EB-2010-0008

THE 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.

Written Argument Of
The Consumers Council of Canada

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WRITTEN ARGUMENT OF THE CONSUMERS COUNCIL OF CANADA

I INTRODUCTION AND OVERVIEW

1. Ontario Power Generation Inc. ("OPG") has applied to the Ontario Energy Board ("Board") for an order approving the payment amounts for its prescribed generating facilities for the period March, 2011 to December 31, 2012. OPG is also seeking an order declaring rates interim effective March 1, 2011, if the order approving the payment amounts is not implemented by March 1, 2011.

2. This is the Written Argument of the Consumers Council of Canada ("Council").

3. The Council will begin with an overview of a general issue which, the Council submits, should inform the Board's approach to the application and influence the Board's determination of specific issues. For ease of reference, we will refer to this general issue as the Total Bill Impact or TBI issue. The Council will then deal with specific issues in the application.

4. The TBI issue is whether, or to what extent, the Board should consider the impact of the granting of the relief sought by OPG on the total amount of the bills paid by typical

residential consumers. Consideration of this issue requires, in turn, consideration of two other matters. One is the Board's proposed consideration of a "Renewed Regulatory Framework for Electricity". The second is the provincial government's announced 10% rebate on the electricity bills of residential consumers.

5. The starting point for the analysis of the TBI issue is the Decision of the Supreme Court of Canada in the *Northwestern Utilities* case. In that case, the Court set out the basic obligation of a regulator in setting rates, as follows:

> The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer, on the one hand and which, on the other hand, would secure to the company a fair return for the capital invested.

> ***(Northwestern Utilities Ltd. v. Edmonton (City)*** **1929 SCR 186 at 192-93 (the "*Northwestern Utilities* case"))**

6. The obligation to balance the respective interests of the ratepayer and the utility lies at the heart of the Board's rate-setting function. It has been set out in the statutory obligation of the Board, when carrying out its responsibilities with respect to electricity, to protect the interest of consumers with respect to prices.

> **(*Ontario Energy Board Act,* S. O. 1998, c. 15 (Schedule B), Section 1(1))**

7. The obligation of utilities to protect the interests of the ratepayers, and of the Board to do so when the utilities do not, was reiterated by the Ontario Court of Appeal in the following observation:

> The principles that govern a regulated utility that operates as a monopoly differ from those that apply to private sector companies, which operate in a competitive market. The directors and officers of unregulated companies have a fiduciary duty to act in the best interests of the company (which is often interpreted to mean in the best interests of the shareholders) while a regulated utility must operate in a manner that balances the interests of the utility shareholders against those of its ratepayers. If a utility fails to operate in this way, it is incumbent on the OEB to intervene in order to strike this balance and protect the interests of the ratepayers. (Emphasis added.)

(*Toronto Hydro-Electric System Limited v. Ontario Energy Board*, 2010, ONCA 284, para. 50 [Leave to Appeal to the Supreme Court of Canada denied.]) (the "THESL Decision")

8. Although OPG is not strictly speaking a monopoly, its dominant position as the generator for electricity gives it, for all intents and purposes, the powers of a monopoly. The Council submits that the principle in the THESL Decision applies to OPG.

9. OPG's application is being considered in a time of continuing economic slowdown in the Province of Ontario and rapidly rising electricity prices. The increases in electricity prices are attributable to a number of factors, only one of which is the payment amounts for OPG's prescribed generating facilities. The factors include, but are not limited to, the costs of the smart meter initiative, the cost of creating a "smart" grid, the cost of renewable energy supply contracts, the costs of connecting rural generation sources to the transmission and distribution system across the province, and the cost of replacing aging infrastructure. This increase in costs occurs, paradoxically, at a time of oversupply in electricity and reduced demand which would, in the ordinary course, have led to lower commodity prices.

10. The forecast scale of the increase in electricity prices has at long last been reduced to numbers and disclosed to the public. In its recent "2010 Ontario Economic Outlook and Fiscal Review", the Ontario government stated that "Over the next five years, however, residential electricity prices are expected by 46 per cent, which is an average annual rate of about 7.9 per cent."

***2010 Ontario Economic Outlook and Fiscal Review*, Budget Papers, p. 12**

11. The Board has recognized that utilities must consider the TBI when setting rates. In its Decision with Reasons in EB-2009-0096, the Board made the following statement:

> Fourth, the Board must take into account the overall increase and prospect of further increases in the commodity portion of the bill. While these charges are outside of the control of the applicant, there are no less real for customers. In giving effect to the Board's objective to protect the interests of consumers the Board cannot ignore the overall impacts on customers.

***Decision with Reasons*, EB-2009-0096, p. 13**

12. That the Board must have regard to the TBI is reinforced, in this case, by the fact that the Minister of Energy wrote to OPG asking it, in the context of the economic conditions of the province, to reassess its application in order to mitigate rate pressures. (**Ex. L4.1, Attachment 1**)

13. The Council submits that the Board must assess whether, or to what extent, OPG took TBI into consideration in developing its application, and whether OPG made material reductions in its revenue requirement to reflect that.

14. In making that assessment, the Board must consider whether, or to what extent, OPG has been relieved of its obligation, to make material reductions in its revenue requirement, by two matters. One is the Board's initiative to develop a "Renewed Regulatory Framework for Electricity", and the other is the provincial government's announced rebate, amounting to ten per cent of the cost of electricity in a residential consumer's bill.

15. Before dealing with each of those matters, the Council will address OPG's argument that the Board cannot legally reduce OPG's just and reasonable payment amounts to account for the TBI.

16. OPG makes the following assertion, at page 5 of its Argument-In-Chief ("AIC"):

> To the extent other forces impact this bill, it would be both unfair and a legal error to reduce OPG's just and reasonable payment amounts to account for those external affects.

AIC, p. 5

17. OPG's support for its assertion of a "legal error" appears on page 64 of its AIC, in the context of its discussion of the fair return standard. (**Tr., Vol. 16, p. 61**) OPG cites a number of authorities in support of the proposition that the Board is legally obligated to allow OPG a fair return on its capital.

18. The Council does not take issue with the proposition that the Board must allow OPG a fair return on its capital. However, the cases cited by OPG do not support the broad proposition that it would be a legal error for the Board to take external factors into consideration

in determining OPG's payment amounts. The cases stand only for the proposition that, once the Board has determined, among other things, the prudent and acceptable level of investment, it must allow OPG a fair return on that investment.[1]

19. The cases cited by OPG do not preclude the Board from reducing forecast spending or proposed capital expenditures out of a concern for their impact on electricity prices. Nor do the cases relied on by OPG preclude OPG from voluntarily reducing its return on equity ("ROE").

20. To accede to OPG's argument would be to find that the Board is precluded from giving effect to its statutory obligation to protect the interest of consumers with respect to electricity prices, and would effectively reverse the finding of the Court of Appeal in the THESL Decision.

21. The Council submits that the Board is not legally precluded from taking TBI into consideration in determining OPG's payment amounts. On the contrary, the Council submits that the Board is legally obligated to take TBI into consideration in determining OPG's payment amounts.

22. The Board's proposal for a "Renewed Regulatory Framework for Electricity" was announced in a letter from the Board dated October 27, 2010. In that letter the Board announces three policy initiatives, one of which is to review its rate mitigation policy.

23. OPG relies on this policy initiative in support of its argument that the Board should not, as it cannot, consider external factors in determining its payment amounts. In its AIC, OPG states:

> On October 27, the OEB announced three policy initiatives directed at how to manage the pace of rate or bill increases for consumers. It is through the OEB's integrated policy framework for the electricity sector that issues of total bill impact should be considered and not through individual rate applications.

