EB-2007-0905

ONTARIO ENERGY BOARD

IN THE MATTER OF THE Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the Ontario Energy Board act, 1998 for an Order or Orders determining payment amounts for the output of certain of its generating facilities.

FINAL ARGUMENT

ON BEHALF OF THE

SCHOOL ENERGY COALITION

July 22, 2008

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INTRODUCTION

1. These are the Final submissions of the School Energy Coalition ("SEC") in the application by Ontario Power Generation Inc. ("OPG") for an Order determining payment amounts pursuant to s.78.1 of the Ontario Energy Board Act (the "Act") and regulations proclaimed in relation thereto, in particular Ontario Reg. 53/05 (the "Regulation").

2. ***Nature of the Proceeding.*** OPG's prescribed assets generate a significant proportion of the electricity required by the province of Ontario. The efficient operation of these assets, therefore, is vital to the economic well-being and standard of living of the people of Ontario.

3. In SEC's submission, the lack of independent regulatory oversight over OPG's operations, and those of its predecessor, in the past has resulted in inefficiencies and costs that are much higher than comparable utilities. The Ontario Energy Board has now been given the important and difficult job of regulating OPG's prescribed assets with a view to ensuring that they operate in a cost effective manner.

4. That task necessitates that the Board take steps to effect immediate and meaningful change at OPG, requiring it to operate like an efficient commercial enterprise.

5. ***The Importance of OPG's History.*** In this context, it is important for the Board to keep the Applicant's history firmly in mind. This is a company that was effectively insolvent ten years ago, and had to offload more than $16 billion of stranded debt to the province because of its own failure to contain the costs of generation. That failure was, in turn, at least partially caused by the fact that the Applicant's predecessor was not subject to independent and binding regulatory oversight.

6. Today, the Ontario Energy Board has the mandate to ensure OPG's costs are and remain reasonable and prudent. In this respect, the Board is trying to achieve what no-one else has done before with this company – ie. cost containment. The advantage this time – and probably the reason why the government elected to hand this responsibility to the Board – is that this Board has considerable experience in keeping the costs of regulated entities to reasonable levels. And, it has sufficient power to ensure that its guidance is followed.

7. But unlike most other entities regulated by this Board, OPG operates within a competitive market. While it is true that their dominant market position, and the public need for their output, mean that OPG has some of the indicia of a monopoly service provider, that is not the whole story. Yes, OPG has market power, but as a practical matter competitors can enter that market too.

8. The importance of that fact is this: If OPG allows costs to spiral out of control again, as it did once in the past, it could easily price itself out of the market. Despite OPG's preferred position, other generators would be able to enter the market and sell electricity at lower prices. If that were to happen, despite Board supervision, the effect on OPG would be the same as the last time – inability to compete at market prices, insolvency, and stranded assets. With rare exceptions, this can't happen with a wires or pipes company. In this respect, the consequences of uncontrolled spending by OPG would be different than a similar problem at Hydro One, or Enbridge, or Ottawa Hydro.

9. We therefore urge the Board, in dealing with each of the issues before it in this proceeding, to focus on its long-term responsibility to ensure that OPG's costs are contained, and that OPG and its customers never again have to go through the pain of writeoffs and restructuring.

CAPITAL STRUCTURE AND COST OF CAPITAL (Exhibit C)

2.1 What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business? (C1/T1/S1, C1/T2/S1, C2/T1/S1)

2.2 What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business? (C1/T1/S1, C1/T2/S1, C2/T1/S1)

10. This proceeding has included the evidence of <u>seven</u> experts on capital structure and cost of capital – one from the Applicant, one from Board Staff, and five from intervenors. Given the thorough nature of the debate before the Board, and the extensive arguments the Board is receiving from other parties on this point, we think it is more useful for SEC to provide, instead of a detailed parsing of the technical issues, an assessment of the various experts' reports and how they fared in this process. We will then set out the conclusions we draw from that analysis later in these submissions.

11. ***The Evidence of Ms. McShane on behalf of the Applicant.*** Kathleen McShane is well known to this Board and to other regulatory tribunals around North America as a cost of capital expert with a great deal of experience, but with a tendency over more than twenty years of giving evidence to propose low debt ratios and high ROE estimates. Not surprisingly, she is almost always retained by utilities, and it is only rarely that a regulatory tribunal adopts her recommendations unamended. In fact, Mr. Penny's attempt to impugn the evidence of Drs. Kryzanowski and Roberts by referring to one of the few decisions in which Ms. McShane"s opinions found regulatory favour [eg. Tr.13:119-120] really only served to highlight what a rarity such an event is.

12. In this case, it is our view that the evidence of Ms. McShane has been completely destroyed by the detailed critique from Drs. Kryzanowki and Roberts [Ex. M, Tab 12, pp. 104-153 and related Schedules], supplemented by their comments in direct evidence [Tr. 13:45-58]. If their critique wasn't devastating enough, the two and a half days of cross-examination of Ms. McShane by the parties and the Board exposed the many utility-side biases inherent in her work.

13. It therefore appears clear to us that the evidence of Ms. McShane has been demonstrated to be not credible, and in our submission it should not influence the Board's decision on capital structure and cost of capital.

14. ***The Evidence of Mr. Chernick on behalf of GEC.*** Paul Chernick has appeared before this Board on a number of previous occasions as well, although not often as a capital structure and cost of capital expert. His expert evidence did not include a thorough review of the issues in this area, and was basically limited to whether it is sensible to have different decisions on capital

for nuclear and for hydroelectric. In the context of the much more detailed and thorough work by others, we did not find his evidence particularly useful, and therefore we urge the Board not to give it any weight.

15. ***The Evidence of Dr. Murphy on behalf of AMPCO.*** This evidence also has a narrow focus. In our submission, while the historical context is useful as a factual reference, this evidence is not persuasive because of the assumption that the identity of OPG's shareholder is the defining fact that controls capital structure and cost of capital. This may indeed be a reasonable position to take, particularly given the history of OPG, but by implication it would require this Board, in making a decision on this one rate case, to make fundamental changes to the well-established "stand-alone" principle.

16. Are changes to the stand-alone principle something worth considering? The answer to that is clearly yes. However, if this Board is going to reconsider the application of that very fundamental principle, in our view there should be a more detailed debate on the issue than that which arose in this proceeding. Evidence on how other jurisdictions have dealt with unique public ownership issues, and expert analysis of the capital market and regulatory implications of modifying the stand-alone principle, are both in our view essential elements of any re-thinking of that principle. That is not possible on the record currently before the Board. Therefore, in our submission the evidence of Dr. Murphy should not influence the Board's conclusions on these issues.

17. ***The Evidence of Dr. Schwartz on behalf of Energy Probe.*** The evidence of Dr. Schwartz was, perhaps unfortunately, characterized by the expert's obvious lack of familiarity with the unusual problems presented in the regulatory arena. In principle, application of a private sector analysis to OPG should be a useful approach, since the stand-alone principle is in essence a private sector construct. In fact, capital structure and cost of capital in the regulatory sphere have developed a lot of nuance of which Dr. Schwartz was clearly not aware.

18. It may be appropriate at some point for this Board to get a fresh look at these issues, untrammelled by a history within the regulatory environment, and in that circumstance Dr. Schwartz may have valuable insights to offer the Board. However, if and when that is

appropriate, the expert will still have to be able to articulate the differences between that fresh, private sector point of view, and the regulated entity point of view that it is proposed to supplant. Without any real understanding of the context, we did not find that the evidence of Dr. Schwartz added significant value to the process in this case, particularly in light of the plethora of more experienced experts already in the mix.

19. ***The Evidence of Mr. Goulding on behalf of Board Staff.*** A.J. Goulding and London Economics are respected in this field, and at a high level the analysis provided in this evidence is persuasive. However, because it does not get down to detail and make specific recommendations (that was not the mandate), its value is more as context than direct guidance. That is, if the Board were planning to reach a conclusion inconsistent with the high level principles set out on this evidence, it would be appropriate to assess whether there was good reason to do so. Conversely, we do not believe it is possible to use the Goulding paper as a roadmap to come to a conclusion on the appropriate capital structure or ROE for OPG. The work lacks sufficient specifics to be used for that purpose.

20. ***The Evidence of Dr. Booth on behalf of CCC/VECC.*** Lawrence Booth is probably as well known to this Board as Ms. McShane, and he presents a thoughtful and pointed analysis of the issues in this case. That analysis has not met with any significant challenge from the Applicant or from any other party. While Ms. McShane clearly disagrees with Dr. Booth (they have disagreed in many regulatory tribunals over the years), as noted earlier Ms. McShane's evidence has been successfully debunked, whereas Dr. Booth's evidence is essentially unshaken.

21. The main concern we have with the evidence of Dr. Booth is that he continues to take the view that Canadian allowed utility ROEs are currently too high due to incorrect analysis by regulators of the risk mitigation effects of the ROE approach they are using. While we agree in principle with his conclusion on this point, it has generally not been accepted by this or any other regulatory tribunal in Canada, and that fact weakens what is otherwise a very good analysis of the issues in this case.

22. It is therefore SEC's submission that the evidence of Dr. Booth should be given substantial weight by this Board in making decisions on capital structure and cost of capital, with

the proviso that his ROE number may be understated due to his particular point of view with respect to Canadian utility ROEs, unless this Board is persuaded that his view in that regard is correct.

23. ***The Evidence of Drs. Kryzanowski and Roberts on behalf of Pollution Probe.*** This paper, from two highly respected experts in this field with a long track record, is the most thorough and rigorous of those filed in this case. The authors speak with authority, and demonstrate through their analysis that they have considered not only overall principles, and detailed technical rules, but also trends and new thinking in the field.

24. It is possible, clearly, to debate each issue and sub-issue discussed in the Kryzanowski/Roberts opinion. What is not possible, it is submitted, is to identify any bias or predetermination in their analysis. Their paper demonstrates an almost relentless pursuit of the "right" answer (in the sense of the empirically defensible answer), as opposed to the answer that suits the purposes of any particular party. Just the fact that their own client, Pollution Probe, would generally like to see higher nuclear costs rather than lower (since that indirectly favours renewable generation), and higher electricity commodity costs rather than lower (since that indirectly favours conservation and demand management), but the experts came in with an overall cost of capital below that of the Applicant, demonstrates their unceasing independence.

25. We also found that as each component of the analysis arose, the authors had not only considered in a very thoughtful way the possible approaches to it, but had looked at the work of many other experts to see who had the best (in the sense of most rigorous) technique, paradigm, or methodology. That intellectual discipline is more pronounced (or perhaps just more obvious) in this evidence than in the evidence of any of the other experts.

26. Our review of the evidence of the seven experts, their interrogatory responses, and the cross-examinations, thus leads us to the conclusion that this Board should adopt the opinion of Drs. Kryzanowksi and Roberts in setting the capital structure and ROE for OPG for the Test Period.

27. ***Capital Structure – Equity Ratio.*** We adopt the recommendation of Drs. Kryzanowski and Roberts that the equity component for OPG should be 47%, made up of 40% for hydroelectric and 50% for nuclear, and generated as the weighted average of those two figures.

28. ***Capital Structure – Nuclear vs. Hydroelectric.*** We note that the capital structure can be separate, or combined. In principle, we believe it would be useful to calculate the costs of nuclear and hydroelectric using different equity ratios appropriate to their different risk levels. This allows the Applicant, this Board, and others including the government, to make or review operating and investment decisions using cost levels that are technology specific. This is the more rigorous approach.

29. The one caveat we have is that none of the nuclear costs are real anyway. Because $16.4 billion [Ex. M, Tab 2, p. 4] of nuclear liabilities were shifted from OPG at the time of its creation, nothing that is being done now represents the true costs of the generation from OPG's nuclear facilities.

30. What is true, however, is that incremental investment decisions (for both nuclear and hydroelectric new build, refurbishment, repair, or similar costs) will be more precise and more reliable if the cost of capital part of the analysis is correct relative to the specific technology.

31. We therefore believe that, whether this Board orders a 47% equity ratio, or a more detailed bifurcated equity ratio, it should direct OPG to maintain records of the relative costs of production and investment using separate equity ratios, and to carry out business case and similar forward-looking expenditure analyses using those technology-specific equity ratios.

32. ***Return on Equity – Overall Level.*** We adopt the (updated) recommendations of Drs. Kryzanowski and Roberts that, assuming a 25% fixed component for nuclear payment amounts, and assuming variance account protection against low water, the ROE should be 7.35% for 2008 and 7.40% for 2009. This is very close to the 7.75% recommended by Dr. Booth, and the 7.64% recommended by Dr. Schwartz, but, not surprisingly, well below the levels proposed by Ms. McShane.

