TORYS LLP

79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2 Canada
P. 416.865.0040 | F. 416.865.7380
www.torys.com

Charles Keizer
ckeizer@torys.com
P. 416.865.7512

December 10, 2014

RESS, EMAIL & COURIER

Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Attention: Ms. K. Walli, Board Secretary

Dear Ms. Walli:

Re: EB-2013-0321 - Ontario Power Generation Inc. - Notice of Motion for Review and Variance of the November 20, 2014 Decision with Reasons

We are counsel to Ontario Power Generation Inc. ("OPG") in the above-referenced proceeding.

Enclosed, please find OPG's Notice of Motion seeking to review and vary the Ontario Energy Board's Decision with Reasons, dated November 20, 2014, in EB-2013-0321.

Yours truly,

Charles Keizer

Tel 416.865.7512
ckeizer@torys.com

CK
cc: OPG
Intervenors

14504-2111 18524536.1

EB-2013-0321

ONTARIO ENERGY BOARD

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

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

AND IN THE MATTER OF Rule 40 of the Rules of Practice and Procedure of the Ontario Energy Board.

NOTICE OF MOTION

Ontario Power Generation Inc. ("OPG") will make a motion to the Ontario Energy Board (the "Board" or the "OEB") at its offices at 2300 Yonge Street, Toronto on a date and time to be fixed by the Board.

The Motion is for:

1. a review and variance of the Board's Decision with Reasons dated November 20, 2014 in EB-2013-0321 (the "Decision"): (i) at page 30 where the Board disallowed the addition to rate base of $88.0M out of the proposed $1,452.6M for the Niagara Tunnel Project, and (ii) at page 101 where the Board directs OPG to reduce its 2014 income tax provision to account for and to recognize the carry forward of its regulatory tax loss in 2013;

2. an Order that OPG satisfies the "threshold test" in Rule 43.01 of the Board's *Rules of Practice and Procedure*;

3. an Order for an oral hearing of the Motion on the merits;

4. an Order:

(a) (i) varying the finding that $88.0M of the Niagara Tunnel Project (the "NTP") capital expenditures were imprudently incurred, (ii) finding that the $88.0M portion of the NTP capital expenditures were prudently incurred, and (iii) finding that the full amount of the proposed $1,452.6M in NTP capital expenditures should therefore close to rate base in the test period;

(b) (i) varying the finding that OPG reduce its 2014 income tax provision to account for and to recognize the carry forward of its $211.6M regulatory tax loss that was incurred in 2013 due to a shortfall of nuclear production, and (ii) finding that OPG is entitled to receive the benefit of the $211.6M regulatory tax loss and that it does not need to reduce its 2014 income tax provision to account for and to recognize the carry forward amount;

(c) varying the amount of OPG's test period revenue requirement by increasing the test period revenue requirement to reflect (a) and (b) above;

(d) amending the payment amounts order (currently pending) to reflect the test period revenue requirement arising from (c) above;

(e) as a method to give effect to (c) above, establishing a deferral account to record the impact of the Board's decision on this motion, over the period from November 1, 2014 until the effective date of the amended payment amounts order arising from this motion, with such amount to be disposed of pursuant to the payment amounts order referred to in (d) above.

The Grounds for the Motion Are:

Part A: Niagara Tunnel Project

OPG's Application and Evidence

1. The NTP is a 10.2 km long tunnel constructed by OPG with an interior diameter of 12.7 metres which runs under the City of Niagara Falls, Ontario. Its purpose is to increase the flow of water to the Niagara plant group, and thereby increase generation by an annual average of approximately1.5 TWh. Following a competitive bidding process, Strabag

Inc. ("Strabag") was selected as the designer and builder of the NTP and entered into a Design Build Agreement ("DBA") with OPG. After several years of construction, the asset was placed in service in March 2013. OPG's capital costs associated with the NTP were $1,472.2 of which $1,452.6M is the amount OPG sought to close to rate base in this application.

2. Of the amount included in the application, $985.2M was approved by the OPG Board of Directors in 2005 as the initial budget. As this approval predated the OEB's first order in respect of OPG in 2008 it was specifically excluded from OEB consideration by section 6(2)4 of O. Reg. 53/05. The issue before the OEB, therefore, was whether the $491.4M that OPG spent beyond the $985.2M budgeted in 2005 was prudently incurred.

3. In its application OPG submitted that the NTP's original budget of $985.2M was a realistic estimate of the project's cost based on extensive geotechnical investigations including consultation with recognized professional and academic experts (Ex. D1-2-1, p. 136, Appendix B; Motion Record ("MR"), Tab 2) and the costs proposed by the three international tunneling consortia that responded to OPG's competitive solicitation.

4. The additional cost of construction of the NTP was due <u>entirely</u> to the extremely difficult rock conditions encountered by Strabag, which were significantly more challenging than expected. An overriding and recurring issue experienced by Strabag was overbreak in the tunnel crown. Overbreak is the cracking and loosening of rocks above the tunnel boring machine ("TBM") cutterhead, which has the effect of distorting the circular profile created by the TBM. Substantial overbreak was encountered as soon as the TBM reached the Queenston shale.

5. The uncontroverted evidence before the Board was that if the rock conditions had been known in advance with perfect foresight, the tunnel would have cost at least what OPG paid and may have cost more (Tr. Vol. 2, pp. 82,148; MR, Tab 3).

The Dispute Review Board Decision

6. Owing to the rock conditions encountered, in May 2007 Strabag issued claims and notices all aimed at recovering additional costs because the subsurface conditions being

encountered were significantly more adverse than were contemplated in the DBA (Ex. D1-2-1, pp. 96-97; MR, Tab 2, p. 56, 57), i.e. differing subsurface conditions ("DSC").

7. Under the DBA, OPG was responsible for the resulting costs if the subsurface conditions actually experienced were more adverse than anticipated.[1] This is a common feature of tunnel projects; the owner, here OPG, bears the risk associated with DSC.

8. OPG disputed Strabag's claims. In February 2008, OPG and Strabag agreed to present the matter to the Dispute Review Board ("DRB") established in the DBA.

9. The DRB process was included in the DBA as a mechanism to address disputes over the project through the use of industry experts familiar with the NTP and without the time and expense of litigation. The DRB is not a court where parties bring different causes of action and ask for a decision on each of them and, unlike a court, the DRB cannot impose remedies based on its findings. What the DRB can do, and what it did do here, is to determine whether it believes that the issues raised by the contractor, individually or collectively, present a valid claim for DSC and recommend to the parties how this claim should be addressed.

10. The DRB hearing was held from June 23 through 26 in Niagara Falls, Ontario.

11. In attempting to convince the DRB, Strabag offered five reasons that it believed supported its claim for DSC. Strabag did not assign separate costs to each of these five reasons because its position was that any one of the five factors or all of them together constituted DSC and were therefore the cause of the extra cost to mine and support the tunnel, and restore its circular profile so that the lining could be installed. There was not one cost for "large block failures" and another for "inadequate stand up time" because the actions that Strabag took addressed all the conditions it was encountering, which it contended differed from those included in the DBA.

[1] The GBR, which is Appendix 5.4 of the DBA, states at page 5, paragraph 4: "Those consequences associated with subsurface conditions more adverse than the baseline conditions are accepted by OPG" (Ex. D1-2-1, Attachment 6 (PDF p. 1724)).

12. On August 30, 15 2008, the DRB issued its Report and Recommendations ("DRB Report") (Ex. D1-2-1, Attachment 7; MR, Tab 4). The DRB's conclusions were unanimous.

13. While the DRB did not accept three of the five reasons offered by Strabag, it found that the other two did and therefore determined that DSC existed. Once the DRB made that determination, responsibility for the cost consequences of the more adverse subsurface conditions became OPG's. Ultimately, there was only one question before the DRB: "Are there differing subsurface conditions?" The DRB answered "yes" to this question and gave reasons for its decision.

14. The DRB proceeded to recommend that the dispute be resolved on a cost sharing basis, stating that:

> [W]e recommend that the Parties negotiate a reasonable resolution based on a fair and equitable sharing of the cost and time impacts resulting from the overbreak conditions that have been encountered and the support measures that have been employed. Both Parties must accept responsibility for some portion of the additional cost, but at the same time the Contractor must have adequate incentives to complete the Work as soon as possible 1 (Ex. D1-2-1, Attachment 7, pp. 18-19; MR, Tab 4).

The Settlement and the Amended Design Build Agreement

15. After receiving the DRB Report, OPG examined a number of potential responses and concluded that negotiating with Strabag based on the DRB recommendations was the path mostly likely to complete the NTP in the least amount of time and at the lowest cost (Ex. D1-2-1, pp. 102-103; MR, Tab 2, p. 59, 60).

16. In reaching its decision, OPG relied on the the independent expert advice of the Contract Litigation Oversight Committee ("CLOC"). The CLOC was formed to advise on the dispute with Strabag. Its purpose was:

> to provide independent oversight of OPG's strategy for contract dispute resolution and negotiations and to advise the CEO on the conduct of the dispute. The CLOC was chaired by OPG's Chief Financial Officer and included external members Norman Inkster,

> former head of the RCMP, and Barry Leon, a lawyer then at Torys who specialized in international litigation and arbitration. Both men have significant experience in investigating and resolving complex disputes.
>
> The CLOC also obtained independent technical advice from John Hester, an expert on tunnel construction and the tunneling industry. In the period leading to presentation of the dispute between OPG and Strabag to the DRB, the CLOC provided independent review of the strategy OPG employed and the presentations OPG made. After the DRB rendered its decision, the CLOC continued to advise the company on negotiations with Strabag until an agreement was reached. (Ex. D1-2-1, p. 50; MR, Tab 2).

17. The advice of the CLOC following the DRB Report was that working with Strabag to achieve an amended agreement rather than seeking to replace it with a new contractor was the preferred alternative to complete the NTP (Tr. Vol. 2, pp. 136-137; 148-149; MR, Tab 3).

18. OPG and Strabag ultimately developed a Principles of Agreement document which was based on a hybrid approach that included resolution of Strabag's past claims for differing subsurface conditions in the Queenston formation and renegotiation of the DBA going forward. This approach closely followed the recommendations of the DRB to share the cost and schedule consequences of the DSC that had been experienced and negotiate a new agreement to finish the NTP "that, while not commercially optimum for either party, will allow the Project to proceed to optimum completion." (Ex. D1-2-1, Attachment 7, p. 19; MR, Tab 4).

19. Following negotiations, OPG agreed to pay Strabag $40M to resolve all issues through November 30, 2008, which reflected a sharing of Strabag's claimed losses of $90M. The parties negotiated an Amended Design Build Agreement (the "Amended DBA") based on the original DBA (Ex. D1-2-1, Attachment 9). Most DBA provisions were retained unchanged except as necessary to convert the agreement to a target cost contract (Ex. D1-2-1, pp. 106-112; MR, Tab 2).

20. As set out above, the extremely difficult rock conditions encountered during tunneling necessitated the revised project schedule and cost forecast of $1,600M contained in the

2009 Superseding Business Case Summary approved by the OPG Board of Directors. The target price contract with cost and schedule incentives allowed the NTP to be completed at a cost some $120M below the approved funding with commercial service beginning nine months sooner than the approved completion date in the Superseding Business Case Summary. The amount OPG spent on the NTP represents the true cost of completing the project given the subsurface conditions actually encountered (Ex. L-4.4-2 AMPCO-016; MR, Tab 6, and Tr. Vol. 2, pp. 85-89; MR, Tab 3).

OPG's evidence on the NTP

21. For many years prior to the application, OPG and the parties were aware that the costs of the NTP would exceed the original budget approved by OPG's Board of Directors in 2005 prior to OEB regulation. OPG and the parties were also aware that once the NTP went into service the OEB would conduct a prudence review of these additional costs, including the costs arising from the Amended DBA. While OPG led extensive evidence on the prudence of these costs, as described below, neither Board staff nor a single intervenor chose to provide any evidence on this issue.

22. OPG presented extensive evidence on the prudence of its NTP costs in this application. OPG's initial evidence included a detailed 145-page narrative on the NTP. OPG's initial filing included copies of the key project documents totaling almost 6,000 pages of material. As a result of this comprehensive evidence, there were relatively few interrogatories on the NTP. As additional project documents were requested through interrogatories, at the Technical Conference or at the hearing, they were provided.

