OEB File No. EB-2007-0905

ONTARIO ENERGY BOARD

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

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 (**"Heritage Asset Rates"**).

ARGUMENT OF
ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

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ARGUMENT OF

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Introduction

> **"It was the best of times, it was the worst of times, it was the age of wisdom, it was the age of foolishness, it was the epoch of belief, it was the epoch of incredulity, it was the season of Light, it was the season of Darkness, it was the spring of hope, it was the winter of despair, we had everything before us, we had nothing before us, we were all going direct to Heaven, we were all going direct the other way…"**
>
> Opening line of *A Tale of Two Cities,* Charles Dickens, 1859

1. In one of his most popular novels, Charles Dickens focused upon the two cities of London, where the theme of resurrection runs throughout the story, and Paris, where the inhumanity of French aristocrats results in the French Revolution, violent change, and the emergence of a new social order.

2. Ontario Power Generation's ("OPG's) first Application to the OEB has also proven to be "a tale of two cities". First is the story of hydroelectric generation that AMPCO finds to be a generally well-managed, competently operated business unit with encouraging future prospects - both from the perspective of the company and Ontario ratepayers.

3. OPG's nuclear generation facilities constitute the second, sad part of the story. The nuclear tale is a tragedy featuring a long, sorry litany of technological and operational failures characterized by prolonged inferior

performance at exorbitant and rapidly escalating costs - all of which fall upon Ontario ratepayers. This dismal situation has led AMPCO to conclude that OPG's nuclear business is a story that is more akin to an exercise in palliative care of uneconomic and unsustainable CANDU technology as opposed to reflecting a business unit characterized and driven by economic sustainability and renewal.

4. For the reasons discussed below, **AMPCO recommends that OPG's requested relief, particularly with respect to cost of capital, should be rejected as being incompatible with the rate-setting criteria and principles upon which the Province established the existing Heritage Asset Rates.**

5. **AMPCO further recommends that in discharging its duty, the OEB should be informed and guided by the criteria contained in the Memorandum of Agreement ("MOA") given that the Heritage Asset Rates established by Ontario in 2005 were done in the cost containment context reflected in the MOA.**

6. Prior to addressing the specific issues in this case, AMPCO wishes to offer the following comment on the nature of this proceeding and its significance. This Application is OPG's first filing pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* and O. Reg. 53/05. Subject to AMPCO's submissions herein, AMPCO believes OPG should be commended in preparing a thorough and comprehensive application. With only a few exceptions upon which we comment below, the information provided by OPG was clear, well organized and comprehensive.

7. The Application reveals that OPG understands that regulation has become an integral part of its business, and is a fixture and "way of life" that is here to stay for the company. AMPCO believes that while the proceeding has generated several loose ends for which conclusions are not readily apparent at this time, AMPCO takes comfort from the fact that with proper direction from the OEB, OPG will be able to improve in future upon the generally solid information it provided the Board in this proceeding. AMPCO understands that part of the significance of this proceeding is that it signals the commencement of a journey toward better transparency and understanding of OPG's businesses and costs. This important new body of information and knowledge will increase over successive Board

proceedings. AMPCO believes the current Application represents a good start on this journey of discovery about OPG.

Organization of AMPCO's Argument

8. AMPCO's Argument is organized as follows:

(a) Summary of AMPCO Recommendations

(b) Context of Application: The Province's unfulfilled expectation and direction that OPG contain costs and improve performance

(c) Rate Base

(d) Capital Structure and Cost of Capital

(e) Capital Projects

(f) Production Forecasts

(g) Operating Costs

(h) Nuclear Asset Retirement Costs

(i) Other Revenues

(j) Ancillary Service Revenue

(k) Design of Payment Amounts

(l) Deferral and Variance Accounts

(m) Determination of Payment Amounts

(n) Rate Implementation

(o) Costs

Summary of AMPCO Recommendations

i) AMPCO recommends that OPG's requested relief, particularly with respect to cost of capital, should be rejected as being incompatible with the rate-setting criteria and principles upon which the Province established the existing Heritage Asset Rates (page 3).

ii) AMPCO further recommends that in discharging its duty, the OEB should be informed and guided by the criteria contained in the Memorandum of Agreement ("MOA") given that the Heritage Asset Rates established by Ontario in 2005 were done in the cost containment context reflected in the MOA (page 3).

iii) AMPCO recommends that for OPG's future applications the Board should direct the applicant to work towards complete structural separation of the regulated hydroelectric and nuclear businesses (page 11).

iv) AMPCO recommends that the Board should not depart from "tried and true" regulatory principles regarding establishing rate base. Rate Base should only include items that are "used and useful" and properly in-service. The Board should apply its discretion to ensure these principles are maintained. Accordingly, AMPCO recommends that the Board reject OPG's Rate Base relief where such relief is inconsistent with this approach (page 12).

v) Summary of AMPCO recommendations on Cost of Capital:

(i) AMPCO recommends a debt/equity structure of 55%/45%

(ii) AMPCO recommends a cost of long-term debt of no more than 5.5%

(iii) AMPCO recommends a cost of short-term debt of 4.0%

(iv) AMPCO recommends a return on equity of 5.85% (page 12).

vi) AMPCO's recommendations result in a revenue requirement reduction for OPG in the amount of approximately $255 M (which do not take into account the further reductions articulated in the CME's submissions) (page 30).

vii) AMPCO recommends that the Board establish for OPG mandatory requirements based upon principles that reflect the policies underlying the recently amended Affiliate Relationship Code for Electricity Transmitters and Distributors.

Specifically OPG should be required to satisfy these same principles with respect to Transfer Pricing, restrictions on sharing of Confidential Information, and similar reporting protocols to the Chief Compliance Officer so that transparency can be achieved to ensure that ratepayers are not subsidizing OPG's unregulated business (page 35).

viii) AMPCO recommends that the Board should provide clear direction to OPG that it must operate Pickering A well enough to justify continued recovery of forecasted costs. AMPCO recommends that the Board should require OPG to file in its next Heritage Assets Rate application, an assessment of the long-term viability of Pickering A. (page 43).

ix) AMPCO has had the opportunity to review the thoughtful and comprehensive submission of Mr. Thompson on the issue of Nuclear Asset Retirement Costs. AMPCO recommends that CME's submissions with respect to this issue be adopted (page 43).

x) AMPCO recommends that the Board direct OPG, at its next rates case, to bring forward options for a more meaningful incentive payment regime that is more closely aligned with customer interests (page 44).

xi) AMPCO recommends that SMO and WT revenues net of costs and without production thresholds should be shared 80/20 to the benefit of consumers and net CMSC revenues should be shared 50/50 pending review of this approach at OPG's next rates case (page 46).

xii) Board Staff in its final submissions proposes an independent review of the hydro-electric incentive mechanism at the next case. Particularly given the uniqueness of the incentive mechanism and its implications in the context of OPG's complex hydro-electric operations, AMPCO recommends that the Board adopt this constructive proposal (page 49).

xiii) AMPCO recommends that the Board should decide in favour of energy-only payments for OPG's nuclear generation (page 51).

xiv) AMPCO recommends the establishment of a variance account to capture variances between forecast and actual costs of IESO non-energy charges experienced by OPG (page 51).

Context of Application: The unfulfilled Provincial expectation and direction that OPG contain costs and improve performance

9. In 2005 AMPCO members were very concerned about the dramatic increase in rates resulting from the government's decision to end Market Power Mitigation Rebates but took considerable comfort from the various Provincial requirements imposed upon OPG when establishing Heritage Asset Rates. The expectation and direction to OPG was to contain costs, to significantly improve its performance, particularly with respect to nuclear performance, and to maximize efficiency.

10. Ratepayers maintain a keen interest in ensuring that OPG achieve these unfulfilled outcomes. This is particularly so since approximately $19.5 billion in stranded debt that resulted from unsustainable Ontario Hydro generation investments continues to be absorbed not by the Province of Ontario, as shareholder, but by Ontario ratepayers (AMPCO Exhibit M, Tab 2, page 4). There is no evidence before the Board that the Province of Ontario has any different views today about the importance of the goals and criteria it had set out in the MOA in 2005.

11. AMPCO submits that the reasonable understanding and expectation of industrial consumers during the restructuring that created OPG in 1998 and 1999 was that the *quid pro quo* for Ontario ratepayers "picking up the tab" for $19.4B in stranded debt costs was that prices consumers would pay for Heritage Asset power would be reasonable and stable. Furthermore, customers expected that the new OPG, with its cleaned-up balance sheet and a commercial orientation and business structure, would perform considerably better than the former Ontario Hydro generation did. The revenue bailout of OPG in 2005, which dismantled key consumer protections, caused concern.

12. Accordingly, in determining the matters before it, particularly OPG's request for another large revenue boost, the Board must carefully consider the MOA between OPG and the Province of Ontario entered into on August 17, 2005 (Ex. A1, Tab 4, Sch. X1, Appendix B). This Agreement was executed shortly after OPG's payment amounts were fixed by Regulation (Transcript Vol. 1, p. 5, line 24).

13. In exercising its jurisdiction pursuant to section 78.1 of the *Ontario Energy Board Act* the Board should be informed by the criteria and requirements of

the MOA and reflect whether or not OPG has complied with them. In other words, the extent to which OPG has satisfied the MOA should inform the Board on how it exercises its discretion on certain matters in the current case.

14. In this regard, AMPCO submits that the fundamental directive that the Province issued to OPG through the MOA, and the basis upon which the current OPG payment amounts were founded, is cost containment and improved performance. The MOA formed the basis for determining the performance of OPG (MOA "Purpose" Section).

15. In the February 23, 2005 Ministry of Energy Backgrounder (AMPCO Exhibit K4.1, page s 8-11) the Ministry explained that the Heritage Asset Rates paid to OPG are designed to:

    (a) "protect Ontario's medium and large businesses by ensuring rates are stable and competitive…";

    (b) "provide an incentive for OPG to contain costs and to maximize efficiencies"; and to

    (c) "allow OPG to better service its debt while earning a rate of return that balances the needs of customers and ensures a fair return for taxpayers" (Backgrounder, page 1).

16. In this same document the Province also explained why it had determined that 5% ROE is adequate and appropriate for OPG. Specifically, as discussed later, the Ontario government associated what might be described as a hybrid ROE to its concern about substandard performance of its subsidiary. Pages 1 and 2 of the Backgrounder state:

> The prices on OPG's regulated assets are based on projected costs of operation, plus a five per cent return on equity (ROE). While the standard ROE for North American utilities is ten per cent, a five percent ROE will generate revenue to service the OPG debt held by the Ontario Electricity Financial Corporation, while putting significant discipline on OPG to contain costs and improve overall operating efficiencies.

17. This indicates clearly that the selection of a 5% ROE was not an interim arrangement to be in place until the OEB decided otherwise but rather an

integral part of a mechanism to achieve the major objective of the MOA: improved operating performance on the part of OPG.

18. To ensure that these cost containment objectives were achieved, the MOA provided for the following critical actions that OPG was required to undertake:

    (a) OPG is directed to operate its "existing nuclear…as efficiently and cost effectively as possible" (Section A.1).

    (b) OPG was required to seek "continuous improvement" in its nuclear generation business and internal services. "OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly-owned nuclear generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet" (Section A. 3).

    (c) OPG will annually establish 3-5 year performance targets based on operating and financial results as well as major project execution. "These performance targets will be benchmarked against the performance of the top quartile of electricity generating companies in North America (Section C.1).

19. It is clear from the record before the Board that OPG has failed to achieve cost containment and the continuous improvement in its nuclear fleet. Notwithstanding OPG testimony that the company is on a program of "continuous improvement" (Transcript Vol. 5, May 29, page 32, line 14), the evidence indicates that:

    (a) OPG Nuclear O&M costs per unit of production increased by 19% between 2005 and 2007 (Ex. J4.10);

    (b) Darlington, OPG's best unit, places in the middle of the bottom half of the pack when compared to all US nuclear operators, based on consistent Electric Utility Cost Group (EUCG)[1] operating cost data (Ex. J4.10);

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[1] OPG's evidence explained the efforts that the EUCG uses to ensure direct comparability of data between different utilities. The cost results as reported by EUCG do not necessarily align with costs reported on the basis of other methodologies.