33. ***Return on Equity – Nuclear vs. Hydroelectric.*** We believe the experts have generally agreed with Dr. Booth that risk is usually (perhaps not always) best managed through equity thickness, not ROE. Therefore, having recommended that this Board assign the two business units different equity ratios, we believe that step reflects and accounts for their differences in risk, and the same ROE should apply to both.

2.3 Is it appropriate to establish a formula for an adjustment mechanism? Is the formula proposed appropriate? (C1/T1/S1, C1/T2/S1, C2/T1/S1)

34. The formula that has been used by this Board for many years has stood the test of time, and in our opinion was not seriously challenged by any of the evidence before the Board in this proceeding. Therefore, we believe that it is appropriate to continue to apply that formula for years after 2009.

2.4 Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate? (C1/T1/S2, C1/T1/S3, C1/T2/S2, C1/T2/S3)

35. We have had the opportunity to review the submissions of AMPCO at pp. 22-24 of their Argument on short and long-term debt rates, and we agree with their conclusions, for the reasons they have presented.

36. We therefore urge the Board to adopt a rate of 5.5% for long term debt, and 4.0% for short term debt, in place of the rates proposed by the Applicant, and recalculate the revenue requirement accordingly.

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

37. As noted earlier, we believe that the variance account for low water, and the fixed monthly charge for nuclear, are risk mitigation devices that, if absent, would have a material impact on the risk levels – and therefore the equity ratio or ROE – of OPG.

38. We note that, with respect to the nuclear fixed charge, we do not believe that the amount that will ultimately be payable by the ratepayers will be any different if the fixed charge is approved, or not. Because of the size of the financial investment by the people of Ontario in the Prescribed Assets, it will be essential that the actual costs of production be recovered from either the ratepayers or the taxpayers over time. In fact, those will include not just the costs incurred by OPG, but also the costs associated with the existing, and any future, stranded assets.

39. There is an old saying in the investment business: "Lend me $100, you're my creditor. Lend me $1 million, you're my partner." Such is the case here. Thus, in our view the only difference between OPG with and without the nuclear fixed charge is its perceived risk, and therefore its cost of capital. Changing payment patterns to achieve a lower cost of capital is, in our view, a sensible approach for this Board to take given the proposal currently before it.

40. With respect to the other deferral and variance accounts, in our view none of them on their own would have a material impact on financial risk and therefore either equity ratio or ROE. We have provided the Board with specific submissions on each of those proposed accounts later in this Argument.

5.1 Are the Operation, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate?

41. For the detailed reasons that follow, SEC believes that OPG's nuclear OM&A costs for the test year are too high. At a high level, there are two reasons for this: first, they represent an unacceptable increase over the historic period; and second, OPG's costs in the historic period were far in excess of those of a reasonably efficient nuclear operator.

42. As we have noted in our introduction, SEC believes that the Board must begin the task of bringing cost sanity to OPG after years of operating with no independent regulatory oversight. Nuclear operating costs are probably the single most important area the Board has to address in that context.

43. For that reason, SEC recommends a reduction in OPG's nuclear OM&A in the amount of $284.4 million in 2008 and $217.1 million in 2009. While those reductions appear to be large in absolute dollars, they represent a combined reduction in the as-filed OM&A budget for the test years of 11.7%, as shown in the following table:

Total Operating Cost - Nuclear (Ex F2/1/1)

$'M	**2005**	**2006**	**2007**	**2008**	**2009**	2009 vs. ***2005***
Base OM&A	1,036.3	1,133.8	1,216.6	1,360.7	1,368.1	32.0%
Project OM&A	155.9	142.1	111.5	144.6	137.1	-12.1%
Outage OM&A	163.0	187.7	215.6	192.2	207.9	27.5%
Allocation of Corporate Costs	356.2	423.2	446.8	457.0	430.2	20.8%
Sub-total	1,711.4	1,886.8	1,990.5	2,154.5	2,143.3	25.2%
Sub-total Assuming 3% Increase per year		**1,797.0**	**1,886.8**	**1,981.2**	**2,080.2**	**21.6%**
Reduction from As-Filed				**284.4**	**217.1**	
Reduction from As-filed- as % of Total[1]					**11.7%**	

44. SEC arrived at the 2008 and 2009 budget amounts by taking the 2005 actual costs and escalating them at a rate of 3% per year. SEC believes that this escalator from 2005 – well in excess of inflation - is a more than reasonable increase in OPG's budgets. It represents increases in budgets that, as discussed in greater detail below, were already higher than they should have been. Also, the increase is applied across all of the OM&A categories, including Project OM&A, even though the Project OM&A budget as filed shows a reduction of 12.1% between 2005 and 2009. In our view, a 3% per year increase on a budget that is already too high is very generous. The only reason we are proposing such a high level is that the resulting level of cutback is still

[1]Equals the combined proposed reduction ($284.4 + 217.1) divided by the combined as-filed nuclear OM&A for the test years ($2,154.5 +2,143.3).

substantial, and this Board may feel that a step in the right direction is to be preferred over a more aggressive approach to containing these costs.

45. In the remainder of section 5.1, as well as in sections 5.3 and 5.4, SEC discusses various elements of OPG's cost structure that are either too high to begin with and/or are increasing at unacceptable levels. In SEC's submission, the discussion more than justifies the proposed overall reduction in OPG's test year OM&A.

46. In addition to the above reductions, SEC also recommends that New Generation Development ($100 million in 2008 and $90 million in 2009) be removed from Base OM&A and capitalized. These expenditures are described as being due to "increasing effort in plant refurbishment programs (Darlington and Pickering B), as well as preliminary investigations into a new nuclear build at the Darlington site." [F2-2-1, p. 25] In SEC's submission, these functions describe capital improvement projects and not operational costs. Those costs should properly be capitalized so that current prices for OPG’s output reflect the costs of that output, not the costs of future output. When that future output arises, these costs to get there should be included in those unit costs. Capitalization of these costs today achieves that result.

Nuclear OM&A

47. OPG's Base OM&A increases by 32% from 2005 to 2009 [F2-2-1, Table 1]. Of that amount, two thirds, or $213 million of the total increase of $331 million, is due to increases in labour costs.[2]

48. Even excluding Generation Development, which increases substantially in 2008 over 2007 largely as a result of new nuclear build [F2-2-2, pg. 4], Base OM&A increases 23% in 2009 over 2005.[3]

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[2] F2-2-1, Table 2, total of rows 1, 2, and 3 ("Labour Regular", "Overtime" and "Augmented Staff", respectively), 2005 vs. 2009.

[3] F2-2-1, Table 1, row 17 less row 13, 2005 vs. 2009.

49. Outage OM&A and corporate costs allocated to nuclear (corporate costs discussed in greater detail below) also increase by 28% and 20% respectively during the same period. [F2-2-2, Table 1]

50. During that time, total labour costs increased by an average of 3.74% per year and total regular staff labour increased by an average of 6.1% per year [L-16-16, pg. 2]. OPG could not explain this increase [Tr4:56].

51. Even excluding pension and benefit costs, which are said to be the main drivers of labour cost increases, OPG forecasts an increase in labour costs per FTE of 6.5% in 2008 [J2.4].[4]

52. These extra expenditures are yielding higher costs for consumers with no resulting increase in production or productivity. As a result, per unit costs, which OPG says exclude the cost of new nuclear build [L-14-6(g), pg.4] have increased substantially during that time.

53. Before turning to the benchmark figures, SEC notes that the various figures presented below do not appear to be consistent. Presented in the paragraphs below are, respectively, data from the EUCG database, the pre-filed evidence, and OPG's financial statements. All appear to yield slightly different unit production costs. The Applicant has not reconciled those discrepancies, and we were unable to do so looking at the evidence on the record. All of these figures, however, appear to be moving in the wrong direction.

54. We begin with the EUCG data, which shows OPG's total cost per MWh of nuclear generation increasing from 2005 to 2007 for all of its nuclear units:

[4] This increase appears to be caused, in part, by a reduction in non-regular staff FTE's. In 2008, regular staff FTE's increase from 7,542 to 8,109, while non-regular staff FTE's decline from 736.8 to 192.3. The net effect, however, is a 5.5% increase in total nuclear labour costs in 2008 over 2007 [see L-16-16, pg. 2, line 19]

EUCG Data	Total Cost /MWh		
	2005	2006	2007
Darlington			
1	21.7	27.37	27.01
2	26.07	23.43	31.11
3	21.15	31.24	27.69
4	24.14	23.74	31.85
Pickering A			
1	319.69	64.41	125.47
4	64.26	74.99	112.12
Pickering B			
5	72.59	43.9	67.05
6	59.87	44.16	53.57
7	38.72	50.96	47.43
8	41.39	64.85	45.32

Source: Exhibit K1.10 (revised May 30, 2008)

55. Next we have the nuclear benchmark results presented in the pre-filed evidence and augmented through undertaking responses:

Production Unit Energy Costs			2008 and 2009 Targets***	
	2006*	2007**	2008	2009
Pickering A	68	119	76	77
Pickering B	50	53	50	50
Darlington	26	29	30	34
OPG average	39****	44	43	46
U.S. industry median	24	23		
U.S. industry top quartile	20	20		

* 2006 figures from A1-4-3, pg. 17

**2007 Figures from J4.6.

***A1-4-3, PG. 13 (Chart 2)

****At Tr4:54, the 2006 total was corrected from the amount shown in the exhibit ($48) to $39.

56. The production unit energy costs (PUEC) taken from OPG's annual reports show a similar trend. What is interesting from this data is that in some cases unit production costs increase even though production, as shown by unit capability factor and total generation, is relatively stable:

	2005	2006	2007
PUEC from OPG Annual Report			
($/MWh- from OPG Annual Report and as broken down in J4.9)			
As broken down in J4.9:			
Pickering A	$113.90	$75.60	$130.10
Pickering B	$51.30	$55.50	$55.90
Darlington	$23.90	$28.70	$31.60
Nuclear average from Annual Reports	$40.24	$42.87	$47.18
Nuclear Capability Factor from OPG Annual Report			
Pickering A	69.9	72	41.3
Pickering B	77.7	75.2	75
Darlington	90.6	88.7	89.5
Nuclear Average	84.4	81.9	77.5
Electricity Generation			
Regulated Nuclear (TWh)	45	46.9	44.2

57. Of particular concern is Darlington, which is OPG's best-performing nuclear plant, whose PUEC increases from $23.90/MWh in 2005 to $31.60/MWh in 2007. During this time Darlington's nuclear capability factor remained stable at around 89%.

58. Part of OPG's explanation for the increased costs at Darlington is that it has been attempting to reduce the elective maintenance backlogs [Tr5:14]. Yet those backlogs, which stood at 400 in 2006, are down only slightly to 373 by 2007 [A1-4-3, pg. 17, and J4.6]

59. All of this is against a backdrop of what OPG agreed was a mandate from its shareholder to control its costs and produce efficiencies [Tr4:13].

60. As a result, OPG's performance compared to other nuclear generators has worsened. The table above shows the PUEC for all of OPG's nuclear units moving away from the U.S. industry median and U.S. top quartile. Those benchmarks show that only Darlington performs close the per unit cost of OPG's U.S. comparators. Even then, Darlington's performance ranks it in the third quartile of the U.S. comparators [Tr4:26; L-2-43].

61. OPG explains in the pre-filed evidence that there are a number of limitations to this data, including the changing U.S.-Canada exchange rate, accounting differences and technology differences as between U.S. (light water) and Canadian (heavy water, or natural uranium) plants. Nonetheless, OPG also states that "the U.S. nuclear industry began improvement programs earlier and have achieved a steady state of top level performance in cost and output. OPG is moving in the same direction, but with the exception of Darlington, has not yet achieved this level [A1-4-3, pg. 18, lines 25-27]. Furthermore, OPG's witnesses stated in cross-examination that this is the best data to use, since the costs presented use standard industry definitions (developed by the Electricity Utility Cost Group) for OM&A costs [Tr4:28-30].

62. SEC makes one final comment with respect to the benchmark figures: although PUEC includes both capital and operating costs, it does not, in the case of OPG, include the cost of stranded debt. In other words, the figures above, which are already far in excess of U.S. comparators, are substantially understated. If they included stranded debt now held by OEFC, which ratepayers are still paying off, the OPG PUECs would be much higher, and much farther out of line with other jurisdictions.

Navigant Study

63. The Navigant study said that the Darlington units are staffed above the benchmark of other CANDU reactors [Tr4:168]. When asked by the Presiding Member, Mr. Kaiser, if that meant that Navigant had concluded they were operating less efficiently than other reactors, the OPG witness disagreed, and stated that the Navigant study was based on a single point in time, early 2006. [Tr4:168]

64. When asked, however, whether that meant that the comparison would be more favourable for 2007, the witnesses did not give a clear answer:

MR. KAISER: So with respect to this conclusion, this advice that Navigant gave you at page 43, those Darlington organizations are staffed above the benchmarks, you would say, yes, but that was true at the time, but it was a temporary situation. If you were to look at 2007, it would be closer?