23. At the application hearing, OPG adduced evidence on the NTP from an expert witness and two fact witnesses:

(a) Mr. Roger Ilsley, an independent expert with 40 years' experience in all aspects of tunnel design and construction who has also served on at least 16 DRBs (Ex. JT1.5, Attachment 1; MR, Tab 7);

(b) Mr. Rick Everdell, OPG Project Director for the NTP, from November 2005 through December 2013;[2]

(c) Dr. Chris Young, OPG Vice President of Hydroelectric and Thermal Project Execution and project sponsor for the NTP until his retirement in 2014.

24. Though they led no evidence, intervenors and Board staff challenged OPG's costs on several grounds and sought disallowances of up to $407.4M (about 83 per cent of the costs in issue). These arguments all failed to recognize the consequences of the fact that DSCs were OPG's responsibility under the DBA.

The OEB's Decision

25. In the Decision, the OEB correctly held that its review of the NTP was a "prudence review" and that the OEB was not permitted to use hindsight when considering OPG's actions. Applying this holding to the evidence as the OEB Panel understood it, the OEB disallowed $88M (or approximately 18%) of the $491.4M cost of the NTP subject to review. The OEB stated that these disallowances were "based primarily on OPG's response to the Dispute Review Board's decision and recommendations, in particular OPG's decision to pay $40M for claims prior to December 2008, and the terms negotiated with Strabag in the Amended Design Build Agreement." The OEB divided its disallowance into these two main components, as described below.

The pre-December 2008 disallowance

26. First, the OEB disallowed $28.0M attributable to pre-December 2008 claims made by Strabag because the OEB was not satisfied that paying Strabag $40M for its claimed loss of $90M up to December 2008 was prudent. The Board specifically found that "the non-binding recommendations of the Dispute Review Board were reasonable, and that some level of shared responsibility between OPG and Strabag was appropriate." The Board went on to find, however, that "paying a $40M settlement (44% of Strabag's $90M claim) is excessive in the Board's view." Specifically, the OEB found that it was:

[2] Mr. Everdell, in fact, had been involved with the NTP in positions of increasing responsibility for nearly 40 years, dating back to 1976.

> … unable to find that a $40M settlement of Strabag's claim was prudently incurred. In the absence of information regarding the costs attributable to each of the five issues, the Board must use its judgment of what is a reasonable amount. In determining the amount, the Board has decided to utilize the findings of the Dispute Review Board. As a result, the Board finds that OPG's ratepayers should not pay any amount for the three issues which OPG was not responsible, but should pay 50% of two issues for which OPG was jointly responsible. In addition, the Board is persuaded by the results of OPG's audit and considers the $77.4M to be the appropriate starting point for the Board's calculation, not the $90M claim by Strabag. There was no evidence or testimony provided supporting Strabag's claimed amount. As a result, the Board finds that ratepayers should only pay 20% of the $77.4M audited amount, or $15.5M. In addition, the Board denies the associated carrying costs of the disallowed $24.5M which results in a reduction of another $3.5M. The Board finds this disallowance of $28.0M reasonable given the evidence provided (Decision, pp. 31-32; MR, Tab 1).

The Amended Design Build Agreement disallowance

27. Second, the Board disallowed $60M associated with the terms of the Amended Design Build Agreement. The Board stated:

> … the Board finds that the incentives offered to Strabag through the Amended Design Build Agreement were excessive. OPG understood that a contractor default was a potential risk, and indeed, it took steps that should have mitigated that risk through a letter of credit and a comprehensive parental indemnity. However, when it came time to renegotiate the Design Build Agreement, OPG did not properly use its leverage to secure a more favourable deal (Decision, p. 33; MR, Tab 1).

28. The Board went on to state that, "OPG agreed to pay Strabag hundreds of millions of extra dollars more than was provided for in the Design Build Agreement. In the Board's judgment, the provision of incentives above this was not necessary and not prudent" (Decision, p. 33; MR, Tab 1).

Material Errors

29. Underpinning the Board's findings in relation to both major aspects of the NTP disallowance is a misapprehension of the evidence relating to the findings of the DRB.

The pre-December 2008 disallowance error

30. The OEB viewed the five items in dispute before the DRB as being independent from one another. The OEB stated:

> There were five issues of dispute that were referred to the Dispute Review Board. The dispute Review Board found that OPG was not responsible for three of the five issues and that OPG had only joint responsibility for the remaining two issues. No evidence was filed on the relative value or cost of the five issues. OPG's witnesses testified that the individual issues were not quantified (Decision, p. 31; MR, Tab 1).

31. This view of the DRB dispute in factually incorrect and inconsistent with the evidentiary record before the Board. This view also shows that the Board fundamentally misunderstood the nature of the DRB process and the findings of the DRB with regard to the dispute between OPG and Strabag over the NTP. There was a single DSC dispute between OPG and Strabag that went to the DRB, which found that DSC existed. Had Strabag offered ten reasons in support of its claim for DSC and the DRB rejected nine of them, the same result would have obtained. The DRB would have found that DSC existed.

32. The Board's failure to understand the nature of the DRB process and the findings of the DRB with regard to the dispute between OPG and Strabag was a fundamental misapprehension of the evidence. As OPG's evidence explains:

> Strabag's fundamental position was that OPG remained responsible for the consequences of the geologic conditions different from those enumerated in the GBR and that the conditions actually experienced in tunnelling were different. Strabag claimed that DSC were evidenced by large block failures, excessive overbreak and inadequate "stand-up" time (i.e., insufficient time to install rock support prior to rock failure). Strabag further claimed that the Table of Rock Conditions and Rock Characteristics in the GBR failed to adequately describe the rock conditions encountered and either represented a DSC on its own, or alternatively confirmed the presence of DSC. (Ex. D1-2-1, p. 99; MR, Tab 2).

33. The DRB summarized the test for DSC in the DBA and the allocation of responsibility among the parties as follows: “The Contractor is responsible for design and construction of the Work. The Owner is responsible for more adverse subsurface conditions than are represented in the GBR. (Ex. D1-2-1, Attachment 7, pp. 5-6; MR, Tab 4).

34. It was materially wrong for the Board to conclude, as it did, that OPG’s ratepayers should not bear the consequences “for the three issues [for] which OPG was not responsible”. The dispute with Strabag was not over the individual reasons that Strabag gave for claiming DSC, or “the relative value or cost of the five issues” (as the Panel expressed the matter), but rather whether the conditions being experienced in mining the NTP constituted DSC. In evaluating this dispute, the DRB agreed with Strabag that DSC existed.

The Amended Design Build Agreement disallowance error

35. In the Decision, the Board concluded that OPG had leverage that it did not use in its negotiations with Strabag over the terms of the Amended DBA. This conclusion also hinged on the Board’s misapprehension of the DRB findings as set out above. Put simply, having lost on the issue of a DSC, OPG simply did not have the leverage the Board wrongly believed that it did.

36. The Board’s error is plain in its reference and reliance on the parental guarantee and indemnity provided by Strabag (the “Indemnity Agreement”). The Indemnity Agreement provides no leverage to OPG. It is an agreement to indemnify OPG in the event of a default by Strabag. However, given the DRB findings there was no reasonable basis to conclude that Strabag was in default; if the matter were litigated (and Strabag had issued a notice of arbitration following the DRB Report), based on the DRB finding of DSC, Strabag, not OPG, was likely to prevail.

37. The Board made other material errors in relation to this disallowance.

38. First, the Board failed to apprehend the nature of the “incentives” paid to Strabag as part of the Amended DBA. At page 33 of the Decision, the Board held that:

> The Board is mindful of the Dispute Review Board's recommendation that Strabag have appropriate incentives to complete the work. However, in the Board's view the Amended Design Build Agreement provided adequate "incentive" even without the specific incentive clauses. OPG agreed to pay Strabag hundreds of millions of extra dollars more than was provided for in the original Design Build Agreement. In the Board's judgment, the provision for incentives above this was not necessary and not prudent. [Emphasis added].

39. The finding that incentives included in the Amended DBA were unnecessary because OPG was agreeing to pay Strabag "hundreds of millions of dollars" in additional costs is inconsistent with the OEB's own recognition that the incentives encouraged Strabag to complete the NTP ahead of schedule and below target cost. Strabag began working on this project in August 2005 when the DBA was signed (Ex. D1-2-1, p. 132; MR, Tab 2). The amended contract meant that Strabag had worked for more than three years to achieve what it considered to be a $50M loss ($90M in claimed loss minus the $40M settlement of past costs) and that going forward, Strabag was agreeing to work for another four and half years at cost (from December 2008, the effective date of the ADBA to June, 2013 the targeted completion). Without the negotiated incentives, Strabag would have had no reason to seek out schedule and cost savings because the benefits of any successful efforts would have flowed entirely to OPG, while the cost and risk of undertaking these efforts would have remained with Strabag.

40. At the time the Amended DBA was agreed to, it was highly uncertain that Strabag could achieve the incentives. While the Amended DBA was being negotiated (Fall 2008 through Spring 2009), the NTP was tunneling through difficult rock in the Queenston formation and was falling further behind schedule (Ex. D1-2-1, pp. 75-76; MR, Tab 2). Of course, in hindsight, Strabag was able to complete the project months ahead of the target schedule and did earn incentives as a result, but this was far from a given when the contract was executed.

41. Using OPG's $77M figure for Strabag's losses (accepted by the Board), Strabag earned a profit of $26M on a $985M contract (or about 2.64 percent) for a project lasting almost eight years. This is a very low level of profit by any estimation for a project of the size,

length and complexity of the NTP and nowhere near "hundreds of millions of dollars" (Tr. Vol. 2, p. 124-125; MR, Tab 3).

42. Second, the Board misapprehended the uncontradicted evidence that Strabag would have abandoned the NTP had OPG not agreed to the incentives that were, in fact, included in the Amended DBA:

> MR. MILLAR: Why did they have to -- you needed them to finish the project, right?
>
> MR. YOUNG: We needed them to finish the project and ultimately - I mean, this was a negotiated solution. There was -- in our opinion, this was the best available solution and it was achieved at the cheapest possible point.
>
> MR. MILLAR: You didn't think you could squeeze them any --
>
> MR. YOUNG: We could not squeeze them further.
>
> MR. MILLAR: And they would have walked away?
>
> MR. YOUNG: They would have walked away. It was fairly close at the end of the day. (Tr. Vol. 2, p. 126; MR, Tab 3)

43. In this respect, Mr. Young also gave uncontradicted evidence that neither Strabag's parent-company guarantee nor its $70M letter of credit would not have dissuaded Strabag from walking away from the NTP (even if available which, as set out above, they were not):

> MS. LONG: As I understood the evidence, you had a contingency amount. I think you had letters of credit from them.
>
> MR. YOUNG: Yes.
>
> MS. LONG: And a parental guarantee and a bond as well to protect you, but you didn't feel that was enough?

> MR. YOUNG: Well, I mean, the total loss that they could have been facing, I mean, effectively, had their contract -- had they executed their contract -- you know, they lost $90 million to the that point -- they would have lost an additional 4- or 500 million on the project to complete it. And, you know, clearly the security wouldn't have been enough. (Tr. Vol. 2, pp. 147-148; MR, Tab 3)

44. The Board's disallowances rest on the conclusion that Strabag having sustained a $40M loss during the first three years of the contract, would have worked at cost for nearly five more years, without the possibility of earning any profit at all, to complete the NTP on budget and ahead of schedule. In its Decision, the Board in hindsight has substituted its own judgment for that of OPG. There is no evidence that supports this ultimate conclusion.

Part B: Tax Loss Carry Forwards

OPG's Application and Evidence

45. In the Application and Pre-filed Evidence, OPG sought approval to recover its 2014 and 2015 income tax expense of $49.7M and $64.2M for the previously regulated hydroelectric facilities, $29.9M and $42.7M for the newly regulated hydroelectric facilities, and $108.3M and $16.8M for the nuclear facilities, respectively, for a total income tax expense of $187.9M in 2014 and $123.7M in 2015 for the regulated facilities (Ex. N2-1-1, Table 1; MR, Tab 8).

46. In 2013, OPG incurred a regulatory tax loss of $211.6M (Ex. J13.4, Attachment 1; MR, Tab 9). OPG did not apply the regulatory tax loss to reduce its forecast 2014 regulatory taxable income since the tax loss arose as a result of a 2013 nuclear operating loss attributable to reduced production levels. In particular, as explained in Ex. L, Tab 6.13, Schedule 1, Staff-166, MR, Tab 10:

(a) OPG's actual nuclear production in 2013 was 44.7 TWh;

(b) OPG's forecast nuclear production was 50.4 TWh for 2011 and 51.5 TWh for 2012, for an average of approximately 51.0 TWh, as approved by the Board in EB-2010-0008;

(c) the difference between OPG’s actual 2013 nuclear production and the average of its approved nuclear production forecasts for 2011 and 2012 (which OPG uses as a proxy in the absence of an approved nuclear production forecast for 2013) represents a shortfall in nuclear production for 2013 of approximately 6.3 TWh;

(d) using the nuclear base payment amount of $51.52/MWh, the 6.3 TWh nuclear production shortfall results in a reduction in revenue in 2013 of approximately $325M; and

(e) as a result of the reduction in its revenue arising from the shortfall in nuclear production, OPG incurred an operating loss of $325M in 2013.