(c) at $119/MWh for operating cost alone, using EUCG data, Pickering A is about five times more costly than the top quartile US nuclear operators (Ex. KJ 4.10);

(d) at $53/MWh Pickering B is more than 2.5 times higher than the top quartile for US nuclear operators (Ex. J4.10);

20. The operating cost benchmarking results for 2007 revealed in the hearing are as follows in Table 1:

TABLE 1		
NUCLEAR GENERATION UNIT	**RESULTS ($/MWH) 2007 AS PER EUCG (J4.6 EXCEPT AS NOTED BELOW)**	**"NUCLEAR BENCHMARKING RESULTS" AS PER OPG PREFILE EVIDENCE**
PICKERING A	**119**	**68**
PICKERING B	**53**	**50**
DARLINGTON	**29**	**26**
US 3RD QUARTILE	**28.3 (EX. L2/51)**	
US MEDIAN (DN PEER SIZE)	**23**	
US MEDIAN (PA/PB PEER SIZE)	**31**	
US TOP QUARTILE	**20**	

21. The Board will note the discrepancies between OPG's "Nuclear Benchmarking Results" (emphasis added) contained in Chart 3 of Ex. A1, Tab 4, Sch. 3, page 17 and the information AMPCO was able to obtain through interrogatories, cross examination and transcript undertakings. In future, when reporting benchmarking results AMPCO recommends that

using actual results rather than OPG's business plan forecasts would make for a clearer and more meaningful presentation to the Board.

22. Ex. KT 1/10 provides actual EUCG data for 2005 and 2007. The data shows that Pickering A is consistently among the worst economic performance of all units tracked by EUCG. In 2007, the best OPG unit is Darlington unit 1 but it places approximately 80th of about 114 units The Pickering B and A units occupy the lowest slots on the ranking.

    (a) Darlington, Pickering A and B are all below the top quartile CANDU unit capability factor percentage (Ex. L2, IR 41 and Ex. A1-T 4, Sch. 3, Chart 3);

    (b) Darlington, Pickering A and B are all significantly unfavourable relative to the US top quartile and US industry median for elective maintenance backlogs (Ex. K4.1, page 13). Over the 2005 to 2007 period Darlington and Pickering B each had years where the total maintenance backlog was more than double the US top quartile of 304. All stations were unfavourable relative to the top US quartile, the worst being Pickering B at 929 backlogs in 2007 (AMPCO IR, Ex. L, Tab 2, Sch. 41, page 2 of 2).

23. **AMPCO recommends that for OPG's future applications the Board should direct the applicant to work towards complete structural separation of the regulated hydroelectric and nuclear businesses.** Ideally the two would be separate companies where the services currently identified as common costs are either self-provided or purchased on a competitive basis. Once this separation is complete managers should be faced with strong incentives to improve cost performance. This is likely to take some time but given the critical role of cost containment, as identified by the MOA, OPG must start now with a plan that will take it in this direction. The Board and electricity consumers should expect to see steady improvements in future rate applications. A separate hydroelectric company would be an excellent candidate for an early move to incentive regulation.

24. Specifically, structural separation of the regulated businesses would facilitate a move towards station specific regulated rates for each of the Heritage Asset stations.

Rate Base

25. **AMPCO recommends that the Board should not depart from "tried and true" regulatory principles regarding establishing rate base. Rate Base should only include items that are "used and useful" and properly in-service. The Board should apply its discretion to ensure these principles are maintained. Accordingly, AMPCO recommends that the Board reject OPG's Rate Base relief where such relief is inconsistent with this approach.**

Capital Structure and Cost of Capital

Summary of AMPCO recommendations on Cost of Capital:

(i) **AMPCO recommends a debt/equity structure of 55%/45%**

(ii) **AMPCO recommends a cost of long-term debt of no more than 5.5%**

(iii) **AMPCO recommends a cost of short-term debt of 4.0%**

(iv) **AMPCO recommends a return on equity of 5.85%**

26. At the outset, AMPCO supports the position of CME and others that OPG's Capital Structure amount to be used to derive OPG's costs of debt and equity capital must not include the value of OPG's unfunded nuclear liabilities recorded in the ARC fixed asset account. AMPCO submits that it is inappropriate for OPG to recover nuclear asset retirement costs from ratepayers as if they were costs of debt and equity capital. Accordingly, AMPCO supports quantifying nuclear asset retirement costs and recovering these costs as a Cost of Service item rather than as a cost of debt and equity.

27. The basis for AMPCO's recommendations is provided below.

28. The principal issues in the determination of the cost of capital component of OPG's revenue requirements are the following:

(a) Capital Structure

OPG's rate application (Ex. C1, Tab 1, Sch. 1, p. 1, lines 14-15) indicates that it relies on the supporting study by Fosters Associates, Inc. (Ex. C2, Tab 1, Sch. 1) to determine its capital structure recommendation. The proposed structure is 42.5% debt and 57.5% equity (Ex .C1, Tab 1, Sch. 1, p. 1, lines 30-31).

(b) The Cost of Debt

OPG's debt level for the test years consists of existing debt allocated to Heritage Assets, project-related debt associated with Heritage Assets and what OPG calls a "long-term debt provision" (Ex. C1, Tab 1, Sch. 2, p. 1, line 9) which is the amount necessary to bring the total debt to the level necessary to satisfy the debt ratio recommended by Fosters Associates in (Ex. C2, Tab 1, Sch. 1). Interest rates are determined for each of these components of debt.

(c) The Return on Equity (ROE)

Again OPG relies on the recommendation of the Fosters Associates study (Ex. C2, Tab 1, Sch. 1) in determining its proposed ROE, 10.5% (Ex. C1, Tab 1, Sch. 1, p. lines 4-6).

29. This section of AMPCO's Argument will examine each of these areas of OPG's Application and present AMPCO's conclusions and recommendations.

Issue 2.1. What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

<u>Capital Structure</u>

30. The general principles involved in determining the appropriate capital structure for a firm are described in OPG's Ex. C2, Tab 1, Sch. 1 Chapter II C pp. 12-14 authored by Ms. Kathleen McShane, Consumer Council's Ex. M, Tab 3, p. 30 and Pollution Probe's Ex. M, Tab 12, p.27 authored by Dr. Kyrzanowski and Dr. Roberts. Because interest costs provide a tax shield and because debt has a priority on cash flows over equity the cost of debt is less than the cost of equity. Consequently, the use of debt in the firm's capital structure lowers the cost of capital and increases the value of the firm. As the use of debt increases at some point the firm will begin to face financial distress, the costs of which begin to add to the cost of capital eventually offsetting the advantage of the lower cost of debt. Conceptually,

there is some point at which the capital structure is optimal in the sense that the cost of capital is minimized.

31. Each of the three authors referred to in the previous paragraph agree that the principal determinant of an appropriate capital structure for a firm is the business risk that it faces (Ex. C2, Tab 1, Sch. 1, p.12, Ex. M, Tab 3, p. 30, Ex. M, Tab 12, p.24). They also agree that, while both capital structure and the ROE vary in response to business risk, a reasonable procedure is to establish the capital structure based on business risk and then use benchmarks to determine an appropriate ROE (Ex. C2, Tab 1, Sch.1, p.21, Transcript Vol. 13, p.141, lines 6-9, Ex. M, Tab 12, p. 25). Where there is significant disagreement on the subject of capital structure is the assessment of business risks faced by OPG. The following examines each of the types of business risk identified in OPG's evidence and assesses OPG's and other interveners' views on these risks.

<u>Revenue and Market-related Risks</u>

32. This class of risk relates to factors that might adversely affect OPG's revenues, primarily lower production than forecast. The OPG evidence first looks at risk in relation to the Heritage Assets as a composite and then examines risk for each of the two asset categories (Ex. C2, Tab 1, Sch. 1, p. 56). In the composite analysis it suggests that a slowing economy and conservation initiatives on the part of the OPA will reduce the demand for electricity. For this to threaten production from the regulated assets, demand would have to be reduced to a level where it could be displaced by production from other base load facilities.

33. The study states, "There are, however, other generators whose marginal costs are similarly low (e.g. Bruce Power, wind generators, Brookfield Power), which can result in OPG's regulated facilities not being dispatched for short periods in which demand is relatively low. That risk will rise as additional low marginal cost generation (which can bid below cost but receive a price specified in its PPA with the OPA) becomes available or demand drops". (Ex. C2, Tab 1, Sch. 1, p. 59). This issue is picked up again under the analysis of Revenue and Market-related risks faced by each type of regulated asset. It states,

> "The emerging risk that OPG's prescribed assets are not dispatched and there will be unutilized base load capacity will impact the hydroelectric facilities first". (Ex. C2, Tab 1, Sch. 1, p. 65).

34. In relation to the nuclear assets Ms. McShane states,

35. "The risk to the nuclear operations that there will be unutilized base load capacity will rise as additional low marginal cost generation becomes available. This is particularly problematic for nuclear generation, given the time required for the plant to ramp production up and down" (Ex. C2, Tab 1, Sch. 1, p.69).

36. AMPCO sought a clarification of OPG's experience with failure of its regulated assets to be economically dispatched since market opening. AMPCO submitted IR #6 and IR #9 which asked for the number of hours prescribed base load hydro and nuclear generation had failed to be dispatched since market opening. OPG's responses were somewhat vague indicating that dispatch failure experience with prescribed hydro generation had mostly to do with peaking rather than base load generation and the number of hours that nuclear failed to be dispatched "would be very few".

37. AMPCO wanted to understand more clearly the likelihood of the Heritage Assets not being dispatched and hence the significance of this risk. In its cross-examination of OPG's witness on this subject, Ms. McShane, it prepared a high level overview of the Ontario electricity market at its low point (AMPCO Ex. K10.1, pp. 13-16 and Transcript Vol. 10, p.58). The data presented to Ms. McShane showed a low Ontario demand point of 13,000 MW. Over the past three years hourly demand had been below this point only 3.4% of the time. The analysis showed that this level of demand could engage Bruce capacity, existing wind capacity, scheduled new wind and nuclear capacity during the test years, all of OPG's nuclear capacity, all 1,900 MW of OPG's regulated hydro electric capacity and still leave approximately 880 MW of demand to be met by additional base load capacity (Transcript Vol. 10, pp. 56-58).

38. The conclusion AMPCO reached from this information is that the likelihood that either type of prescribed asset would not be dispatched for economic reasons (that is, for reasons other than system constraints etc.) even with the new capacity scheduled for the test years is insignificant. Ms. McShane indicated that she had not done any independent analysis to support her

assertions about Heritage Asset dispatch risk. AMPCO was very surprised to learn that Ms. McShane had simply relied on what she had been told by OPG (Transcript Vol. 10 p.58 lines 25-26). Accordingly, the Applicant's evidence concerning prescribed asset dispatch risk is that of OPG and not Ms. McShane and is not founded in her area of qualified expertise.

39. Others reached the same conclusion as AMPCO. Dr. Booth in his evidence on behalf the Consumer's Council states in his assessment of OPG's dispatch risk "…it is inconceivable that these plants (prescribed generation assets) face any significant competitive risks" (Ex. M, Tab 3, p.52 lines 18-19). The evidence of Dr. Kryzanowski and Dr. Roberts on behalf of Pollution Probe reaches essentially the same conclusion, "Because OPG is a base-load, low marginal cost generator it is not expected to experience a significant level of demand or dispatch risk" (Ex. M, Tab 12, p.30).