MR. ROBINSON: I wouldn't say necessarily that it would be closer. Again, one of things that you want to do when you do benchmarking is, when you are benchmarking against the best, then you can look at those and say, you know, they're doing this better than we are.

But Darlington station is performing better than any of the Canadian CANDU plants, and, therefore, we would have to be very careful about where we looked for opportunities for reduction at Darlington so that we would not drive the performance in the wrong direction.

…

MR. KAISER: …You said there was an opportunity. That's a politer way of putting it, I suppose. As a result of this conclusion, this recommendation by Navigant, did you take any action?

MR. ROBINSON: We, over the course of the business plan, basically followed the process that is laid out, and looking at the targets that we have, looking at how we achieve those targets and looking at how other folks achieve those targets, if in fact they are achieving them.

So I go back to the best example, because it's the one that comes to mind. Yes, we looked at the operations and maintenance numbers at Darlington. We looked at them compared to this benchmark, and we said, Yes, they're high.

We then said, Do we know why they're high? We said, Yes, we do. We forced them high to deliver this product, and we're delivering that product now and those numbers will come down.

[Tr4:171-172]

65. In fact, as discussed above, the experience at Darlington after 2006 shows the situation has actually worsened. Darlington's PUEC increased from $28.70/MWh in 2006 to $31.60/MWh in 2007, a 10% increase in a single year. During that time, Darlington's Base OM&A has increased from $278.6 million to $294.6 million, with a further increase to $311.2 million in 2008.

66. In response to Navigant, OPG pointed to some staff reductions in respect of its nuclear supply chain costs. Nuclear Supply Chain, however, represents less than 8% of total Base

OM&A.[5] In any event, total Nuclear Supply Chain OM&A actually increased from 2005 to 2008 (from $54.9 million to $60.4 million), despite the decrease in headcount.

67. The OPG witnesses were asked several times in cross-examination whether OPG intended to proceed with the subsequent phases set out in the Navigant report (Phase 2, Set OPG Strategy & Performance Target; Phase 3: Develop and Execute Implementation Plan; Phase 4: Continuous Improvement). These subsequent phases seem to be directed at actually addressing the disparities between OPG's status and that of the comparators. OPG's answers, however, made reference only to actions taken with respect to nuclear supply chain. [see Tr5:27-28]

68. In fact, OPG's appears to take no guidance at all from the benchmark figures:

> MR. WARREN: Now, do I take it that that is -- for purposes of this Board's scrutiny of your efforts to make yourself more efficient, that that is, … a meaningless number which you don't accept, that there are… relative circumstances that are changing all the time, and that the Board should pay effectively no attention to that 12 percent figure. Is that a fair interpretation of your evidence?
>
> MR. ROBINSON: You have to take into context what that number means, and saying that we were 12 percent above the benchmark at that point in time is an accurate statement.
>
> **It is not indicative of performance.** It is not indicative of special projects that you have going on at that time to improve performance that the other benchmark utilities would not have.
>
> [Tr5:57; emphasis added]

69. OPG's position, however, assumes that other utilities have no special projects or other initiatives to improve their performance.

70. Even if that were true, it would still be an indication of OPG's poor performance. That is, what OPG describes are catch-up expenditures to bring OPG's nuclear plants in line with other more efficient operators.

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[5] 2008 Nuclear Supply Chain OM&A=$60.4 million versus total 2008 Base OM&A of $787.5 million. See F2-2-1, pg. 42 and F2-2-1, Table 1.

71. It is evident, therefore, that despite its past failures, and despite a mandate from its shareholder to control costs, OPG has failed to do so. In SEC's submission, it is up this Board to exercise independent financial control over OPG that has been sorely lacking throughout its history.

No Clear Plan for Pickering A and B

72. In response to questions from Energy Probe, the OPG witnesses said that, despite the poor performance of the Pickering A and B relative to other nuclear units, both in terms of costs of operating and in term of capability factors, OPG does not have a plan in place to determine when and if the units are no longer efficiently providing power to Ontario ratepayers and should be shut down. The OPG witnesses' answer was that OPG's job is to operate the units safely and if OPG determined that it could not operate them safely, they would, presumably, be shut down. [Tr4:71]. OPG's witnesses also testified that they do not expect Pickering B units will ever perform as well as Darlington [Tr4:131]. Presumably, that answer would also apply to the Pickering units' performance versus other nuclear units as shown in the U.S. examples.

73. OPG also testified that with sufficient investment in reliability, it would expect Pickering A and B to be sufficiently reliable and that consequently the per unit costs will start to decline [Tr4:108]. In SEC's submission, those investments should have occurred already.

74. In SEC's submission, a supplier in a competitive market would not continue to operate a plant that was so much more costly to operate relative to its peers, as are Pickering A and B. Therefore, SEC submits that the Board should demand to see, by the next payment amounts proceeding, a clear plan to have Pickering A and B operate at a level that is at least reasonably proximate to other nuclear generators. If that is not possible, then the Board, and OPG (and presumably OPA and the province) should start to consider whether there are more economical alternatives to the generating capacity produced by Pickering A and B.

Corporate OM&A

75. The allocation methodology for allocating corporate costs as between regulated and unregulated operations is discussed under section 5.4 below. Here we discuss the overall quantum of corporate costs.

76. The level of Corporate Support Costs in the test years is up substantially from the historical period. Departmental costs (Finance, Corporate Affairs, CIO, Corporate Centre, Energy Markets, Human Resources and Real Estate) are up 25% in 2008 versus 2006. [F3-1-1, Table 1, line 8]

77. The main drivers of this increase are the Corporate Affairs and CIO budgets. The Corporate Affairs budget increases from $16.7 million in 2006 to $31 million in 2008, a 85% increase in two years. During the same period, the CIO budget increases from $146.4 million to $192.3 million, a 31% increase.

Corporate Affairs

78. A breakdown of the increase in the Corporate Affairs budget is found at L-1-37 and L-3-79. Almost all of the increase is due to expenditures on Consultant/Purchased Services. This category of costs increases from $3 million in 2005 to $17.2 million by 2008 [see L-3-79, tables on pg. 1 and 2 thereof]

79. Of the $8.7 million for Consultants/Purchased services in the Corporate Affairs-Regulatory Affairs and Strategic Planning budget, almost all of it pertains to this proceeding. [Tr8:23]

80. OPG has forecasted spending an equivalent amount in 2009 for another rate proceeding in that year. [Tr8:24]

81. The 2008 budget for the Consultants/Purchased Services for Regulatory Affairs and strategic Planning is mainly related to non-consultant purchased services. Of the $8.7 million total, $6.4 million is related to non-consultant related purchased services such as OEB fees, OEB cost awards and temporary hearing office. [J8.4]

82. Given the fact that many of these fees (in particular OEB fees and intervenor cost awards) are not under OPG's control, and given the uncertainty around the actual timing of the next OPG rate proceeding, SEC submits these costs should be subject to deferral account treatment.

Corporate Affairs: Nuclear Advertising

83. OPG has included in its revenue requirement for the test years $3 million for the cost of its membership in the Canadian Nuclear Association ("CNA") [J8.10]. Of this amount, $2.3 million is for "OPG's contribution to Canadian Nuclear Association's advertising initiatives" [ibid].

84. OPG spends an additional $3.7 million of its own on advertising initiatives in support of nuclear generation [JT1.2].

85. Together these expenditures account for $1.9 million of the $4 million increase in Corporate Affairs budget from 2006 to 2008. [JT1.2]

86. With respect to the advertising by the Canadian Nuclear Association, the presentation describing the CNA's communication strategy explained its objectives as follows:

- to "reclaim the word nuclear by overcoming certain negative emotional aspects associated with 'nuclear' and 'nuclear energy';
- to utilize the public education/advertising platform as a hub from which other CAN and industry initiatives can be built around;
- to leverage within our advertising program a strong call to action to the website to allow the public to learn more about the benefits of nuclear *as part of the energy mix.*

[J4.2, Attachment 3, pg. 2; emphasis added]

87. The Program and Business Plan for Nuclear Public Affairs, provided in response to Undertaking J8.11, further described the nuclear public affairs objective as follows:

- Maintain status quo on very high opinion leader research results;

- Move forward the top 30 per cent 'opinion shapers' who influence opinion leaders: targeted earned media, enhanced nuclear advertising, other targeted outreach initiatives;

[J8.11, Attachment 1, pg. 6]

88. In response to undertaking J8.12, OPG says the word "against" in J4.2, Attachment 3, Slide 4 (which is a CNA document summarizing its advertising strategy with respect to newspapers and stating that newspaper placement serves to "increase support against stakeholders"), was a typographical error and should be read as "among". With respect, SEC doubts it was a typographical error. The CNA is an advocacy organization whose mandate is to promote nuclear power and counter those who oppose it.

89. In SEC's submission, the timing of this advertising drive, coming as it does just as the proceeding in respect of the OPA's supply mix plan was getting underway, demonstrates that these advertising objectives are not simply meant to create a supportive atmosphere for nuclear plants as is claimed by OPG [J4.2, line 36]. Rather they are meant to influence public opinion on an important public policy debate, namely, the future of Ontario's energy supply mix.

90. It would be inappropriate, in SEC's submission, for the government to fund such advertising directly given the context of the IPSP proceeding. Other forms of energy suppliers do not have access to ratepayer-subsidized advertising to convince the public of the virtues of their respective form of energy supply. It is equally inappropriate, in SEC's submission for the government to fund such advertising indirectly through OPG or OPG’s contributions to the CNA.

91. It is therefore submitted that nuclear support advertising expenses should be disallowed, whether made directly or made indirectly through the CNA.

Corporate Affairs: CIO Costs

92. The CIO costs include information technology costs from the New Horizon Systems Solutions contract. These costs increase significantly in the test years, from $126 million in 2007 to $155.4 million in 2008, a 23% increase in one year [L-3-80]. Some of the increase is offset by reductions in CIO costs as a result of shifting some work previously done in-house to NHSS [Tr8:140]. The net result, however, is still an $18.3 million increase in 2008 over 2007, a 10% increase.

93. Although some of the increase in NHSS costs is related to new initiatives such as the re-engineering of the OPG help-desk, much of the NHSS increases are in areas unrelated to new initiatives. For example, the budgets for Contracts and Application Maintenance budgets both increase by 25% in 2008 over 2007. These two line items increase by the exact same percentage as the Infrastructure Management line item, even though the Infrastructure Management budget includes the cost of the $7 million help-desk re-engineering initiative [Tr8:143]. No specific justifiation has been provided by the Applicant, and it appears to us that these substantial increases are just ballparks picked out of the air without any underlying foundation.

94. In addition, with respect to Infrastructure Management, $7 million of the $10.5 million increase in 2008 is due to the re-engineering plan. In the first place, that plan has not yet been approved [Tr8:144-145]. Secondly, the budget for 2009 remains at the same level as 2008. When asked by Member Chaplin why that is the case, the OPG witnesses had no answer [Tr8:147].

5.3 Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate? (F3/T4/S1)

95. SEC has dealt with the quantum of labour costs, as they feed into the total nuclear or hydroelectric OM&A budgets, in issue 5.1 above. In this section we add additional submissions regarding OPG's wage and benefits issues.

96. OPG argues that its labour costs track well against comparable nuclear generators. The only other comparator provided, however, was Bruce Power.

97. There was a suggestion in cross-examination by Mr. Stephenson on behalf of PWU that Bruce Power is the best comparator, in terms of salaries, for OPG on the basis that it: operates in Ontario using the same technology as OPG; used to be operated by OPG; and has many former OPG employees working for it [Tr3:83-84]. In SEC's submission, the latter two, which PWU suggested were evidence of Bruce Power being a good comparator for OPG, in fact demonstrate why it is not. As a successor employer to OPG, Bruce Power inherited the legacy collective agreements and labour costs from OPG. If Bruce and OPG have a common problem that doesn't make it any less of a problem.

98. Other evidence suggests that OPG's labour costs are well above market. The benchmark summaries from the Mercer Compensation Review, for example, shows OPG's total compensation versus non-utility and utility comparators [F3-4-1, Figures 1 and 2 respectively]. Although these tables show OPG to be both above and below market depending on the pay band, in general OPG is below market in only a few categories, namely, pay bands A, B, and C in the non-utilities comparison [Figure 1]. In SEC's submission, those bands are likely influenced by incidence of very high pay for senior executives in the non-utilities sector. In the utilities sector, OPG's compensation for Band A (the only band for which comparators are available) is in fact almost 200% higher than the average.