47. OPG absorbed the operating loss. The loss is not recoverable from rate payers as OPG (and therefore its shareholder) bears the risk related to production levels and any resulting loss. In effect, the actual 2013 production level was below the level of production reflected in payment amounts applicable in 2013. OPG should receive the benefit of the associated tax loss since to do otherwise would unfairly subsidize the rate payer to the detriment of OPG and be inconsistent with accepted regulatory principles as established by the Board.

48. The principle endorsed by the Board in EB-2007-0744, and further articulated by the Board in EB-2007-0905, is that ratepayers should only bear the costs for which they are responsible and, if ratepayers are held responsible for costs then they are entitled to the tax benefits associated with the costs. However, if ratepayers do not bear the costs, they are not entitled to the tax benefits associated with the costs.

49. As the $325M operating loss due to the 2013 nuclear production shortfall was incurred by OPG and was not borne by ratepayers, it is OPG, not ratepayers, that is entitled to the benefit of the resulting tax loss. On this basis, OPG did not apply the $211.6M regulatory tax loss from 2013 to reduce its forecast 2014 regulatory taxable income for the benefit of ratepayers.

The Board’s Decision

50. In the Decision, the Board directed OPG to reduce its 2014 income tax provision to recognize and carry forward its regulatory tax loss in 2013 on the basis that this finding

was consistent with the Board's 2006 Electricity Distributor's Rate Handbook (the "Handbook").

51. The Board reached this conclusion on the basis of a series of findings.

52. First, the Board found that OPG's circumstances in 2013 are distinct from the two Board decisions referenced by OPG in its reply submissions (Decision, p. 101; MR, Tab 1). Those decisions were in EB-2007-0744 and EB-2007-0905.

53. Second, the Board found that the Handbook was not applied by the Board in EB-2007-0744 (Decision, p. 101; MR, Tab 1).

54. Third, the Board indicated that the "benefits follow cost" principle has been interpreted differently by the parties (Decision, p. 102; MR, Tab 1), but provided no interpretation of its own. Instead, it relied only on the strict wording of the Handbook.

55. Fourth, the Board found that the fact that OPG incurred a tax loss was a risk OPG decided to take on its own accord and should not change the application or treatment of the Board's tax loss carry-forward policy (Decision, p. 102; MR, Tab 1). In this regard, the Board found that OPG decided not to apply to change its payment amounts for 2013, which had the effect of continuing its (then current) payment amounts for 2013.

Material Errors

56. In concluding that OPG should carry forward its 2013 regulatory tax loss of $211.6M for the purpose of reducing its 2014 income tax provision for the regulated facilities, the Board erred by failing to consider and misinterpreting several significant aspects of the evidence and by giving weight to certain irrelevant information. As a result, the Board failed to apply established regulatory principles relating to cost responsibility, namely the principle that benefits follow costs.

57. The Board's errors raise material questions as to the correctness of its Decision because it can be concluded that but for the errors, the principle of benefits follow costs should have been applied such that OPG's 2013 regulatory tax loss is not used to reduce its 2014 income tax provision for the regulated facilities. The specific areas in which the Board

failed to consider significant aspects of the evidence or gave weight to irrelevant information are as follows.

Incorrectly Concluding that OPG's 2013 Circumstances are Distinct from Precedent Cases and Incorrectly Applying the Handbook Thereby Failing to Consider and Apply Regulatory Principles Adopted by the Board

58. In its reply submissions, OPG referred the Board to its decision in the Great Lakes Power Limited ("GLPL") proceeding EB-2007-0744 which stands for the proposition that when interpreting and applying the Handbook in respect of tax loss carry forwards the Board must look at the basis for the loss and its attribution to the shareholder or ratepayer in order to correctly apply the regulatory principle of benefits must follow the cost.

<u>Circumstances are Not Distinct</u>

59. At p. 102 of the Decision that is the subject of this motion, the Board erroneously concluded *"OPG's circumstances in 2013 are distinct from the two referenced Board decisions."* The basis for this finding is that GLPL conducted both regulated and non-regulated businesses and, according to the Board, the Board's decision in EB-2007-0744 *"addressed the fact that the corporate tax loss carry-forwards arose due to losses in Great Lakes Power Limited's non-regulated businesses"*. The Board goes on to state that OPG's circumstances in 2013 are distinct because *"there is no evidence filed to indicate the tax loss was related to OPG's non-regulated businesses"*.

60. The Board's findings with respect to OPG's 2013 factual circumstances and their application to Board precedents are incorrect. Pages 41 to 44 of the decision in EB-2007-0744 (MR, Tab 12) specifically considers the benefit of tax losses in GLPL's *regulated* business. On an entirely separate issue, the Board considers issues related to the unregulated business elsewhere in the EB-2007-0744 Decision. The Board, in the Decision that is the subject of this motion, only turned its mind to that part of the EB-2001-0744 decision related to the unregulated business.

61. Furthermore at page 43 of the EB-2007-0744 decision the Board stated that "[s]ince the Board has denied recovery of a major portion of account 1574, the amount denied would be excluded from GLPL's pre-2007 financial results thereby indicating that GLPL would have incurred significant **operating losses** for the period 2002 to 2006" (emphasis added) (MR, Tab 12). The Board took note that any pre-2007 losses, arising from the Board's denial of recovery of account 1574, related to variations in load or expenses compared to the amounts on which GLPL's then existing rates were based. The Board stated further that "[i]t is highly unlikely, in the Board's view, that GLPL's customers absorbed any of those losses. Except for some increases in rates authorized by the Board to collect certain regulatory assets, GLPL's distribution rates have not increased since May 2002, when GLPL's rates first became subject to Board oversight."

62. The finding that the facts relating to OPG's loss in 2013 are distinct to those applicable to GLPL in EB-2007-0744 is incorrect. Both related to losses arising only from the regulated business and both related to tax losses that were due to costs, which were absorbed by the utility and its shareholder and not the ratepayer.

Handbook Was Misapplied

63. The Board's finding that the Board did not apply the Handbook in the GLPL EB-2007-0744 decision is also incorrect. The Board specifically interpreted and applied the Handbook and its underlying policy in EB-2007-0744 (MR, Tab 12). In EB-2007-0744, the Board specifically stated:

> "The 2006 DRH sets out for electricity distributors how the Board generally intended to address applications for 2006 distribution rates. Among other issues, it dealt with how loss carry-forwards would be treated in setting the 2006 revenue requirements of distributors. The DRH sets out the consensus view of the working group as to how loss carry-forwards should be treated:
>
> *'A distributor expecting to have any loss carry-forwards still available on December 31, 2005 must disclose the amount of those loss carry-forwards in the 2006 application, apply them in full to*

reduce the taxable income calculated in the 2006 regulatory tax calculation.'

The Report of the Board that accompanied the 2006 DRH discussed the Board's rationale for approving this treatment of loss carry forwards:

'The Draft Handbook requires the distributor to take into account the potential reduction in actual taxes payable where a loss carry-forward is applicable.

Hydro One submitted that any loss carry-forward resulting from revenue or expense variations in prior years was irrelevant for the 2006 calculation. It argued that the ratepayer has not contributed to the prior loss and therefore is not entitled to the future tax savings. Hydro Ottawa made similar submissions.'

'<u>Conclusions</u>

<u>The Board has no evidence before it to determine whether loss carry-forwards are the result of revenue or expense variations or whether the loss carry-forwards arise for reasons that may be related to ratepayers.</u> The Board notes that the consensus approach [take loss carry-forwards into account when setting 2006 rates] will reduce the variance between taxes collected in rates and actual taxes paid. The Board will accept this approach in the Handbook.28 (emphasis added)' [by the Board in EB-2007-0744]

Although the Board accepted the position in the 2006 DRH that loss carry-forwards should be taken into account in setting 2006 rates, **the Board does not believe that position is applicable in all rates cases before the Board. It is clear from the highlighted sentence in the Report of the Board that the Board attaches some significance to the reasons for losses.** It is also clear from that sentence that approval of the 2006 DRH position on loss carry-forwards was taken without the opportunity to hear any evidence on what might have led to the losses." (emphasis added)

64. Furthermore, in interpreting and applying the Handbook in EB-2007-0744, the Board then proceeded to apply the principle of benefits follows the cost and stated as follows:

"that the pre-2007 losses of the distribution business should not be used to eliminate the tax provision for the 2007 test period. The Board reiterates its view **that the benefits of a tax loss should be realized by the party - shareholders or ratepayers - that bore the expenses or losses that gave rise to the tax loss** . . . the

> resulting losses should not be attributed to ratepayers but rather to GLPL, which sustained those losses and should retain the related tax benefits” (emphasis added).

65. As a result, when interpreting and applying the Handbook in respect of tax loss carry forwards the Board must look at the basis of the loss and its attribution to the shareholder or ratepayer to correctly apply the regulatory principle of benefits must follow the cost.

Principle Not Applied

66. The Board, erred in not applying the “benefits follows the costs” principle in the decision that is the subject of this motion. Relying only on its erroneous interpretation of the Handbook, the Board only stated that “it is apparent to the Board from the submissions of OPG and the parties that the “benefits follow cost” principle has been interpreted differently by the parties (Decision, p. 102, MR, Tab 1).

67. Notwithstanding this finding, the Board fails to identify the various interpretations to which it refers or to engage in any consideration whatsoever of the relative merits of those interpretations. Moreover, the Board fails to offer its own determination as to how the “benefits follow cost” principle should be interpreted or how it should be applied in OPG’s circumstances. The Board also does not attempt to reconcile any of the interpretations to which it refers with any of the Board’s prior interpretations of the principle, including in particular those set out in EB-2007-0905 (MR, Tab 14) and EB-2007-0744 (MR, Tab 12).

68. Rather than grappling with this fundamental issue, the Board simply relies on its observation that different parties in the hearing process put forward different interpretations of the principle. By failing to determine how the “benefits follow cost” principle should be interpreted in this case, the Board is effectively concluding - contrary to established regulatory principles - that regardless of whether a cost is borne by ratepayers or not, the ratepayers will always receive the benefit. Furthermore, if the Handbook is to be applied, the Board has misapplied the Handbook in respect of OPG’s tax loss carry forward.

69. OPG also referred the Board to its decision in EB-2007-0905. The Board failed to consider or ignored the fact that the Board's decision in EB-2007-0905 related to tax loss carry forwards and not just to the Board's uncertainty regarding OPG's tax calculation. In the Decision that is the subject of this motion, the Board finds that the circumstances in EB-2007-0905 "were unique and are not comparable to OPG's current circumstances" and that "the Board's finding in that case resulted from the absence of information and the Board's uncertainty regarding OPG's tax calculation" (Decision, p. 102; MR, Tab 1). The Board then provides, as support for its finding, a quotation using selected passages from pages 169-170 of the decision in EB-2007-0905 (MR, Tab 14).

70. In reaching its conclusion that the decision in EB-2007-0905 is not comparable to OPG's current circumstances, the Board has failed to consider a key part of the decision in EB-2007-0905. At page 170 of the EB-2007-0905 decision (MR, Tab 14), the Board states:

> **The Board believes that the benefit of tax deductions and losses that arose before the date of the Board's first order should be apportioned between electricity consumers and OPG based on the principle that the party who bears a cost should be entitled to any related tax savings or benefits.** The Board has adopted this principle in other cases where a company owns both regulated and unregulated businesses.
>
> The practical consequences of this principle can be illustrated by reference to two of the items that OPG cites as causes for the 2005 to 2007 regulatory tax loss . . .
>
> OPG's evidence indicated that in 2007 its **regulated operations** incurred an $84 million loss before income taxes . . . It would appear that the operating loss in 2007 was **borne completely by OPG's shareholder. Consumers have not been required to absorb that loss because the payment amounts for 2007 were set in 2005 and did not change. Accordingly, in the Board's view, none of the tax benefit of that loss should accrue to consumers.** (emphasis added)

71. Based on the foregoing, it is clear that the circumstances considered by the Board in EB-2007-0905 are directly analogous to the circumstances under consideration in the Decision. In each case, OPG experienced losses in its regulated operations, those losses were borne entirely by OPG's shareholder and consumers did not absorb any of the

operating loss. However, whereas the Board in EB-2007-0905 applied the principle of benefit follows cost and concluded that none of the tax benefit arising from the loss should accrue to ratepayers, the Board in the Decision ignores this finding and has instead determined that all of the tax benefit arising from the loss should accrue to ratepayers. As such, the Board has erred in the Decision by failing to consider or address these critical aspects from the EB-2007-0905 decision.

