62 percent of the regulatory asset balance for the entire electric
26 distribution industry. Clearly, the balances in OPG's accounts are big enough to warrant a
27 departure from the generic approach.

28

29 The exception to the use of a forecast long-term debt rate is the PARTS Deferral Account.
30 The balance is to be recovered over a period not to exceed 15 years as required by O. Reg.
31 53/05. The balance in this account is substantial at \$183.8 M as of December 31, 2007 (Ex.
32 J1-T1-S1, page 8). These costs were incurred in 2005 and 2006, and the proposed recovery

1 continues until December 31, 2019 (Ex. J1-T2-S1 page 1). The recovery period established
2 under the Regulation is longer than any recovery period ever approved by the OEB, and
3 longer than any long-term debt issue in the history of OPG. If there was ever a candidate for
4 using WACC as the carrying cost, this is it. OPG submits that this is an exceptional situation,
5 therefore the development of thresholds and criteria advocated by CCC are not necessary.

6
7 In conclusion, for all of the reasons set out above and in its evidence and argument-in-chief,
8 the OEB should accept OPG's proposal to use its approved long-term debt rate for its
9 deferral and variance accounts, except for the PARTS account where the approved WACC is
10 appropriate and should be used.

11
12 **Issue 9.7**

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

15
16 Continuation of Current Deferral and Variance Accounts

17 As summarized in OPG's argument-in-chief, the Regulation mandates the following for the
18 test period:

- 19 • Continue the PARTS Deferral Account per subsection 5(4)
20 • Establish the Nuclear Liabilities Deferral Account per subsection 5.2(1)
21 • Establish the Nuclear Development Variance Account per subsection 5.4(1)
22 • Continue the Capacity Refurbishment Variance Account per subsection 6(2)4

23
24 OPG also proposes to continue the Water Conditions and Ancillary Services accounts and
25 the SMO and Water Transactions account.

26
27 Intervenors either supported the continuation of these accounts or were silent on them.
28 OPG's arguments regarding the mechanics for sharing the SMO and Water Transaction net
29 revenues are discussed under Issue 6.1. For the reasons set out in OPG's evidence and
30 argument-in-chief, the OEB should approve these accounts as proposed by OPG (including
31 the sharing of SMO and Water Transaction net revenues) for the test period.

1 New Deferral and Variance Accounts Proposed by OPG

2
3 *Nuclear Fuel Cost Variance Account*

4 Three intervenors (CCC, SEC and VECC) supported creation of this account and no
5 intervenor objected to it or OPG's methodology for determining the amounts to be recorded
6 in the account. CCC noted that OPG faces hedging constraints in the market and the
7 residual risk and costs incurred over or under forecast are beyond management's control
8 (CCC argument, para. 140). Accordingly, and for the reasons set out in OPG's evidence and
9 argument-in-chief, the OEB should approve the establishment of this account and the
10 account methodology proposed by OPG.

11
12 *Pension/OPEB Variance Account*

13 Five intervenors objected to this account (AMPCO, CME, CCC, SEC and VECC) and one
14 supported it (PWU).

15
16 CCC urged the OEB to reject this account on the basis that forecast risk and interest rate risk
17 are fundamental business risks for a regulated entity forecasting short-term and long-term
18 debt rates. The CCC submitted that shareholders are compensated for these risks through
19 the deemed capital structure and return on equity.

20
21 CCC also expressed concern that approval of this account would set a regulatory precedent,
22 establishing the basis for all OEB regulated entities to seek a similar account. VECC noted
23 that OPG had failed to demonstrate that there are material differences between its pension
24 and OPEB plans and those of other regulated entities. AMPCO supports the consistent
25 treatment among regulated utilities. The SEC argued that pension and OPEB costs are a
26 core element in OPG's cost of service, and that the focus on one factor impacting OPG's
27 costs did not take into account the potential for other factors to change costs in the opposite
28 direction.