99. In the middle and lower pay bands, where the bulk of OPG's employees would fall, the data show OPG to be either at or far above market, as is demonstrated by the following table:

		OPG vs. Non-Utility Average		**OPG vs. Utility Average**	
Band	**OPG Avg.**	Non-utility average	% Difference OPG vs. Non-Utility	Utility Average	% Difference OPG vs. Utility
A	$2,128,187	$3,940,045	(45.9%)	$719,055	**195%**

B	$939,899	$1,678,582	(44.0%)	n/a	
C	$662,380	$1,109,467	(40.2%)	n/a	
D	$454,198	$408,467	11.2%	n/a	n/a
E	$322,905	$354,457	(8.9%)	$219,228	**47%**
F	$241,875	$252,627	(4.3%)	$241,923	0%
G	$187,405	$181,494	3.3%	$16,5316	13
H	$161,263	$142,180	**13.4%**	$168,797	(4%)
I	$121,947	$105,303	**15.8%**	$116,010	5
J	$90,315	$85,208	6	n/a	n/a
K	$82,603	$75,116	1	n/a	n/a
L	$71,303	$60,683	**17.5**	n/a	n/a
M	$55,191	$45,951	**20.1**	n/a	n/a

Towers Perrin Study

100. OPG also included in the pre-filed evidence a summary of a study conducted by Towers Perrin comparing OPG positions with the 75th percentile of power services industry in Canada. The study showed that, of the 33 positions profiled, OPG is above the 75th percentile for 28, and lower for 5. In addition, for 11 of the positions profiled, OPG is between 15-28% above the 75th percentile of the market. [see F3-4-1, pg.35 and L-1-35].

101. OPG states in the pre-filed evidence that the results of this study show it to be "slightly above the 75th percentile of market on an overall basis." [F3-4-1, pg. 31, line 24]. When asked how OPG could consider itself to be "slightly above" market given these percentages, OPG explained that in standard compensation practice, the term "on market refers to a value that is within plus or minus 10 percent of the median values." [L-1-53] Despite the fact that the 75th percentile is not, of course, the "median value", OPG nonetheless considers itself to be within the "market" range if it is within 10% **of the 75th percentile**. [Tr8:93].

102. Without knowing the distribution of absolute salaries it is not possible to determine precisely where 10% above the 75th percentile would put OPG on a percentile basis, but a threshold of 10% above the 75th percentile would likely mean OPG's salaries could be above the 80th percentile of the market and still be considered, by OPG, to be within the "market range." In SEC's submission, there is no point in doing a benchmark comparison if your attitude appears to be that your results are acceptable even if you're near the top of the market.

103. Even using OPG's inflated "benchmark" threshold, however, 19 of the 33 positions are more than 10% above the 75th percentile.

104. In addition, the wage comparisons do not include the licence retention bonuses and/or leadership allowance that some OPG staff receive [Tr8:162]. These substantial additional compensation amounts would put OPG further offside to the industry benchmarks.

Performance Incentives

105. In addition, SEC is concerned that the performance incentives do not seem to be responsive to actual production performance of the regulated facilities. In particular, the evidence shows that performance incentives increased by about 18% between 2005 and 2007 even though the per unit production costs *increased* by 19% during that time.

106. When asked about this issue during cross-examination, the OPG witnesses said is there is nothing in scorecards that determine performance incentives that would link performance incentives to unit production costs. [Tr8:56]

107. Although the scorecard does reward employees for completing scheduled work at or under budget, that cost component of the scorecard represents only about 18% for employees in the corporate function, and as little as 8% for other employees. The OPG witness testified that it might be more for some employees[6], but based on the data available it was not possible to verify that statement, or find any details.

[6] See Tr9:61.

108. In SEC's submission, OPG's performance incentives need to be more explicitly, and more proportionately, tied to achieving cost efficiencies. This is a company that succeeds or fails based on the efficiency of its day to day operations. It is not developing new technologies. It is not finding new markets for its products. The essence of its business is efficient production of the same product – electricity – day in and day out. Their focus should be on that efficiency, and performance should be incented on that basis.

Licence Retention Bonus

109. The total cost of these bonuses in the Test Period is $10.1 million, $4.9M in 2008 and $5.2M in 2009 [J8.17]. The OPG witnesses said that, for those who receive them, the value can range from between 15-28% of salary [Tr8:96].

110. OPG said that these bonuses are necessary in order to provide an incentive for employees who require a licence to be in a particular job classification to keep that licence. When asked whether the pay for the classification wouldn't itself compensate the individual for holding the licence, the OPG witnesses said that the terms of the collective agreement require that the individual keep the same salary even if they lose their licence. [Tr8:162]

111. In addition, OPG stated that the Licence Retention Bonus and the Leadership Allowance are included in pensionable earnings. OPG's witnesses said that this is common in the nuclear industry but acknowledged that these sorts of bonuses are not usually included in pensionable earnings in the private sector [Tr8:167].

112. In SEC's submission, the need for the Licence Retention Bonus is obviously due to an imprudent decision on the part of OPG to agree to a provision in the collective agreement that forces it pay employees, who are paid a salary increment for working in a position that requires a licence, the same salary whether they retain the licence or not. This is, in our view, a good example of the problems that can arise when a company like OPG does not have effective independent oversight. With a vigilant regulator in place, saying "If you agree to provisions like this in your collective agreement, we will not permit you to recover the cost from your customers", OPG would have a compelling reason to make more prudent decisions.

Post-Retirement Benefits

113. OPG's post-retirement benefits are increasing at a rapid rate: OPEG attributed to regulated operations are projected to increase by 47% from 2005 to 2009 [from $44.6 combined (hydro plus nuclear) in 2005 to $65.7 million in 2009- see F3-4-1, pg. 26, Chart 6]. These costs are likely to increase further in future years [Tr8:104]. OPG says that the increase is related to changes in the discount rate that resulted in much larger increases for pension costs, as well as increase in the number of employees covered [Tr8:104-105].

114. OPG's post-retirement benefits essentially continue employees' health and dental benefits in retirement as if the employee was still employed. Retirees do not pay any portion of the premiums and benefits continue for life [Tr8:99-100]

115. In response to questions from Energy Probe, the company said that its post-retirement benefits are in line with comparator employers. In support of that contention, OPG cited the Watson Wyatt survey [L-6-14 and Tr8:100] OPG states, for example, that "the majority of comparators in the Energy, Resources and Utilities sector [in the Watson Wyatt survey] do provide post-retirement benefits and …most of those who do provide them do not require contributions." [L-6-14]

116. A copy of the Watson Wyatt survey was provided in response to Undertaking J8.9. While it is true that the majority of respondents in the Energy, Resources and Utilities sector do not require contributions from retirees for health and dental benefits [J8.8, pg. 33, 37], the survey also shows that only 18% of respondents in the same sector provide health coverage for future retirees "the same as active employees", and only 25% provide dental benefits "the same as active employees" [J8.9, pg,. 34, 38].

117. OPG also noted that, though the Watson Wyatt survey does not address the issue of length of benefits, it is OPG's understanding that life-long benefits are common in the public sector: "It's not a common benefit within the private sector, but it certainly is in the public sector where most of the utilities began." [Tr8:101]

118. Public sector employers, however, do not receive a commercial rate of return. In SEC's submission, OPG cannot have it both ways: it cannot insist on a commercial rate of return, as a proxy for the return it would earn in the private, competitive, market, yet insist on comparing itself, in terms of costs, to non-commercial enterprises. If OPG is to begin receiving a rate of return that mimics what a private company would earn, then it should start acting like one. Otherwise, ratepayers will be saddled with the extra cost of paying a commercial rate of return with none of the benefits of efficiency and lower cost that would accrue to a company operating under competitive pressure of the private market.

Summary- Labour Costs

119. As stated above, the days when OPG can simply compare itself to public sector employers are gone. OPG is applying for a commercial rate of return. The basis for granting regulated utilities a rate of return is that they are treated as if they were commercial entities competing in a competitive market.

120. In SEC's submission, the reason OPG's labour costs are so excessive is there has never been a market mechanism, or mechanism in lieu of a market mechanism, such as OEB oversight, to exert a counter-balance to the demands posed by the unions representing OPG's employees. As long as labour costs are simply a flow through to ratepayers, there is no incentive for OPG to bring them into line. The Board, in its position as economic regulator, now stands in the place of a competitive market. This is the first time in its history, therefore, that OPG will be subject to the sort of pressures created by market forces. In order for the Board's oversight of OPG to have any effect on OPG, however, the Board must exercise its jurisdiction as the proxy for a competitive market and tell OPG it must bring its costs in line or face financial consequences.

Summary- OM&A and Labour Costs

121. For all these reasons, SEC believes that OPG's OM&A budget for the test years should be substantially reduced from the amounts requested by OPG. As set out in greater detail above, a number of OPG's costs are out of line with comparable utilities. The Board has been given an important task of imposing economic regulation on a company that has already once become

insolvent and, given its current cost structure, could do so again. In SEC's submission, only immediate and substantial reductions to its proposed expenditures will produce meaningful change at a company that has long operated without the imposition of external discipline.

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

122. In response from questions from intervenors, Mr. Penny, on behalf of the company, responded that the company's position is that it is unnecessary for the company to have to comply with an affiliate code-like regime. The company's rationale is that the company has been organized historically so as to achieve efficiencies and not cross-subsidize [Tr2:2-3]

123. In SEC's submission, whether or not that is true has no bearing on whether OPG should be subject to an affiliate relationships code similar to the one that applies to electricity distributors and transmitters. OPG has significant centrally-organized costs and significant unregulated operations. In SEC's submission, the need for an affiliate-relationships Code is just as pressing, if not more so, for OPG than it is for distributors or transmitters.

124. Total OPG costs allocated to its regulated operations appear to be increasing at a much faster rate than costs allocated to its non-regulated operations. Exhibit K8.1, pg. 5, for example, shows that costs allocated to the non-regulated operations increased by 6.5% from 2005 to 2007, while costs allocated to regulated operations increased by 37.7% during the same period [Exhibit K8.1 pg. 5].

125. In addition, corporate support costs allocated to regulated operations equal 72.2% of OPG total OM&A[7], even though generating capacity for the regulated business is approximately 45% of the total.[8] By revenue, the regulated operations represent 55-58% of OPG total [Tr9:27]

126. OPG's answer is that the bulk of the increase is due to increases in costs that are directly allocated to the regulated divisions, such as pension costs [Tr8:77-78].

[7] Total OPG OM&A of $2,974 million [A2-1-1, Appendix A, 2007 Financial Results, pg. 4] versus total regulated OM&A of: $125.9 for hydro [F1-1-1, Table 1, line 5] and $2,023.8 for nuclear F2-1-1, Table 1, line 7.

[8] Taken from Exhibit A2-1-1, Appendix "A", OPG 2006 Annual Report, pg. 19.

127. As is seen from the following table, however, corporate support group costs (i.e. excluding directly allocated centrally held costs) allocated to the regulated hydroelectric businesses also appear to be increasing faster than total corporate costs or corporate costs allocated to nuclear:

Department		**% Increase: 2005-2009**		
	OPG Total	Unregulated Operations	Nuclear	Hydro
Finance	21.89%	8.41%	21.09%	165.22%
Corporate Affairs	87.88%	2.86%	115.22%	1233.33%
CIO	27.29%	28.89%	24.80%	57.89%
Corporate Centre	5.88%	16.67%	-2.52%	21.05%
Energy Markets	15.15%	4.23%	46.43%	100.00%
Human Resources	18.74%	12.31%	20.00%	47.06%
Real Estate	-9.11%	-11.22%	-11.08%	61.54%
Total	21.37%	14.24%	20.31%	97.26%
Total less Corp Affairs	18.14%	14.93%	16.13%	73.43%

Source: Exhibit K8.3, adapted from Exhibit F3-1-1, Tables 1-3.

128. The company explained that part of the reason for the relatively larger increase in corporate costs allocated to regulated business was that the 2008 and 2009 hearing costs are allocated exclusively to regulated [Tr8:153]. Those costs are mainly in the Corporate Affairs budget. Even excluding that line item, however, the table above shows the total departmental costs allocated to regulated hydroelectric increases 73.43% between 2005 and 2009. By comparison, OPG total corporate support groups, exclusive of Corporate Affairs, increase by 18% during the same period.[9]

[9] Exhibit F3, Tab 1, Schedule 1, Table 1: total corporate support groups for 2005 equal $355.6, less $16.5 million for Corporate Affairs equals $339.1 million; for 2009, the equivalent figures are $431.6 million total, less $31 million for corporate affairs, for a total, exclusive of corporate affairs of $400.6 million. The adjusted 2009 total ($400.6M) is 18.1% greater than the adjusted 2005 total ($339.1M).