72. As a result of its error in finding that OPG's circumstances in 2013 are distinct from the facts in EB-2007-0744 and EB-2007-0905 and because of its failure to consider the Board's previous findings in respect of the Handbook, the Board in the Decision failed to consider the reason for OPG's underlying loss and the party that incurred the consequences of the loss and, as such, it failed to apply the principle of "benefits follow cost". As a consequence, rate payers improperly and unfairly receive the benefit of the tax losses and are in being effect subsidized by the utility resulting in rates that are not just and reasonable.

Giving Weight to the Fact that OPG Did Not Apply for New Payment Amounts for 2013

73. The Board erred by giving weight to the fact that OPG decided not to apply to the Board to change its payment amounts for 2013, which fact is not relevant to the consideration of the nature of the loss incurred by OPG or the treatment of the tax loss. The Board sees significance in the fact that OPG did not apply to change its payment amounts for 2013. In particular, the Board's view is that when OPG decided to not apply for new payment amounts for 2013, it did so with the knowledge that by making this choice OPG took a risk (Decision, p. 102; MR, Tab 1).

74. Given the Board's approach to rate-setting on a forward test year basis, an application for 2013 payment amounts would have had to be filed by OPG sometime in 2012 based on forecast production levels for 2013. As such, even if it did seek new payment amounts for 2013, OPG could not have known that it would end up having an operational loss in 2013 or the magnitude of that loss where such loss would give rise to a tax loss. It is unreasonable for the Board to suggest that OPG ought to have applied for 2013 payment amounts so as to avoid losses.

75. The approach taken by the Board is retrospective in nature with the application of hindsight and is not based on an accepted regulatory principle or practical in its application.

Part C: The Threshold Test is Satisfied:

76. The above errors of fact raise material questions as to the correctness of the Board's decision in respect of (a) OPG's Niagara Tunnel Project, and (b) OPG's tax loss carry forward, and should be corrected by granting the relief sought above. The Board's findings are contrary to the evidence that was before the panel. Once corrected, the amount that OPG will be permitted to add to its rate base in respect of the Niagara Tunnel Project, as well as the amount of the tax expense approved for recovery in the test period, will be materially different than as set out in the Decision. As such, on each of these issues OPG has satisfied the threshold test in Rule 43.01 of the Board's *Rules of Practice and Procedure*.

77. In establishing just and reasonable rates, the Board is obligated to permit the recovery of, and OPG is entitled to recover, its reasonable and prudently incurred costs. Because of the errors set out herein, the Decision does not permit OPG to recover a return on the full amount of its reasonable and prudently incurred capital costs associated with the Niagara Tunnel Project, or its reasonable and prudently incurred income tax costs for the test period and, as such, the payment amounts are not just and reasonable.

78. The Board's *Rules of Practice and Procedure*.

79. Such further grounds as counsel may advise and the Board may permit.

The Following Documentary Evidence will be used at the motion:

80. The Following Documentary Evidence will be used at the motion:

(a) materials from the record in EB-2013-0321;

(b) the Decision;

(c) OPG’s submissions on this Motion to be delivered in accordance with the Board’s procedural order or orders; and

(d) such further evidence as counsel may advise and the Board may permit.

December 10, 2014

Torys LLP
79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2
Fax: 416.865.7380

Charles Keizer (LSUC#: 34735D)
Tel: 416.865.7152
Crawford Smith (LSUC#: 42131S)
Tel: 416.865.8209

Counsel for the Applicant,
Ontario Power Generation Inc.

TO: Ontario Energy Board
2300 Yonge Street, 27th Floor
P.O. Box 2319
Toronto, ON M4P 1E4

AND TO: All Intervenors

ONTARIO ENERGY BOARD

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

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

AND IN THE MATTER OF Rule 40 of the Rules of Practice and Procedure of the Ontario Energy Board.

MOTION RECORD
OF THE MOVING PARTY ONTARIO POWER GENERATION INC.

December 10, 2014

Torys LLP
79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2
Fax: 416.865.7380

Charles Keizer (LSUC#: 34735D)
Tel: 416.865.7152
Crawford Smith (LSUC#: 42131S)
Tel: 416.865.8209

Counsel for the Applicant,
Ontario Power Generation Inc.

MOTION RECORD

on behalf of

ONTARIO POWER GENERATION INC.

INDEX

Tab	**Description**
1.	Ontario Energy Board, *Decision with Reasons dated November 20, 2014* (EB-2013-0321), pp. 21-34 and 98-103.
2.	Pre-filed Evidence, Exhibit D1, Tab 2, Schedule 1, pp. 49-50, 74-76, 96-97, 99, 102-103, 106-112, 132, 136-140.
3.	Oral Hearing Transcript, Volume 2, pp. 23-25, 81-82, 85-89, 124-126, 136-137, 147-149.
4.	Pre-filed Evidence, Exhibit D1, Tab 2, Schedule 1, Attachment 7, pp. 1, 5-6, 18-19.
5.	Pre-filed Evidence, Exhibit D1, Tab 2, Schedule 1, Attachment 6, PDF p. 1724.
6.	Pre-filed Evidence, Exhibit L, Tab 4.4, Schedule 2 AMPCO-016.
7.	Exhibit JT1.5, Attachment 1.
8.	Pre-Filed Evidence, Exhibit N2, Tab 1, Schedule 1, Table 1.
9.	Exhibit J13.4, Attachment 1.
10.	Exhibit L, Tab 6.13, Schedule 1, Staff-166.
11.	Ontario Energy Board, *2006 Electricity Distributor's Rate Handbook*, Chapter 7.
12.	Ontario Energy Board, *Decision and Order re Great Lakes Power Limited*, dated October 30, 2008 in EB-2007-0744, pp. 41-44.
13.	Ontario Energy Board, *Report of the Board* dated May 11, 2005 in RP-2004-0188, p. 57.
14.	Ontario Energy Board, *Decision with Reasons re Ontario Power Generation*, dated November 3, 2008 in EB-2007-0905, pp. 168-172.

TAB 1

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2013-0321

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES FOR 2014 AND 2015

DECISION WITH REASONS

November 20, 2014

for 2014 and 2015. OPG failed to meet its in-service capital addition budget (or approved level) for its previously regulated hydroelectric facilities in 2010 and 2012, however the budget was exceeded in 2011 and 2013. In the case of additions being lower than budgeted, OPG's witnesses testified that issues arose on specific projects that led to in-service date delays beyond the year in which they were proposed to be in-service. The Board notes that in years in which capital additions exceeded the budget, the amount of overage was much less than the years when the capital additions were below the budgeted level. Over the four year period (2010 to 2013) SEC put forward that the average capital additions were only about 73% of the planned in-service additions.

The Board finds that some level of reduction to the in-service capital additions is required. OPG has not satisfied the Board that it will meet its in-service capital addition budget for 2014 and 2015. Rather than the $13M reduction per year suggested by Board staff, the 17% reduction suggested by SEC or the 27% reduction proposed by LPMA (the latter both based on the four year average additions variance), the Board finds it appropriate to reduce the capital in-service additions by 10% in 2014 and 2015. This amount represents a relatively minor reduction but reflects the fact that the Board is not satisfied by the evidence provided that there will not be in-service delays in 2014 and 2015. The capital additions approved by the Board are therefore $119.9 M in 2013 (actuals), $77.5M in 2014 and $136.4M in 2015.

2.4 Niagara Tunnel Project

(Issues 4.4 and 4.5)

The Niagara Tunnel Project is a 10.2 km long tunnel constructed by OPG with a diameter of 12.7 metres which runs under the City of Niagara Falls. Its purpose is to increase the flow of water to the Niagara plant group, and thereby increase generation by 1.6 TWh annually. After several years of construction, the asset was placed in service in March 2013 at a cost about 50% greater than originally budgeted.

In this application, OPG is seeking the Board's approval to close $1,452.6M in capital expenditures (in-service) (see line 5 of Table 10) to the test period rate base. OPG states that the cost above the original budget arose entirely from the fact that the rock conditions encountered during construction were worse than OPG reasonably anticipated.[8]

The Board's consideration of the costs of the Niagara Tunnel Project is guided by section 6(2)4 of O. Reg. 53/05, which states:

> The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,
>
> i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or
> ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

The OPG Board of Directors approved the expense of $985.2M in 2005, prior to the Board's first order in 2008. OPG states that the issue before the Board is whether the $491.4M in expense beyond the $985.2M was prudently incurred. None of the parties have disputed this assertion.

The PWU submitted that the geological investigations and studies undertaken were appropriate and that OPG's conduct during and after the differing subsurface condition dispute was appropriate. PWU states the $491M additional cost was incurred reasonably and prudently. However, a number of parties found fault with OPG's management of the Niagara Tunnel Project, and argued for a range of disallowances to the amount closing to rate base.

Background

The initial budget for the project approved by OPG's Board of Directors in 2005 was $985.2M. There were a number of delays and cost over-runs resulting from

[8] Argument-in-Chief page 23

unanticipated subsurface conditions. Ultimately the total cost of the Niagara Tunnel Project was $1,476.6M of which OPG is seeking to close $1,452.6M to rate base in this application.[9] A summary of project costs is provided in the table below.

Table 10: Niagara Tunnel Project

	$ millions*	Pre- 2008 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Test Year	2015 Test Year	Total
1	Budget Approved/Revised by OPG Board	985.0	985.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	
2	Capital Expenditures	300.2	131.3	213.5	231.8	264.2	231.2	86.6	13.0	0.4	
3	Accumulated Capital Expenditures	300.2	431.5	645.0	876.8	1,141.0	1,372.2	1,458.8	1,471.8	1,472.2	
4	Gross Plant in-service (Opening Balance)	19.2	19.2	19.2	19.2	19.2	19.2	19.2	1,458.4	1,471.4	
5	Gross Plant additions	-	-	-	-	-	-	1,439.2	13.0	0.4	1,452.6
6	Gross Plant in-service (Closing Balance) **	-	-	-	-	-	-	1,458.4	1,471.4	1,471.8	
	Source: OPG Reply Argument p.26 & Exh L-4.5-Staff-25										
	*Numbers may not add up due to rounding										
	** To calculate the total cost of the Niagara Tunnel Project, $4.6M in removal costs (treated as operating expenses) is added to the $1,472.2M in total capital(in-service) expenditures. This results in a Niagara Tunnel Project total cost of **$1,476.6M**. The $4.6 M is recorded in the Capacity Refurbishment Variance Account.										

OPG's preparatory geotechnical investigation for a Niagara Tunnel began in 1983. The tunnel passes through geologically challenging conditions, including the Queenston shale formation. OPG's initial investigations included 59 boreholes and an exploratory adit (a test tunnel).

OPG undertook a request for proposal process in 2004/2005. The request for proposal mandated a tunnel boring process, which was a requirement of the environmental assessment. The request for proposal was based on OPG's geotechnical investigations and OPG's risk assessment analysis. Strabag AG of Austria and its wholly owned subsidiary Strabag Inc. ("Strabag") were the successful bidders.

Strabag's bid was based on a "design-build" approach, whereby OPG would hire a single firm (i.e. Strabag) to design and build the project to OPG's pre-established specifications.[10] The OPG Board of Directors approved the release of $985.2M, of which $112M was contingency. The business case presented to the OPG Board of Directors stated that the project economics compared favourably against other renewable generation options. The Design Build Agreement with Strabag was signed in August 2005. The new tunnel was projected to be in service by June 2010 and was

[9] The $24M difference is comprised of amounts added to rate base prior to 2008 and an amount attributed to OM&A.
[10] The other common approach is design-bid-build, whereby OPG would hire a firm to design the tunnel, issue a request for proposal on the basis of the design, and then select a firm to construct it.

expected to increase generation by 1.6 TWh. The initial cost of the tunnel itself, as reflected in the Design Build Agreement, was $622.6M to be paid to Strabag.