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[1] One of the cases cited by OPG in support its argument is the *Northwestern Utilities* case. In his concurring judgment in that case, Smith, J. made the following observation: "The question of a fair return on a risky investment is largely a matter of opinion… and appears to be one of the things entrusted by the statute to the judgment of the Board." (*Northwestern Utilities*, p. 199)

AIC, p. 5

24. In the Board's letter of October 27, 2010 the Board stated the following:

> The Board has already indicated that it is willing to consider, on case-by-case basis, alternative approaches and rate treatments to facilitate network investments related to the GEA projectives. This review will examine alternative approaches and rate treatments that might smooth the impact to consumers of rate bill increases.

Letter from the Ontario Energy Board, October 27, 2010, p. 2

25. By making that statement, the Council submits that the Board is reiterating that it will continue to consider reductions in revenue requirements, on a case-by-case basis, notwithstanding this policy initiative.

26. The OEB's policy initiative, with respect to rate mitigation, is specifically tied to green energy investments. The policy initiative is not directed, as OPG argues, at how to manage the pace of rate or bill increases for consumers generally.

27. The hearing panel cannot either know or predict the outcome of the policy initiative. Aside from any other consideration, it would be unfair to ratepayers to assume that the policy initiative will have any impact on TBI.

28. The Board's policy initiative cannot, as a matter of law, override the Board's statutory obligation to consider the impact of its decision on the prices paid for electricity by consumers. In addition, it cannot override the obligation of OPG's Board, reiterated by the Court of Appeal in the THESL Decision, to protect the interests of it ratepayers.

29. The Council submits that the OEB's policy initiative with respect to rate mitigation does not relieve OPG of the obligation to make material reductions in its revenue requirement to give effect to TBI. In addition, the Council submits that the policy initiative does not, and cannot, relieve the Board of its obligation to consider TBI and require OPG to make material reductions in its revenue requirement.

30. As noted above, the provincial government announced, in its recent "2010 Ontario Economic Outlook and Fiscal Review", that it would be providing residential consumers

with a 10 per cent rebate on their electricity bills. The question arises as to whether this rebate relieves OPG from the obligation to make material reductions in its revenue requirement, to reduce the impact on consumers, and, more broadly, whether it relieves the Board of its obligation to take the impact of the granting of the relief OPG seeks on the rates paid by residential consumers.

31. The Council submits that the answer, to both those, is no.

32. As a matter of law, the government's announced rebate cannot relieve OPG of the obligation, reiterated by the Court of Appeal in the THESL Decision, to protect the interests of ratepayer. That obligation exists regardless of what the government does with respect to utility rates. That obligation is one which OPG owes to its ratepayers regardless of the actions of the government.

33. That the Board itself does not regard the announced rebate as sufficient alone to protect the interests of consumers with respect to electricity prices is evidenced by the fact that it is continuing the policy initiative referred to in paragraph 22 above.

34. Accordingly, the Council submits that, notwithstanding the Board's policy initiative and the government's electricity rate rebate, OPG remains under an obligation to demonstrate that it has taken every reasonable measure to mitigate the impact of its requested payment amounts on the rates paid by ratepayers.

35. As noted in paragraph 12 above, the Minister of Energy and Infrastructure wrote to OPG asking that it reassess the contents of its rate application in order to mitigate rate pressures. (**Ex. L 4.1, Attachment 1**) OPG's response, in a letter dated June 24, 2010, referred to cost-reduction measures OPG had taken and to OPG's decision to extend the period for the recovery of certain costs. (**Ex. L 4.1, Attachment 2**)

36. That OPG would have taken measures to make itself more efficient, and in the process reduce its costs, is something that would have been expected of OPG in the ordinary course, and regardless of the particular economic circumstances of its ratepayers. It is the expectation that every regulated utility must satisfy if it is to demonstrate that its rates are just and reasonable. The reality is that OPG did nothing, beyond delaying the time for the recovery

of certain costs, in response to the Minister's letter. In particular, OPG made no material cuts in its forecast spending, either for OM&A or capital.

37. The Council submits that OPG has failed to respond appropriately to the Minister's request. More importantly, the Council submits that OPG has failed to fulfill its obligation to protect the interests of its ratepayers with respect to prices. Instead, OPG has made proposals which add materially to the burden on ratepayers but which are wholly unnecessary to sustain its operations.

38. There are two striking examples of this. One is OPG's claim to have CWIP for the Darlington Refurbishment Project ("DRP") included in ratebase. The second is OPG's apparent failure to even consider reducing its level of ROE. Alone and together they add materially to OPG's revenue requirement. Neither is required to support the safe operation of OPG's facilities or to sustain the development of new facilities.

39. The Council makes submissions, below, on specific areas where it believes the Board should reduce OPG's revenue requirement. In so doing, the Board should also keep in mind the TBI of OPG's proposal, and OPG's evident failure to protect the interests of its ratepayers.

II THE ISSUES

40. The requested payment amounts have been determined separately for the Hydroelectric and Nuclear business units. For its Hydroelectric business OPG has forecast a revenue deficiency of $27.7 million. The proposed payment amounts are $37.38 per MWh for regulated hydroelectric with a payment rider of $2.46 per MWh. The rider is to refund $45.8 million in deferral and variance account balances.

41. For the Nuclear business, OPG is projecting a revenue deficiency of $233.1 million. The proposed payment amounts are $55.34 per MWh with a rider of $5.09 per MWh. The rider is to collect $692.5 million from customers of which $412.8 million is attributable to the tax loss variance account.

42. The application is seeking a 6.8% increase in the payment amounts relative to those currently in place. This represents $1.86 on the monthly bill of an average residential consumer.

43. In its submission the Council will address the following specific topic areas:

- Business Planning and Consumer Impacts (Issues 1.2 and 1.3)
- Hydroelectric Business
    - Operating, Maintenance and Administration (Issues 6.1 and 6.2)
    - Capital Costs (Issues 4.1, 4.2 and 4.3)
    - Production Forecasts (Issue 5.1)
    - Incentive Mechanism (Issue 9.2)
- Nuclear Business
    - Darlington Refurbishment (Issues 4.4, 4.5 and 4.6)
    - Pickering B Continued Operations (Issue 6.7)
    - Production Forecast (Issue 5.2)
    - Nuclear Fuel Costs (Issue 6.6)
- Compensation and Benefits (Issue 6.8 and 6.10)
- Corporate Function Costs (Issue 6.9)
- Cost of Capital
    - Capital Structure
    - Return on Equity
- Deferral and Variance Accounts (Issue 10)
- Methodology for Setting Payment Amounts (Issue 12)

44. The Council is not making submissions on all of the Issues on the Issues List. The Council has cooperated with other intervenors, both during the hearing and in the preparation of argument, with a view to deferring to others on some issues. Where appropriate, the Council adopts the arguments made by other intervenors and Board Staff.

BUSINESS PLANNING AND CONSUMER IMPACTS (Issues 1.2 and 1.3)

45. The Council's submissions on these matters are contained in the "Introduction and Overview" section above.

<u>HYDROELECTRIC BUSINESS</u>

OPERATING AND MAINTENANCE COSTS (Issues 6.1 and 6.2)

46. The regulated hydroelectric operating costs include base OM&A, project OM&A and Gross Revenue Charges ("GRC"). In addition, the hydroelectric business is allocated a shared of the corporate and centrally held costs. With the exception of the costs associated with the St. Lawrence Power development Visitor`s Centre and OPG's overall compensation costs the Council is not taking issue with OPG's proposed hydroelectric operating costs.

CAPITAL COSTS (Issues 41., 4.2 and 4.3)

47. Hydroelectric capital costs for 2011 are $328 million and for 2012 the forecast is $235.8 million. OPG is seeking approval of regulated hydroelectric in-service additions of $60.9 million for 2010, $42.9 million for 2011 and $51.5 million for 2012. (**Ex. D1/T1/S2, Tables 1-5**) The majority of the capital spending for the test period is associated with the Niagara Tunnel Project. The project is not forecast to go into service in the test period, but OPG did provide a status report on the project in this proceeding. The Council is making submissions on the Niagara Tunnel Project and the St Lawrence Power development Visitor's Centre.