129. OPG explained that the larger allocation to hydroelectric in departments like Finance, for example, has to do with the fact that regulated hydroelectric has a number of large capital projects underway, such as the Niagara Tunnel Project. Because those costs are allocated, under OPG's methodology, using a OM&A capital blend allocator, regulated hydroelectric would be allocated a larger share of the overhead costs [Tr8:157].

130. SEC submits, however, that either those incremental costs are related to operations, or to capital projects. If they are related to operations, OPG should explain why an increase that substantial is forecast given that operating output is expected to be fairly stable. I they are related to the Niagara Tunnel Project, or other capital projects, it is not clear why they would not be included in the capital costs of those projects, so that they are included in the unit costs of production from those projects, rather than being included in the unit costs from unrelated current production.

6.1 Are the proposals for the treatment of revenues from Segregated Mode of Operation, water transactions and congestion Management Settlement Credits appropriate?

i.) Segregated Mode of Operations

131. OPG proposes to share net revenues from segregated mode of operations on a 50/50 basis when its production is below 1,900MWh. For transactions occurring when OPG's production is above 1,900MWh, OPG proposes to keep 100% of the revenues.

132. SMO revenues are the revenues produced when OPG has excess hydroelectricity production. OPG proposes to keep the bulk of those revenues. When the reverse is true, that is, when hydroelectric revenues are less than expected due to lower than forecast water flows, OPG is protected by a variance account, namely the Hydroelectric Water Conditions Variance Account that was established under the Regulation for the interim period. OPG seeks to continue that full downside protection through continuation of the variance account [OPG Argument-in-Chief, pg. 103].

133. The combination of these two proposals by OPG is that OPG would keep 50% or 100% of SMO revenues when it has excess hydroelectric production, and would also be protected in the event of lower than expected revenues when water conditions are lower than forecast.

134. When asked why a 50% incentive is required for OPG when gas distributors receive 10% incentive for similar transactions, the OPG pointed out the risk of the transactions as well as a rate of return. As a result, OPG indicated that it may engage in SMO transactions less frequently if the incentive were lower [L-2-53]

135. However, the OPG witnesses admitted that none of the risk the company has identified [at L-1-68] have ever resulted in the company incurring a loss on SMO transactions [Tr3:8-10]

136. In fact, the economics of SMO transactions make it unlikely that OPG would ever experience such a loss. In response to a Board Staff interrogatory, OPG explained that SMO transactions are entered into "when the basis or spread between Ontario and the receiving market exceeds the costs" [L-1-105].

137. The only real risk, therefore, is that the costs would exceed the price for each transaction. But given that the costs are relatively easy to predict, and the transactions typically take place a day in advance, and "are in response to market signals" [Tr3:59], that is unlikely to happen.

138. Furthermore, the evidence shows that the ancillary benefits of SMO transactions also provide a benefit to OPG and therefore the incentive to engage in them does not have to be as high as OPG claims it should be.

139. The OPG witnesses agreed, for example, that SMO transactions allow the company to manage excess load, which is beneficial to the company because it prevents it from having to take other steps to manage load, such as shutting down a nuclear reactor. The witness agreed that the company would not need an incentive to engage in SMO transactions under those conditions [Tr4:68]. Similarly, the witnesses agreed that the company would not need an incentive to minimize spillage from hydroelectric resources [Tr3:68].

140. The third benefit that OPG claims accrues from SMO transactions is the economic benefit to Ontario from SMO transactions. The rationale is that energy OPG sells is used to pump water into a reservoir somewhere else- New York or Quebec- and then when the peak period of the day arrives, the owner of that water can sell it to the highest bidder- if it's Ontario, then it can re-import the power (presumably at a higher price) [Tr4:51]. That benefit, however, is external to the company [Tr4:68]. In other words, OPG would not take that supposed economic benefit into account regardless of the incentive mechanism. Furthermore, OPG has no way of quantifying that benefit [Tr3:69].

141. In SEC's submission, therefore, SMO revenues should properly be considered revenue offsets and be credited 100% against OPG's revenue requirement. There is no real risk to OPG in carrying out the transactions, and there are ancillary benefits to OPG which would make the transactions economic regardless of the incentive mechanism SEC also points out that the assets upon which OPG is able to earn SMO revenue are already included in rate base, and therefore already incur a rate of return. SEC also submits that the company has an obligation to operate the system as efficiently as possible, and that means maximizing revenue from ratepayer-funded assets. SEC submits that it is inappropriate for OPG to keep a portion of the marginal revenues from those assets while ratepayers pay 100% of the average cost, including a commercial rate of return on invested capital.

142. That having been said, we propose below a compromise, based on the natural gas model, that in our view provides an incentive as requested, but gives the ratepayers a benefit as well.

SEC Proposed Incentive Mechanism for SMO Revenues

143. If SMO revenues were forecast then, just like any other forecast item, OPG would have a financial incentive to beat the forecast.

144. OPG has stated that it is difficult to forecast SMO revenues "as they are a response to hourly market-based signals and prices." [G1-1-1, pg. 7]. There is, however, a history of SMO revenues on which to base a forecast and, frankly, we see no reason why it is any more difficult to forecast this revenue item than to forecast any other aspect of OPG’s revenue or expenses.

SEC suggests that the average of the last three years be used as the basis for the revenue requirement offset.

145. So that OPG has an incentive to beat the forecast despite the variance account, OPG suggests an incentive mechanism whereby OPG keeps a portion of the net revenues in excess of the forecast amount.

146. SEC submits that an appropriate mechanism is to follow the approach used for transactional services revenues for gas distributors. These are revenues earned by gas distribution companies for storage and transportation capacity which is surplus to their requirements to serve in-franchise customers. The in-franchise customers are paying to have the assets available, but sometimes those assets can be utilized more efficiently, so this Board incents the utilities to do so. Many of these transactions are short-term, short-notice transactions similar to SMO transactions.

147. The incentive mechanism for transactional services works as follows:

(a) 75% of the forecast amount is embedded in rates as an offset to revenue requirement. The ratepayers get the benefit of this amount regardless of what actually happens.

(b) The company keeps 100% of any revenues between 75% and 100% of the forecast amount. Thus, management has a 25% incentive to meet forecast.

(c) All revenues in excess of the forecast amount are split 75/25 in favour of ratepayers.

148. In EB-2005-0001, the Applicant, Enbridge Gas Distribution Inc. proposed to change the above-referenced sharing mechanism on the basis that: a) revenues were too difficult to predict; b) the "risk/reward" sharing of the mechanism was assymmetrical and penalized the company for failing to meet the guaranteed (75% of forecast) amount.[10] The Board rejected the Company's proposal and continued the existing sharing mechanism. Furthermore, although the Applicant

[10] See EB-2005-0001, Decision with Reasons, para. 6.1.6.

had been asked to provide a "best efforts" forecast for the upcoming year, the Board felt that that forecast was too low and instead used a simple average of the past five years of transactional services revenue.[11]

149. The effect of this approach to transactional services was to cause a substantial increase in these revenues at both Union and Enbridge over a several year period. In essence, it worked.

150. In SEC's submission, the transactional services transactions are comparable to SMO transactions and the incentive mechanism used for those TS revenues should be adopted by the Board for SMO revenues.

ii.) Congestion Management Settlement Credits

151. OPG proposes to keep 100% of its Congestion Management Settlement Credits it receives from the IESO. These revenues totaled $28.8 million in the interim period [G1-1-1, pg. 15].

152. OPG's rationale for keeping 100% of the Congestion Management Settlement Credits it receives from the IESO is that the credits represent costs to OPG resulting from inefficient operation of the generation system, either from being forced to operate when it is otherwise inefficient to do so, or being forced to constrain production when it is otherwise efficient to generate electricity [Tr3:25].

153. OPG was asked to demonstrate that the costs for which it is being compensated directly offset the revenues that it receives. The answer came in a response to interrogatory from the Consumers Council of Canada [L-3-96]. OPG offered two examples, one where it was constrained off and one where it was constrained off. The response, however, demonstrates that the cost to OPG is not a physical cost, but rather the loss of efficiency in having to operate when it is not most efficient to do so, or not being able to operate at peak efficiency.

154. Besides the anecdotal evidence provided in L-3-96, OPG was not able to quantify the costs versus the revenues of congestion management settlement credits.

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[11] Ibid, at para. 6.2.7.

155. OPG's position is that the CMSC revenue simply equals its costs and neither the lost production nor extra costs are factored into its revenue requirement forecasts. [Tr3:38]

156. In SEC's submission, it is impossible for the Board, based on the evidence on the record, to make a determination that the CMSC revenue simply equals the *incremental unforecasted* costs (lost revenue or incremental expenditures) involved in congestion management activity. OPG has provided no evidence to substantiate that claim, just their assertion of that conclusion.

157. In order to accept OPG's unsubstantiated contentions that all of these revenues are simply compensation for unforecasted loss of revenue or incremental expenditures, one would have to believe that OPG's revenue and expenditure forecasts are done with such precision as to exclude any contingency for less than optimal operation. Given the size of OPG's revenue requirement and revenue forecasts, SEC submits that that is highly unlikely.

158. As a result, SEC submits that the Board should conclude that CMSC revenue is incremental revenue that offsets revenue loss and expenditures that are likely already included in the forecasts used to determine OPG's requested regulated payment amounts. They should be treated, therefore, as revenue offsets.

7.1 NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING

159. OPG claims the "rate base" approach to nuclear liabilities is the most appropriate for three reasons:

(a) It is the method adopted by the Legislature in setting interim 2005 to 2007 rates;

(b) O.Reg. 53/05 requires the OEB to allow OPG to recover these costs using the rate base method;

(c) The rate base is the best and most appropriate approach.

160. The following sections will deal with each of these contentions in turn. However, before doing so it is appropriate to step back and assess this from a more general perspective, raising two overriding issues.

161. ***Nature of the Problem.*** This is, mathematically, a "saving for retirement" type of problem. It has four steps:

(a) *What amounts in the future do you need to have available?* This is about assessing what spending requirements will arise, and when. The Legislature has overseen a process to determine this part, through the Reference Plan and its updates.

(b) *What rate of return can you plan on earning, over time, on your savings?* The spending requirements will be met in part by money you save, and partly by the return on those savings. Therefore, you need a return assumption to calculate the split between those funding sources.

(c) *What pattern of saving is reasonable?* This is about the shape of the savings plan, rather than the amounts. For a person saving for retirement, for example, the shape will be heavily influenced by changes in income levels, and other obligations, year by year. For a utility setting aside funds for "negative salvage", the shape is more likely to be influenced by the unit production from the facilities expected year by year, since matching the cost to the production is generally the most stable form of saving.

(d) *What amount of savings annually is required?* This is a mathematical exercise. Given known future costs, an assumed rate of return, and a savings shape, the savings amount in any given year can be calculated without the application of any judgment, or any policy debates. It is what it is.

162. If the appropriate information were available to it, this Board could do the above calculations and get a number for the Test Period (or any other period of time) that is the correct amount to set aside applicable to that period. We emphasize the term "correct".

163. Unfortunately, the Applicant has not filed sufficient information for the Board to carry out that analysis, and during the course of a lengthy interrogatory and hearing process, and despite the best efforts of all concerned (as late as last week), the other parties have not elicited

that information. The Board is, therefore, being asked to order the recovery of $704 million over the Test Period for this "expense", and yet it does not have the right information on which to make that decision.

164. ***Accounting vs. Regulatory Treatment.*** The second general aspect of this problem that needs to be highlighted is the fact that this Board does not do accounting. The mandate of this Board is to determine "just and reasonable rates" and, in the context of nuclear negative salvage, to determine the just and reasonable amounts to be recovered from ratepayers in any given Test Period. The fact that there is a particular accounting treatment associated with an asset, expense, or obligation, is not determinative of the regulatory treatment.

165. This is not to say that the Board must reinvent the wheel. The Board regularly accepts accounting rules and standards and does not challenge their utility in the regulatory context. The reason is that accounting rules and standards are themselves the result of extensive analysis and review. They are not simply picked out of the air. Experts spend countless hours assessing and debating the optimum approach to various accounting issues, and the Board quite rightly gives significant weight to the results of those processes.

166. But it is also true that sometimes the goals of accounting – fair disclosure, conservatism, etc. – are not identical to the goals of regulation, and therefore an accounting rule does not achieve the regulatory goals. An oft-cited example is future tax liabilities, which GAAP says must be treated as a current expense. Regulators have concluded that, while the principle of conservatism may require that it be a current expense, a tax expenditure that is not in fact going to be made until far into the future should not be recovered from ratepayers today, because that would not be just and reasonable. There are numerous other examples.