The terms of the Design Build Agreement were based in part on a Geotechnical Baseline Report. The purpose of the Geotechnical Baseline Report was to establish a contractual baseline for subsurface hydro-geological conditions. Initially OPG prepared a geotechnical baseline report which was included with the request for proposal and bidders including Strabag provided geotechnical baseline reports (based on OPG's report) with their bids – these are referred to in the evidence as Report A and Report B respectively. The final Geotechnical Baseline Report (sometimes referred to in the evidence as Report C) was negotiated jointly by OPG and Strabag as part of the Design Build Agreement. Unless otherwise specified, references to the Geotechnical Baseline Report in this Decision refer to this final Report C.

In the event that the actual subsurface conditions were found to be materially different from the conditions anticipated in the Geotechnical Baseline Report, the Design Build Agreement provided a number of potential remedies. If OPG agreed that there was a "differing subsurface condition", the parties could negotiate changes to the schedule and price. If OPG did not agree that there was a differing subsurface condition, the Design Build Agreement outlined a dispute resolution process, which included recourse to a third party Dispute Review Board.[11]

One of the subsurface issues addressed in the Geotechnical Baseline Report was "overbreak". Overbreak is the cracking and loosening of rocks above the tunnel boring machine[12] as it moves through the rock to create the tunnel. It was recognized by both OPG and Strabag that overbreak could be an issue, particularly in the Queenston shale formation through which portions of the tunnel were expected to pass. OPG's original assessment was that there would be approximately 45,000 m^3 of overbreak, whereas Strabag estimated only 15,000 m^3. In the final Geotechnical Baseline Report (which was part of the Design Build Agreement), the parties agreed to a figure of 30,000 m^3.

Construction began in September 2005. Excavation by the open tunnel boring machine commenced in September 2006. Starting in spring 2007, significant quantities of overbreak were reported, which resulted in delay and additional expense to Strabag. Strabag considered this excessive overbreak to be due to a differing subsurface

[11] Exh D1-2-1 Attachment 6, Design Build Agreement, sections 5.5-5.7.
[12] Exh D1-2-1 page 72

condition more significant than had been previously identified, and attempted to negotiate changes to the Design Build Agreement with OPG. By February 2008, it was clear that the parties would be unable to resolve the issue on their own, and the dispute was referred to a Dispute Review Board.

Strabag argued before the Dispute Review Board that one or more differing subsurface conditions existed based on five issues of dispute, including the excessive amount of overbreak. OPG's position was that no differing subsurface condition existed and that Strabag was at fault for the overbreak because it substantially modified its tunnel boring machine design and rock support from the original proposal.

The Dispute Review Board held that for three of the issues identified (large block failures, insufficient "stand-up" time, and an issue related to tunneling under the buried St. Davids Gorge) there was no differing subsurface condition. For the other two issues (excessive overbreak and the table of rock conditions and rock characteristics) the Dispute Review Board found that there was a differing subsurface condition. With respect to the differing subsurface conditions, the Dispute Review Board report stated:

> Since the development of the [Geotechnical Baseline Report] was the mutual responsibility of both Parties, we recommend that the Parties negotiate a reasonable resolution based on a fair and equitable sharing of the cost and time impacts resulting from the overbreak conditions that have been encountered and the support measures that have been employed. [13]

Following negotiation, OPG agreed to pay Strabag an extra $40M to resolve all issues to November 30, 2008 (Strabag had claimed additional costs of $90M). After considering several options, OPG determined that the best way to ensure the completion of the Project was to renegotiate the Design Build Agreement. The excessive amount of overbreak required tunnel profile restoration (infill to restore tunnel profile to a circular shape), realignment of the tunnel route, and additional cost and time. An Amended Design Build Agreement, based on target cost instead of fixed price, was approved by the OPG Board of Directors in May 2009. The total project cost estimate was revised to $1.6 billion, of which $985M was now allocated to Strabag for constructing the tunnel. The Amended Design Build Agreement moved the completion date for the project from June 2010 to June 2013. The supporting business case stated

[13] Exh D1-2-1 Attachment 7 page 18

that completing the tunnel was still economic when compared with alternative energy supply options.

Ultimately the tunnel was completed in March 2013, for less than the $1.6 billion revised cost. The final total cost for the Niagara Tunnel Project was $1,476.6M (see footnote to Table 10). Strabag earned a number of incentives for completing the project ahead of the revised schedule and for less than the revised budget.

As part of its application, OPG filed a report by Mr. Roger Ilsley, a geotechnical and tunnel expert. The report concluded that OPG's site investigations were appropriate and completed to professional standards. Similarly Strabag's design work was completed to professional standards.[14] Mr. Ilsley also appeared as a witness at the oral hearing.

Geotechnical Baseline Report

The submissions of Board staff, AMPCO, CME and SEC criticized the Geotechnical Baseline Report. OPG was solely responsible for the initial Report A which was the basis for the request for proposal and subsequent reports. The bidders provided Report B, a supplemented version of Report A, with their bids. The final Report C was agreed to by OPG and the successful bidder, Strabag. It was submitted that the contractually binding Report C was ambiguous and not in compliance with the *Geotechnical Baseline Reports for Construction – Suggested Guidelines*. AMPCO submitted that the ambiguity in the original Report A misled Strabag to propose open tunnel boring instead of closed tunnel boring and that OPG's expert, Mr. Ilsley, agreed in cross examination that Report C was ambiguous.[15]

As summarized in the Dispute Review Board's report:

> The [Dispute Review Board] agrees that the Table of Rock Conditions and Rock Characteristics is inadequate to be used for the identification of [Differing Subsurface Conditions] and, further, that the inclusion of such terms as the "closest match" and "all other conditions" essentially renders the concept of [Differing Subsurface Conditions] meaningless and makes the [Geotechnical Baseline Report] defective.[16]

[14] Exh F5-6-1
[15] Tr Vol 2 page 53
[16] Exh D1-2-1 Attachment 7 page 18

OPG spent $57M on geotechnical investigations. OPG asserts that this was a considerable amount of investigation, and the results were unchallenged by five contractors who did not seek additional geotechnical data to submit their bids. Further, the geotechnical investigation and results were supported by Mr. Ilsley. The guidelines for geotechnical baseline reports recognize that it is not always possible to describe geologic conditions precisely. OPG stated that AMPCO's criticism that the geotechnical baseline report was misleading to bidders is incorrect as Strabag considered both closed and open tunnel boring.

In OPG`s view, the parties have not pointed to a single action that OPG took that was unreasonable in developing the Geotechnical Baseline Report.

Risk Management

The submissions of Board staff, AMPCO and SEC find fault with OPG's risk assessment process and the risk OPG assumed in the project. Some parties noted that OPG's contracting approach was a risk since tunnels in North America have traditionally been constructed using Design-Bid-Build contracts instead of Design Build. SEC observed that of the 59 borehole tests conducted, only 20 were located along the proposed route. SEC also questioned OPG's decision to rely on 1993 borehole data as testing methods and instrumentation had likely improved in the interim.

In OPG`s view the Design Build approach was selected to appropriately allocate project risk and to obtain as much upfront price certainty as possible. OPG stated that the criticisms of the vintage of borehole data are contrary to the evidence of Mr. Ilsley, who testified that while the electronic methods to record geotechnical results have improved, the tests themselves are unchanged.

OPG submitted that all the project risks identified by OPG were mitigated to low risk except subsurface conditions which remained at medium risk. OPG`s mitigation activity to move the risk from high to medium was the extensive field investigation over 10 years, the 3 stage geotechnical baseline report process and contingency for the tunneling work. While total project contingency was $112M, the contingency for the tunneling portion of the project was $96M. OPG stated that to mitigate to low risk would be costly. As OPG assumed full responsibility for geological conditions in design build, the parties submitted that OPG assumed too high a risk.

OPG replied that, "While it is clear in hindsight that OPG underestimated the potential severity of the rock conditions encountered, particularly the nature and extent of the overbreak, this occurred because the rock conditions were much more challenging than OPG, its experts and Strabag expected based on extensive geotechnical sampling and analysis, and not because OPG's risk identification and quantification efforts were deficient."[17]

Contract Renegotiation

Several parties submitted that OPG was not prudent in its renegotiations with Strabag and that the Amended Design Build Agreement did not reflect sharing of responsibility for losses as determined by the Dispute Review Board. SEC observed that few options were presented to the OPG Board of Directors and that the Amended Design Build Agreement was for all intents and purposes final when it was presented to the OPG Board.

When Strabag filed its claim for $90M, tunneling had advanced to the 3 km point. OPG had paid Strabag $40M, or $13.3M/km. CME observed that the Amended Design Build Agreement provided for an additional $243M for the remaining 7 km, or $34.7M/km. CME submitted that OPG should not have paid Strabag more than $13.3M/km for the remaining 7 km, and that the difference would result in a $149M disallowance.

A number of parties submitted that OPG could have achieved a better result through the Amended Design Build Agreement. OPG stated that the understanding of the parties with respect to sharing of risk is incorrect. At the end of three years of work, Strabag had a loss of $90M, which was settled by a $40M payment. Strabag finished the tunnel with what OPG characterized as a very small profit after an additional four years of work. OPG argued that CME`s understanding of additional costs per km are incorrect as the $90M claim did not include tunnel profile restoration, which had to be undertaken in addition to completion of the remaining 7 km.

OPG also argued that there would have been significant costs for terminating the Strabag contract. Mr. Ilsley referred to the Seymour-Capilano project in Vancouver which was rebid at 1.8 times the original cost for the remaining 40% of the work with potential litigation by the original contractor.[18]

[17] Reply Argument page 52
[18] Tr Vol 1 page 80

Disallowances Proposed by Parties

Board staff and the parties have proposed reductions to the rate base addition ranging from $50M to $407.4M:

- Energy Probe submitted that a $50M rate base addition reduction was appropriate as OPG's use of the design build model limited its ability to terminate Strabag.
- Board staff listed 7 items to deduct from rate base additions totaling $105M, including the $40M paid to Strabag pursuant to its claim, design costs, overhead costs and carrying charges.
- In addition to $149M related to contract renegotiation, CME agreed with several of the items that Board staff proposed for disallowance, and proposed a $208.5M total disallowance.
- SEC proposed that rate base additions should be reduced by $245.7M, i.e. half of the amount in excess of the originally approved $985.2M
- AMPCO's submission listed 9 items, including the entire diversion tunnel expense beyond the original estimate of $280.3M and $10.8M paid to OPG's representative, Hatch. AMPCO submitted that $407.4M should be removed from OPG's proposed rate base additions.

OPG replied that all of these disallowances should be rejected, and that the analysis of Board staff and parties is inadequate. Other than Mr. Ilsley, there were no expert witnesses that gave evidence related to the Niagara Tunnel. OPG argued that the parties did not fully understand the evidence and the arguments are selective reviews based on hindsight. Although the parties claimed imprudence, in OPG's view the parties failed to identify a single action that OPG took or failed to take that was unreasonable at the time.

OPG stated that the Niagara Tunnel Project costs are reasonable and that "if the rock conditions had been known in advance with perfect foresight, the tunnel would have cost at least what OPG paid and may have cost more."[19]

[19] Reply Argument page 39

Board Findings

The Board finds that $1,364.6M in Niagara Tunnel Project capital expenditures (in-service) should close to rate base in the test period. This represents a disallowance of $88.0M (or approximately 6%) from the $1,452.6M proposed by OPG. The disallowances are based primarily on OPG's response to the Dispute Review Board's decision and recommendations, in particular OPG's decision to pay $40M for claims prior to December 2008, and the terms negotiated with Strabag in the Amended Design Build Agreement.

The Board accepts OPG's argument that the Board's review of the Niagara Tunnel Project is a "prudence review", and that the Board is not permitted to use hindsight when considering OPG's actions. The Board also accepts OPG's assertion that, pursuant to section 6(2)4 of O. Reg. 53/05, only the $491.4M in expenses incurred after 2008 are subject to review. As a result, the Board will not opine on the actions of OPG prior to the commencement of the Board's regulation of OPG in 2008.

Settlement of Strabag's $90M Claim

In its report, the Dispute Review Board recommended "that the Parties negotiate a reasonable resolution based on a fair and equitable sharing of the cost and time impacts resulting from the overbreak conditions that have been encountered and the support measures that have been employed. Both Parties must accept responsibility for some portion of the additional cost, but at the same time the Contractor must have adequate incentives to complete the Work as soon as possible."[20]

Based in part on this recommendation, OPG decided on two courses of action. First, it agreed to settle all of Strabag's pre-December 2008 claims for $40M (Strabag had claimed $90M). Second, OPG determined that the best solution moving forward was to renegotiate the Design Build Agreement with Strabag. The resulting Amended Design Build Agreement target cost was $985M plus incentives (compared with the Design Build Agreement contract cost of $622.6M).