48. The amount closing to rate base for the St. Lawrence Power Development Visitor's Centre ("Centre") is $12.6 million for 2010. (**Ex D1/T1/S2/table 2**) In addition, that annual operating costs associated with the project are $500,000 for staffing, heating, maintenance etc. (**Tr., Vol. 1, p. 56**) The revenue requirement impact is $3.5 million. (**Tr., Vol. 1, p. 44**) The NPV of the project is (-$17 million). (**Tr., Vol. 1, p. 54**) According to OPG, the construction of the Centre will provide a venue near OPG's second largest generating station to "tell the hydroelectric story" and maintain improved public acceptance of the station and its continued operation. It is also intended to promote OPG's corporate brand image and with respect to all of OPG's generation types and serve to educate students and the public about the

operations and the benefits of power generation, with the main focus on hydroelectric power. (**Tr., Vol. 1, p. 45**)

49. The Council submits that it would be inappropriate to include the costs associated with the Centre in the test period revenue requirement. The Centre is not an integral part of OPG`s operations. It has nothing to do with the generation of power from the regulated assets. Although a relatively small portion of the Centre is devoted to a water safety exhibit, the majority of the Centre has not been established for that purpose. (**Tr., Vol. 1, p. 50**) The Centre includes, among other things, an exhibit about the development of the St. Lawrence Seaway.

50. OPG has also admitted that the Centre is intended to promote OPG's corporate brand image. In addition, OPG indicated that one of the purposes of the Centre has been to build goodwill with the City of Cornwall. (**Tr., Vol. 1, p. 52**) There have been issues between the City of Cornwall and OPG regarding the fact that, although the Saunders Plant is in the City, it is not subject to municipal taxes, an arrangement made between OPG and its shareholder. (**Tr., Vol. 1, p. 51**) OPG has publicly stated that the establishment of the Centre would promote tourism in the area an potentially offset the problems with the City of Cornwall.

51. OPG can choose the activities on which it spends money to promote its corporate image and improve public acceptance of its facilities. It is inappropriate, however, to ask Ontario ratepayers to fund those activities. It does not require a $12.5 million facility, and an operating budget of $500,00 per year, to undertake its water safety messaging. OPG has clearly not made a case to include what amounts to a "gold-plated" facility as part of its regulated operations. Although the facility may serve a purpose, it is not directly related to the operation of the regulated facilities and should therefore not be included in rate base.

PRODUCTION FORECAST (Issue 5.1)

Regulated Hydroelectric

52. OPG is seeking approval of a test period production forecast of 38.4 TWh (19.4 TWh in 2011 and 19 TWh in 2012) for its regulated hydroelectric facilities. (**Ex. E/T1/S1/p. 1**) The forecast is impacted by water availability, which in turn is affected by meteorological conditions including precipitation and evaporation. OPG's forecast is developed through

computer modelling. The models are used to derive flow and production forecasts for the regulated facilities. Forecast monthly water flows, generating unit efficiency ratings and planned outage information are used to convert forecast water availability into forecast energy production. (**Ex. E1/T1/S1/p. ***)

53. OPG's methodology used in this application is essentially the same as the methodology that was approved by the Board in the last proceeding. The one exception is the fact that OPG has included an adjustment for surplus base load generation ("SBG"). SBG is a condition that occurs when electricity production from base load facilities is greater than Ontario demand. Essentially, it is the amount of water converted into energy that has been spilled because there is more base load generation available than there is demand on the Ontario system. (**Tr., Vol. 1, p. 66**) During 2009, SBG was more prevalent in Ontario due to reduced electricity demand resulting from depressed economic conditions, relatively moderate temperatures, and an increase in electricity supply.

54. OPG's forecast does account for reduced production attributable to system operational conditions, including condense-mode operations, the provision of automatic generation control and operating reserve based on historical performance. OPG's position is that the model used in the past did not adequately account for decreased production attributable to SBG experienced in 2009. (**Ex. E1/T1/s1/p. 5**) OPG is forecasting that significant SBG will continue through the test period based on anticipated levels of Ontario electricity demand and generation supply. Accordingly, OPG has made an adjustment to the production forecast to explicitly account for anticipated levels of SBG. The main driver for the adjustment is the planned expansion of wind power in the Province and other renewables. (**Ex. J2.3**)

55. In 2008, the actual level of SBG was negligible and in 2009, it increased to .19 TWh. (**Tr., Vol. 2, p. 39**) The 2010 year-to-date level of SBG was, at the time of the proceeding, 20.4 GWh (**Ex. J1.1**) whereas the forecast for the year was .2 TWh. In support of its forecast for 2010 OPG is relying on the IESO`s 18-Month Outlook which cites that there is a residual risk of SBG towards the end of 2010 as base load generation returns from planned outages, but OPG admits that the levels will likely not hit the .2TWh as projected. (**Ex. J1.1, Tr., Vol. 2, p. 50**)

56. The SBG adjustments OPG is proposing are .5TWh for 2011 and .8 TWh for 2012. (**Ex. E1 T1 S2, Table 1**) If there was no adjustment for SBG in the test year period the revenue requirement would decrease by $32.5 million. (**Ex. 5-24**) The 2012 level is four times that experienced in 2009. The Council submits that OPG has not presented a convincing case as to why its forecast should be adjusted so significantly to reflect its projection of SBG for the test period. The issue for the Board is whether to accept OPG`s adjustment, approve a different adjustment, or approve the forecast without an adjustment for SBG. Alternatively, the Board could approve a deferral account to adjust for actual SBG experienced during the test period.

57. The Council is concerned that OPG`s SBG adjustment results in ratepayers paying an additional $32.5 million over the test period. To the extent that the level of SBG assumed does not occur, this would represent a windfall for OPG. Given that SBG is a relatively new concept, and it appears to be difficult to forecast, it would be inappropriate for the Board to accept OPG`s current forecast. OPG has admitted that SBG in 2010 will not be consistent with its forecast, and will in fact be less. OPG was also reluctant to provide an update to its forecast for 2011 and 2012. (**Tr., Vol. 1, p. 171**)

58. OPG has indicated that it has the ability to track SBG spill at its hydroelectric facilities (**Tr., Vol. 2, p. 119**) The Council submits that given SBG is difficult to forecast and outside the control of OPG it should be subject to deferral account treatment. OPG should be required to track SBG as it occurs and provide its results at its next proceeding. Amounts accumulated in the deferral account will be subject to review and clearance at that time. In the absence of a deferral account, to the extent SBG does not materialize as expected, ratepayers will be adversely affected.

59. Although outside of the Board's jurisdiction in this case, this issue has highlighted a critical problem within the Ontario electricity sector, that ultimately impacts the price of electricity paid by consumers. In times of low demand, cheap clean hydroelectric power is being displaced by much higher cost sources. The Council submits that OPG should be encouraged to work with the IESO, if possible to develop potential ways to avoid what appears to be unnecessary water spillage in periods of low demand.

60. OPG has provided in its evidence a comparison of its hydroelectric production forecast in each year since 2007 relative to the actual level of production. The results for 2007 to 2009 are as follows:

- In 2007 total regulated hydroelectric production was 4% or .7 TWh above the budget
- In 2008 total regulated hydroelectric production was 9% or 1.6 TWh above the budget
- In 2009 total regulated hydroelectric production was 5% or .9 TWh above the budget (**Ex. E1/T1/S2/p.** 7)

61. With respect to 2009 OPG stated, “Niagara Plant Group actual production was almost 3% above plan and R.H. Saunders was actual production was 9 per cent (0.6TWh) above plan. While SBG was significant in 2009 and resulted in reduced production due to spill the effects of SBG were more than offset by flows that exceeded forecast values”. (**Ex. E1/T1/S2/p. 3**) OPG confirmed that it was using the same forecasting methodology it was using in previous years to develop the forecast for the test period. (**Tr., Vol. 1, p. 65**)

62. The Council makes the observation that the methodology OPG has used to develop the forecast has, in 3 of the last 4 years, resulted in a forecast that has been lower than the actual production. If OPG’s actual production continues to exceed the forecast, the Council submits that the Board should consider this when assessing how much to clear from the SBG deferral account in the next proceeding.