167. In the case of nuclear negative salvage, it is submitted that the Board should determine independently what it believes a reasonable recovery amount should be in any given year, taking into account the fact, noted earlier, that this is a "saving for retirement" type of problem. To the extent that the accounting rules mandate a different calculation, the Board should accept that there may be a difference, because the goals of the Board in balancing the interests of the

ratepayers and the Applicant may not, in this case, be the same as the goals of GAAP in achieving the clearest, and most conservative, financial statement presentation.

168. We note that, with respect to this difference between accounting and regulatory goals, as with the basic calculation discussed earlier, the Board does not have sufficient information to do a thorough analysis. With better information, the Board could determine whether the GAAP approach to negative salvage can (or should) produce the right annual recovery from ratepayers. On the information currently before the Board, it is not possible to assess why GAAP produces the results it does, whether those results differ from a more straightforward (and technically correct) approach, and which is more appropriate in the ratemaking context.

169. ***Further Review.*** It is therefore SEC's submission that all the Board can do in this situation is order an interim solution, while recognizing that a more thorough review, with proper information, is required. Given the fact that over the course of the next several years, many billions of dollars will be payable by ratepayers to fund nuclear negative salvage, it is, in our opinion, essential that such a review be carried out. We therefore urge the Board to establish a process – whether by way of consultation, working group, expert study, or a combination – to determine the proper approach to calculating the revenue requirement associated with nuclear negative salvage.

170. We note that negative salvage is currently a live issue at the National Energy Board, and the specific subset of nuclear negative salvage will be a concern in a number of jurisdictions around the world. There should be a wealth of information available to make a sound policy decision. The problem is simply that all of that information is not on the record in this proceeding.

171. The remainder of our submissions on this issue therefore proceed from the premise that some amount must be included in the Test Period, and the Board must, in effect, do the best it can with the limited information it has available.

i) What Guidance has the Legislature Given to the Board on this Issue?

172. The Applicant's first two arguments boil down to telling the Board that it should not exercise its independent judgment on how to determine the amounts recoverable from ratepayers for nuclear negative salvage. The first argument says that the Board should blindly follow the Legislature's lead when it set the payment amounts for the interim period. The second argument says that the Legislature has, obliquely, "instructed" the Board to use the rate base approach to calculating the amounts recoverable from ratepayers.

173. Let's start with a basic truth: if the rate base method is the "just and reasonable" approach to recovery of nuclear negative salvage, then neither of these arguments is relevant. The Board simply does what is correct, and the Legislature's views, however expressed, are immaterial. It is only if the rate base method is NOT the "just and reasonable" approach that the Board has to consider whether the Legislature has given it guidance on this point.

174. Once you realize that these two arguments are only relevant if the rate base method is not the best approach, it is much simpler to consider them.

175. ***Follow the Legislature's Example for the Interim Period.*** The Board does not have before it any basis on which to assess how the Legislature determined the nuclear negative salvage recovery for the interim period. Was there a study done? Were the practices in other jurisdictions analysed or assessed? Did the Legislature even know what those practices were? To what extent, if any, was the Legislature influenced by the views of OPG, untested by debate and analysis?

176. With respect, this Board is not even bound by the precedent of its own previous decisions, made in open and transparent processes after thorough deliberation. Even when the Board looks at one of its own previous decisions, it looks at the evidentiary basis for the decision, the underlying reasoning, and any facts that make it more or less applicable to the instant situation. After such a review, the Board then assesses whether it agrees with the decision and its current applicability, and therefore should apply it to the case before it. In fact, if the Board concluded after review of those factors that applying the previous decision would not produce a just and reasonable result in the in case before it, the Board would not apply it.

177. Here, the situation is much worse. The Board is not in a position to look at how the Legislature's decision on nuclear negative salvage was made, nor the evidence it had before it, nor whether the specific circumstances of that decision are different from the current situation. For example, did the Legislature decide "There are so many things going on with the Reference Plan, and the plans for new build, that the nuclear negative salvage amounts are going to be changing soon anyway. The best thing to do is just take the GAAP approach for now, and when the independent regulator takes over in 2008, they will get to the bottom of what approach is the best." Is that what they decided? We don't know.

178. We could propose numerous other plausible bases for their decision at that time which would make that decision clearly inapplicable to the current situation. The point is that this Board cannot look at that decision in a proper manner, and therefore the Legislature's decision on interim payments cannot have any influence on the Board's decision in this case. If rate base treatment is the just and reasonable approach, it should be used. If not, the fact that the Legislature used it in a different, and non-transparent, context is not a proper consideration for the Board. As we have said many times in the past, this Board has a mandate to make decisions. It should not decline that jurisdiction without the clearest possible evidence that the mandate has been circumscribed.

179. ***Has the Legislature Directed the Rate Base Approach?*** The last point leads directly to this one. If the Legislature has validly determined that the Board should not exercise its independent judgment on the proper way to calculate nuclear negative salvage for rate recovery purposes, then the Board cannot exercise that jurisdiction. It would be circumscribed. Conversely, if the Legislature has not validly limited the Board's jurisdiction or discretion on this issue, then the Board <u>must</u> exercise its independent judgment. It does not have the freedom to elect not to worry about this issue, because it still has a positive obligation to ensure that rates are just and reasonable.

180. The Regulation does not deal explicitly with the regulatory treatment of nuclear negative salvage, or any nuclear liabilities. OPG's argument that the Regulation requires that nuclear liabilities be given rate base treatment is based on its interpretation of the indirect implication of various provisions of the Regulation. Nowhere in its Argument in Chief does OPG point to a

specific provision in the Regulation directing the Board to give nuclear liabilities rate base treatment.

181. OPG's position is that the combination of sections 6(2)5(i) and 6(2)6(i) "make it clear that asset values resulting from accounting policy decisions approved by OPG's auditors and OPG's Board of Directors must be accepted by the OEB in making its first order." [OPG Argument-in-Chief, pg. 83]

182. Section 6(2)5(i) and 6(2)6(i) O.Reg 53/05 state as follows:

> 5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:
>
> > i. Ontario Power Generation Inc.'s assets and liabilities…
>
> 6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,
>
> > ii. the revenue requirement impact of accounting and tax policy decisions,

183. These sections, however, refer only to the Board's first order and do not define "revenue requirement impact." These sections alone, therefore, cannot give the Board guidance as to the future treatment of nuclear negative salvage.

184. Next OPG points to s.6(2)8, which states that the Board, in making an Order for payment amounts "shall ensure that OPG "recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan."" Again, however, revenue requirement impact is not defined in this section. In this section, it is left up to the Board to determine the revenue requirement impact, something that is, of course, a central aspect of the Board's normal regulatory function.

185. OPG then points to section 6(2)7 of the Regulation. This section refers to the determination of the amounts in the two deferral accounts contemplated by s.5.1 and 5.2 of the Regulation. This provision does appear to contemplate that the amounts recorded in the deferral accounts will include a "return on rate base."

186. OPG then extrapolates from that to argue that the Legislature could not have meant to employ one approach for dealing with the balance in the deferral account and a different method to recover the costs of existing obligations from the reference plan itself. [Argument-in-Chief, pg. 84]

187. To the extent that this provision is meant to apply after the interim period, however, it is problematic. Section 6(2)7 of the Regulation refers to the "following items" as reflected in the OPG's audited financial statements. The "following items" are "return on rate base"; depreciation expense, income and capital taxes, and fuel expense.

188. The problem, however, is that there is no "return" or "rate base" reflected in OPG's audited financial statements. These are regulatory constructs. The Board determines what constitutes rate base. Although generally rate base includes fixed assets, that is not always the case: there are in virtually every case differences between regulatory “rate base” and accounting “fixed assets”.

189. The Board has in the past, for example, made a distinction between accounting treatment and regulatory treatment. In EB-2007-0598, for example, the Board was hearing an application from Union Gas Ltd. ("Union") in which Union sought to include certain the cost of certain deferred tax liabilities be included in the calculation of its Earnings Sharing Mechanism. The deferred taxes had to do with the removal from rate base of Union's ex-franchise storage assets as a result of a previous Board decision (the "NGEIR" decision) to forbear from regulating those assets. With respect to the deferred tax liability on those assets, Union argued that, because the assets were no longer regulated, accounting rules precluded it from continuing to use the "flow through" approach to those assets.

> Union’s contention is that the Canadian Generally Accepted Accounting Principles (“GAAP”) require that once a segment of a utility’s operation ceases to

> be rate regulated, as is the case with ex-franchise storage services, that portion o the company's operation ceases to qualify for deferred tax accounting treatment Accordingly, the deferred tax deferral account which has been in place since 1997 cannot continue to capture amounts related to these operations.
>
> …
>
> The Board notes that while accounting treatment can be an important consideration in the regulatory treatment of matters, it is not always predictive of the regulatory outcome. The fact that Union may have to change its accounting treatment of the deferred tax account as a result of the NGEIR decision, does not automatically lead to the conclusion that the accounting tax liability associated with it should come into rates now, or at all. In the absence of a near certain revenue stream that matches future costs, a company must book the future liability. Regulated entities have the assurance that prudently incurred costs will be offset by regulated revenues and therefore they need not book the future liability. In these circumstances, this rule has limited relevance for how the change may be reflected from a regulatory point of view. The respective accounting treatments for regulated and non-regulated entities reflect the distinction of one entity having a predictable revenue stream where as the other does not. Furthermore, the CICA handbook does not consider the disposition of the historic costs or who bears them in a regulatory context. This remains the purview of the regulator.
>
> [EB-2007-0598, pg. 6, 8-9]

190. In fact, OPG states in response to an interrogatory from Board Staff that in the U.S. "utilities with nuclear generation recover decommissioning costs as part of depreciation expense (depreciation and accretion charges net of any decommissioning fund earnings)". That is essentially the flow through method. In that same interrogatory response, OPG says that with respect to accounting treatment, the approach appears to be consistent that such costs are recorded as a liability and the asset retirement costs are capitalized [L-1-82]. Clearly, therefore, the regulatory and accounting treatments differ for U.S. utilities.

191. In addition, the "return" on rate base is a function of the Board's determination of the rate base, but also the Board's determination of the capital structure, cost of debt, and return on equity. These are not – except by accident - the capital structure, cost of debt, and return on equity that would be shown in the financial statements.

192. Finally, although s.6(2)7 of the Regulation refers to the deferral account established pursuant to s.5.2(1) of the Regulation, this account is only effective from and after the date of the

Board's first order. [12] To the extent that s.6(2)7 is intended to apply prospectively therefore, the interpretation urged by OPG in their Argument in Chief would mean the OPG Board of Directors deciding in perpetuity the contents of the deferral account through approval of the financial statements. This would be a very surprising breach of normal regulatory practice, and inconsistent with the Legislature's obvious decision to give regulatory responsibility over OPG to the Board.

193. In our submission, the appropriate way to resolve this problem of interpretation of the Regulation is in three steps:

(a) Can the provision be applied by this Board using a simple, plain language interpretation of its words?

(b) If the answer to (a) is no, as we will suggest it is, then what is the purpose of the provision?

(c) Once the purpose is identified, what is a reasonable reading of the provision that achieves that purpose?

194. The first question is answered easily by looking at the four enumerated items in 6(2)7:

(a) As noted above, the financial statements do not have either return or rate base anywhere, so on a plain reading there is no "return on rate base" for the Board to allow. In fact, a simple reading of the words would suggest that, given this does not appear in the financials, the result is that no return on rate base can be allowed in the deferral accounts.

(b) "Depreciation expense" is included in the financial statements, but is not normally disaggregated into line items. Further, the depreciation expense calculated on a rate base number will in most cases be different from the accounting depreciation.

[12] Section 5.2(1) of the Regulation stipulates that OPG is to establish a deferral account that records "*on and after the effective date of the Board's first order* under 78.1 of the Act the revenue requirement impact of changes in its total nuclear decommissioning liability…"

This provision would, on this interpretation, appear to contemplate that unlike every other asset of a regulated entity, this item would be depreciated on an accounting basis, not a regulatory basis.

(c) "Income and capital taxes" are accounted for differently for regulatory and accounting purposes. The financial statements, for example, will record the difference between the flow-through tax impacts and the accrual-based tax impacts. Although an amount may be deductible for tax purposes, a different amount may be expensed for accounting purposes, and under the accounting rules the tax impact of the latter amount is the one reflected in the financial statements. On the other hand, for regulatory purposes it is the tax impact of the former amount that is reflected. If the Regulation is read literally, this would mandate that, for this category of expenditure, conventional deferred tax accounting must be applied to the regulatory sphere. It would be surprising if the government intended to make such a major change without saying so expressly.