40. Standard & Poor's states, "The combined output of the generator's base-load regulated assets (about 60 TWh per year) is among the lowest cost generation in the province and is not all available nuclear generation output from OPG and its competitor Bruce Power Inc. (Bruce Power). OPG's unregulated hydroelectric generation can easily compete with higher cost oil- or gas-fired production to meet intermediate and peaking demand in the Ontario electricity spot market" (Ex. A2, Tab 3, Sch. 1, S&P pp. 3-4). London Economics International in its evidence on behalf of OEB staff concluded, "When we examine the internal supply curve for Ontario, even when we consider 2015 and the Reference Case 1A scenario of the OPA's integrated power supply plan (IPSP), we find that, relative to average off peak demand, all of the prescribed assets would operate under most demand conditions" (Ex. M, Tab 2, p.29).

Regulatory Risk

41. Ms. McShane concludes, "On balance, I view the regulatory risk for OPG as higher than that of the typical regulated utility in Canada and in Ontario" (Ex. C2, Tab 1, Sch. 1, p.63). In the same discussion she states, "For purposes of the business risk assessment, I proceed on the assumption that OPG will be treated no differently from any other utility subject to the Board's (OEB's) jurisdiction. OPG will be provided a reasonable opportunity to recover its prudently incurred costs and earn a return that reasonably reflects the risks to which it is exposed" (Ex. C2, Tab 1, Sch.1, p. 60). These two statements would appear to be completely at odds.

42. If it is expected that OPG will be able to recover prudently incurred costs, then where is the regulatory risk? Pollution Probe pointed out the inconsistency in its evidence and submitted an IR (Pollution Probe IR #49) to get OPG's clarification. OPG's response to the IR indicated essentially that the OEB would attempt to apply the same regulatory standards to OPG as it does to other regulated entities but since it is new at regulating generation it may have difficulty in doing so. Pollution Probe's witnesses rejected this explanation, "This argument lacks any logical basis" (Ex. M, Tab 12, p. 35).

43. Board panel members also sought clarification of Ms. McShane's conclusion that OPG faced higher regulatory risk than other utilities. Mr. Kaiser asked for a clarification of the unique features of OPG costs that would present problems or challenges for the Board in regulating OPG (Transcript Vol. 10 p.108). Ms. McShane's responses were unable to provide any clear or legitimate examples of why the OEB would be unable to regulate OPG in a manner consistent with the regulation of the other 90 electric and natural gas utilities under its jurisdiction.

44. AMPCO concludes that there is no basis for Ms. McShane's assertion that the regulatory risk faced by OPG is higher than for other utilities. AMPCO's conclusion is similar to that reached by other intervenors. Dr. Booth concludes that the regulatory process will be applied to OPG as it is to other utilities. This process in his view passes risks on to consumers, protecting the regulated utility; "The history of regulation in Canada is that when risks arise to potentially cause losses to utilities they are invariably transferred to rate payers as part of the dynamics of regulation" (Ex. M, Tab 3, p.41). Dr. Kryzanowski and Dr. Roberts state that Ms. McShane's position on regulatory risk is not supported by logic and expect it will be regulated in a manner similar to other utilities (Ex. M, Tab 12, p.35).

Political Risk

45. In her evidence Ms. McShane states, "With the electricity market still in flux, the regulated operations of OPG remain subject to political risk. Since the initial restructuring that began in 1998 with the *Energy Competition Act*, there have been several interventions by the government into the operation of the electricity market" and goes on to assert "…the risk of future political intervention in the market is higher than in other Canadian jurisdictions" (Ex. C2, Tab 1, Sch. 1, p. 64).

46. Ms. McShane makes no reference to the fact that the government that is intervening in the market place is OPG's sole shareholder. Indeed we are instructed by her to ignore this fact. "The proper application of the stand-alone principle to the determination of the deemed capital structure (and return on equity) for OPG's regulated operations ignores the happenstance of ownership; the capital structure should reflect the business risks of OPG's regulated operations irrespective of the identity of ownership. This makes sure that the shareholder is properly compensated for the total risk borne" (Ex. C2, Tab 1, Sch. 1, p. 54). Ms. Sidford, OPG's Vice President and Treasurer, contradicted Ms. McShane's position on the "happenstance" nature of OPG's ownership by indicating that government ownership translates directly to a higher credit rating for OPG (Transcript Vol. 1, p. 26, lines 14-23).

47. It is precisely because ownership makes a difference to the risks borne that it must be taken into consideration by the Board. The need to consider the circumstances of the specific entity under consideration should have been evident to Ms. McShane who states in relation to capital structure, "The capital structure should be consistent with the business risks of the specific entity for which the capital structure is being set" (Ex. C2, Tab 1, Sch. 1, p.54). This is recognized by both DBRS and S&P who cite the ownership of OPG as an important factor in the determination of OPG's debt rating (Ex. A2, Tab 3, Sch. 1, DBRS pp.1-3 and Standard & Poor's p.2).

48. The political instability since 1998 that Ms. McShane refers to in the above reference was reviewed by AMPCO in its evidence (Ex. M-T2 pp.2-7). This review shows that in all cases the ownership of OPG allowed it to ensure that the consequences of these political changes were passed on to consumers. Dr. Booth agreed with this conclusion. In reference to the passing on of stranded debt to consumers he states, "Again this is an example of a utility going back after the fact to layoff risks to ratepayers." (Ex. M, Tab 1, p. 54, lines 7-8).

49. During cross examination by Mr. Rodger on behalf of AMPCO, Ms. McShane was asked about the unique ability of OPG's shareholder to pass on the cost of political intervention to customers. Mr. Kaiser stated, "It (OPG's shareholder) can, as Mr. Rodger has pointed out, shift any losses to the ratepayers, as it has done in the past." Ms. McShane's response was "…I suppose you are right, that it could" (Transcript Vol. 10, p.73, lines 2-7).

50. Even if one viewed political uncertainty as creating risk for OPG it is not clear why OPG's shareholder should be compensated for this since it is after all the sole source of this uncertainty. Ms. Chaplin put this question to Ms. McShane. Ms. McShane's response did not explain why OPG's shareholder should warrant such compensation (Transcript Vol. 10, p.74, lines 11-24).

51. Contrary to Ms. McShane's conclusion, the actual experience in Ontario has been that government ownership and political influence have resulted in direct benefits to OPG: a defacto indemnity or all-risks insurance policy. For example, O. Reg. 53/05 is an illustration of political intervention by OPG's sole shareholder. When OPG failed to meet its productivity targets and approached a solvency crisis the Province remedied this situation by boosting OPG's revenues through O. Reg. 53/05.

52. Throughout this proceeding OPG has placed considerable emphasis upon its interpretation of O. Reg. 53/05. Specifically, OPG's states that with respect to a number of cost categories, the Board has no jurisdiction to determine prudence of OPG's expenditures, i.e., the OEB's role is akin to an accounting function to determine if OPG has transcribed the figures correctly - with no authority to judge whether certain costs are reasonable and prudently incurred.

53. Another view articulated in more detail by Board Staff and CME is that OPG has overstated the lack of authority vested in the Board as a result of O. Reg. 53/05 and the Board has broader discretion to determine the reasonableness of costs claimed and the prudence or lack or prudence OPG has shown in connection with such costs.

54. In AMPCO's view, regardless of where the OEB lands on the legal interpretation of O. Reg. 53/05, the practical implications for the Board's decision on the cost of capital is the same. That is, either approach illustrates that OPG does not face the menu of risks that it claims in its evidence. If OPG is correct about its interpretation of O. Reg. 53/05, it constitutes another clear and powerful example of OPG's sole shareholder, the Government of Ontario, using its power to establish laws that expressly remove risk from OPG. In short, O. Reg. 53/05 trumps OEB jurisdiction to consider and evaluate costs : the Board has no choice but to approve them.

55. On the other hand, if the OEB's discretion is broader and if the Board were to render a decision on a particular cost that OPG's shareholder finds unsatisfactory, the Province can issue a Directive to the OEB, examples of which have already occurred, that guarantees OPG cost recovery. Under either scenario OPG's risk is eliminated. Ms. McShane agreed with AMPCO that the Province of Ontario could act to protect its investment in OPG (Transcript Vol. 10, page 62, lines 7-10).

Production, Operating and Cost Recovery Risk

56. There appears to be a consensus that the principal source of risk facing OPG is that related to the operation of nuclear generation assets. It is important to break this risk down into that which relates to the environmental aspects of nuclear generation and that which is technical and operational in nature.

57. With respect to the former, OPG and the Province have entered into the Ontario Nuclear Funds Agreement (ONFA), which deals with decommissioning and used fuel risks. Under the ONFA OPG makes contributions to Decommissioning and Used Fuel Funds (DF and UFF) according to an agreed upon formula and the Province provides a guarantee that the funds will be available to deal with the actual costs in these areas. According to Standard & Poor's (Ex. A2, Tab 3, Sch. 1, S&P, p.9) the ONFA puts a cap on OPG's potential liabilities in this area and in doing so significantly reduces its risk. In evidence prepared for OEB Staff, London Economics International (LEI) stated, "Essentially, OPG is receiving, at little cost, insurance from Ontario taxpayers, which limits OPG liabilities related to treatment of spent fuel" (Ex. M, Tab 2, p.18). OPG does bear the risk related to the adequacy of returns on the DF but DBRS notes that this fund is currently over funded (Ex. A2, Tab 3, Sch. 1, DBRS, p.4). Overall LEI concludes, "The ONFA significantly reduces any uncertainty premium hypothetical investors would demand related to nuclear fuel treatment and site remediation" (Ex M, Tab 2, p.18).

58. Moreover the risks related to erroneous cost estimates are mitigated by deferral and variance accounts provided in Regulation 53/05 (Ex. A1, Tab 6, Sch.1, Appendix B). Sections 5.1(1) and 5.2(1) allow OPG to pass on to consumers through its revenue requirements changes in its nuclear decommissioning liability resulting from changes in the decommissioning reference plan.

59. With respect to the technical operational aspects of nuclear generation OPG's risk exposure has been reduced by the provision under Regulation 53/05 of deferral and variance accounts:

    (a) Section 5(1) (b) provides for a variance account to cover unexpected costs related to nuclear regulatory costs and technological changes.

    (b) Section 5(4) provides for a deferral account for the non-capital costs related to the return to service of Pickering A.

    (c) Section 5.3(1) and 5.4(1) ensure that OPG costs related to planning for and developing new nuclear facilities are passed on to consumers.

60. In addition OPG is applying for an additional variance accounts to cover all nuclear fuel costs as well as variance accounts for pension costs and taxes.

61. Dr. Booth states that the deferral and variance accounts effectively transfer all of OPG's operating risks to consumers. He concludes, "Overall, it would seem that the risks of OPG's nuclear assets have been largely removed, while the risk of OPG's hydro assets is pretty low to start out with" (Ex. M, Tab 1, p.57 lines 7-8). He further states, "the risk of OPG's operations is not borne by the shareholder but by the ratepayer". (Ex. M, Tab 1, p.55 lines 21-22).

62. The evidence provided by LEI also emphasizes the reduction in risk provided by the deferral and variance accounts. It states, "It is clear that the variance and deferral accounts serve to reduce business risk to OPG. OPG's exposure is reduced with regards to fluctuations in water availability, uranium prices, and increased costs associated with refurbishment planning, planning for new nuclear capacity, and addressing the Pickering A return to service.

63. At the same time, however, the arrangements do not completely shield OPG from risk – OPG retains a degree of operating risk, despite being protected from the impact of several other variables" (Ex. M, Tab 2, p.24). It goes on to say, "While OPG still bears some operational risk, it can call upon its decades of operating history to predict the extent of potential planned and unplanned outages at the units" (Ex. M, Tab 2, p.25). These remaining risks are controllable risks that are in the normal course of business. Dr. Kyrzanowski and Dr. Roberts point out, "to the extent that such

production shortfalls are due to factors under the control of management, they do not constitute a risk for which a company should be compensated" (Ex. M, Tab 12, p.36). Further, the prospect of rates set afresh by the Board in 2009 mitigates longer-term risk.