The Project was completed pursuant to the terms of the Amended Design Build Agreement. Strabag earned the incentives described in the Amended Design Build

[20] Exh D1-2-1 Attachment 7 pages 18-19

Agreement. Overall OPG estimates that Strabag earned a profit of approximately $26M on the Project as a whole.[21]

Several parties questioned whether the Amended Design Build Agreement appropriately allocated responsibility for the additional costs between OPG and Strabag. OPG's witnesses testified that absent a successfully renegotiated Design Build Agreement, Strabag would have likely walked away from the Project. OPG would then have been forced to find a new contractor to complete the Project. OPG expected that the costs of finding a new contractor at that stage of the Project would have greatly exceeded the cost of renegotiating the Design Build Agreement with Strabag.

The Board is not satisfied that paying Strabag $40M for its claims up to December 2008 was prudent. This Board finds that the non-binding recommendations of the Dispute Review Board were reasonable, and that some level of shared responsibility between OPG and Strabag was appropriate. However, paying a $40M settlement (44% of Strabag's $90M claim) is excessive in the Board's view. There were five issues of dispute that were referred to the Dispute Review Board. The Dispute Review Board found that OPG was not responsible for three of the five issues and that OPG had only joint responsibility for the remaining two issues. No evidence was filed on the relative value or cost of the five issues. OPG's witnesses testified that the individual issues were not quantified.

As a result of the contract renegotiation with Strabag, OPG had the right to audit Strabag's claimed losses of $90M. To the extent that the $90M was not substantiated in the audit, the $40M payment could be reduced proportionately. OPG's witnesses testified that OPG's internal auditors conducted the audit and found that a total of $12.6M was not associated with legitimate expenses, resulting in a loss of only $77.4M.[22] The auditors did not recognize inter-company transfers within Strabag's organization, thereby reducing the amount from $90M to $77.4M.[23] OPG's evidence was that they could reduce the $40M settlement proportionately based on the audit, but did not do so.[24]

The Board is unable to find that a $40M settlement of Strabag's claim was prudently incurred. In the absence of information regarding the costs attributable to each of the

[21] Tr Vol 2 page 124
[22] Exh L-4.5-SEC-41 Attachment 16
[23] Tr Vol 2 page 149
[24] Exh D1-2-1 page 106

five issues, the Board must use its judgment of what is a reasonable amount. In determining the amount, the Board has decided to utilize the findings of the Dispute Review Board. As a result, the Board finds that OPG's ratepayers should not pay any amount for the three issues which OPG was not responsible, but should pay 50% of two issues for which OPG was jointly responsible. In addition, the Board is persuaded by the results of OPG's audit and considers the $77.4M to be the appropriate starting point for the Board's calculation, not the $90M claim by Strabag. There was no evidence or testimony provided supporting Strabag's claimed amount. As a result, the Board finds that ratepayers should only pay 20% of the $77.4M audited amount, or $15.5M. In addition, the Board denies the associated carrying costs of the disallowed $24.5M,[25] which results in a reduction of another $3.5M.[26] The Board finds this disallowance of $28.0M reasonable given the evidence provided.

Terms of the Amended Design Build Agreement

The Board finds that not all of the costs associated with the Amended Design Build Agreement should be passed on to ratepayers.

The Board accepts that absent a revised Design Build Agreement, there was a possibility that Strabag would have abandoned the Project. Had that occurred, the cost of completing the Project with a new contractor might well have exceeded the costs of the Amended Design Build Agreement. In the Board's view, however, the possibility of project abandonment and the speculation of the financial impact of this does not justify the level of incentives offered to Strabag in the Amended Design Build Agreement. The question is not: Would it have cost OPG more had Strabag walked away? Instead, the salient question is: Could OPG have achieved better terms than it did in negotiating with Strabag to move forward after the Dispute Review Board findings?

The risk of the contractor abandoning the Project was recognized in the original 2005 Business Case. The project risk profile identified this risk as "medium" before mitigation, and "low" after mitigation. The mitigation activity described in the project risk profile was a requirement for the contractor to provide bonds and/or letters of credit as security, and to provide a parental guarantee. As part of the Design Build Agreement, Strabag was required to post a letter of credit for $70M, and provide a parental indemnity guaranteeing Strabag's performance of the contract and indemnifying OPG

---

[25] $40M – (20% x $77.4M)
[26] $24.5M x 5.25% x 33/12 months

for any damages resulting from a breach by Strabag.[27] The Indemnity Agreement provided that Strabag's parent company "irrevocably and unconditionally agrees to indemnify and save harmless OPG from and against all costs, damages, expenses, losses, liabilities, demands, claims, suits, actions, proceedings, judgments and obligations (including, without limitation, legal fees and expenses) arising in respect of any breach" of the Design Build Agreement. The Indemnity Agreement further allowed OPG to make credit inquiries about the parent company, and provided OPG with three years of financial statements.[28]

OPG's witnesses further confirmed that Strabag would suffer serious repercussions were it to walk away from the Project, including being sued by OPG for breach of contract, and suffering a serious blemish on its business reputation.[29]

Strabag, therefore, had very strong incentives to reach an agreement with OPG to find a way to complete the Project. Walking away from the Project would have been an extremely expensive and unpalatable option for Strabag, and for its parent company.

Under these circumstances, the Board finds that the incentives offered to Strabag through the Amended Design Build Agreement were excessive. OPG understood that a contractor default was a potential risk, and indeed it took steps that should have mitigated that risk through a letter of credit and a comprehensive parental indemnity. However, when it came time to renegotiate the Design Build Agreement, OPG did not properly use its leverage to secure a more favourable deal. The Board will disallow recovery of $60M.[30] The Board is mindful of the Dispute Review Board's recommendation that Strabag have appropriate incentives to complete the work. However, in the Board's view the Amended Design Build Agreement provided adequate "incentive" even without the specific incentive clauses. OPG agreed to pay Strabag hundreds of millions of extra dollars more than was provided for in the original Design Build Agreement. In the Board's judgment, the provision for incentives above this was not necessary and not prudent.

The total disallowance related to the capital expenditures of the Niagara Tunnel Project is $88.0M, which the Board finds to be imprudently incurred. The Board approves

[27] Exh D1-2-1 page 37
[28] Indemnity Agreement – Appendix 4.1(e) to the Design Build Agreement.
[29] Tr Vol 2 pages 122-123
[30] Exh D1-2-1 Attachment 9 - $40M schedule and cost performance incentive, $10M interim completion fee, and $10M substantial completion fee

$1,364.6M as the amount of Niagara Tunnel Project capital expenditures (in-service) to close to rate base in the test period.

2.5 Hydroelectric Other Revenue

(Issue 7.1)

OPG earns revenue from a number of sources other than through the regulated payment amounts for hydroelectric generation. These sources of other revenue include ancillary services, segregated mode of operations and water transactions.

The historical and forecast other revenues for the previously regulated and newly regulated hydroelectric facilities are summarized in the following table.

Table 11: Hydroelectric Other Revenue

$million	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Previously Regulated Ancillary Services	26.2	22.2	20.8	17.8	37.1	18.1	18.5
Seg Mode of Operation	-0.9	1.7	-0.8	1.6	4.1	0.0	0.0
Water Transactions	5.5	7.5	1.6	6.0	1.0	1.7	1.7
HIM Adjustment				6.5	6.5		
Total	**30.8**	**31.4**	**21.6**	**31.9**	**48.7**	**19.8**	**20.2**
Total: Exhibit N1 Update (Ancillary Services: $32.2M - 2014, $32.9M - 2015)						**33.9**	**34.6**
Newly Regulated Ancillary Services	**26.4**	**26.1**	**25.9**	**22.2**	**35.7**	**22.7**	**23.1**
Source: Exh G1-1-1, Exh L-1-Staff-2, Exh N1-1-1							

The IESO purchases the following ancillary services from OPG: black start capability, reactive support/voltage control service, automatic generation control and operating reserve. A forecast of the revenues from ancillary services is applied as an offset to the hydroelectric revenue requirement. Differences between the forecast and actual revenues are recorded in the Ancillary Services Net Revenue Variance Account – Hydroelectric. OPG has proposed that the account also apply to the newly regulated hydroelectric facilities.

The Exhibit N1 update is the result of higher forecast revenue for operating reserve and a new contract for regulation service, resulting in an increase in ancillary services years and SEC proposed 150 years. OPG argued that there was no evidentiary basis for the proposals of the parties.

Board Findings

The Board finds that OPG responded appropriately to the direction in EB-2010-0008 by having an independent depreciation study undertaken. The Board accepts the study results, predicated on OPG's continued application of the average life group method. The Board will not require OPG to file another study using the equal life group method, as the data is not available. The Board accepts Gannett Fleming's evidence that OPG lacks the necessary data to use the equal life group method and the cost to develop the data would be prohibitive.

OPG's depreciation and amortization expense for the test period incorporates all the recommendations made by Gannett Fleming. The Board accepts the evidence of Gannett Fleming and its recommended 95 year useful life for the Niagara Tunnel. Although the useful lives of the Sir Adam Beck Tunnels are longer than 95 years, the useful lives were reviewed and extended after 45 years in-service. The Board will not consider extending the useful life of the Niagara Tunnel at this time.

The Board approves the depreciation expenses as filed to be included in the calculation of the payment amounts.

4.7 Taxes

(Issue 6.13)

OPG seeks approval for property taxes of $16.3M in 2014 (assuming full year for the newly regulated hydroelectric facilities) and $16.8M in 2015 for the regulated business. No submissions were filed on property taxes, and the Board approves OPG's request.

OPG uses the taxes payable method for determining regulatory income tax for the regulated facilities. The tax is allocated based on each business's regulatory taxable income. OPG seeks approval of income tax expense of $187.9M in 2014 (assuming full year for the newly regulated hydroelectric facilities) and $123.7M in 2015 for the regulated business.

This section addresses two sub-issues relating to a tax loss carry-forward from 2013 and deferred taxes associated with the newly regulated hydroelectric assets.

4.7.1 Tax Loss Carry-Forward

In 2013, OPG incurred a regulatory tax loss of $211.6M that OPG attributes to a shortfall in nuclear production. OPG submitted that the associated tax loss carry-forward that was created should not be applied to regulatory taxable income in 2014 to reduce the tax provision included in the payment amounts. OPG argued that OPG's shareholder incurred the costs associated with the loss in 2013 and should receive the benefit of the resulting tax loss carry-forward in 2014. As a result, OPG posted an accounting entry to its corporate retained earnings, to the benefit of its shareholder. OPG relied upon a principle that "benefits follow costs" as stated in the *Accounting for Public Utilities*, published in the United States in 2005 to support its proposal.

> …if ratepayers are held responsible for costs, they are entitled to the tax benefits associated with the costs. If ratepayers do not bear the costs, they are not entitled to the tax benefits associated with the costs.[101]

OPG also referred to two prior decisions in which the Board referenced this principle, namely the OPG EB-2007-0905 decision and the Great Lakes Power EB-2007-0744 decision. In OPG's submission, the situation in 2013 is similar to the situation in 2007 when it incurred a tax loss and the Board did not approve the associated tax loss carry-forward for determining OPG's 2008 payment amounts.

OPG also argued that the Board cannot adjust rates in a future period without a deferral or variance account, as this would amount to retroactive ratemaking.

Board staff submitted that the tax loss should be carried forward and applied to the test period tax provision to the benefit of ratepayers. OPG's payment amounts that were in effect in 2013, when the tax loss occurred, included a recovery amount for income tax. The 2013 payment amounts were established based on the 2011 and 2012 test period and included recovery of approved income tax amounts of $60.9M and $91.1M respectively. The payment amounts approved for 2011 and 2012 persisted into 2013 as OPG did not apply for new 2013 payment amounts. Board staff submitted that since

[101] Accounting for Public Utilities, by Robert Hachne and Gregory Aliff, Part V, Chapter 7, September 17, 2005

ratepayers have borne the tax costs included in the payment amounts in 2013, the 2013 regulatory tax loss carry-forward calculated by OPG should be used to reduce regulatory taxable income in 2014.

Board staff submitted that this treatment is consistent with the Board's long-established policy requiring tax loss carry-forwards to be applied to reduce regulatory taxable income, as stipulated in the 2006 Electricity Distribution Rate Handbook.[102] At the hearing, Board staff cited several Board examples of electricity distributors in their rate applications carrying forward income tax losses from a prior year(s) to reduce or eliminate taxable income in a future year's test period. In addition, Board staff cited several Board decisions approving tax loss carry-forwards to reduce regulatory income taxes.

LPMA and CME supported Board staff's submission.