HYDROELECTRIC INCENTIVE MECHANISM (Issue 9.2)

63. In the EB-2007-0905 Decision the Board approved the hydroelectric incentive mechanism. Under the mechanism OPG is financially obligated to supply a given quantity of energy in all hours and receives the regulated rate for the hourly volume in all hours regardless of the actual output from its regulated hydroelectric facilities. If it produces more in any a given hour, OPG is paid market prices for the incremental amount of energy above the hourly volume. If its energy production from the regulated hydroelectric facilities is less than the hourly volume in any given hour the amount payable to OPG at the regulated rate is reduced by the production shortfall multiplied by the market price. The point of the incentive mechanism is to improve OPG’s operational drivers by tying operational decisions, regardless of hourly output, to market prices instead of the regulated rate. **Ex. E1/T2/S1/p. 1**) As noted, it is OPG`s position that using

market signals in this way facilitates the movement of energy from low value periods (typically off-peak) to high value periods (typically on-peak) ultimately reducing overall demand weighted market prices and costs to customers. (**Ex. E1/T2/S1/p. 2**)

64. In the last proceeding OPG forecast that the incentive mechanism would provide it with approximately $12 million in incremental market revenues in 2009. The actual revenue was $23.2 million. OPG attributed the difference to the following factors:

- More energy was shifted from off-peak hours to on-peak hours than what was forecast. The actual hourly production at Niagara where most of the shifting occurs was approximately 25% higher;
- The difference between the average on-peak and off-peak market prices was higher than forecast. (**Ex. E1/T2/S1/p. 3**)

65. The forecast amounts for 2011 and 2012 are $13.3 million and $16.3 million. OPG is using the same methodology it used for 2009, but noted the difficulty associated with forecasting the value associated with peaking resources: "It should be noted that forecasting the value associated with peaking resources, including the PGS, is subject to a great deal of uncertainty as the PGS can operate in response to significant short-run differences in hourly prices that are both difficult to forecast and not adequately described by average price spreads." (**Ex. E1/T2/S1/p. 3**) The incentive amounts for 2011 and 2012 are lower than the amounts earned in 2009 as the price spreads are expected to fall. (**Tr., Vol. 2, p. 111**) For 2010 OPG has already exceeded it forecast of revenues expected under the incentive mechanism. (**Tr., Vol. 1, p. 81, J1.2**)

66. The Council supports the continuation of the incentive mechanism. The Council agrees however, with Board Staff that OPG`s position that this has effectively reduced average market prices by $1.14/MWh has not been supported by the evidence. (**Board Staff Submission, p. 89**) OPG characterized the $1.14/MWH as "merely an attempt by us to illustrate a benefit to the ratepayer." (**Tr., Vol. 1, p. 89**)

67. The Council questions why OPG needs such a significant incentive, which is incremental to its ROE, in order to operate its facilities in an economic manner. Any amount of incremental revenue should provide OPG with an incentive to operate its system economically.

In addition, from the Council's perspective, OPG, as a publicly-owned entity, should be looking for ways to reduce the overall cost of electricity to its customers.

68. Board Staff has proposed that the incentive be changed to ensure that consumers benefit from the actions OPG undertakes because of the incentive. Board Staff's proposal is for a tiered level of sharing the actual revenues earned under the incentive. (**Board Staff Submission, p. 90**)

69. The Council submits that the Board should maintain the incentive mechanism for OPG, but establish a sharing mechanism for OPG and its ratepayers. The Council submits that a model similar to that used to deal with transactional services revenue in the natural gas sector should be adopted. That type of model creates an incentive by allowing the utilities to earn some portion of the revenue generated through the sale of transactional services. The majority of the revenues are credited to the ratepayer under those models.

70. The mechanism proposed by the Council would have OPG record all amounts earned under the incentive, as currently structured in a deferral account. At OPG's next rate proceeding OPG would be required to credit to its customers 75% of the revenues earned. OPG's shareholders would be entitled to 25% of the revenue. This would provide OPG with a financial incentive to operate economically while at the same time ensuring the ratepayers are the primary beneficiaries.

NIAGARA TUNNEL

71. OPG is currently constructing a water diversion tunnel in Niagara Falls. The tunnel is part of the Niagara River Hydroelectric Development planned by OPG in the 1980s and submitted for environmental assessment approval in 1991. OPG did not proceed at that time. In 2004 OPG decided to proceed with construction of one of the EA-approved diversion tunnels and in 2005 it Board of Directors approved a the project with a projected cost of $985 million and a completion date of late 2009. (**Ex. D1/S1/T1 p. 13**)

72. Phase I of the project was completed at the end of August 2005. Phase 2 started on September 1, 2005, and included a contractual completion date of October 9, 2009. The progress of the tunnel excavation by the contractor Strabag AG has been much slower than

expected due to significant difficulties excavating and supporting the Queenston shale formation. In June 2009 following a Dispute Review Board hearing OPG and Strabag renegotiated the original Design Build Agreement into a Total Cost Contract. In May 2009 OPG's Board of Directors approved the revised project estimate of $1.6 billion and the revised completion date of December 2013. (**JX2.4 non-confidential version**)

73. The Council recognizes that the Niagara Tunnel Project costs are not included in the 2011 or 2012 revenue requirement and that prudence of the project will not be considered by the Board until the project comes into service. The Council is concerned, however, that a project that was once budgeted at $985 million is now forecast to cost ratepayers $1.6 billion.

74. OPG provided it Project Execution Plan ("PEP") for the project as an undertaking in the proceeding (as Exhibit JX2.4). The purpose of the plan is to ensure that all key issues important to the success of the project are identified, defined and understood at the earliest possible stage. It also provides the project team members, end-users and line authority with a common understanding of the project and the planned method of execution. It sets out project objectives, scope responsibilities, strategies, constraints, processes and mechanisms to be employed in managing and controlling the project. As noted by OPG it is intended to be a "living document". It will be regularly reviewed and updated as necessary throughout the project execution. (**Ex. JX2.4 non-confidential version**) In the PEP OPG notes that OPG intends to ensure that it provides sufficiently detailed reporting to the OPG Board of Directors and the Province of Ontario such that their confidence in OPG's ability to execute large projects is maintained.

75. The Council submits that OPG should be required to provide the Board and intervenors with its PEP reports until such time the project is brought before the Board for approval. We see value in being informed of the progress of the project as ratepayer money is funding this massive capital undertaking. Having what effectively constitutes progress reports will assist the Board and intervenors in the final assessment of the project. In addition, to the extent the progress report raises alarms the Board and intervenors will be notified. We note that detailed reporting will be provided to OPG's Board and the Province and believe that the Board and intervenors should be afforded the same opportunity to assess the project as it proceeds.

NUCLEAR

Darlington Refurbishment Project (Issues 4.4, 4.5 and 4.6)

76. These submissions address the Darlington Refurbishment Project ("DRP"), and the associated request to include the CWIP for the DRP in ratebase.

77. OPG's request for the recovery of costs related to the DRP raises the following questions:

1. At the most basic level, what relief is OPG seeking and whether CWIP treatment is appropriate?

2. What are the implications of granting the relief requested? In particular, is granting the relief requested tantamount to approval of the DRP as a whole?

3. What is the role of the Board in determining whether to grant the relief requested, in relation to the roles of the Province and the OPA? In particular, is "approval" of the DRP by the Province and the OPA relevant to the Board's decision-making and, if so, how?