29
30 OPG disagrees with CCC's comparison to debt costs. A 25 or 50 basis point difference in
31 forecast interest rate will have a small impact on OPG's debt costs for the test period since it
32 will only affect incremental debt raised in the test period. In contrast, a 25 or 50 basis point

1 difference in interest rates can have a \$50M to \$110M impact on pension expense, all other
2 things being equal (Ex. J15.3). So the two cost impacts are just not comparable. CCC
3 advanced four criteria for evaluating new deferral and variance accounts: prudence,
4 materiality, causation and controllability (CCC argument, page 138). The evidence in this
5 proceeding was clear that the potential balances in this account would be material and that
6 they would arise from circumstances beyond OPG's control. On this basis the CCC's own
7 test is satisfied.

8
9 With respect to the point about consistency with other utilities, OPG notes that the OEB did
10 approve the creation of pension costs deferral accounts for Hydro One Brampton Networks
11 and for Enersource Hydro Mississauga Hydro (EB-2005-0215, Decision and Order, March 2,
12 2005; EB-2005-0196, Decision and Order, February 11, 2005). For both these distributors,
13 the Board specifically authorized the creation of a specific Pension Contributions sub-
14 account to the Other Regulatory Assets Deferral account (No. 1508) (Ibid.). VECC notes that
15 while these accounts were subsequently discontinued, this only occurred after "pension cost
16 contributions to OMERS were incorporated in the distribution rates" (Accounting Procedures
17 Handbook, July 31, 2007, page 17). Given the OEB approved inclusion of OMERS pension
18 costs in rates and that rates for the vast majority of electric distributors have been
19 established on an historical test period basis, the discontinuance of this account for electricity
20 distributors is not surprising. As past pension contributions are known with certainty and the
21 OEB has permitted these amounts to be directly incorporated into utility rates, the utility is not
22 subject to on-going "forecast risk"; therefore an on-going account is not required.

23
24 During the hearing, OPG provided precedents for pension-related variance accounts, two of
25 which apply in Ontario: Hydro One Distribution and Hydro One Transmission (Ex. J14.6). The
26 Hydro One accounts arguably provide a greater level of protection than that sought by OPG
27 in that any change in pension costs, whether or not management can exercise some level of
28 control or influence, is covered. In response to SEC's concern, OPG would not oppose
29 increasing the scope of this account to capture all factors incorporated into the forecasting of
30 pension and OPEB costs.

1 Interestingly, the Hydro One precedent was accepted by CCC, VECC, SEC and AMPCO as
2 part of the settlement agreement in that case (Appendix 2, Settlement Proposal, EB-2006-
3 0501 Decision with Reasons for 2007 and 2008 Electricity Transmission Revenue
4 Requirements for Hydro One Networks Inc., August 16, 2007). None of these parties
5 indicated in their submissions why they would support an arguably broader account for Hydro
6 One and yet oppose one for OPG.

7
8 For all the reasons given above, in evidence and in its argument-in-chief, OPG submits that
9 its proposed account is appropriate and should be approved by the OEB.

10
11 Changes in Tax Rate, Rules and Reassessments Variance Account

12 All intervenors that made submissions on this issue either supported the establishment of
13 this account, or were neutral. Some parties would limit the scope of the account as outlined
14 in Account 1592 of the Uniform System of Accounts for Electric Distribution Utilities. CME,
15 VECC, SEC would accept OPG's proposal only "on the same basis as applies to distributors"
16 (SEC argument, para. 247). OPG notes that its proposed account generally accords with the
17 scope of Account 1592, but OPG's proposal also includes a provision to record variances
18 associated with tax reassessments.

19
20 VECC wants to ensure that the OEB and intervenors would have an opportunity to explore
21 the circumstances leading to any reassessment-related impacts before there was any
22 clearing of amounts. CME argued that recoverability of reassessments should be considered
23 on a case-by-case basis.