SEC supported Board staff's submission yet also referred to the "benefits follow costs" principle which was used by the Board in OPG's first payment amount decision (EB-2007-0905). SEC submitted that the "benefits follow costs" principle was used by the Board to ensure that there was a principled way of allocating costs and benefits to regulated and unregulated periods, which was not the case for OPG in 2013. In this case, the loss arose during a period in which OPG was collecting regulated rates from ratepayers. That is a similar situation to the electricity distributors, who do have to apply tax loss carry-forwards in one regulated year to reduce taxable income in subsequent regulated years.

SEC submitted that the "benefits follow costs" principle was never intended to allow a utility to collect money from ratepayers for PILs, then keep that money for their own purposes because they were unable to operate the regulated business at a profit.[103]

In reply, OPG argued that Board staff incorrectly applied the principle in its submission and SEC fundamentally misunderstood the Board's application of the principle. OPG asserted that the tax loss arose because of an operating loss. As OPG and its shareholder had to bear the operating loss, not ratepayers, OPG submitted that its shareholder is entitled to receive the benefit of the associated tax loss.

[102] 2006 Electricity Distribution Handbook, May 11, 2005, page 61
[103] SEC Final Argument page 72

Board Findings

The Board directs OPG to reduce its 2014 income tax provision to recognize and carry forward its regulatory tax loss in 2013. This finding is consistent with Board policy as indicated in the Board's 2006 Electricity Distributor's Rate Handbook (the "Handbook") and in subsequent Filing Requirements.[104] The Board understands the policies contained in the Handbook and the Filing Requirements apply to electricity distributors, not directly to OPG as an electricity generator, yet finds that the underlying Board policy should be applicable to OPG in this application.

The rate regulation of the electricity distribution sector shows a history of tax loss carry-forwards being routinely used in the rate setting process for distributors. This approach is completely consistent with Board policy for tax losses to be applied to reduce income tax to be included in rates, and there is no reason for OPG to be treated any differently in this instance.

OPG referred to two decisions in which the Board did not apply the policy, namely OPG's EB-2007-0905 decision and Great Lakes Power's EB-2007-0744 decision. The Board finds that the circumstances in these two cases were unique and are not comparable to OPG's current circumstances.

The Board's findings in the EB-2007-0905 decision address the fact that OPG was not regulated by the Board prior to 2008, when the tax loss occurred. The Government set OPG's rates in 2005, 2006 and 2007. The Board's EB-2007-0905 decision in 2008 did not reference the policy in the Handbook. The Board finds that the circumstances in OPG's first payment amounts proceeding were unique and the Board's finding in that case resulted from the absence of information and the Board's uncertainty regarding OPG's tax calculation.

> The Board is not convinced that there are any "regulatory tax losses" to be carried forward to 2008 and later years, or if there are any, that the amount calculated by OPG is correct….The Board does not have the information necessary to determine the tax benefits which should be carried forward to offset payment amounts in 2008 or later periods.[105]

[104] A requirement to identify any loss carry-forwards and when they will be fully utilized has been included in the Board's Filing Requirements for electricity distributors' cost of service applications since 2012. With the issuance of the 2012 Filing Requirements (for 2013 rates), the Board included any remaining relevant sections of both the 2000 and 2006 Electricity Rate Handbooks.
[105] Decision with Reasons, EB-2007-0905, pages 169-170

The circumstances in the Great Lakes Power EB-2007-0744 proceeding were unique as Great Lakes Power Limited conducted both regulated and non-regulated businesses. The Board's decision addressed the fact that the corporate tax loss carry-forwards arose due to losses in Great Lake Power Limited's non-regulated businesses. The Board referred to the "stand-alone principle" and that it would be inappropriate for regulated service rates to be affected by the income or loss of a non-regulated business.[106]

> It would be fundamentally unfair to take such tax losses into account when setting rates for regulated service. To abandon the stand-alone principle in this case would give rise to the inappropriate result that rates for regulated service would be affected by the income or loss of a non-regulated business.

OPG's circumstances in 2013 are distinct from the two referenced Board decisions. In 2013, when OPG's tax loss arose, OPG was regulated by the Board and there is no evidence filed to indicate the tax loss was related to OPG's non-regulated businesses. To the contrary, the first line of OPG's reply argument under the Loss Carry-Forward section heading states that the $211.6M regulatory tax loss in 2013 was due to a shortfall in nuclear production.

OPG made a decision to maintain its (then current) payment amounts for 2013. OPG decided not to apply to the Board to change its payment amounts for 2013 based on updated information, including an updated nuclear production forecast. The fact that OPG incurred a tax loss was a risk OPG decided to take on its own accord and should not change the application or treatment of the Board's tax loss carry-forward policy.

In addition, even if one accepted the argument that the circumstances of these prior cases were similar to OPG in 2013, the Board continued to apply the Handbook's policy to electricity distributors after both of those decisions were issued.[107] Accordingly, the Board does not consider either case to have set a precedent. Further, it is apparent to the Board from the submissions of OPG and the parties that the "benefits follow cost" principle has been interpreted differently by the parties.

[106] Decision and Order, EB-2007-0744, Great Lakes Power, pages 40-41
[107] Decision and Order, EB-2008-0322, Hydro One Remote Communities, page 10, Decision and Order, West Perth Power and Clinton Power Corporation, EB-2009-0262/EB2010-0121, page 22

OPG argued that application of the policy would result in retroactive rate making during the term of a final rate order without a deferral or variance account. The issue before the Board is a tax loss carry-forward. The tax loss is carried forward to a subsequent year by definition. The question in this application is whether OPG's shareholder or its ratepayers receive the future benefit, the opportunity to reduce a future year's tax provision by the amount of the tax loss from a prior year.

The Board does not find there to be an issue with retroactive rate making in the context of tax loss carry-forwards in this case. The Board policy was established in 2005 and it has been applied in subsequent years. The Board's Handbook policy did not and does not require the establishment of a deferral account. Therefore, there is no issue of retroactive ratemaking in the Board's view.

4.7.2 Deferred Tax

The December 31, 2013 audited financial statements indicate $181M in deferred income taxes for the newly regulated hydroelectric facilities. OPG submitted that the deferred income taxes on OPG's December 31, 2013 financial statements is to be excluded from the revenue requirement impacts associated with regulating the newly regulated hydroelectric assets. The deferred tax is related to pension and OPEB expense recognition and higher capital cost allowance that is allowed for tax purposes compared to OPG's accounting depreciation.

The Board is required to accept the assets and liabilities of the newly regulated hydroelectric facilities as set out in OPG's December 31, 2013 audited financial statements. This requirement is set out in O. Reg. 53/05, section 6(2)11 part ii

> The Board shall accept the values for the assets and liabilities of the generation facilities referred to in paragraph 6 of section 2 as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors before the making of that order. This includes values relating to the income tax effects of timing differences and the revenue requirement impact of accounting and tax policy decisions reflected in those financial statements.

SEC submitted that the $181M net tax liability has been charged as an expense by OPG prior to January 1, 2014, but has not actually been paid yet. SEC disagrees with OPG's proposal which would require ratepayers to pay for tax costs in the future, tax

TAB 2

CAPITAL EXPENDITURES - NIAGARA TUNNEL PROJECT

1.0 PURPOSE

This Exhibit describes the Niagara Tunnel Project ("NTP") from its origin in studies and assessments performed by Ontario Hydro during the 1980s to its completion in 2013. The material that follows establishes that the NTP was an extremely large, complex and challenging construction project that OPG completed safely and cost effectively given the conditions encountered. The emissions free electricity produced from the water flowing through the NTP will benefit the people of Ontario into the next century.

Photo 1 - Looking out the Tunnel at the Outlet Site

NTP. OPG and Strabag met approximately every 6 weeks to review the Combined Risk Register. At these meetings, the parties identified new risks, tracked mitigation measures and evaluated the impact of such measures on existing risks. Items that were viewed as no longer representing a hazard were marked as closed, but were kept in the register for reference.

6.4 Oversight

6.4.1 OPG Management

Given the size and scope of the NTP and the importance that OPG places on its successful completion, the project has received significant management attention since its inception. The OPG executives directly responsible for managing the NTP, the Project Sponsor and Project Director, have been discussed above. This section discusses the additional oversight provided by OPG's senior executives.

The senior executive for hydroelectric matters, historically the Executive Vice President, Hydro ("EVP Hydro") and now the Senior Vice President Hydro-Thermal Operations ("SVP Hydro-Thermal"), is responsible for all of OPG's regulated and unregulated hydroelectric activities.[16] He oversees the execution of all hydroelectric development projects including the NTP. The NTP Project Sponsor reports to him. Since 2005, the EVP Hydro was directly involved in all significant decisions with respect to the NTP.[17] The SVP Hydro-Thermal sits on the Steering Committee established under the ADBA to resolve any disputes between OPG and Strabag that arise during the construction of the NTP.

Since the beginning of NTP construction, the status of the project and issues associated with it have been discussed at the standing OPG senior management meetings that address matters significant to the overall operation of the company.

---

[16] In January 2012, these responsibilities were incorporated into the newly created position of Senior Vice President Hydro-Thermal.

[17] Prior to December 2005, the Senior Vice President, Energy Markets was responsible for the NTP.

The EVP Hydro (now the SVP Hydro-Thermal) was the primary liaison between the NTP team and the MPC, which provided OPG Board oversight of the project throughout most of its history.[18] In addition, SVP Hydro-Thermal develops materials and recommends items for the CEO to submit to the OPG Board in relation to the major approvals necessary for the NTP.

During the period of the dispute with Strabag over differing sub-surface conditions, discussed below, OPG also created a Contract Litigation Oversight Committee ("CLOC") to provide independent oversight of OPG's strategy for contract dispute resolution and negotiations and to advise the CEO on the conduct of the dispute. The CLOC was chaired by OPG's Chief Financial Officer and included external members Norman Inkster, former head of the RCMP, and Barry Leon, a lawyer then at Torys who specialized in international litigation and arbitration. Both men have significant experience in investigating and resolving complex disputes.

The CLOC also obtained independent technical advice from John Hester, an expert on tunnel construction and the tunneling industry. In the period leading to presentation of the dispute between OPG and Strabag to the DRB, the CLOC provided independent review of the strategy OPG employed and the presentations OPG made. After the DRB rendered its decision, the CLOC continued to advise the company on negotiations with Strabag until an agreement was reached.

[18] In mid-2010, the Risk Oversight Committee (ROC) assumed responsibility for OPG Board oversight of major projects and the MPC was disbanded.

In mid-October 2007, Strabag issued a progress schedule which showed a further delay in final completion to almost nine months beyond the contracted date. This was the first schedule revision that put project completion outside the date approved by OPG Board. On OPG's behalf, the OR requested Strabag to provide a Recovery Plan to mitigate the anticipated schedule overrun. Strabag's response was that the schedule delays were entirely attributable to the DSCs previously raised in various Project Change Notices ("PCN"s). Strabag also stated that it had taken whatever actions possible, so far uncompensated, in an attempt to keep the project on schedule. Strabag closed its response by indicating that the path forward required a resolution of its outstanding DSC claims.

At the end of November 2007, senior executives from OPG and Strabag met and agreed that the two parties would try to resolve their differences based on realigning the tunnel. They further agreed that if the issues pertaining to the new alignment and the DSC claims raised in the PCNs were not resolved within three months, the matter would go to the DRB for resolution as soon thereafter as possible.

By the end of November 2007, the tunnel drive reached the beginning of the area under the buried St. Davids Gorge.[29] Over the next few months, while tunneling under the gorge, overbreak increased and Strabag resumed installing spiles. Progress slowed.

At the end of December 2007, the OR received a letter from Strabag with a new realignment proposal that superseded the realignment options previously discussed. This proposal involved both a horizontal realignment, that placed the tunnel mainly underneath Stanley Avenue and reduced its distance by approximately 200 metres, and a vertical realignment to a considerably higher elevation in order to reduce boring in the Queenston shale. The proposal envisioned the completion of tunnel boring on August 27, 2010, more than two

[29] The DBA (section 5.5 (e)) defined an 800 metre area under the buried St. Davids Gorge (from approximately 1,400 to 2,200 metres) where Strabag could not claim differing subsurface conditions. This provision was included because Strabag's RFP response proposed raising the low point of the tunnel some 50 metres higher than shown in the RFP's conceptual design. Strabag made this proposal in order to reduce the tunnel's slope, which shortened the tunnel, improved its water flow characteristics and allowed Strabag to use rubber tired vehicles rather than rack and pinion rail transports.