78. The DRP is a project to refurbish the existing nuclear facilities at Darlington. The DRP is to proceed in four phases, as follows:

1. Project initiation, which includes preliminary assessment and viability recommendation;

2. Project definition, which includes front-end project planning including detailed engineering and the development of the project's scope, cost, and schedule baseline;

3. Execution, which includes outage preparation and refurbishment outage execution, including project monitoring and control;

4. Close-out, which is the close-out of the major project.

(**Ex. D2/T2/S1, p. 6**)

79. The relief requested, in this proceeding, is for the definition of the phase of the DRP.

80. According to OPG, at the end of each of the phases there will be "gates" and that, at each of those gates, the DRP can either be delayed or stopped. (**Tr., Vol. 13, pp. 81-82**)

81. OPG has projected that the Levelized Unit Energy Cost ("LUEC") for the output from a refurbished Darlington facility would be between six and eight cents a kilowatt hour. On the basis of that estimate, OPG asserts that the OPA has indicated its "support" for the DRP. (**Ex. D2/T2/S1, pp. 5 and 7**)

82. The OPA's expression of "support" for the DRP is set out in a letter dated April 1, 2010, to the OPG. That support is explicitly predicated on the reliability of the OPG's projected LEUC of between 6 and 8 cents per kilowatt hour. The OPA stated that "if this proves to be the case, refurbishment of Darlington would be an economic alternative in comparison to the cost of other baseload resources". (**Ex. F2/T2/S3, Attachment 2**)

83. In that letter of April 1, 2010, the OPA provides but one example of alternatives to the cost of other baseload resources. The Council submits that the OPA's analysis is slightly below the threshold of exhaustive.

84. The only evidence with respect to the OPA's position on DRP is the letter of April 1, 2010. The OPA was not called as a witness, and so was not subject to cross-examination. Indeed, it would appear to be OPG's view that the onus of calling the OPA lay on intervenors. In response to a question from the Chair of the hearing panel, OPG's witness stated:

> It was certainly my expectation that there would be a lot of interrogatories directed at the OPA, that there would be requests for the OPA to empanel witnesses, but those did not emerge in this proceeding. (**Tr., Vol. 14, p. 15**)

85. The Council submits that, if OPG wishes to rely on the OPA's position as evidence of the prudence of the DRP, the onus is on OPG to lead evidence from the OPA and to call representatives of the OPA as witnesses. The onus does not lie on the intervenors to make

OPG's case. The Council submits, with respect, that the Board should place no weight on the OPA's "support" for the DRP.

86. OPG's board has approved the timing of the DRP, the decision to proceed with the DRP and the overall strategy. (**Tr., Vol. 13, p. 82**)

87. OPG's decision to proceed with the DRP was not considered in relation to other generation options. In particular, it was not considered as part of the long-term energy planning project recently announced by the provincial government. Indeed, it is OPG's position that there is no value in waiting until the integrated resource planning is concluded before proceeding with the DRP. (**Tr., Vol. 13, p. 39**)

88. Notwithstanding the fact that the project is to proceed in phases, and that at the end of each phase it may be stopped, OPG bluntly asserts that it is the province's position that fifty per cent of baseload supply will come from nuclear. OPG's witnesses were candid in asserting that DRP will proceed, even if the relief requested in this proceeding is denied. (**Tr., Vol. 14, pp. 119-120**)

89. OPG's view, of the respective roles of the Board and the provincial government, is admirable, if only for its bluntness. OPG's witness stated:

> The minister, speaking on behalf of the project, has endorsed our plans for proceeding with the refurbishment of the Darlington plant.
>
> We take that endorsement of our plans as an indication -- or a determination by the province that proceeding is in the public interest, because I think the logic is that the minister or the province would not be endorsing something they thought was contrary to the public interest.
>
> I think, to be fair, that we would not say that public interest determination by the province is binding on the Board, but we believe that the Board should give it significant weight in its own determination of what is in the public interest.
>
> **(Tr., Vol. 13, p. 149)**

90. OPG's view of the role of the Board with respect to the DRP remains somewhat murky. OPG concedes that the Board must approve the recovery of the cost consequences of proceeding with the DRP in the test period. What exactly the Board would be doing, however, remains unclear. OPG asserts that the Board would not be approving the DRP as a whole, and would not be assessing the prudence of the project. OPG asserts that the Board's assessment of prudence would be a retrospective one, namely one which takes place at some time after the DRP has been completed. OPG's witness stated the following:

> The Board looking forward, in setting rates on a forecast test year, has to be satisfied that the expenditures are reasonable, and sometimes reasonable can be synonymous with prudent. But in terms of a prudence review, to me that is a retrospective enquiry where the Board might have a concern that there was some imprudent spending and wants to be satisfied that there wasn't. That is the distinction I am drawing. **(Tr., Vol. 13, p. 86)**

91. The Council submits that the fact that the provincial government has endorsed the DRP and that the OPA "supports" it, is not relevant to the exercise of the Board's jurisdiction. As noted above, the OPA only approved the DRP on the basis of the LUEC analysis undertaken by OPG, and without its own, independent analysis. In addition, and again as noted above, the OPA's "support" for the DRP was not subject to examination in this proceeding. Even if the OPA had undertaken an independent analysis, what it does or does not decide about the DRP has no bearing on the Board's jurisdiction.

92. In like fashion, the fact that the province, as a shareholder of OPG, has approved the DRP has no bearing on the Board's jurisdiction. Having said that, however, the Council submits that the Board can, and indeed should, take into consideration that it is apparently the policy of the provincial government that the DRP will proceed.

93. The relief which OPG seeks, for DRP, is the following:

1. Approval of test period OM&A costs of $5.9 million and $4.5 million in 2011 and 2012, respectively, for the definition phase work;

2. Changes in ratebase, return on ratebase, depreciation expense, tax expense, and Bruce lease net revenues that result from the impacts of the service life

extension, for purposes of calculating depreciation, and the change in the nuclear liabilities associated with Darlington Refurbishment;

3. An increase in ratebase to reflect the inclusion of CWIP for the DRP;

4. Recovery of the difference between forecast 2010 non-capital costs associated with the DRP and the costs underlying the payment amounts established in EB-2007-0905.

(**Ex. D2/T2/S1, p. 4**)

94. For the reasons described, in detail, below, the Council submits that the Board should not grant the CWIP relief. With respect to the balance of the relief, the Council submits that it should only be granted on the basis that the Board is not approving the DRP as a whole, and that the Board is reserving the right to review the prudence of the project as a whole.

95. OPG's request for the inclusion of CWIP in ratebase would result in a test period impact of $37.9 million on the nuclear revenue requirement. (**Ex. D2/T2/S2, p. 1**)

96. OPG's request for CWIP treatment is based, principally, on three considerations. The first is what they describe as the "rate shock issue". The second is a concern with its own credit metrics. The third is the difference between the IDC rate and the AFUDC rate. **(Tr., Vol. 14, p. 17)**

97. In the first instance, however, OPG's proposal for CWIP treatment for the DRP flows from the *Report of the Board* in EB-2009-0152.

98. In that Report, the Board made the following observation:

> The Board's approach to alternative mechanisms should not be viewed, as one stakeholder commented, as a significant departure from many of the well-established and fundamental principles of utility regulation. Utilities will still be expected to demonstrate that the investment is needed, that it is prudent, and that it is economically feasible. Rate impacts will also be assessed. Further, the need to ensure that shareholder risk and reward are properly matched will continue to guide the Board's approach to rate-making.

> The Board emphasizes that alternative mechanisms will not be granted as a matter of course for all such investments. An applicant must demonstrate that there is a requisite relationship between the alternative mechanism proposed and the investment project, in the sense that the proposal is tailored to address the demonstrable risks and challenges faced by the applicant.

(***Report of the Board,* EB-2009-0152, p. 14**)

99. The Council submits that the evidence provided by OPG in this case does not satisfy those "well-established and fundamental principles of utility regulation". In particular, the Council submits that OPG has not demonstrated that the DRP is prudent. Indeed, OPG asserts, as noted above, that the demonstration of prudence will take place only after the fact.