24
25 The CCC observed that tax assessment lags create a unique risk for regulated utilities with
26 forward test years (CCC argument, para. 147). CCC also acknowledged that for OPG, an
27 assessment or reassessment of a tax year prior to April 1, 2008 could have implications on
28 both the tax expense forecast for the test years and the amount of tax losses available for
29 mitigation. Despite these acknowledgements, CCC proposes limiting any reassessment to
30 the period after April 1, 2008, when OPG was first subject to rate regulation by the OEB.

1 CCC's proposal is unfair and unbalanced. OPG is seeking the inclusion of impacts of
2 reassessments for the years prior to regulation by the OEB because it is voluntarily providing
3 the benefits of the calculated tax losses from the 2005 to 2007 period. If there is a
4 reassessment that reduces the actual losses for 2005 to 2007, then OPG would have given
5 ratepayers a benefit that turns out not to have existed (OPG argument-in-chief, page 106; Tr.
6 Vol. 14, pages 197-201; Tr. Vol. 15, page 20). In this circumstance, OPG believes it is
7 entirely appropriate to include reassessments in the tax variance account.

8
9 OPG submits that the OEB should accept the matters to be recorded in this account as
10 described by OPG in its argument-in-chief and in Ex J1-T3-S1, pages 14 to 16.

11
12 New Variance and Deferral Accounts Proposed by Others

13 AMPCO proposed two new accounts for OPG: 1) IESO Non-Energy Charges Variance
14 Account to capture differences between forecast and actual charges; and 2) CMSC Account
15 for sharing CMSC revenues on a 50/50 basis (AMPCO argument, paras. 185 and 156). In
16 addition, CCC proposed a new account to capture differences between budgeted and actual
17 expenditures for Regulatory Affairs in conjunction with a reduction in the 2009 budget to 50
18 percent of the 2008 budget (CCC argument, para. 85).

19
20 OPG submits that none of these accounts should be established by the OEB.

21
22 With respect to its request for an account to capture variances between forecast and actual
23 IESO non-energy charges, AMPCO provides two grounds. The first is that these charges are
24 difficult to forecast and not subject to the control of management. OPG does not dispute
25 these points. The second is that OPG's forecasting methodology is suspect because it relies
26 on a data set that only goes back to 2005. OPG rejects this criticism and submits that its
27 methodology is sound. OPG's forecast of global adjustment costs is based on a regression
28 analysis that used all of the monthly HOEP and global adjustment charges data available
29 since the inception of the global adjustment mechanism in January 2005 (Ex. L-1-60;
30 http://www.ieso.ca/imoweb/b100/b100_GA.asp). Monthly data back to 2005 is sufficient to
31 produce a reasonable forecast of these charges.

32

1 In addition, the potential variance in this forecast is unlikely to be material. The forecast of
2 IESO non-energy charges is \$18.5M in each of 2008 and 2009 for nuclear and \$35.9M and
3 \$35.2M in 2008 and 2009, respectively for regulated hydroelectric. Even a 10 percent
4 variance in these numbers would not produce a material variance.

5
6 CMSC payments provide an offset to OPG's costs as discussed above under Issue 6.1. As
7 explained in that section, there is no net revenue to share and therefore a variance account
8 is not necessary.

9
10 OPG's basis for opposing CCC's proposal for variance account for regulatory costs in 2009
11 is discussed above under Issue 5.4. As explained there, CCC does not appear to appreciate
12 that OPG is planning on filing another payment amounts application in Q1 2009. As a result,
13 it is entirely reasonable that the Regulatory Affairs budgets for 2008 and 2009 are similar,
14 since level of activity and cost is expected to be similar.

15

1 **10. DETERMINATION OF PAYMENT AMOUNTS**

2
3 **Issue 10.1**

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

6
7 No intervenors objected to OPG's calculation of its regulatory income and capital taxes. As
8 such, and for all the reasons set out in its evidence and argument-in-chief, these amounts
9 should be accepted by the OEB as filed.

10
11 **Issue 10.2**

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

14
15 All of the intervenors who specifically commented on this issue (CCC, CME, and SEC)
16 supported OPG's proposed treatment of the loss carry forwards. PWU also indicated its
17 support for OPG's application as filed, implicitly indicating its support for the proposed
18 treatment.