(d) Fuel expense is, of course, not separately set out in the financial statements, and in any case on a plain reading this would appear to require that all nuclear fuel costs are charged to the deferral account. This would be inconsistent with the purpose of the account set out in 5.2(1), which is only supposed to record impacts from a change in the reference plan.

195. We could continue with examples of why a plain reading will not work, but these are probably enough. It is clear, we submit, that the government in enacting this Regulation did not intend 6(2)7 to be read literally, without consideration of the context and purpose of the section.

196. The overall purpose of the Regulation appears to be twofold:

(a) To determine what amounts the Board must accept in making its first Order under s.78.1. Generally, they are based on amounts approved by the OPG Board of Directors where they refer to amounts set out in audited financial statements.

(b) With respect to Orders after the first Order, the Regulation also gives guidance to the Board on what should be included in future orders by way of recovery from ratepayers. In every place where it does so (except arguably 6(2)7), that guidance is an explicit instruction as to a goal the Board should achieve, not a re-allocation of jurisdiction from the Board to another body, like the OPG board of directors.

197. The wording of 6(2)7 is clearly unfortunate, but in our view it should not be interpreted as allocating the entire decision-making responsibility for recovery of nuclear negative salvage to the OPG board of directors. If that were the intent, it is submitted that the Regulation would say so expressly, just as it has provided express directions in 6(2)8 and 6(2)9, to take but two examples.

198. Instead, we believe that the Board should interpret s. 6(2)7 of the Regulation to mean that calculation of the revenue requirement impact of a change in the reference plan, with respect to the deferral account to be established under s. 5.2(1), should include:

(a) A reflection of the time value of money, to the extent that cash outlays and accounting liabilities arise, or will arise, at different times. This time value of money can use any reasonable approach the Board determines, and should apply a just and reasonable discount or interest rate.

(b) An allocation of the principal amount (ie. the actual amount to be saved to deal with the future liability) to time periods, essentially an expression of the accounting rule called the "matching principle". This can be based on accounting depreciation, regulatory depreciation, or any other reasonable amortization methodology.

(c) A reflection of the actual tax impacts of the accruing liability and the funding regime associated with it.

(d) A reflection of any change in fuel expense associated with the change in the reference plan, to the extent that it is not otherwise a current operating expense.

199. Under this interpretation of the Regulation, the Board at some future date, when OPG seeks clearance of the s. 5.2(1) account, would look at the amount of the regulatory asset as recorded in the most recent audited financial statements approved by the OPG board of directors, and determine whether, based on the Board's guidance as to how the items in the last paragraph are to be calculated, those amounts have been "accurately recorded" in the account. If they have, then the Board will accept the figure in the audited financial statements and order its recovery over not more than three years. If not, the Board will order that they be corrected, and then order such recovery.

200. In our submission, under this more reasonable interpretation of 6(2)7, the Board asks whether the number in the financials followed their instructions, and if so there is no further debate. Intervenors cannot at that time, for example, question whether the methodology the Board proposed was the best one, or argue that the amount is so high that the Board should arbitrarily reduce it. If the OPG board has approved a number that complies with the Board's instructions, there is certainty that it will be recovered.

201. In SEC's submission, this Board should not fetter its discretion to determine payment amounts under s.78.1 on the basis of an implied direction in s.6(2)7. The Board should only decline jurisdiction when its mandate is clearly and expressly circumscribed, which is not the case here. The alternative is for the Board to implement rate recovery for nuclear negative salvage on a basis that the Board knows (or at least suspects) is not just and reasonable, on the theory that the government <u>may have</u> indirectly limited the Board's jurisdiction to do what is right.

202. In addition, the "implied direction" that has been postulated only arises on an interpretation of 6(2)7 that produces an absurd result. When 6(2)7 is interpreted using a more purposive approach, no such implied direction arises, and the Board's discretion with respect to the deferral account itself is only fettered to the extent that it would otherwise not allow time value of money, principal, tax impacts or fuel cost impacts in the deferral account balance. This would leave the Board free, on the same basis, to determine what it believes to be the just and reasonable approach to recovery of nuclear negative salvage.

203. For all these reasons, we urge the Board to reject the proposition that the apopropriate way to include nuclear negative salvage in rates has been pre-ordained, and the Board should not exercise its expertise and judgment to implement the approach it determines to be just and reasonable.

ii) Is Rate Base Treatment the Just and Reasonable Method?

204. OPG's final submission is that the rate base approach is, in any event, the most appropriate method of recovering the nuclear waste management costs. OPG's argument in can be summarized as follows: a) the CICA accounting rules require OPG to recognize asset retirement costs as part of its fixed assets; and b) the approach recognizes the reality that an investor will require recovery the cost of capital associated with the asset and the asset retirement obligation. [OPG Argument in Chief, pg. 84]

205. SEC submits that, as noted earlier, the Board has insufficient information on which to determine whether this approach produces the just and reasonable result, and so for this First Order the Board should adjust the rate base approach requested for obvious problems, and order a more detailed review in time for OPG's next rate application.

206. In this regard, it is submitted that the amounts OPG proposes to recover from ratepayers for nuclear negative salvage during the Test Period are set out in detail in Exhibit H1, Tab 1, Schedule 3, page 2, as follows:

(a) Time value of money category. OPG proposes $148 million for 2008 and $186 million for 2009, total $334 million, based on debt and equity returns on rate base at their proposed capital structure and return rates.

(b) Depreciation expense category. OPG proposes $135 million for 2008 and $172 million for 2009, as set out under the headings "Depreciation of Asset Retirement Costs (ARC)" and "Low level & intermediate level waste provisions".

(c) Tax impact category. There are no impacts in the Test Period, as taxes are sheltered by loss carryforwards.

(d) Fuel expense category. OPG proposes $26 million for 2008 and $36 million for 2009, as set out under the heading "Used fuel storage & disposal provisions".

207. With respect to the amounts in categories (b), (c) and (d) above, it is submitted that, without further information, the Board is not in a position to determine if those amounts are correct or not. However, as they all relate to future liabilities, and we are proposing that the Board initiate a more thorough review, we believe that the Board should accept them as filed. If it turns out, on further review, that they are not correct, they can be adjusted in a subsequent payment order from the Board.

208. That just leaves the time value of money. In our submission, the "rate base method" has the effect of misleading the Applicant into thinking that nuclear negative salvage should be treated like other assets. That is not the case.

209. The concept of rate base is designed, in the regulatory context, to accomplish two unrelated goals.

210. First, **in the same way** as fixed assets in accounting, rate base is used as a method, via depreciation, of allocating capital costs to multiple time periods in order to comply with the matching principle. In effect, capital costs are, through this method, converted into annual charges reflective of the amount "used up" through operations in any given year. In this respect, rate base and depreciation work in almost exactly the same way as fixed assets and amortization, and in fact the regulatory rules are based directly on the accounting rules.

211. Second, and **unlike** fixed assets in accounting, rate base is used to calculate the appropriate amounts to be recovered for capital requirements of the enterprise. There is no equivalent in accounting, which in fact looks at what real debt exists, and the actual interest on it, and leaves return on equity as a residual number, not a prescribed number as is the case in the regulatory environment.

212. The use of rate base to calculate the amount of allowable debt (and therefore interest recovery), and the amount of allowed equity (and return on it), presupposes that this amount of capital is needed by the utility to operate. That is, the regulatory methodology used starts from

the assumption that the utility needs to be capitalized by an amount equal to the rate base, through issuing either debt or equity. That assumption is only correct in the circumstance where the rate base involves real capital expenditures, actually incurred and needing to be funded.

213. That is not true in the case of nuclear negative salvage. No money has been spent, and no capital has to be raised through debt or equity. To assume that capital is required is wrong, because we know for a fact that it isn't.

214. Therefore, under the time value of money category, the $334 million claimed by OPG is clearly incorrect. That leaves open the issue, what is the correct figure? In our submission, the Board has three choices:

(a) Zero, since no capital requirement means no cost of capital.

(b) 4.6%, the discount rate used to discount the future liabilities to the present.

(c) 5.25%, being the real interest rate guaranteed by the Legislature on the funded portion, 3.25% [L-1-72], plus a 2.00% long term inflation rate (ie. the Bank of Canada inflation target).

215. The first option, zero, is akin to the treatment of unfunded pension obligations. When a pension obligation is unfunded, no amount is recoverable from the ratepayers. The ratepayers pay the funding requirements, and as those are paid any time value of money is caught up at the same rate as funding is caught up.

216. OPG was asked about the consistency of treatment between the unfunded liability with respect to OPG's pension plan, and the unfunded nuclear liability.

> MR. BRYDON: If you're asking if there is a consistency between other post employment benefits and the nuclear liability, I would -- I believe that there is not.
>
> As we indicated when we discussed the nuclear liability, associated with the nuclear liability is what we referred to as the asset retirement costs, which are -- is a cost that is then associated with the costs of the fixed assets, whereas in an OPEB liability, there is no such equivalent to an asset retirement cost. It associates itself with the value of any asset.

> The value of the OPEB liability -- first of all, it is part of a deferred compensation plan that -- to be part of costs today associated with people who are employed today, but when we say it is a deferred compensation plan, the payments will actually be made in -- sometime in the future.
>
> So as part of that, then there's a current service cost. The fact that there is a liability that's unfunded, that is that is actually a funding decision. So if there is an unfunded liability, that would appear on OPG's financial statements.
>
> [Tr9:51]

217. In SEC's view, an amount payable in the future relating to someone’s employment today is not different from an amount payable in the future relating to nuclear production today. In both cases, they are a future liability arising out of present operations. To the extent that they are funded, the ratepayers pick up the tab. To the extent that they are unfunded, the cost to the ratepayers is deferred. This would result in a $334 million reduction in revenue requirement.

218. The second option, 4.6%, has the value of symmetry. A future liability is discounted by 4.6% per annum to today. The amount by which the liability naturally increases from one year to the next – ie. the time value of money component of that increase – is by definition 4.6%, since that’s the time value of money used to get the current value in the first place. The recovery from ratepayers would be $180 million over the Test Period ($80 million in Q2-4 2008, and $100 million in 2009), a reduction of $154 million in revenue requirement.

219. The third option, 5.25%, uses a quasi-funding model. In effect, it assumes that the discounted future liability has to earn the same rate as the sinking fund in order to keep the Applicant whole in the long term. This is not actually true, but there is an argument to be made that this is a more conservative approach to the 4.6% figure. The recovery from ratepayers would be $205 million over the Test Period ($91 million in Q2-4 2008, and $114 million in 2009), a reduction of $129 million in revenue requirement.

220. In our submission, the appropriate time value of money to be used is the mathematically correct one, 4.6%. Although this is not consistent with how pensions and other future costs are treated, it ensures that the full extent to which we are edging closer to having to actually spend the money on nuclear cleanup is included as a cost of current nuclear production, as it should be.

221. If the Board accepts this submission, the amount to be recovered from the ratepayers over the Test Period for nuclear negative salvage would be the following:

(a) Time value of money - $180 million.

(b) Depreciation - $307 million (as filed).

(c) Tax impacts – nil (as filed)

(d) Fuel expense - $62 million (as filed)

222. The total of these amounts is $549 million. We note that this is very close to the total revenue requirement for the flow-through method, $556 million [K7.2]. While we are not advocating the flow-through method, due to lack of evidence before the Board on which to make that decision, we believe that the close result between the corrected rate base method we have proposed and the flow through method suggests that this result may be a reasonable interim approach for the Board until it can dig more deeply into this issue.

223. In this regard, we note that OPG has not cited any regulatory precedent for the rate base approach to nuclear liabilities. In fact, the two examples cited in response to an interrogatory from Board Staff [L-1-82] appear to suggest that other jurisdictions use the flow through method:

(a) New Brunswick Power: the annual expense amounts related to nuclear liabilities (depreciation and accretion charges) are recovered through a power purchase agreement with the distribution company;

(b) In the US, utilities with nuclear generation recover decommissioning costs as part of depreciation expense (depreciation and accretion charges net of any decommissioning fund earnings.) The liability for used fuel lies with the US federal government, too whom utilities pay a per kWh charge for assuming the disposal obligation.[13]

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[13] Although the ultimate disposal obligation has been transferred to the federal government in the United States, the creation of the nuclear deferral account under s.5.2 of the Regulation has effectively also transferred the obligation away from OPG as well. The deferral account has, in effect, treated the obligation as a flow through for OPG, since

224. Therefore, while we are not proposing the flow-through method, the interim result proposed using a corrected rate base method produces a similar recovery level to the method used by many other nuclear jurisdictions.