100. The analysis and recommendations, in the *Report of the Board in EB-2009-0152*, were derived in large part from the experience in the United States. There, CWIP was used as an incentive for private sector utilities to undertake large infrastructure projects. These are not the circumstances of the DRP. It is a government-mandated project, backed, ultimately, by the Province of Ontario.

101. In particular, the Board's proposal for alternative regulatory treatments for infrastructure investment was directed at the investments arising out of the *Green Energy Act*. The Board stated the following:

> The Board is of the view therefore that alternative mechanisms should be available in appropriate cases in relation to Green Energy Act-related investments. Alternative mechanisms can serve to address the unique risks that may arise with respect to those investments. Such mechanisms can also facilitate the timely development of the needed infrastructure, without the Board being required to mandate those investments. The Board is also of the view that the alternative mechanisms should be available in respect of a Green Energy Act-related investment regardless of whether the cost of the investment may be recovered from ratepayers throughout the Province under the mechanism set out in section 79.1 of the *Ontario Energy Board Act, 1998*.

(*Report of the Board*, EB-2009-0152, p. 13)

102. The DRP is not a Green Energy Act-related investment. OPG explicitly acknowledged that. (**Tr., Vol. 13, p. 76**). Accordingly, the DRP is not a "qualifying investment" within the meaning of EB-2009-0152.

103. Even if the DRP were a qualifying investment, it would not meet the criteria, set out in its Report in EB-2009-0152, for CWIP treatment. (***Report of the Board*, EB-2009-0152, p. 21)**

104. In attempting to justify CWIP treatment, on the basis of the Board's Report, OPG has referred to the cost of the project in proportion to the current rate base of the utility. However, its comparison is with the total cost of the DRP. The Board is only being asked to approve the recovery of CWIP in relation to the definition phase, and for the test period. The capital cost in that period is very small in relation to the rate base of the utility.

105. In addition, the Council submits that there are limited risks associated with the completion of the DRP. Indeed, OPG itself has a high degree of confidence about its ability to manage risks. OPG's witness stated:

> We expect the project to be executed. As we have laid out, we expect that we will be able to achieve our plan. There are risks there, but we expect that those risks are manageable.

(**Tr., Vol. 13, p. 116**).

106. This is a project which is mandated by the province. It is inconceivable that the province would ever let the project fail.

107. OPG argues that CWIP treatment will avoid rate shock when the Darlington facilities are returned to service. However, OPG's own data, set out in Exhibit J 14.2, suggests that the "rate shock" will not be that significant, and would only take effect, in any event, in 2020. To avoid this rate shock, consumers would be required to pay, now, for a project that would not be in use for a decade and for which there has been no assessment of prudence.

108. The Council submits that OPG's concern with its credit matrix remains hypothetical only. OPG led no evidence that its credit rating will in fact suffer if the Board does not, in relation to the definition phase of the DRP, allow CWIP treatment. Given the impact of allowing CWIP treatment, on ratepayers, the Council submits that the Board should not act on hypothetical concerns.

109. The Council submits that the Board should reject OPG's request for CWIP treatment for the DRP. The Council submits that the DRP meets none of the criteria, established by the Board in its EB-2009-0152 Report, for CWIP treatment.

110. Beyond that, however, the Council submits that there are a number of policy reasons why CWIP treatment should be rejected. Included in those policy reasons is the fact that allowing CWIP treatment will result in significant intergenerational unfairness. Ratepayers in 2011 and 2012 will be paying for the cost of a project which will not be in use until at least 2020. While, as OPG argues, some intergenerational unfairness is inherent in all utility ratemaking, the Council submits that this is a particularly egregious example of it, and therefore unacceptable.

111. Granting OPG's request for CWIP treatment would have an immediate impact on OPG's rates, and therefore on the TBI. The Council submits that, knowing that, OPG could have, and indeed should have, decided that, in the interests of its ratepayers, it would forego a request for CWIP treatment.

112. That OPG failed to do so, and that it proceeded with its request for CWIP treatment, reflects OPG's failure to fulfill its obligation to protect the interests of its ratepayers with respect to prices. It also reflects OPG's evident refusal to respond to the Minister's request that it reassess its application to mitigate the impact of its rates.

PICKERING B CONTINUED OPERATIONS (Issue 6.7)

113. OPG is proposing to extend the life of the two Pickering B units by extending their operating lives by four calendar years. This would move the planned shut-down of the Pickering B units from the currently anticipated dates of 2014-16 to 2018-2020. The test period costs for continued operations are $92.9 million. (**Tr., Vol. 5, pp. 92-93**)

114. OPG's evidence is that the decision to embark upon Pickering B Continued Operations was undertaken in the context of evaluating the potential for refurbishing Pickering B. In addition, the Minister of Energy and the OPA have both concurred with OPG's position to undertake this extension. (**AIC, pp. 29-30**) Unlike Darlington, there was no formal directive from the Minister to undertake the project. (**Tr., Vol. 15, p. 55**)

115. From the Council's perspective it would be premature for the Board to approve the Pickering B Continued Operations at this time. The OPA will be undertaking a long-term supply plan which will come before the Board for approval. The need and economics for the Pickering B Continued Operations program should be considered in the context of that plan relative to other supply and demand options for Ontario.

PRODUCTION FORECAST (Issue 5.2)

116. OPG is seeking approval of a production forecast of 98.9 TWh for the 2011-2012 test period for its nuclear facilities. This represents an increase of 3.9 TWh over the actual production achieved during 2008-2009. As noted in the evidence nuclear facilities are designed as base load generators which means generator output is not intended to vary with market demand. The annual nuclear production forecast is equal to the sum of the generating units' capacity multiplied by the number of hours in a year, less the number of hours for planned outages or forced production losses. The production planning process is focused on establishing annual planned outage schedules, in accordance with established outage scheduling guidelines and on estimating forced production losses. (**Ex. E2/T1/S1/p. 2**)

117. OPG undertakes an extensive nuclear production planning process and generates an annual "Integrated Plan" The plan is finalized after a Chief Nuclear Officer review and then submitted as part of OPG's business planning process. At each stage of the planning process material updates on production, capacity and reliability are provided to the IESO in order to ensure compliance with the market rules. (**Ex. E2/T1/S1/pp. 3-4**)

118. OPG's actual nuclear production has been less than the approved forecast by 3.5 TWh on average during the period 2005-2008. OPG's assessment of the production shortfalls was that they were largely the result of forced outages and forced extensions to planned outages due to major unforeseen events. As a result of this assessment OPG is proposing to adjust its production forecast methodology in the 2010-2014 Business Plan to include a 2TWh per year allowance for "major unforeseen events" with the expectation that these types of events will continue to occur in the future. **Ex. E2/T1/S1/p. 11**) The adjustment is being applied across the fleet because according to OPG they cannot know where these events might occur. (**Tr., Vol. 6, p. 8**) This adjustment is in addition to the allowance for uncertainty in each station's outage

duration. (**Ex. E2/T1/S1/p. 9**) The impact of the 2TWh adjustment on the test period revenue requirement is $200 million. (**Tr., Vol. 6, p. 80**) OPG is not aware of any other utility that includes a similar adjustment. (**Tr., Vol. 6, p. 81**)

119. The Council submits that OPG's adjustment for major unforeseen events has not been justified. OPG's Board of Directors approved a business plan for the period 2010 to 2014 on November 19, 2009. That business plan includes a forecast of 50.9 TWh for 2011 and 52T Wh for 2012. OPG's evidence at the hearing was, "We expect to get 50.9 in 2011 and 52 in 2012." (**Tr., Vol. 6, p. 82**) OPG's forecasting methodology incorporates forced loss rates and a fleet level contingencies. To simply add on another contingency would be inappropriate and redundant.

120. We note that OPG's incentive compensation will be tied to the lower forecast despite OPG' s contention that they expect to meet the higher forecast. The Council submits this is inherently unfair to ratepayers.