64. OPG has based its request for a major change in its capital structure on the business risks it faces. A review of these risks shows that they have been very significantly exaggerated in the evidence prepared for OPG by Ms. McShane. OPG has requested the equity ratio be increased from the current deemed level of 45% to 57.5% (Ex. C1, Tab 1, Sch. 1, p. 1, lines 30-31). Dr. Booth recommends that the equity ratio be reduced to 40%. Dr. Kyrzanowski and Dr. Roberts recommend an equity ratio of 47% (Ex. M, Tab 12, p.8). Dr. Schwartz in his evidence for Energy Probe recommends the equity ratio remain at its current deemed level of 45% (Ex. M, Tab 6, p.3).

65. **AMPCO concludes that the evidence provided by OPG for its recommended increase in the equity ratio is seriously flawed. The deemed equity and debt ratios should remain at the current levels of 45% and 55% respectively.**

Issue 2.4. Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

<u>The Cost of Debt</u>

66. The total cost of debt for the test years consists of the cost of long-term debt and the cost of short-term debt. Looking at the cost of long-term debt first, this cost is based on the level and composition of long-term debt and the interest rates applicable to each component of long-term debt. The composition of long-term debt consists of allocated existing long-term debt, allocated project-related debt, and a provision for long-term debt. The last of these is the difference between the deemed long-term debt level as proposed by Ms. McShane and the sum of the other two long-term debt components (Ex. C1, Tab 2, Sch. 2, p.1). The existing corporate long-term debt is allocated based on the share of the net book value of prescribed assets to total the net book value of total assets. The project-related assets are assigned to specific prescribed assets (Ex. C1, Tab 2, Sch. 2, p.2).

67. These two (existing and projected-related debt) are judged by AMPCO to be determined in a reasonable way. The provision for long-term debt is too low, since the proposed deemed debt level as recommended by Ms. McShane is too low as described above. Table 3 in Ex. C1, Tab 2, Sch. 1 illustrates OPG's cost of debt for the year 2008. In that exhibit total debt is assumed to be $3,145.4 M and the other long-term debt provision is $758.9 M. Assuming that the deemed debt ratio remains at 55% the total debt would be $4,070.4 M and the other long-term debt provision would be $1,683.9 M.

68. The interest rates charged on existing debt, including existing project-related debt, is the rate actually paid on that debt. This is acceptable. The rate on new debt which includes planned new projects, the refinancing of new and maturing corporate issues and the other long-term debt provision is based on a forecast of 10-year Canada bond rates plus a credit risk spread for OPG. The March 2008 Consensus Forecast for June 2008 and March 2009, which is used in the determination of ROE estimates, is 3.6% and 4.1% respectively (Response to CCC/VEC IR #11 L-3-011).

69. OPG is proposing to use a credit risk spread of 130 basis points despite the fact that it paid 74.25 basis points spread on Niagara Tunnel project financing in June 2007 (Ex. C1, Tab 2, Sch. 2, p.5, lines 25-26). The rationale for a higher spread based on heightened concerns about credit risk is not convincing based on the Province's ownership of OPG and the fact that it borrows funds through the OEFC. London Economics International points out, "the ability to rely on OEFC for debt financing means that OPG is partially shielded from market disruptions like the recent credit crunch which has delayed financing for large capital intensive projects both in and outside of the electric power industry" (Ex. M, Tab 2, p.19).

70. Assuming an average 10-year Canada's rate for 2008 and 2009 of 4.25% (just slightly lower than Ms. McShane's 4.5% in her response to CCC/VEC IR #11) and the 2007 credit spread the average interest rate on new long-term debt would be 4.25% + .75% = 5.0%. OPG uses rates of 5.65% in 2008 and 6.47% in 2009 that AMPCO judges to be too high (Ex C1, Tab 2, Sch. 1, Tables 2 and 3). **AMPCO recommends a rate of no higher than 5.5% for the test years.**

71. Furthermore, in the rate making process for Ontario distributors, the Board has made it clear that where renewed long term debt is held by an affiliate, for regulatory purposes the utility shall only be permitted to recoup the

lower of the negotiated rate or market rates. This principle should also apply to OPG *vis a vis* its debt obligations that are associated with the Province of Ontario and its agencies such as OEFC.

72. With respect to short-term interest rates, Ex. C1, Tab 1, Sch. 3, Table 1 (columns d and e and rows 1 and 4) show that OPG's implicit interest rate on its commercial paper is 8.4%. Given that the prime corporate paper rate is currently 3.17% OPG's short-term debt costs would appear to be excessive. Similarly the second source of short-term financing for OPG is A/R securitization with an average interest cost of 5.54% appears to be well above current short-term interest rates. OPG should explore alternative sources of short-term funds.

73. **AMPCO recommends that a target cost of short-term funds in the region of 4% is more consistent with current conditions in financial markets.**

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

The Cost of Equity

74. Ms. McShane recommends that three methods be used in estimating the return on equity (ROE): the capital asset pricing model (CAPM which she refers to as the risk-adjusted equity market risk premium test); the cash flow model (DCF) and the comparable earnings model (Ex. C2, Tab. 1, Sch. 1, p.22). Dr. Booth and Drs. Kyrzanowski and Roberts accept the first two of these as being theoretically acceptable, with a preference for the capital asset pricing model but reject the third approach, the comparable earnings test as being unacceptable both on theoretical and practical grounds (Ex. M, Tab 3, pp. 74, 79, 83-86; Ex M, Tab 12, pp. 54-55, 60).

75. Looking at the CAPM approach, first there are three steps in arriving at an estimate of ROE. The first involves estimating a risk-free rate. Here all three of the above agree that the Consensus Forecast of the rate on 10-year Canada bonds should be used. Next a market risk premium must be estimated. Finally the market risk premium must be adjusted for the specific case of OPG with the use of a beta adjustment factor.

76. The three main studies (McShane, Booth and Kyrzanowski and Roberts) use historical information on the S&P/TSE stock market index for equities and the return on long-term Canada bonds for a risk free rate in calculating a market risk premium. Comparable measures are used for the U.S. Booth uses 1924-2007 as a data period, Kyrzanowski and Roberts uses 1926-2007 and McShane 1946-2006). Foster and Kyrzanowski and Roberts use both arithmetic and geometric means to average returns and Booth adds to this an OLS estimate. Table 2 summarizes the results.

Table 2
Market Risk Premium

	Stock Return	Bond Return	Risk Premium
McShane			
1947 – 2006			
Canada			
Arithmetic mean	12.4	7.0	5.5
Geometric mean	11.2	6.5	4.7
US			
Arithmetic mean	13.2	6.2	6.9
Geometric mean	11.9	5.7	6.1
Booth			
1924 - 2007			
Canada			
Arithmetic mean	11.8	6.5	5.3
Geometric mean	10.3	6.1	4.2
OLS	10.4	5.6	4.8
US			
Arithmetic mean	12.3	5.8	6.5
Geometric mean	10.4	5.5	4.9
OLS	11.2	4.9	6.3
1957 – 2007			
Canada			
Arithmetic mean	11.1	8.0	3.1
Geometric mean	9.9	7.5	2.4
OLS	10.4	8.6	1.8
US			
Arithmetic mean	11.8	7.3	4.5
Geometric mean	10.5	6.8	3.3
OLS	11.3	7.7	3.6
Kryzanowski and Roberts			
1926-2007			
Arithmetic mean	11.6	6.5	5.1
Geometric mean	10.1	6.1	4.0
1957-2007			
Arithmetic mean	11.1	8.0	3.1
Geometric mean	9.9	7.5	2.4

Source:
McShane: C2-1-1 Schedule 3, p. 217
Booth: Exhibit M-Tab3, Appendix E. Schedules 1 and 6
Kyrzanowski and Roberts: Exhibit M – Tab 12, Schedule 4.3, p. 211

77. The above table shows that if we focus on the results using Canadian data and a long time period all the studies indicate that the market risk premium should be in the range of 4.5-5.5%. If we use a shorter time period the premium would be lower than this, in the range of 2-3%. Yet the McShane study derives a different conclusion than the other two. Booth (Ex. M, Tab 3, p. 71) and Kyrzanowski and Roberts (Ex. M, Tab 12, p.77) recommend a 5% market risk premium while McShane recommends 6.5% (Ex. C2, Tab 1, Sch.1, p.31).

78. With respect to the beta adjustment factor, all three studies use a combination of data related to individual utilities and utility index information to estimate beta. Moreover, different time periods are used and rather arbitrary adjustments are made to take out what are considered to be unusual events. For example, McShane uses a time period that eliminates data for the period of "technology bubble". Similarly, both McShane and Booth agree that the data should be cleaned of the impact of Nortel. Conventionally, a five-year period is used to measure beta so the studies calculate beta for various five-year periods.

79. Kyrzanowski and Roberts use rolling five-year periods from 1990. They find that beta varies significantly depending upon the five year period used. They find that for the first four rolling periods the mean beta was 0.54, for the middle five periods it was 0.27 and for the most recent five periods it was 0.18. This suggests a clear trend towards a decline in beta (Ex. M, Tab 12, p.86). McShane's evidence on raw betas shows a similar trend. Ex. C2, Tab 1, Sch. 1, Schedule 8 shows betas for selected Canadian utilities falling from the 0.50 in the early 1990s to about zero in the early 2000s before increasing to 0.35 in 2006. Dr. Booth goes back to the mid-1980s and tracks the same trends in beta estimates (Ex. M, Tab 3, p. 66). From this analysis Booth and Kyrzanowski and Roberts recommend that a beta of 0.50 be used (Ex. M, Tab 3, p.69 and Ex. M, Tab 12, p.89).

80. Ms. McShane on the other hand states that estimated betas are too low because they fail to take into consideration the interest sensitivity of regulated utilities. The method she chooses to correct for this problem introduces a bias towards the value one. Since the beta of utilities is expected to be less than one this inflates the estimated beta. Both Booth and Kyrzanowski and Roberts are critical of the method chosen by McShane to deal with interest sensitivity (Ex. M, Tab 3, p.68 and Ex. M, Tab 12,

p.89-91). They prefer to use two stage estimates of beta to capture interest sensitivity and this procedure does not alter their beta estimate significantly. With the use of her adjustment mechanism McShane arrives at a final beta estimate of 0.65 to 0.70 compared to 0.50 for the other two studies.

81. Having supposedly used essentially the same input data, Ms. McShane arrives at an ROE recommendation based on the CAPM of 9.25-10.25% compared to 7.25% for Booth (Ex. M, Tab 3, p.75) and 6.35% and 6.75% for 2008 and 2009 respectively for Kyrzanowski and Roberts (Ex. M, Tab 12, p.94).

82. The second approach used to estimate ROE is the DCF approach that is based on the Gordon dividend model. This requires that share prices be available for the entities chosen in the data used. That requirement limits the range of data that can be considered. Ms. McShane uses U.S. utility information (utilities which face a different risk and regulatory environment than OPG) and analyst's forecasts of earnings.

83. The data on which Ms. McShane bases her DCF conclusions are deemed to be inappropriate by Booth (Ex. M, Tab 3, p.83) and Kyrzanowski and Roberts (Ex. M, Tab 12, p.129). In any case the result is a set of ROE recommendations that is almost identical to that arrived at using CAPM.

84. Only Ms. McShane uses the comparable earnings method of estimating ROE. From this she derives an ROE estimate that is significantly above the other methods i.e. 12.5%. She then takes a weighted average of the results of these three methods to arrive at her overall recommendation for ROE.

85. In addition to the ROE just estimated, each of these studies recommends an additional allowance for "financing flexibility" (Ex. C2, Tab 1, Sch. 1, p.44). The purpose of this allowance is to allow the utility to "to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity" (Ex. C2, Tab 1, Sch. 1, p.45). Both McShane and Booth (Ex. M, Tab 3, p.75) recommend an allowance of 50 basis points while Kyrzanowski and Roberts recommend 75 basis points in 2008 and 50 in 2009.

86. Dr. Schwartz states and AMPCO agrees "The various reasons given in the OPG Expert Opinion for adding 50 basis points to the ROE for "financial flexibility" are unconvincing" (Ex. M, Tab 6, p.3). As OPG points out all of

its borrowing will be from the OEFC (Ex. C1, Tab. 1, Sch. 1, p.3, lines 19-20). Moreover, there is no expectation that OPG will raise equity capital during the test years. AMPCO agrees with Dr. Schwartz that the traditional allowance for financial flexibility for privately owned utilities is inappropriate in this case.