8.1 Are OPG's suggested changes to the hydroelectric incentive payment system appropriate? (I1/T1/S1)

225. Section 4(2) of the Regulation provided that hydroelectric generation in excess of 1,900 MWh in any hour was to be paid by the IESO at the market price. Since section 4(2) refers to section 78.1(2)(a) of the Act, which only applies to payment amounts during the interim period, this incentive mechanism applies to payment amounts during the interim period (up to April 1, 2008) only.

226. For payment amounts beyond the interim period, therefore, the Board is free to determine any incentive mechanism for hydroelectric output, or none at all. That is, the Board's options in this proceeding are not simply to decide whether to continue the existing incentive mechanism (as set out in s.4(2) for the interim period) or adopt OPG's proposed changes. The Board must decide whether to continue *any* incentive mechanism.

OPG's Proposed Incentive

227. OPG's proposed incentive replaces the 1,900MWh threshold set out in the Regulation with a threshold that is based on the difference from OPG's *own* average energy production for the month.[14] That is, OPG would receive the market price not for exceeding an energy production target which the Legislature deemed to reflect peaking energy requirements (i.e. 1,900MWh in a given hour) but for exceeding its own average monthly production.

228. OPG admitted in cross-examination that it would receive an incentive on days when its production is greater than its own monthly average [Tr15:109].

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the revenue requirement impact of any changes to the liability are recorded therein. The Legislature has therefore insulated OPG from any risk that the ultimate obligation will be larger than forecast, making the OPG situation very similar to the US situation.

[14] I1-1-1, pg. 12 states that the incentive mechanism changes each month and is "equal to the actual average hourly net energy production over the month [calculated by taking] the net energy production…*from the prescribed assets* for that month [and dividing by] the number of hours in the month." [emphasis added]

229. OPG was asked in cross-examination about the problem of its proposal in effect rewarding OPG for a lower hourly average production. OPG's response was that the proposed incentive mechanism did not produce a perverse incentive for OPG since a lower average production would also mean lower revenues from regulated payments. That is, although revenues are higher on the specific day when production exceeds the monthly average, revenue is lower for other periods since OPG would forgo the regulated payments as a result of having lower production. [Tr15:108-109]

230. In the first place, that is not entirely accurate since, under the existing proposal, production that is diverted to other jurisdictions through SMO is not included in the monthly average for the purpose of triggering the triggering point for the incentive [I1-1-1, pg. 12, line 8-9]. OPG does, however, receive market rate for that revenue. OPG can therefore reduce its average monthly production total without necessarily reducing its revenue.

231. In any event, the point is that OPG's proposal provides it with a reward - market prices - for generating electricity at a time that is not necessarily related to market peak. Because the production target that triggers the incentive is OPG's own average monthly production, OPG is being rewarded simply for exceeding its own average production on a particular day, and not for exceeding a production target that is exogenously determined to meet peak production requirements.

232. In SEC's submission, that is a fundamental flaw in OPG's proposal and it should, therefore, be rejected.

233. That leaves the question of what, if any, the incentive mechanism should be. In SEC's submission, there was insufficient evidence in the proceeding regarding whether or not the existing 1,900MWh incentive should be continued and if so what the trigger point should be.[15]

[15] It appears there was only one interrogatory on the subject, L-1-86(b). That interrogatory, however, was a high level question as to how OPG would operate its system absent the incentive mechanism. OPG's answer was also at a high level: "In a scenario where the 1900MWh in any hour threshold is eliminated and OPG receives the regulated rate of $33/MWh for all of the output from the regulated hydroelectric facilities, economically rational operation would result in OPG operating its assets with a flat production profile to maximize total energy output, instead of time-shifting water."

SEC submits that the existing mechanism be continued on an interim basis, and that the issue be revisited at OPG's next payment amounts proceeding, at which time OPG and the IESO should be invited to submit evidence as to whether or not the existing 1,900MWh trigger point has had the effect of providing a sufficient incentive to generate electricity from prescribed assets at peak times.

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

234. SEC also notes that all of the cost of capital experts who testified in the proceeding agreed that a fixed payment would significantly reduce OPG's risk. In addition, having 25% of its revenues fixed would not, in SEC's view, be a significant disincentive to the company to operate efficiently. SEC therefore supports the fixed payment proposal.

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

235. SEC's submissions will follow the same format used in OPG's Argument-in-Chief, which distinguishes between non-mandated accounts OPG is seeking to continue and non-mandated accounts OPG is seeking to establish.

236. Subject to SEC's submission in other sections, in particular, section7.1, SEC has no submissions on the four accounts (PARTS Deferral Account, Nuclear Liability Deferral Account Nuclear Development Variance Account, and Capacity Refurbishment Variance account) that are mandated to continue in, and/or be established for, the test period.

i.) Non-Mandated Accounts, <u>Created by Regulation</u>, that OPG Proposes to Continue

237. These are existing accounts that OPG proposes to continue and which were created by the Regulation for the interim period but not statutorily mandated to continue in the test period. OPG seeks approval from the Board to continue these accounts.

a.) Hydroelectric Water Conditions Variance Account

238. In SEC's submission, the existence of this account significantly reduces OPG's risk with respect to its hydroelectric operation. On that basis, SEC supports the continuation of this account.

b.) Ancillary Services Variance Account

239. This account, established by the Regulation, tracks the impact of changes to revenues from ancillary services from the regulated facilities. OPG claims that the revenues from these services (black start capability, operating reserve, automatic generation control, and reactive support/voltage control service) are unpredictable and beyond their control [Argument in Chief, pg. 103] Indeed, the level of ancillary services in the interim period ranges from $24 million in 2005, to $44.1 million in 2006, to $35.6 million in 2007 [G1-1-1, Table 1]. The evidence also shows a possibility of significantly under-forecasting these revenues.[16] On that basis, SEC supports the continuation of the variance account.

ii.) Non-Mandated Accounts, <u>Created by OPG</u>, that OPG Proposes to Continue

240. There is only one account in this category, the Segregated Mode and Water Transactions Net Revenue Variance Account. For reasons set out in greater detail in section 6.1 above, SEC supports the continuation of this account.

iii.) Non-Mandated Accounts that OPG Proposes to Establish

241. These are new accounts that OPG proposes to establish and for which OPG claims no statutory authority.

a.) Nuclear Fuel Cost Variance Account

242. Similar to SEC's submissions in respect of the fixed payment structure, SEC supports this account on the basis that it significantly reduces OPG's risk. The corollary, of course, is that all of the risk of volatile fuel prices is placed on consumers.

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[16] Under-forecast by $4.5 million in 2006 ($39.6 million forecast vs. $44.1. million actual) and $4 million in 2007 ($31.6 million forecast vs. $35.6 million actual)- see G1-1-1, Table 1.

b.) Pension/Other Post Employment Benefit ("OPEB") Cost Variance Account

243. SEC is opposed to the creation of this account. Pension and benefits costs are a core element of OPG's cost of service. OPG has justified the creation of this account by arguing that it only applies to changes emanating from changes to the discount rate, which is beyond OPG's control [J1-3-1, pg. 12-13]. The discount rate, however, is only one factor that determines OPG's pension and other employment benefits. It is OPG's responsibility to manage these costs overall. Allowing OPG to have a variance account over one component of this cost would amount to single issue rate making. At the same time as changes to the discount rate increase OPG's pension costs, for example, other aspects of OPG's pension and benefits costs may decrease. In addition, the discount rate itself may reflect changes in the economy- such as inflation rates- that may produce reductions in OPG's other costs. These savings would not be passed on to ratepayers.

244. In addition, allowing deferral account treatment for changes to the discount rate would set a dangerous precedent. Many of the costs included in utilities' revenue requirement, such as cost of debt, leasing costs, and construction costs, are potentially impacted by the discount rate.

c.) Changes in Tax Rates, Rules and Assessments Variance Account

245. As noted in Board Staff's submissions, OPG's proposed account would capture a broader array of tax changes than does Account 1592 used by electricity distributors. Specifically, OPG proposes that changes to its taxes payable resulting from audits or reassessments of prior tax years be recorded in the variance account. OPG acknowledged in questioning from Member Rupert that its proposal is broader than the parameters of Account 1592 [Tr14:163]

246. OPG also stated that, in the event the reassessment of its 1999 taxes resulted in a tax payable, it would not seek to bring those costs forward into the test period. On the other hand, OPG's position is to the extent such a reassessment caused a recalculation of the tax losses that accrue during the interim period that it is proposing to bring forward, there would be an effect [Tr15:20] Either way, the result would be that ratepayers would be responsible for a reassessment of OPG's taxes from the 1999 tax year.

247. In SEC's submission, if the Board approves this variance account, it should be on the same basis as applies to distributors.

iv.) Interest Rate on Deferral Accounts

248. OPG proposes to apply interest rate on its deferral accounts as follows:

- Interest at the long-term debt rate for all deferral accounts except the Pickering A Return to Service ("PARTS") Deferral Account;

- Interest equivalent to the weighted average cost of capital on the PARTS Deferral Account.

[J1-3-1, pg. 2]

249. In both cases, the proposed rate is significantly higher than the interest rate allowed on deferral accounts of all other utilities in the Legislature.

250. The only justification provided by OPG is that its accounts will be paid out over a longer period than most other accounts held by other distributors; and, its account balances are larger, on an absolute basis, than most other deferral accounts.

251. OPG provided no evidence to substantiate either claim. In SEC's submission, both points are speculative and irrelevant. As pointed out by Board Staff [at pg. 45 of the Board Staff Submission] other utilities have recorded large balances accumulated over several years in their deferral and variance accounts. These utilities have all applied the Board's prescribed interest rate for deferral and variance accounts. In addition, of course, the size of the account balance should be considered relative to the size of the utility, not in absolute terms as is suggested by OPG. OPG's deferral account balances, as a proportion of its size, are much smaller than the balances carried by many electricity distributors.

10.2 Is the proposed treatment of OPG's loss carry forwards for the regulated business appropriate? (K1/T1/S2)

252. SEC supports the use of loss carry forwards to mitigate the payment amount increases during the test years. SEC notes, however, that absent the, temporary, mitigating effect of the loss carry forwards, the increase in payment amounts would be substantially higher than they appear to be in this application. SEC submits that the true impact the Board should look at is the increase in payment amounts that will result once the loss carry forwards are used up; this is the actual amount consumers will pay in the long run.

253. In addition, SEC questions the way in which the previous year tax losses have been allocated as between the regulated and unregulated businesses. In particular, OPG has used losses generated by the regulated business to shelter income tax payable on income earned by the unregulated businesses [Tr9:78-79]

254. SEC recognizes that OPG files income tax as a single corporate entity for both regulated and unregulated business units. For regulatory purposes, however, OPG should have to separate both income and losses generated by the two sides of the business. That means that losses generated by the regulated business should not be used to decrease income tax payable by the unregulated business. In SEC's submission, the losses applied against the unregulated business income should be carried forward, for regulatory purposes, and be used to offset the income tax component of OPG's revenue requirement in the next rate period following 2009.

Implementation Date

255. Though not on the Issues List, the order making OPG's payment amounts interim as of April 1, 2008 has raised the issue of what the effective date of the new payment amounts should be. OPG has addressed this issue in its Argument in Chief [at p.110-111].

256. The Regulation establishing interim payment amounts, which went into force in 2005, specifically contemplated that the Board would set new payment amounts effective April 1, 2008.

257. The Filing Guidelines for Ontario Power Generation were not issued, however, until July 27, 2007. In SEC's submission, OPG moved with reasonable diligence to file its application within a reasonable time after the Board issued its Filing Guidelines. Could OPG have filed

sooner? Yes, but in our view the difference between the filing date and the earliest reasonable filing date is not sufficiently material that the Board should place responsibility for the late order in this case at the feet of OPG.

258. Nonetheless, making the effective date of the new payment amounts April 1, 2008 as suggested by OPG would force ratepayers to absorb the revenue deficiency from a planned 21-month test period in a 13- or 14- month span (depending on the date of the Board's decision). As a result, OPG's estimated total bill impact from its application, 2.73% for average customers, would likely be in the range of 4%. That is, as a result of payment amounts to OPG alone, customers in Ontario would be seeing a 4% increase in their electricity bill.

259. SEC proposes that new payment amounts be effective April 1 with the exception of the portion relating to the increased return on equity. That portion of the payment amounts should be effective on the implementation date of the new payment amounts. In our submission, this is a reasonable compromise that balances the interests of the shareholder and the ratepayers in this difficult situation.

Costs

260. SEC participated responsibly in this proceeding and cooperated extensively with other parties to reduce the time spent by all concerned. SEC therefore respectfully requests that it be awarded 100% of its reasonably incurred costs.

All of which is respectfully submitted this 22nd day of July, 2008:

John De Vellis

Jay Shepherd

Counsel to the School Energy Coalition