NUCLEAR FUEL COSTS (Issue 6.6)

121. OPG is projecting nuclear fuel costs of $235.6 million for 2011 and $261.7 million for 2012. (**Ex. F2/T5/S1**) These amounts represent significant increases over the levels last approved by the Board. OPG is also seeking approval to continue the Nuclear Fuel Cost Variance Account.

122. The Council is not taking issue with the forecast of nuclear fuel or the continued existence of the variance account. We do note the submissions of Board Staff which questioned whether OPG's fuel procurement strategy was appropriate and in the best interests of its ratepayers. Accordingly we support the proposals set out by Board Staff to restructure the variance account.

123. OPG indicated that it had not undertaken any studies which evaluated the cost of indexed contracts vs market contracts. In addition, OPG has not, in recent years commissioned an external analysis of its procurement strategy. (**Ex. J4.6**) The Council submits that OPG should be required to retain a third-party assessment of its nuclear procurement strategy. As part of that study the consultant should assess the comparative value of indexed contracts and market

contracts. Ultimately, the consultant should provide OPG with its assessment as to how best to balance the security of supply issue with the issue of minimizing the cost of fuel to ratepayers.

COMPENSATION AND BENEFITS (Issue 6.8 and 6.10)

124. OPG is seeking approval of $1.38 billion in 2011 and $1.4 billion in 2012 for its overall compensation costs. This includes total wages, benefits and pension/other post-employment benefits costs ("OPEB").

125. OPG has a large proportion of unionized workers (90%) and of the total employees who work in support of the regulated businesses, 95 % work for the nuclear division. (**Ex. F4/T3/S1/p. 2**) In its AIC OPG has concluded, "In light of the demands placed on OPG's workforce and the skills, education and training that are required to operate, maintain and renew OPG's prescribed facilities, the compensation and benefits they receive are appropriate and should be approved by the OEB." (**AIC, p. 47**)

126. OPG argues that because its union agreements have been in place (with some modifications) since the time of the demerger with Ontario Hydro they are effectively tied to those agreements. Any changes to compensation levels can only be made through the collective bargaining process. The Society Of Energy Professionals ("Society") collective agreement expires on December 31, 2010. The agreement with the Power Worker's Union ("PWU") runs through March 2012. The general wage increases for the PWU and the Society have been between 2 and 3 percent for the past few years and this trend will likely continue. (**AIC, p. 48**) OPG has also forecast an additional 1 percent increase to account for step progressions and promotions by PWU and Society personnel. (**Tr., Vol. 9, p. 17-19**)

127. OPG has identified that because of the *Public Sector Compensation Restraint Act*, there will be a reduction of $12 million in its operating costs because of the legislated 2-year salary freeze for management employees. OPG has not reflected this in its revenue requirement because of an offsetting increase in the revenue requirement associated with increased CNSC fees. (**AIC, p. 49**)

128. From the Council's perspective regardless of whether collective agreements are in place the Board has an obligation to assess overall compensation levels and make adjustments, if

required, to the revenue requirement to reflect that assessment. For OPG to simply say they are tied to those agreements is not reason for the Board to accept their forecast of compensation costs.

129. Board Staff has set out in its submissions a convincing analysis of OPG's compensation levels. By looking at the Towers Perrin study used by OPG, OPG has compared 30 of its positions to the 75th percentile of market data. OPG chose the 75th percentile because of the relative complexity of work in a large, regulated and nuclear environment. (**Tr., Vol. 8, p. 163-170**) Board Staff submitted that use of the 75th percentile is not appropriate and that the 50th percentile is more appropriate. Board Staff noted that if OPG was to move its labour cost for the 30 positions in the Towers Perrin study to the 50th percentile the revenue requirement would be reduced by $37.7 million. That amount only refers to the 30 positions. Board Staff also submitted, however, that the results are likely representative of all of OPG's union-represented jobs, that adjustment could be almost four-fold higher. **Board Staff Submissions, p. 66**)

130. Comparing OPG compensation levels to other like entities is one of the only ways in which the Board can assess the reasonableness of the total compensation costs included in the revenue requirement. The evidence in this proceeding is that OPG's compensation levels for its union employees are above market. Accordingly, the Council submits that the Board should make an adjustment to the revenue requirement to reflect this. In addition, an adjustment is clearly justified in light of the introduction of the *Public Sector Compensation Restraint Act* and the Government's related policy statement. Although no there are no guarantees that the new Society collective agreement will incorporate the freeze, the Government has publicly announced that all employers and employee groups will be expected to do their part.

131. The Council submits that, given the $37.7 million adjustment refers to only 30 positions within OPG, the adjustment made to the annual revenue requirement should be greater. The Board needs to signal to OPG that it compensation levels are clearly above market. The Council supports the proposal by CME to adjust the revenue requirement by $134.48 to reflect the fact that all of OPG's unionized positions have salary levels that are above market, as defined by the 50th percentile in the Towers Perrin Study.

CORPORATE FUNCTION COSTS (Issue 6.9)

132. OPG's Corporate support groups include Business Services and Information Technology, Finance, Human Resources, Corporate Affairs, Executive Office , Corporate Secretary, Law and Corporate Business Development. The budgets for OPG's corporate groups are established through the corporate business planning process.

133. Exhibit F3/T1/S2 sets out a comparison of Corporate Costs for the period 2007-2012. The following summarizes the variances:

Hydroelectric:

2007 - Corporate support costs were $1.4 million below budget
2008 - Corporate Support costs were $2 million below budget
2009 - Corporate Support costs were $4 million below budget

Nuclear:

2007 - Corporate Support Costs were $9.8 million lower than budget
2008 - Corporate Support Costs were $31.5 million lower than the budget
2009 - Corporate Support Costs were $32.9 million lower than the budget

134. OPG has indicated that the primary driver for the fact that Corporate support costs were below budget in the period 2007-2009 was the delay in the payments hearing (2009) and hiring lags. (**Ex. L4.28**) The Council submits that these variances are troubling. Particularly on the nuclear side, OPG's shareholders have benefited substantially in recent years as OPG's actual corporate function costs have been significantly below its forecast levels.

135. Included in these costs are the costs for OPG's regulatory activities. The forecast regulatory costs are $6.36 million in 2011 and $9.570 million in 2012. Board Staff has set out an analysis arguing for a reduction to OPG's regulatory budget. They propose a reduction of up to $2.1 in 2011 and $3.6 million in 2012.

136. The Council submits that OPG's corporate support costs should be reduced for 2011 and 2012 based on the fact that these costs at some level appear discretionary and there is a clear pattern of actual amounts coming in well below the forecast. Vacancies and hiring lags have been cited as contributing factors as are IT cost reductions, and regulatory cost savings. (**Ex. L4.28**) The hydroelectric allocation should be reduced by $2.46 million and the nuclear

allocation should be reduced by $24.7 million. These represent the average variances over the three year period and include a reduction for regulatory costs as proposed by Board Staff.

CAPITAL STRUCTURE AND COST OF CAPITAL (Issue 3.1)

137. In the last proceeding several parties took the position that OPG should recognize the higher risks of the nuclear business in its capital and OM&A expenditure decisions. The Green Energy Coalition relied on the evidence of Mr. Paul Chernick who proposed that the Board select a combined cost of capital for the two divisions (hydroelectric and nuclear) and then adjust the nuclear division equity ratio and return on equity ("ROE") upward with a corresponding downward adjustment to the values for hydroelectric. OPG's position was that the alleged benefits of technology specific cost of capital either do not exist or are insignificant.