87. It is AMPCO's view that the application of the CAPM and DCF models in the case of OPG's Heritage Assets is inappropriate. The data used by Ms. McShane, Dr. Booth and Drs Kyrzanowski and Roberts are all based on utilities whose history and circumstances do not reflect those of OPG and its Heritage Assets.

88. Moreover, in each case the data are selected and massaged according to the judgment, theoretical preferences and interests of the analysts. As the evidence prepared by Dr. Murphy (Ex. M, Tab 2) on behalf of AMPCO pointed out, the Heritage Assets transferred to OPG are unique. They were transferred without the associated stranded debt that was assigned to consumers. Similarly, the equity held by the Province in OPG is unlike that held by a private shareholder. Under the debt-equity swap at the time of the formation of OPG, the Province assumed a part of the debt obligation of OPG to the OEFC.

89. The Province has stated explicitly that it will not allow electricity costs to be passed on to taxpayers i.e. that the shareholder will bear no risk (Ex. M, Tab 2, p.6, lines 16-26). It has also stated explicitly what return its expects from its investment in OPG. Its expectation is that the return will cover the debt service cost it assumed when it exchanged equity for debt (Ex. M, Tab 2, p.6, lines 16-26) and provide strong incentives for OPG to control costs.

90. AMPCO submits that OPG is a financial hybrid with a government-assigned ROE reflective of its character as a government-owned, but commercially structured body. In AMPCO's view, the initial conditions established in O. Reg. 53/05 were well considered at the time of issuance and remain appropriate. They recognized the fact that consumers had assumed the burden of the stranded debt that in normal markets would have been the obligation of the shareholder. The setting of the ROE was a fair solution that recognized the role consumers had played in assuming stranded debt obligations while at the same time providing for OPG's financial needs. In these circumstances to burden consumers with higher prices for Heritage Asset electricity would be unconscionable.

91. In its argument-in-chief OPG states "the continued and reliable operation of the regulated facilities requires an appropriate level of maintenance and investment. Without the funds necessary to conduct required maintenance and to make required investments in these facilities, OPG will not be able to maintain the value or reliability of these assets"(OPG Argument in Chief, page 4, lines 18-21). This claim is not applicable to OPG's application. The testimony of OPG's witness, Mr. Long, directly contradicts this submission by clearly indicating that the existing 5 percent ROE had no adverse impact whatsoever on OPG investments or its capital spending.

92. During cross-examination by Mr. Rodger, OPG indicated that the current ROE target had not prevented OPG from undertaking any planned capital expenditure projects:

> Mr. Rodger: "In your planning over the past few years, did you ever look at your ROE and say, Well, it is only 5 percent; therefore, we're not going to invest as much in our regulated assets, because of this ROE?"
>
> Mr. Long: "No." (Transcript Vol. 1, page 29, lines 4-9)

93. This discussion continued:

> Mr. Rodger: "Would you agree with me, Mr. Long, when I say that since 2004/2005, when you have been doing your business planning, that you felt in no way constrained in the amount of capital spending that you may want to do with respect to regulated prescribed assets as a result of this 5 percent ROE set by the province; is that fair?
>
> Mr. Long: "As a result of the 5 percent? No." (Transcript Vol. 1, page 30 lines 10-16)

94. AMPCO submits that the Board should be guided by a core objective to promote a viable electricity sector. Since the evidence is clear that 5 percent ROE has in no way impaired OPG's investment plans, the Board should not be concerned about establishing a ROE similar to the status quo given that this outcome has not impaired OPG's ability to invest in capital or maintenance.

95. Indeed the credit rating agencies have indicated that OPG's financial performance has improved under the current arrangements, "The financial profile of OPG has improved since 2004, following the announcement of the interim regulated rate structure that came into effect on April 1, 2005" (Ex.

A, Tab 3, Sch. 1, DBRS, p. 2) and "Although OPG's financial profile has been weak in the past several years, it has shown improvement in 2005 and is expected to continue to strengthen in 2006" (Ex. A, Tab 3, Sch. 1, Standard & Poor's p. 3).

96. **AMPCO recommends that the ROE be set to the true cost to the shareholder of having assumed this segment of OPG's debt obligation to the OEFC, namely the interest rate on this debt, which is 5.85%. Since the debt relates to all assets this should apply to all Heritage Assets.** As pointed out in AMPCO's IR #12 a higher ROE that increases OPG's net income simply flows to OEFC and is dedicated to reducing the stranded debt earlier than currently planned. Neither the OEFC nor the Provincial government has indicated the need for an accelerated reduction in stranded debt.

97. AMPCO also urges the Board to separate the cost of capital issues from OPG's request for a fixed payment amount for nuclear generation as the Province did in 2005 when it set the ROE at 5 percent with nuclear paid only for production. These two matters are distinct and should be decided independently from one another. AMPCO addresses this matter further in the section on Payment Amounts.

98. Table 3 below summarizes OPG's proposed treatment of cost of capital and AMPCO's recommendations. The following table provides calculations incorporating OPG's rate base as filed. AMPCO supports CME's proposed adjustments to rate base, but excluded those adjustments from the following Table for purposes of clarity. **AMPCO's recommendations result in a revenue requirement reduction for OPG in the amount of approximately $255 M (which do not take into account the further reductions articulated in the CME's submissions).**

Table 3
Cost of Capital
2008

OPG Proposal

	Principal ($M)	Component (%)	Cost Rate (%)	Cost ($M)
Short-term debt	189.3	2.6	5.83	11.0
Existing long-term debt	2,197.2	29.7	5.79	127.2
Provision for LT Debt	758.9	10.3	5.65	42.9
Common equity	4,255.5	57.5	10.50	446.8
Rate Base	7,400.8	100.0	8.48	627.9

Source: Ex C1-T2-S1 Table 3

AMPCO Recommendation

Short-term debt	245.0	3.3	4.00	9.8
Existing long-term debt	2,197.2	29.7	5.79	127.2
Provision for LT Debt	1,628.2	22.0	5.50	89.5
Common equity	3,330.4	45.0	5.85	194.8
Rate Base	7,400.8	100.0	5.69	421.3

2009

OPG Proposal	Principal ($M)	Component (%)	Cost Rate ($M)	Cost
Short-term debt	189.3	2.6	5.98	11.3
Existing long-term debt	2,362.7	32.1	5.79	136.8
Provision for LT Debt	573.2	7.8	6.47	37.1
Common equity	4,228.4	57.5	10.50	444.0
Rate Base	7,353.7	100.0	8.56	629.1

Source: Ex C1-T2-S1 Table 2

AMPCO Recommendation

Short-term debt	245.0	3.3	4.00	9.8
Existing long-term debt	2,362.7	32.1	5.79	136.8
Provision for LT Debt	1,436.8	19.5	5.50	79.0
Common equity	3,309.2	45.0	5.85	193.6
Rate Base	7,353.7	100.0	5.70	419.2

99. Table 4 below breaks down AMPCO's cost of capital estimates into components applicable to each of regulated hydroelectric and nuclear assets using OPG's allocators. This allows a determination of the impact of AMPCO's cost of capital estimates on revenue requirements, revenue deficiencies and payment amounts for each type of Heritage Asset. In summary, the results show that with AMPCO's cost of capital estimates the total revenue deficiency is $255 M lower than OPG's estimate for 2008 and 2009 (again, for simplicity, this figure does not reflect any adjustments for rate base as contained in CME’s submissions). Morever, the payment amount for regulated hydroelectric assets is reduced from OPG's requested $37.9/MWh to $33.5/MWh.

100. For nuclear assets the payment amount assuming payment is made on energy produced only would be $54.0/MWh. This compares with an implicit required energy-only payment amount of $55.4/MWh based on OPG's revenue requirement estimates. In fact, OPG requests a three-part payment scheme consisting of a fixed amount, an energy based amount, and a rate rider. As described elsewhere in this submission, in AMPCO's view this scheme eliminates much needed incentives necessary to improve OPG's cost performance.

Table 4

Revenue Requirement and Payment Amount Determination

($ Millions except where indicated otherwise)

	2008			**2009**		
	Reg. Hydro	**Nuclear**	**Total**	**Reg. Hydro**	**Nuclear**	**Total**
Rate Base (ExK-1-1 Table 1 & 2)	3,880.2	3,509.1	7,389.3	3,869.9	3,483.8	7,353.7
Capitalization (AMPCO recommendation)						
Short-term debt	129.0	116.0	245.0	129.0	116.0	245.0
Long-term debt	2,008.3	1,817.1	3,825.4	1,999.4	1,800.0	3,799.4
Common equity	1,748.5	1,582.0	3,330.5	1,741.5	1,567.7	3,309.2
Total capital	3,885.8	3,515.1	7,400.9	3,869.9	3,483.7	7,353.6
Cost of capital-rates (AMPCO recommendation)						
Short-term debt	4.00%	4.00%		4.00%	4.00%	
Long-term debt	5.67%	5.67%		5.67%	5.67%	
Common equity	5.85%	5.85%		5.85%	5.85%	
Cost of capital (AMPCO recommendation)						
Short-term debt	5.2	4.6	9.8	5.2	4.6	9.8
Long-term debt	113.8	102.9	216.7	113.3	102.0	215.2
Common equity	102.3	92.5	194.8	101.9	91.7	193.6
Total cost of capital	221.2	200.1	421.3	220.3	198.3	418.6
Expenses (ExK-1-1 Table 1 & 2)	326.8	2,082.0	2,408.8	435.4	2,783.8	3,219.2
Other revenues (ExK-1-1 Table 1 & 2)	-24.3	-101.2	-125.5	-33.1	-133.4	-166.5
Revenue requirement	523.7	2,180.9	2,704.6	622.6	2,848.7	3,471.3
Forecast production (TWh)	12.9	38.3	51.2	18.5	49.9	68.4
Prescribed payment amount ($/MWh)	33.0	49.5		33.0	49.5	
Indicated production revenue	425.7	1,895.9	2,321.6	610.5	2,470.1	3,080.6
Revenue requirement	523.7	2,180.9	2,704.6	622.6	2,848.7	3,471.3
Revenue requirement deficiency	98.0	285.1	383.1	12.1	378.7	390.8
OPG revenue deficiency estimate(1)	122.4	306.4	428.8	122.3	478.2	600.5
OPG revenue deficiency excess over AMPCO	24.4	21.3	45.7	110.2	99.5	209.7
Revenue requirement-Apr1-08 to Dec31-09	1,146.3	5,029.6	6,176.0			
Mitigation & Amortized amounts (2)	-90.1	-266.0	-356.1			
Revenue requirement recovery	1,056.2	4,763.6	5,819.9			
Forecast production (TWh)	31.5	88.2	119.7			
Payment amount ($/MWh)	**33.5**	**54.0**				
OPG request(2) ($/MWh)	37.9	41.5	plus fixed payment of $58.2 M per month plus payment rider of $1.25/MWh			
Energy-only OPG payment amount for nuclear		55.4				

(1) OPG K1-1-1 Table 3.

(2) OPG K1-2-1 Table 1 and K1-3-1 Table 1.

Capital Projects

101. AMPCO has no submissions on this topic.

Production Forecasts

102. No evidence was filed at the proceeding as an alternative to OPG's Production Forecasts. AMPCO submits that OPG's Production Forecasts should be accepted by the Board.

Operating Costs

Corporate Support and Central Costs

103. As a general matter, AMPCO is concerned by the evidence that indicates that OPG's corporate support and central O&M costs associated with its regulated assets are increasing at a significantly higher rate than the costs associated with OPG's unregulated assets. The record shows that regulated nuclear asset costs have increased from $356.2 M in 2005 to $446.8 M in 2007, reflecting an increase of approximately 25%. For regulated hydroelectric assets the costs increase from $27.6 M in 2005 to $38 M in 2007 reflecting an increase of approximately 38%. In contrast, OPG's unregulated costs over the same time period total only 6.5% (Transcript Vol. 8, pages 35-36). AMPCO is concerned about the potential for cross subsidization between the regulated and unregulated components of OPG's business.