19
20 SEC's submission demonstrates that it does not quite understand OPG's approach (SEC
21 argument, paras. 253-254). OPG is required to file one tax return which includes both the
22 regulated and unregulated segments of its generation business, and losses can only be
23 applied against the taxable income of the entire company. OPG cannot file two separate
24 returns or segregate the losses and pay tax for one segment of the business and carry
25 forward losses for the other segment. For purposes of establishing the payment amounts,
26 OPG retained 100 percent of these losses within its regulated operations in order to eliminate
27 regulatory income taxes from the revenue requirement and to further mitigate the revenue
28 requirement. For regulatory purposes no tax losses were allocated to the unregulated
29 businesses.

30
31 Since OPG pays its taxes on a corporate basis, it makes no sense to follow the suggestion
32 by SEC that losses generated by the regulated business not be used to lower overall actual

1 corporate taxes. As noted above, this approach has no impact on what ratepayers pay since
2 the losses are notionally preserved within the regulatory operations.

3
4 Given that there are no real objections to OPG's proposals, and for all the reasons set out in
5 its evidence and argument-in-chief, the Board should accept OPG's proposed treatment of
6 tax losses as filed.

7
8 On a related issue, OPG notes that certain intervenors (CCC, CME, and SEC) object to
9 including within the proposed Tax Variance Account an ability to reflect the impact on the tax
10 losses of post 1999 reassessments. As OPG pointed out in its argument-in-chief, there is
11 uncertainty with respect to the amount of tax losses available from the April 1, 2005 to April
12 1, 2008 period since the Provincial Tax Auditors have not completed their audits for the post-
13 1999 period. Despite this uncertainty, OPG has proposed to return to ratepayers its best
14 current estimate of the tax losses available – something that intervenors have been happy to
15 accept. It is somewhat disappointing, that these objecting intervenors are prepared to accept
16 the return of tax losses that OPG voluntarily dedicated to mitigating the rate increase without
17 giving the company a reasonable degree of protection against an unexpected tax audit
18 result.

19
20 **Issue 10.3**

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

23
24 There were no objections from intervenors with respect to OPG's method for removing Q1
25 costs, revenues and production. As such, and for all the reasons set out in its evidence and
26 argument-in-chief, these amounts should be accepted by the Board as filed.

27

1 **11. IMPLEMENTATION OF NEW PAYMENT AMOUNTS**

2
3 Only AMPCO and SEC made submissions on OPG's proposal for implementing the new
4 payment amounts. AMPCO indicated that it supported OPG's proposal to recover the
5 retrospective amounts back to April 1, 2008 using actual consumption (AMPCO argument,
6 para. 187). SEC proposed that the new payments amounts be effective April 1, 2008 except
7 for that portion related to OPG's increased return on equity (SEC argument, para. 259). SEC
8 made this proposal even though it acknowledges that: 1) OPG moved with reasonable
9 diligence to file its application once the Board issued its Filing Guidelines and 2) that OPG is
10 not responsible for the delay in the establishment of new payment amounts (SEC argument,
11 para. 257). Given these admissions, the Board should reject the SEC proposal. SEC's
12 proposal is patently unfair to OPG and completely inconsistent with the Board's statutory
13 obligation to set just and reasonable payment amounts.

14
15 Given the lack of intervenors' objection, and for the reasons set out in its evidence and
16 argument-in-chief, the OEB should accept OPG's proposal for implementing the new
17 payment amounts.

18
19 Once the OEB reaches its decision in this matter, OPG proposes that it be provided the
20 opportunity to calculate the test period payment amounts that result from that decision. There
21 are complex interactions among some of the components of the payment amount calculation,
22 for example, the calculation of tax losses during the test period and the associated impact on
23 the payment amounts, and OPG is best positioned to correctly perform these calculations
24 within the parameters set by the OEB. This approach is analogous to that used in rate
25 hearing where the OEB directs the applicant to file a draft rate order reflecting the Board's
26 findings.