138. The Board noted in that Decision that, given the two businesses face different risks, there may be some merit in establishing separate capital structures for the two businesses. From the Board's perspective it saw merit in establishing separate capital structures for the two businesses as it would enhance transparency and more accurately match costs with the payment amounts. Given that the evidence in that case was not sufficient to support the establishment of two separate capital structures, the Board concluded that the issue was worthy of investigation in the next proceeding. (**Decision with Reasons, EB-2007-0905, p. 161**)

139. OPG intends to continue with a capital structure of 53% debt and 47% equity as approved by the Board in the EB-2007-0905 proceeding. In addition, OPG has adopted the approach set out in the Board's Cost of Capital Report for the determination of its ROE. The proposed ROE of 9.85% will be updated using data for the month that is three months prior to the effective date of the new payment amounts. (**Ex. C1/T1/S1/p. 3**)

140. With respect to separate capital structures OPG retained Foster Associates to consider the issue in this case in response to the Board's findings in the last case. The Foster Report concluded that none of the cost of capital methodologies examined yielded a robust and analytically sound basis for specifying a technology specific cost of capital. (**Ex. C3/T1/S1/p. 60**)

141. Dr. Kryzanowski and Roberts, retained by Pollution Probe, concluded that the hydroelectric division business risk is low to moderate and that the nuclear division risk is higher. As a result of their analysis the proposed an equity ratio of 43% for hydroelectric and 53% for nuclear. (**Ex. M10.15**) The evidence of Drs. Kryzanowski and Roberts was substantially the same as the evidence they gave in the last proceeding.

142. OPG's continues to support the use of a single cost of capital for its prescribed facilities. OPG concluded that moving away from a single cost of capital would add unnecessary complexity and would not improve the accuracy in the matching of costs. In addition, it is OPG's view that it would not improve OPG's assessment of project specific risk as these risks are already incorporated into OPG's assessment of project cash flows. (**AIC, p. 69**)

143. The Board did conclude in the last case that establishing separate capital structures may have merit as it would provide transparency and more closely match costs of the business units to the payment amounts. Kryanowski and Roberts have concluded that it is possible to develop estimates of technology specific capital. Ms McShane was unable to provide an analysis that supported different values.

144. From a ratepayer perspective, what would be the value of establishing separate capital structures? If the objective is to reflect more costs in the nuclear payment amounts relative to the hydroelectric payment amounts because the nuclear business is more risky, we are not clear as to what the implications of that adjustment would be. Would it mean fewer nuclear projects would go ahead? This is not likely, as the decision to proceed with major nuclear projects is made by OPG's shareholder. Even if that is the objective does the Board have enough sufficient evidence before it to support specific values? The Council submits that it does not. The Kyranowski and Roberts analysis was largely a judgemental, qualitative approach. (**Tr., Vol. 12, p. 144**) The evidence of Ms McShane is that none of the methodologies traditionally used to evaluate capital structure and ROE levels would be analytically sound. So is there sufficient evidence to support an equity thickness of 43% for hydroelectric relative to 47%? We say no.

145. If the objective is to influence OPG's overall planning process and its decisions as to whether or not to undertake specific projects, OPG indicated in that it would not improve its

planning process or its assessment of project-specific risk. The Council submits that there is no compelling reason to establish technology-specific capital structures for OPG's two business units.

DEFERRAL AND VARIANCE ACCOUNTS (Issue 10)

146. The Council has had the benefit of reading Mr. Shepherd's thorough submissions on the tax loss variance account. The Council adopts Mr. Shepherd's submissions.

147. The evidence about the tax loss variance account is dauntingly complex. It bears stating the obvious that the cost consequences, one way or another, are significant for ratepayers. The Council submits that the Board should consider, as an alternative approach, deferring consideration of the issue to a separate proceeding, one in which, among other things, the Board would retain an independent expert to provide a report on the issue.

148. OPG is proposing to clear the actual audited balances in its existing deferral and variance accounts as of December 31, 2010. The updated projection has a $17.4 million credit balance for regulated hydroelectric and a debit balance of $690.1 million for nuclear. (**Ex. H1/T2/S2**) In terms of clearance OPG is requesting test period rate riders for a 22 month period commencing March 1, 2011 with the exception of the Tax Loss Variance Account which it is proposing to recover over 46 months. (**AIC, p. 90**)

149. OPG is proposing to continue with its existing accounts and is also proposing two new accounts. The new accounts are the IESO Non-Energy Charges Variance Account and the Pension and Other Post-Employment Benefits Costs Variance Account. (**Ex. H1/T3/S1**)

150. With respect to recovery of the account balances the Council agrees with the submission of Board Staff that the proposed recovery of the Bruce Lease Net Revenue Variance Account should be over a longer period of time to mitigate potential rate impacts. The account balance of $296.6 million should not be recovered over a 22-month period as proposed by OPG. Instead, the Council submits a 46 month period is more appropriate.

151. With respect to OPG's request to establish the account to record IESO non-energy charges the Council is not opposed to OPG's request. The charges are difficult to

forecast and outside of the control of OPG. In effect, they are a pass-through. The Council supports the suggestion by Board Staff that OPG will be required to demonstrate that it has made efforts to reduce its energy consumption prior to clearing the account.

152. With respect to OPG's proposal for a Pension and OPEB Variance Account the Council supports the analysis and position advanced by Board Staff that the establishment of the account is not warranted at this time with the amounts calculated on a cash basis and not on the accounting basis proposed by OPG.

METHODOLOGY FOR SETTING PAYMENT AMOUNTS (Issue 12)

153. The Board in the last payments proceeding expressed an interest in whether the payment amounts could be determined through some form of incentive regulation mechanism going forward. When determining the Issues List for this proceeding the Board narrowed the scope of the issue to a consideration of what steps might be appropriate to establish a framework for incentive regulation or other form of alternative regulation that would be applied in a future test period.

154. OPG has proposed that, following a decision in this proceeding, it would file an application setting out its proposal for incentive regulation. A hearing process would be initiated including the introduction of expert evidence. Under OPG's proposal, the Board would determine the form of incentive regulation to be applied to OPG and OPG would file a base year, cost of service application for the post 2010 period. (**AIC, p. 99**)

155. Board Staff commented on OPG's approach in its submissions characterizing it as "aggressive and in all probability unrealistic." (**Board Staff Submissions, p. 107**) In addition, Board Staff pointed to the fact that determining an IRM rate adjustment plan for OPG prescribed assets would be complicated relative to the development of a plan for transmission or distribution utilities. Board Staff pointed to the complexity associated with OPG's nuclear asset retirement obligation, the absence of a total factor productivity study, and the lack of any precedents. In addition, Board Staff raised the issue as to whether there should be a technology specific IRM plan for each of OPG business units. **Board Staff Submissions, pp. 107-108**)

156. The Council has participated in many processes and proceedings that have dealt with the development of IRM plans. These issues are complex and take a great deal of time to sort out. In addition, achieving consensus as to how the plans are structured is a difficult process. The Council agrees with Board Staff that, in the absence of precedents and given the complexity of the generation business, the development of a plan for OPG would be time and resource intensive, likely more so than the development of plans for the electric and gas distributors.

157. The Council is not convinced that an IRM mechanism is necessarily appropriate for OPG. The unique issues that OPG faces, like the nuclear asset retirement obligation and the accounting associated with tax losses, may make a standard type of plan inappropriate for OPG. In addition, OPG's capital spending can be very lumpy, as extremely large projects are brought on line like the Darlington Refurbishment and the Niagara Tunnel Project. Traditionally, IRM has been better suited where a more steady state level of spending is occurring. There may be some merit in having elements of OPG's revenue requirement subject to incentives, but not necessarily all of the elements.

158. The Council suggests that, prior to a determination by this Board that incentive regulation is the right approach for OPG, the Board should hold a workshop with OPG and other stakeholders. The purpose of the workshop would be to consider first, if incentive models could be applied to OPG. We are not convinced, at this time that they can, and would like to hear the views of OPG and other stakeholders as to what approaches might be considered. The workshop could also be used to determine the issues relevant to an IRM model for OPG. From there OPG could initiate an application for approval of a plan. The Council urges the Board to carefully consider whether IRM at all could work for OPG, before moving forward on the assumption that IRM can and should be applied to OPG. The workshop, in our view, would be an appropriate forum to consider that threshold issue.

III COSTS

159. The Council asks that it be awarded 100% of its reasonably-incurred costs for its participation in this proceeding.

All of which is respectfully submitted.

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