104. There was considerable discussion during the hearing about OPG's hydroelectric generation revenues coming from both regulated and unregulated activities. While the Rudden report on cost allocation (Ex. F4) describes the process through which OPG apportions costs of regulated and unregulated activities, AMPCO believes that a more stringent set of structures and methodologies need to be put in place to ensure that the regulated part of OPG's business does not cross-subsidize OPG's unregulated ventures, particularly in light of the significant imbalance in the level of cost increases experienced by OPG as between its regulated and unregulated assets.

105. All other electric utilities regulated by the Board must adhere to the Affiliate Relationships Code in commercial transactions between regulated and unregulated affiliates. These Codes are mandatory licence conditions for

distributors and transmitters. OPG is the only electric utility regulated by the OEB that is not subject to an ARC even though regulated and competitive businesses are commingled within one single company.

106. AMPCO was surprised that a central witness in OPG's hydroelectric business were not aware that all other utilities regulated by the OEB were subject to an Affiliate Relationships Code (Transcript Vol. 3, May 26, page 19, lines 4 to 15). AMPCO submits that given OPG's extremely large revenue requirement (over $6.4B) and the vast scale of its regulated generation operations, mandatory adherences to ARC principles are justified. Any incremental cost to OPG, which will be borne by ratepayers, needs to be understood in the context of the overall revenue requirement.

107. In the discussion below on Deferral and Variance Accounts AMPCO makes a recommendation on IESO Non-Energy Charges reflected in the corporate costs.

108. **AMPCO recommends that the Board establish for OPG mandatory requirements based upon principles that reflect the policies underlying the recently amended Affiliate Relationship Code for Electricity Transmitters and Distributors. Specifically OPG should be required to satisfy the same principles with respect to Transfer Pricing, restrictions on sharing of Confidential Information, and similar reporting protocols to the Chief Compliance Officer so that transparency can be achieved to ensure that ratepayers are not subsidizing OPG's unregulated business.**

Operating Costs: Nuclear

109. The evidence shows OPG to be highly resistant to nuclear benchmarking clinging to its self-identified claims of uniqueness notwithstanding shareholder direction to benchmark its performance.

110. The Memorandum of Agreement between the Ontario government and OPG includes the following requirement:

> "OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly owned nuclear electricity generators in North America. OPG's top operational priority will be to

> improve the operation of its existing nuclear fleet." (Exhibit A1, Tab 4, Schedule 1, Appendix B)

111. The only sense in which OPG might fairly claim to have complied with this explicit instruction is that it has made some efforts to improve its nuclear operation and has undertaken some benchmarking. The results of this benchmarking, which shows that OPG's overall nuclear results compare unfavourably with its peers and are clearly slipping, appears to have made little effect on its business operations.

112. AMPCO accepts that CANDUs outside of Canada may face substantially different safety and labour standards, and may have lower wage rates and that therefore, these reactors may be somewhat inferior benchmarks. The remainder of Canadian CANDU fleet and the US reactor fleet may be better comparators for OPG's nuclear operations.

113. AMPCO presented this general approach to OPG's witnesses during cross-examination, only to find OPG resistant to the concept that it can be usefully compared to other Canadian nuclear operators.

114. Specifically regarding Pickering B vs. Point Lepreau, AMPCO pointed out that Point Lepreau is a little older, lacks the advantages of a multi unit station, and lacks the advantage to Pickering B of learning from Pickering A. AMPCO also pointed out that the unit size at the two stations is similar. AMPCO then asked OPG's witness to acknowledge that Point Lepreau is the best available comparison for Pickering B, only to be rebuffed by OPG.

> MR. RODGER: I don't think you have to turn it up, but in an answer to interrogatory L1-34, part of your answer was you thought it was more meaningful to benchmark costs based on a plant-by-plant comparison using plants of similar size.
>
> I guess my question to you, if you don't think Point Lepreau is a good comparator, what would you put forward as the best comparator for Pickering B?
>
> MR. PASQUET: Pickering B does not have a good comparator. Pickering B and Pickering A are similar design, but there is nothing of a Pickering B type designed plant that exists. (Transcript Volume 4, page 25)

115. However OPG itself, despite contrary protestations, effectively endorsed exactly AMPCO's approach in 2006 by retaining Navigant to perform a CANDU benchmarking study on staffing levels. Navigant 2006 study updated a previous similar study conducted for OPG in 2003, but based then on US data (Transcript Vol. 5, page 26). The 2006 Navigant study created a comparator group for OPG by assembling data from the other Canadian CANDU operations.

116. Under cross-examination by AMPCO, OPG revealed that the comparator group used as the basis for the Navigant study was specified by OPG. (Transcript Vol. 5, page 22, lines 11-17). This group included Point Lepreau. OPG agreed with AMPCO during cross-examination that multi-unit nuclear stations have a staffing efficiency advantages relative to single unit stations. (Transcript Vol. 5, page 24)

117. The 2006 Navigant study cost $95K. AMPCO submits that commissioning this type of independent assessment is valuable and AMPCO encourages OPG to continue to engage in such studies and to file benchmarking reports as a normal requirement for future Heritage Asset Rate applications.

118. The PWU suggested, and OPG agreed, that the nuclear operations at Bruce Power were an appropriate comparator for OPG.

119. Despite the background for the Navigant study, OPG's witness clung to the assertion that Pickering B should not be compared to Point Lepreau.

> MR. PASQUET: We spent a fair bit of time on Tuesday talking about the specific differences between Lepreau and Pickering B. I believe the question was asked regarding age, and we talked a lot about the design differences. We talked about the complexities, Pickering versus Lepreau. We spent a lot of time discussing that (Transcript Vol. 5, page 24).

120. AMPCO observes that over the period 2005-2007, the figures the reported in NB Power's annual reports indicate that the operating costs of the Point Lepreau unit were about two thirds those of Pickering B. OPG had no substantive explanation for this shortcoming other than to point to some differences in the respective CANDU technologies (Ex. L2/46).

121. OPG's nuclear production over the period 2005-2007 was 13 TWh (9%) below the levels it forecast which were included as part of the basis for Regulation 53/05. OPG's forecasted production for 2008 and 2009 has

declined by 15 TWH or 13% from its 2005 business plan compared with its current proposal (Exhibit L2/29) As previously noted, nuclear operating costs per unit of production rose 19%. Counsel for CME established in cross-examination that OPG's staffing levels are 12% above the benchmark that OPG specified in the study (Transcript Vol. 5, pages 37-38). Notwithstanding its current excessive staffing , the regular FTE outlook indicates an even larger expansion of OPG's regular nuclear staffing, partly driven by a conversion of irregular staff to regular staff. Regular FTEs are rising from 7,542 in 2007 to 8,109 in 2008 and 7,934 in 2009 (Exhibit F2/1/1 Table 1).

122. Despite this legacy of failure, OPG's response to concerns about its nuclear operations failing to meet production objectives, failing to compare favourably to other comparators, and experiencing rapidly declining productivity is to emphasize the scale of its efforts to improve.

> (Transcript Vol. 5, p. 32) MR. RODGER: Would you agree with me, Mr. Robinson, that, again, recalling the provincial memorandum of agreement and the directive to be, you know, to benchmark against the top quartile, that the job is not done yet? You've still got a ways to go to meet that target. Do you agree to that?
>
> MR. ROBINSON: Well, this is a continuous improvement process that we're on, yes.

123. One of the major themes of OPG's nuclear evidence was repeated assertions of what it calls "continuous improvement".

> MR. ROBINSON: From the standpoint of seeking continuous improvement, we do that on a day-to-day basis…And it is our priority, as shown in the business plan, to **improve performance** at our nuclear stations. (Transcript Vol. 4, p. 43) (emphasis added)
>
> MR. ROBINSON: I don't expect that Pickering B will run as well as Darlington, but I would expect to see **improved performance** as a result of material condition improvements, i.e. the reduction of the backlogs. (emphasis added)

> So I would expect to see **better performance** as those backlogs come down, yes. (Transcript Vol. 4, p. 131) (emphasis added)

> MR. KAISER: Now, looking at J4.9, the US median has declined a bit.
>
> Bruce is flat. I am talking over this period 2005-2007. Then we go to Darlington. It has gone up significantly, about 30 percent. Pickering B has gone up. Pickering A, of course, went up a fair chunk.
>
> Does it bother you that your plants are going up in cost, while the two comparators we have are going down or staying flat? Should we draw any conclusion from that?
>
> MR. ROBINSON: The conclusion that we draw from that is that **we are making,** over this period, **improvements** to the plants that will **improve reliability** and our expectation is that over time, those numbers will come back down. (Transcript Vol. 5, p. 77) (emphasis added)

124. Assertions that nuclear operations are in continuous improvement, that they are turning around, that the problems of the past are behind us have a long history in Ontario, including in sworn testimony before this Board, as documented in AMPCO's evidence (Ex. M, Tab 2). As only one of many examples, Ontario Hydro's final Annual Report (January 1998 - March 1999) claimed: "The Nuclear business made substantial progress towards its multi-year goal of moving performance back to the top quartile of world nuclear industry standards." Given what is now on the public record about the inherent problems facing operations at Pickering, it is difficult to understand the continuing bases for these inflated claims.

125. In short, after more than a quarter century of similar commitments being made to both the Board and ratepayers, AMPCO members have become extremely weary and impatient regarding OPG's, and its predecessor Ontario Hydro generation's, sustained failure to keep its promises. Tangible, sustained performance improvements are long overdue. After 25 years AMPCO believes the time has come for OPG to deliver tangible performance results and for the Board to insist on nothing less. Ongoing performance failures should come at the expense of OPG and its shareholder – not Ontario ratepayers. To once again borrow from Charles Dickens, OPG's commitment to nuclear improvements that are "just a revenue

deficiency away from being remedied" should be received by the Board as "the epoch of incredulity".

Pickering A and B Nuclear Units

126. The Board will know from receiving submissions from AMPCO over more than two decades that AMPCO is a fervent believer in benchmarking and incentives. During the early procedural discussions surrounding the case in early 2007, AMPCO supported Board Staff's initial thinking suggesting that incentive regulation might be suitable for regulating OPG. Ultimately a decision was taken to pursue a cost of service approach although the Board indicated in its procedural direction that moving towards incentives in the future was a desired direction.

127. Although AMPCO is an active proponent of incentives, AMPCO members recognize that OPG's hybrid status reduces the effectiveness of conventional incentives. What does profit really mean to a government department? Adopting a forecast cost of service approach to regulation with a government-owned utility where the government has declared that shareholders will not bear responsibility for costs creates a challenging environment in which to encourage efficiency. The Pickering Nuclear Generating Station constitutes a particularly difficult case.

128. During the hearing, notwithstanding OPG's understandable efforts to put the best possible gloss on the facts, the real situation of Pickering began to emerge from the wealth of information provided by OPG in its prefiled evidence, interrogatory responses, and testimony. As the true state of affairs emerged, the Board panel grappled with exactly the puzzling problem of accountability given Pickering's extremely unfavourable results.

> MS. CHAPLIN: Although because of the technology differences, they will perhaps still not be as good as other types of units, because of age and size and that.
>
> I guess what I am interested in know is, why -- and there was some questions also as to how the maintenance backlogs got to the state that they were at. What I perceive is that, as part of your materials, you're saying that in a sense extra money needs to be spent now in order to continue to bring those backlogs down to meet the industry standard.
>
> MR. ROBINSON: That's correct.

> MR. PASQUET: That's correct.
>
> MS. CHAPLIN: So why would it be that ratepayers should pay for that now? Why should that not have been -- why should ratepayers pay for that correction, if I could characterize it that way, to bring that maintenance backlog down to an industry standard and, therefore, in a sense bring those Pickering A and B costs sort of to the optimal level that can be achieved for them, given their technology?
>
> [Witness panel confers]
>
> MR. PASQUET: So by making the investment, the objective is to get increased production and lower costs for the generation that's coming into those units.
>
> So I guess by making the investment, the ratepayer then also gets the benefit, as well.
>
> MS. CHAPLIN: Okay, I will leave it there.
>
> MR. KAISER: I wonder if I could just follow up on that. One of the jobs we have - and I am sure you appreciate this - is to make sure a utility is operating efficiently and, if it's not, then the ratepayer shouldn't pay; the shareholders should pay. It is the shareholder's responsibility, through the board of directors of any of these companies, including yours, to operate efficiently.
>
> I understand the Pickering argument that it's bad technology, and you have it and it doesn't look like many other people have it, and it has costs and you are stuck with it, more or less. (Transcript Volume 4 pages 167-168)

129. Pickering has had a long and difficult capital cost and operating experience since the unplanned retubing of Pickering A starting in 1983. The overall failure of Pickering A's second major full station refurbishment, undertaken by OPG starting in 1998 ultimately resulted in the issuance by the government of O. Reg. 53/05, thereby creating the Board's mandate for its current oversight of OPG.

130. During the hearing, Energy Probe's representative noted that "this decision will, in effect, either approve or not payments to continue the operation of Pickering and Darlington" (Transcript Vol. 4, p. 72). Although the discussion that ensued in the hearing addressed only the question of

refurbishment of Pickering B, the evidence adduced in the hearing raises serious questions about the viability of operations of Pickering A.

131. Retaining the privilege of receiving regulated recovery in rates based on forecasted costs can only be justified if the underlying value of the power produced justifies the expenses paid by Ontario ratepayers.

132. The incremental cost of producing power at Pickering A during the period 2005 through 2007 is provided in Table 5. Capitalized costs are included on the grounds that there is a continuing stream of capital expenditures flowing into Pickering A and although the capitalization of expenses where benefits flow over a period of time is appropriate for rates purposes, capitalization of costs does not change the fundamental economics of the decision about whether to continue or stop operations.

Table 5 **(Corrected)**

Pickering A Incremental Cost History and Forecast

Year	Actual (forecast for '08/09) production (TWh)	Actual PUEC ($/MWh)	Op Cost ($M)	Station specific capital costs ($M)	Common Nuclear Capital ($M)	Pickering A Share of common assumed @20%	Incremental cost per MWh of PA output
2005	3.6	113.9	410.04	2.7	52.7	10.54	$117.58
2006	6.4	75.6	483.84	6.8	34.8	6.96	$77.75
2007	3.6	130.1	468.36	35.4	50.6	10.12	$142.74
Sum	13.6		1362.24	44.9	138.1	27.62	
						Average	**$105.50**
2008	7.1	76	539.6	25.4	58.6	11.72	$81.23
2009	7.3	77	562.1	5.1	140.8	28.16	$81.56
Sum	14.4		1101.7	30.5	199.4	39.88	
						Average	$81.39
Source:	E2-1-1	L2/41 actual, A1/T4/S3 Chart 2 forecast		D2/1/1	D2/1/1		

133. Over the period 2005-2007, the average incremental cost of Pickering A power was 10.06 cents/kWh -- an amount approximately double both HOEP and the payment amount to OPG under O. Reg. 53/05. Note that this analysis ignores recovery of any historic investment costs and the costs associated with the Pickering 2/3 isolation project.

134. Over the period 2005-2007, the production of electricity at Pickering A was uneconomic by a wide margin. It has been a drain on the resources of OPG, harmed consumers, and raises serious questions about the prudence of continued operations of the station.

135. Over the period 2008-2009, the forecast incremental cost of production from Pickering A averages 8.1 cents/kWh. Achieving this level of cost is a key challenge for OPG. At this level of cost, the question of prudence is less acute, but still a concern.

136. If the performance of Pickering A does not significantly and sustainably improve, there is a serious concern as to whether this station has any economic future. AMPCO believes the Board has a very important role to play in terms of establishing parameters on the long-term viability of Pickering A and the extent to which ratepayers should continue to assume new and increasing obligations associated with this uneconomic and ever-deteriorating asset.

137. OPG recently deferred the finalization of its decision on Pickering B refurbishment into the 2009. The deferral of the Pickering B refurbishment decision creates an opportunity to consider fully synergies that might be realized by closing the entire station through such measures as not proceeding or finding significant simplification with the P2/3 isolation project.

138. **AMPCO recommends that the Board should provide clear direction to OPG that it must operate Pickering A well enough to justify continued recovery of forecasted costs.** This direction would provide a powerful incentive for OPG to turn around the poor performance demonstrated over the past decade. Cursory efforts and rosy predictions about “continuous improvement” are simply not good enough.

139. **AMPCO recommends that the Board should require OPG to file in its next Heritage Assets Rate application, a long-term assessment of the viability of Pickering A.**

Nuclear Asset Retirement Costs

140. **AMPCO has had the opportunity to review the thoughtful and comprehensive submission of Mr. Thompson on the issue of Nuclear Asset Retirement Costs. AMPCO recommends that CME's submissions with respect to this issue be adopted.**

141. OPG is required to provide financial assurances for the Canadian Nuclear Safety Commission with respect to the adequacy of its provisions for nuclear waste disposal and decommissioning costs. The advent of OEB regulation of OPG's nuclear operations effectively transfers the ultimate payment responsibility to ratepayers by way of the Board's regulatory oversight. In its submissions, the CME observes several important gaps in the evidentiary record preventing an appropriately comprehensive review of the options. For this reason, and also with reference o the ongoing NEB review and the overall gravity of the decisions, CME recommends that the Board undertake further review of this complex area. AMPCO emphasizes its support for this recommendation and suggests that the scope of this review should focus on meeting financial commitments while minimizes the burden on ratepayers. In this review the OEB should include consistency of treatment for nuclear liabilities in the Board's review of the Integrated Power System Plan scheduled to commence in September, 2008.

Incentive Compensation

142. AMPCO is troubled by evidence arising in this case indicating a culture of entitlement within OPG's nuclear operation. OPG's Argument in Chief (page 59) states that "failure to achieve performance targets has a direct impact on management compensation". The evidence before the Board does not support this claim. In fact the opposite appears to be the case.

143. The evidence clearly indicates that notwithstanding the dramatic decline in nuclear productivity as evidenced by the 19% increase in overall nuclear operating costs per unit of production over the period 2005-2007, OPG paid out increasing amounts of incentive pay. Exhibit F3, Tab 1, Sch. 1, Table 2 shows nuclear incentive pay rising from $24.6 million in 2005, to $28.9

million in 2006, to $29 million in 2007. Economic performance is clearly disconnected from performance pay.

144. OPG notes that its "incentive values are much lower than they are in the US" (Transcript Vol. 8, p.56). This is only understandable since nuclear operators in the US so significantly outperform OPG.

145. Under cross examination OPG also indicated that under its performance pay regime and scorecard approach, there is no price per unit of output that would be so high and so unacceptable to OPG that would result in no performance incentives being paid to staff (Transcript Vol. 8, page 54, lines 6-10). AMPCO submits that OPG's performance incentive regime requires redesign to align bonus payouts to improved operational performance and cost control. OPG's current performance incentive program is disconnected from ratepayer interests.

146. **AMPCO recommends that the Board direct OPG, at its next rates case, to bring forward options for a more meaningful incentive payment regime that is more closely aligned with customer interests.**

Other Revenues

147. OPG's approach to net revenue from Segregated Mode of Operations (SMO) and Water Transactions (WT) during the interim period, appears to AMPCO to be fair, even considerate of consumer interests. However, it would be appropriate for the Board to order an approach for SMO, WT, and Congestion Management Settlement Credits (CMSC) more suited for a regulated environment.

148. In support of its proposed approach for SMO, OPG claims two benefits, first that SMO helps to manage excess baseload generation and second that consumers can gain indirect benefits by boosting energy available in neighbouring markets for potential import into Ontario (OPG Argument in Chief p. 73). OPG has provided no quantification of these claims. AMPCO considers that these claimed benefits are of little or no value to Ontario consumers. In fact, the direct impact of SMO transactions is to raise the HOEP in Ontario by directly removing generation from the Ontario market.

149. Another key fact is that the costs to OPG associated with SMO transactions are either directly covered in its regulated rates, or in the case of transaction

specific costs, netted out against the gross revenue. OPG effectively has no net exposure for costs. OPG has a reasonable claim for incentives to optimize the utilization of regulated facilities, but customers should be entitled to the remaining value of production.

150. Both the design of the SMO incentive approach and the proposed net income sharing ratio raise concerns.

151. For the purposes of calculating SMO net income sharing, OPG proposes to maintain the 1900 MW/hr threshold that applied to the interim period. AMPCO considers that the 1900 MW threshold should no longer be applicable. The threshold is simply a vestige of a previous incentive mechanism that has no application going forward. OPG's proposed approach for hydroelectric operational incentives, which AMPCO generally supports, eliminates the need for a fixed threshold. OPG's incentive to optimize the value of hydroelectric production should not be a function of amount of output at any particular time. Consumers have a claim on some of the net income from all SMO transactions because consumers are covering all of the costs underpinning those transactions. OPG should remain responsible for the prudence of SMO transactions.

152. The proposed sharing ratio of 50/50 also raises a concern. AMPCO accepts that OPG needs some incentive to pursue SMO transactions. However, since all costs associated with these transactions are netted against the gross revenue, prior to any consideration of sharing, the transactions are effectively riskless to OPG. AMPCO recommends a sharing ratio of 80/20 in favour of the customer to be appropriate and to provide adequate incentive for OPG to actively pursue beneficial transactions.

153. The approach recommended here with respect to SMO – no volume threshold and 80/20 sharing - should also be applied to WT.

154. With respect to CMSC revenues, OPG's is proposing zero sharing. OPG's argument hangs on an assumption that CMSC credits, which are designed by the IESO to hold the generator harmless in the event of out-of-market operational instructions. Although OPG has demonstrated that CMSC can reduce the efficiency of generation, it has failed to demonstrate that CMSC revenues are totally absorbed by the incremental costs. AMPCO recommends that 50% sharing of any CMSC revenues net of clearly identifiable incremental costs is appropriate.

155. Given the forecast uncertainty associated with these amounts, AMPCO accepts that deferral account treatment of the net income entitlement ultimately determined by the Board is appropriate.

156. In summary, **AMPCO recommends that SMO and WT revenues net of costs and without production thresholds should be shared 80/20 to the benefit of consumers and net CMSC revenues should be shared 50/50 pending review of this approach at OPG's next rates case.**

<u>Ancillary Service Revenue</u>

AMPCO accept OPG's submissions with respect to Ancillary Service Revenue.

<u>Design of Payment Amounts</u>

Issue 8.1 Are OPG's suggested changes to the hydroelectric incentive payment system appropriate?

157. OPG is proposing to change the incentive payment mechanism for its regulated hydroelectric generators.

158. Under OPG's proposal, OPG would provide to Ontario consumers a certain volume at the Board-determined regulated price. OPG proposes to continue to operate its hydroelectric units in the short-run based on market prices.

159. OPG proposes an hourly volume for the incentive mechanism that changes each month and that is equal to the actual average hourly net energy production over the month. Under OPG's proposal, the hourly volume would be calculated as the sum of the net energy production (i.e., energy production net of load including Sir Adam Beck PGS pump load) from the prescribed assets for that month (in MWh) divided by the number of hours in the month. At the end of each month, the actual net energy production supplied into the IESO market for each hour of the month would be reconciled against the hourly volume for that month. Production arising from Segregated Mode of Operation would be excluded from the monthly average calculation under OPG's proposal (Exhibit I1, Tab 1, Schedule 1, Page 12 of 17).

160. Except with respect to the proposed treatment of pumping energy and SMO volumes, AMPCO supports the approach proposed by OPG. The present hydroelectric incentive mechanism based on a predetermined volume of

production is flawed in that it produces perverse disincentive to efficient operations under some market conditions. A mechanism that reflects the market price of power at all hours, and gives OPG an incentive to pursue all "time-shifting" (including PGS pumping) that adds total net market value, is an improvement.

161. In Transcript Undertaking 15.6, OPG acknowledges that electrical energy used for pumping at the Beck Pumped Generation Station (PGS) is effectively double-counted in its proposal. The hypothetical scenario which is the basis of the undertaking posed by Energy Probe's representative was not intended by Energy Probe to be more than illustrative of the double counting problem associated with OPG's proposed incentive methodology. OPG's attempt to downplay the information contained in undertaking as hypothetical and revealing only a small amount of double counting misses the point – the incentive mechanism, despite its many virtues, contains important flaws.

162. OPG's response to Transcript Undertaking 15.6 demonstrates that pumping has the effect of decreasing the average monthly volume used to set the incentive mechanism threshold. Since, *ceteris paribus,* a lower threshold translates into a higher monthly average realized price for OPG than a higher threshold, the incentive for OPG to pump at the PGS is greater than indicated by the expected differential in market prices between peak and off-peak demand periods.

163. Based on OPG's response to AMPCO's interrogatory #60 (L2/60), on average over the period 2005-2007 for every 100 MWh of energy used for pumping at the PGS, 46 MWh were ultimately generated.

164. There is a relatively simple solution to the problem Energy Probe's Transcript Undertaking has revealed. Adding 54 MWh to the monthly total for every 100 MWh used for pumping would eliminated the double counting that would otherwise result under OPG's proposal.

165. A similar double counting problem arises with respect to volumes exported out of the Ontario market under segregated mode operations (SMO). Generation removed from the Ontario market by way of SMO has the effect of decreasing the average monthly volume used to set the incentive mechanism threshold. The marginal value to OPG of the SMO units would equal the direct gain available from the SMO transaction plus the indirect

gain of higher value to all of the remaining units of production committed to regulated Ontario supply.

166. Just as for pumping, since, *ceteris paribus,* a lower threshold translates into a higher monthly average realized price for OPG than a higher threshold, the incentive for OPG to undertake SMO transactions is greater than indicated by the expected differential in market prices between peak and off-peak demand periods.

167. The remedy for the perverse incentive associated with SMO whereby SMO volumes increase revenues to non-SMO volumes is to include all SMO production in the calculation of the monthly average production.

168. **Board Staff in its final submissions proposes an independent review of the hydro-electric incentive mechanism at the next case. Particularly given the uniqueness of the incentive mechanism and its implications in the context of OPG's complex hydro-electric operations, AMPCO recommends that the Board adopt this constructive proposal.**

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

169. For regulated hydro-electric generators, where production is highly reliable and effectively forecast, OPG emphasizes the importance of incentives to promote value optimization. For nuclear, where production is highly unreliable and the forecasting record is terrible, OPG seeks to transfer production risk to customers (see Appendix A).

170. OPG is seeking approval of a payment amount for the nuclear facilities of \$58.2M/month irrespective of output (up from zero under existing government direction) plus \$41.50/MWh (down from \$49.50/MWh under existing government direction) plus a rate rider.

171. OPG indicates that it is seeking "economically efficient operation" of nuclear. However, the fundamental driver of economic efficiency for high fixed cost, low marginal cost assets such as nuclear, is to maximize output. OPG acknowledges this fact in Mr. Penny's opening statement when he commented on the objective for nuclear to "operate at maximum capacity" (Transcript Volume 1 page 15). Mr. Penny continues by claiming that "OPG is not seeking any form of incentive payment for nuclear" (Transcript

Volume 1, page 15, lines 12-14). By removing incentives for efficiency, AMPCO considers OPG's fixed charge proposal clearly to be an incentive approach, although one perversely tilted against efficiency and the interests of consumers.

172. One principle that animated the government's 2005 design for OPG was that OPG should be encouraged to maximize production by being paid only for output delivered. This approach arose from a period where OPG had dramatically failed in its nuclear operations to deliver its intended output. As KPMG noted in the report "Ontario Power Generation Inc.: Financial Review of Operations" March 15, 2004 the key drivers for OPG's growing financial problems in 2003 were as follows: "The underperformance of OPG' s nuclear assets had a cascading negative financial impact on OPG' s overall operations. The cost overruns and delays on Pickering A, and the increased outages experienced by the nuclear fleet in general caused OPG to rely much more heavily than expected on relatively expensive fossil generation" (AMPCO Ex. M, Tab 2, p. 14). Similar problems persisted over the 2005-2007 period.

173. AMPCO strongly believes that relieving OPG of the incentive to maximize nuclear productivity inherent in the nuclear payment structure approved by the provincial government in 2005 would be inappropriate.

174. AMPCO presented an uncontested historical review to the Board of the nuclear production challenges in Ontario in Exhibit M, Tab 2. AMPCO's review is based on primary documents produced mainly by OPG or its predecessor Ontario Hydro or other official parties. Subsequent to the filing of intervenor evidence, OPG provided additional information in L2/29 also captured in the table. This data is attached in Appendix A. The extent of forecast bias is obvious.

175. OPG has no independent evidentiary support for its fixed payment proposal. Ms. McShane acknowledged that no other entity in the Ontario market gets paid irrespective of its ability to produce – no one else gets this benefit (Transcript Vol. 12, page 69, lines 2-25). In Exhibit J12.3, London Economics noted the "none of the utilities studies reached the 25% level requested by OPG for their nuclear assets".

176. The Board's methodology report (EB-2006-0064) indicated its intention to move toward incentive regulation. In light of this direction, OPG's proposed fixed payment is a retrograde step.

177. During AMPCO's cross-examination of the payment amounts panel we raised the recommendation of CIBC in 2005 (Exhibit L2/10 Attachment 1 page 14) where CIBC noted, "We have concluded that fixed rates are not required for OPG." Mr. Barrett sought to distinguish the circumstances of the market now from those that prevailed in 2005. AMPCO draws the Board's attention to the following in response to Mr. Barrett's testimony:

> - OPA contracts for non-dispatchable renewable generation, which contributes to a similar generation requirement to the baseload nuclear units, are designed on the basis of energy-only payment,
>
> - Capacity payments are only paid under OPA contracts for peaking generation, where the capacity payment acts like a standby fee to ensure adequate generation is available.

<u>Distinguishing LDCs from OPG's Heritage Assets</u>

178. OPG also attempts to establish a linkage between connection charges by LDCs and OPG's proposed fixed payment for nuclear. One fundamental difference between distribution utilities and OPG, which OPG ignores, is the fact that when distributors where transformed from municipal utilities to Ontario *Business Corporation Act* companies, the enabling transfer bylaws passed by Ontario municipal governments transferred existing assets and liabilities to the new companies. There were no stranded debts transferred from the Ontario distributor sector to ratepayers, as was the case when Ontario Hydro generation was reconstituted as OPG.

179. **AMPCO recommends that the Board should decide in favour of energy-only payments for OPG's nuclear generation.**

<u>Deferral and Variance Accounts</u>

180. Tax Changes. AMPCO has no submissions with respect to the establishment of this account.

181. Pension and Other Post-Employment Benefit Costs. The Board should apply the same approach to OPG with respect to this issue as it does to the

other utilities the Board regulates. It appears to AMPCO that OPG is requesting special treatment for OPED.

182. Nuclear Fuel Costs. AMPCO does not object to the creation of this account.

183. Interest Rates. AMPCO adopts the submissions of Board Staff regarding the level of interest rates that OPG should be allowed to recover. Ontario distribution utilities have held account balances for comparable periods (e.g. Regulatory Assets) that are directly comparable to OPG's accounts such as the Pickering A Return to Service ("PARTS") deferral account. Accordingly, AMPCO submits that the Board's Prescribed Interest Rate Policy should also apply to OPG.

184. Other Accounts. Issue 9.7 states "What deferral and variance accounts, other than those mandated by O. Reg. 53/05 should be established for 2008 and 2009?" OPG has proposed to continue the Hydro-electric Water Conditions Variance Account, the Ancillary Services Variance Account and the SMO and WT Net Revenue Variance Account. AMPCO supports the continuation of these accounts with the proviso of our recommended changes for SMO and WT as discussed above.

185. In addition, **AMPCO recommends the establishment of a variance account to capture variances between forecast and actual costs of IESO non-energy charges experienced by OPG.** The grounds for this recommendation are: 1) such costs are difficult to forecast and not subject to control of management, and 2) the methodology used by OPG for forecasting purposes relies upon regression analysis using a short time history starting in 2005 which raise questions regarding the reliability of the forecast. As parties know well, the summer of 2005 saw unusual and protracted high temperatures which caused electricity prices to be especially high relative to those which one would normally expect. AMPCO is concerned that the choice of 2005 as the base year for OPG's analysis runs the risk of skewing OPG's analysis downward.

Determination of Payment Amounts

186. AMPCO has no submissions regarding this matter.

Rate Implementation

187. AMPCO supports OPG's proposal to implement the new rates by using the actual load consumption for the period beginning April 1, 2008.

Costs

188. In its letter of intervention dated January 7, 2008 AMPCO requested eligibility for costs in this proceeding. The Board found that AMPCO was eligible for costs for the OPG consultation process that occurred prior to the commencement of the hearing.

189. The Board will be aware that 2007-2008 continues to be an extremely busy period for AMPCO and other intervenors given the great number of proceedings and consultations currently underway pursuant to the Board's regulatory calendar. In addition to the OPG case to establish Heritage Asset Rates, AMPCO is undertaking a major role in the OPA's IPSP proceeding, Hydro One Distribution and Transmission rate cases, various Local Distribution Company rate applications and Board policy consultations such as 3rd Generation IRM and Transmission Connection Cost Responsibility.

190. These multiple and complex initiatives, many of which are occurring simultaneously, are resulting in significant financial strain for AMPCO. To be able to intervene effectively AMPCO has been required to significantly expand its expert team to facilitate interventions in these multiple proceedings and consultations. This has created unprecedented cost pressures for AMPCO.

191. Accordingly, AMPCO respectfully requests that the Board make its Cost Order for this proceeding before it renders the final decision in this case. In the normal course we would expect a final decision from the Board sometime this fall with the decision on costs to follow thereafter. The result, in the ordinary course, is that can several months can pass from the time of the filing of final argument until a determination on costs is made and until AMPCO ultimately receives reimbursement for its professional and consulting expenses. Having the cost decision made at this time would

significantly assist AMPCO in managing its expenses over the balance of 2008.

All of which is respectfully submitted.

J. Mark Rodger

Counsel to the Association of Major Power Consumers in Ontario

July 21, 2008

Appendix A: Nuclear Production Forecast vs. Actual

	Actual Nuclear Output	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
	Ontario Hydro		68.0	60.5	73.7	66.9	80.9	92.9	87.9	79.4	71.4	60.7	61.9								
	OPG													60.3	63.5	42.1	38.0	42.4	44.9	46.9	44.0
	Bruce															21.0	24.7	33.8	33.0	36.6	35.5
Forecast Source	Forecast Date																				
OH Business Plan	Jan-88	69.2				98.2					99.7										
OH Business Plan	Jan-89	67.5	72				96.6					96.5									
OH Demand/Supply Plan	Dec-89		70	76	82	88	94	100	100	100	100	100	100	100	100	100	100	100	100	100	100
OH Business Plan	Jan-90		65.8	72.7				98.8					104.3								
OH Business Plan	Jan-91			59.5	76.4				89.4					100.5							
OH Business Plan	Jan-93					66.2	79.8														
CES 93-4	Fall 1993							86.2	88.6	86.5											
OHN Business Plan	Nov-93							88.8	86.9	87.2											
OH Corp Plan 1998-2000	Feb 17, 1998											56.3	59	62.7							
NAOP/IIP	May-99												57				83				
BP 2001																			60.7		
BP 2002																			60.4	60.7	
BP 2003																			54.6	59.3	62
BP 2004																			47.5	51.9	55.3
O.Reg 53/05	Fall 2004																		45.2	50.6	53
BP 2005																			45.2	50.5	52.8
BP 2006																				49.3	49.9
BP 2007																					49.8

(Data from M2 and L2/29)