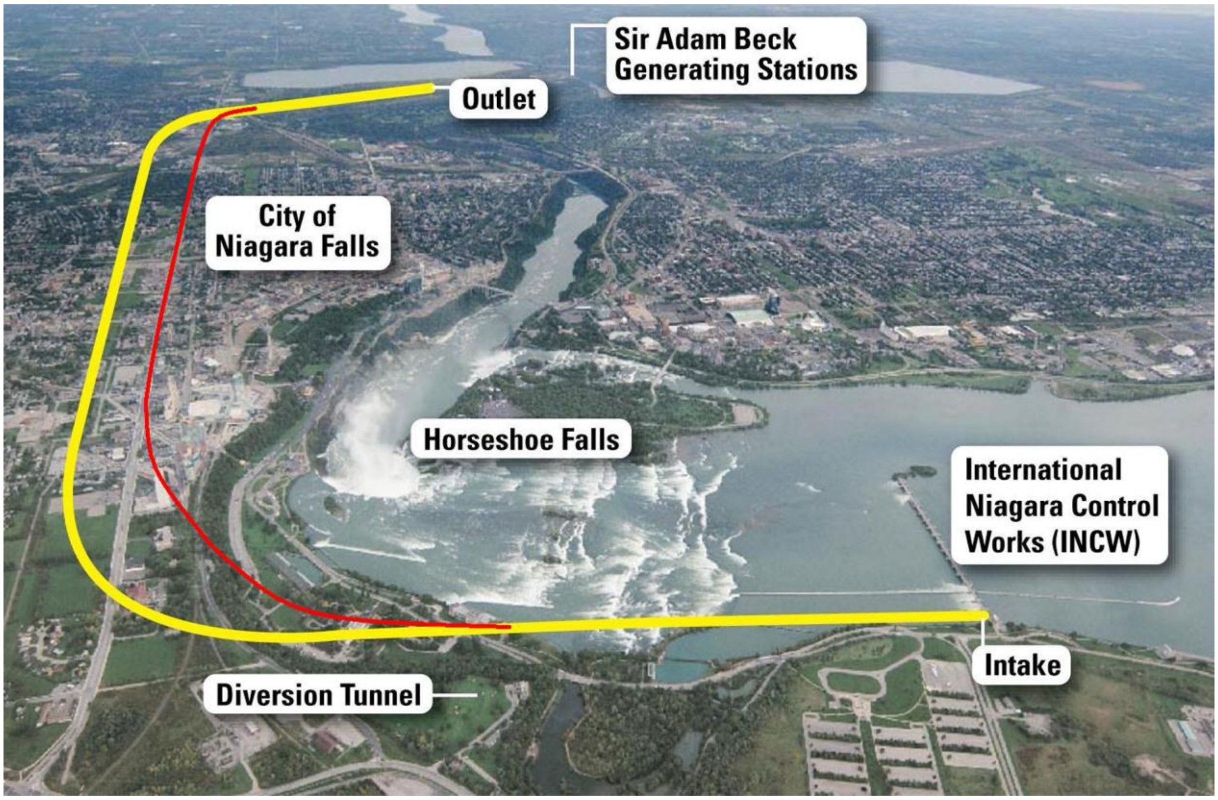
years later than the contracted schedule. The forecasted substantial completion date was June 18, 2011, some 20 months later than contracted.

OPG began exploring the issues associated with the proposed realignment. These issues included the additional subsurface property rights expropriation that would be required, the potential impacts on groundwater and BTEX rock quantities, and the potential impact on the existing tunnels. OPG submitted an application for the minor EA amendment required by the realignment, which was approved on March 31, 2008.

Throughout the early months of 2008, slow progress continued as the TBM worked under the buried St. Davids Gorge. Strabag continued to install measures to reduce overbreak and used spiles where the amount of overbreak warranted. Talks between OPG and Strabag continued in an effort to reach an agreement on a new alignment and to resolve ongoing disputes over the rock conditions and the resulting slow progress of the project. In early February, Strabag submitted a proposal for recovery of the additional costs it claimed due to DSC. By mid-February 2008, the parties agreed that they had reached an impasse and determined to take their dispute to the DRB.

During the spring of 2008, TBM progress continued to be slow, although advance rates improved as the TBM emerged from the zone of influence of the buried St. Davids Gorge. In May, OPG and Strabag agreed on horizontal realignment; vertical realignment was put on hold pending resolution of the dispute by the DRB.

Photo 10 - Aerial View of Horizontal Realignment



Although the TBM made relatively steady progress in the summer of 2008, averaging more than 250 metres per month from June through September, advance rates remained below plan and the schedule continued to slip. While Strabag began tunneling along the realigned horizontal route in early September, it maintained its position that vertical realignment would be addressed only in the context of an overall resolution of outstanding issues. Discussion of this overall resolution began after the DRB issued its decision in late August as discussed in Section 7.0, below.

While OPG and Strabag renegotiated the contract, tunnelling proceeded. In the fall of 2008, Strabag resumed spiling to address the substantial overbreak (greater than three metres) being experienced. In light of these conditions, Strabag determined, with OR concurrence, to begin the vertical realignment to exit the Queenston shale as soon as the horizontal realignment moved the tunnel route out from below the existing tunnels. In late October, therefore, prevent chloride ion diffusion from the rock for all loading conditions for the design life of the tunnel.

The OR prepared an additional report in February 2013 summarizing all the investigations conducted with respect to the low point swelling issue. It concluded that although the Queenston shale below the invert at the low point of the tunnel was exposed to infiltration of fresh water during construction, efforts to extract the water, repair the cracks in the concrete liner, and the application of contact and interface grouting effectively sealed any damaged membrane and prevented further water penetration into the rock. The OR determined that the as-built tunnel liner complied with the Owner's Mandatory Requirements and applicable code requirements.

7.0 DIFFERING SUBSURFACE CONDITIONS DISPUTE

7.1 Overview

The contract between OPG and Strabag provided for the establishment of a Dispute Review Board ("DRB") to assist the parties in dispute resolution as discussed in Section 5.0 above. Pursuant to those provisions, a DRB chaired by Peter Douglass, with P.E. Sperry and Dennis McCarry as members, was created. The DRB established procedures on how it would interact with the owner and contractor, keep informed of project progress through periodic meetings and offer informal advice when requested by both parties. The DRB also set the framework for formally resolving any matters presented through Dispute Requests. This framework required written materials, presentations at a hearing and a decision rendered in the form of written recommendations.

In May 2007, after almost nine months of tunneling, Strabag issued a Notice of Differing Subsurface Conditions ("DSC") pursuant to section 5.5(a) of the DBA. Strabag followed up by issuing Project Change Notice ("PCN") 17, which claimed that the actual rock conditions encountered were significantly more adverse than those described in the GBR between 806.50 metres and 839.70 metres. This notice was triggered by the fall of a large rock onto the TBM on May 16, 2007, which stopped tunneling for more than three weeks. PCN 17 claimed an unspecified increase in contract costs, to be determined once technical solutions to address the new rock conditions were developed and implemented.

Over the next six months, while tunneling continued, Strabag and OPG (through the OR) exchanged letters and other documentation about the existence of DSC with little agreement. On November 7, 2007, Strabag issued Dispute Notice 001, which sought to resolve this outstanding issue using the claims procedure in section 5.7 of the DBA or through an immediate referral to the DRB. OPG replied, stating that the dispute must be held in abeyance until tunnel boring is complete because it is covered by DBA section 5.5(c), which addresses rock support changes stemming from DSC. Strabag disagreed with this interpretation of the contract and urged OPG to allow this matter to be put before the DRB forthwith.

As mentioned above, at the end of November 2007, senior management at OPG and Strabag agreed to spend a maximum of three months attempting to resolve the dispute informally and develop a new tunnel alignment. These efforts proved unsuccessful and in mid-February 2008, the parties agreed that they had reached an impasse and would refer the matter to the DRB for a hearing as soon as possible.

On February 27, 2008 Strabag issued Dispute Notice 002 reiterating the position it took previously regarding PCN 17. This second notice continued to assert that the conditions encountered constituted DSC and further asserted that the financial responsibility for them rested with OPG as the owner.[34] The notice requested that the dispute be resolved pursuant to Section 11 of the DBA, which covers the DRB.

In early March the parties met with the DRB to establish the procedures and timing of the hearing. Both Strabag and OPG submitted questions in advance to the DRB to guide the discussion. Strabag's questions were as follows:

---

[34] Dispute Notice 002 actually states that financial responsibility rests with the OR, but this is best viewed as either a typo or a shorthand reference to the owner.

"any other rock condition not covered") an exhaustive catalogue of the types of rock conditions agreed to by the Parties as their geotechnical baseline?

- Is Strabag precluded from requesting an adjustment in the contract price or contract schedule for any differing subsurface conditions in respect of its work under the St. Davids Gorge by the provisions of DBA Section 5.5(e)?
- Is Strabag precluded from requesting an adjustment in the contract price or contract schedule for rock overbreak in excess of the baseline 30,000 m^3 set out in Section 8.1.2.7 of the GBR, other than for amounts pre-agreed to be reimbursed for disposal of rock overbreak and for application of shotcrete at unit rates set out in DBA Appendix 1.10?

The DRB discussed the possibility of establishing whether Strabag's means and methods were the source of the overbreak as a threshold issue as OPG proposed, but ultimately decided to hear the issues of Strabag's means and methods and the existence of DSC concurrently. The DRB established the type and order of presentations for the hearing that was held in June 2008.

7.2 Dispute Positions

7.2.1 Strabag

Strabag's fundamental position was that OPG remained responsible for the consequences of the geologic conditions different from those enumerated in the GBR and that the conditions actually experienced in tunnelling were different. Strabag claimed that DSC were evidenced by large block failures, excessive overbreak and inadequate "stand-up" time (i.e., insufficient time to install rock support prior to rock failure). Strabag further claimed that the Table of Rock Conditions and Rock Characteristics in the GBR failed to adequately describe the rock conditions encountered and either represented a DSC on its own, or alternatively confirmed the presence of DSC. Strabag's position was that any changes that it made to the means and methods of rock support were the result of DSC, rather than the cause of DSC. Finally, Strabag claimed that it was entitled to relief from DSC anywhere they were encountered, including under the buried St. Davids Gorge.

The DRB's conclusions were unanimous. At the end of the document the DRB added the following additional finding:

> The DRB members have rarely experienced such an excellent, cooperative atmosphere between the Parties on a tunnel project. This is especially impressive considering the pioneering nature of the Work and the problems and issues encountered. The Board is confident that the Parties can negotiate an amendment(s) to the DBA that, while not commercially optimum for either Party, will allow the Project to proceed to optimum completion. DRB Report, page 19.

8.0 RESPONSE TO DRB DECISION

8.1 Identification and Assessment of Options

In response to the DRB Report, OPG in consultation with the OR concluded that four options were available:

- Negotiate changes to the existing DBA based on cost sharing as recommended by the DRB including revising the Table of Rock Conditions and Rock Characteristics and GBR as required.
- Settle all outstanding disputes with Strabag and negotiate a new target cost contract for project completion including incentives and disincentives based on cost and schedule to completion.
- Reject the DRB recommendations and pursue arbitration under the Rules of Arbitration of the International Chamber of Commerce as provided in the DBA (Section 11.5, as amended).
- Seek to replace Strabag with a new contractor to complete the tunnel.

These options are discussed in more detail below in Section 10.0, "Superseding Business Case."

OPG quickly concluded that the fourth option should only be considered as a last resort because of the cost and schedule consequences of locating, hiring and mobilizing a replacement contractor. While OPG remained concerned about schedule delays and Strabag's claimed cost overruns, OPG was generally satisfied with the quality of work

Strabag was doing on the project and with Strabag's continuing commitment to operate safely in the face of challenging rock conditions.

OPG also rejected arbitration as an initial approach. OPG concluded that there was no advantage in pursuing arbitration unless attempts at negotiation failed. Arbitration was seen to entail greater risk, require additional time and provide a less certain outcome than negotiation.

Ultimately OPG concluded that negotiation with Strabag toward a resolution of outstanding disputes and a path forward to complete the tunnel on a target price basis with risk/reward incentives was the preferred option to explore, as it encouraged continuing efforts to achieve or exceed targets. Strabag continued to perform well despite the fact that during this period rock conditions were particularly challenging and Strabag had to resume installing spiles to contain the overbreak, as discussed above in Section 6.5.4.2, "The Tunnel Drive."

The fact that Strabag continued working safely in these challenging rock conditions and continued to cooperate with OPG to complete the tunnel further supported OPG's view that negotiation was the preferred approach. OPG assessed that keeping Strabag engaged in completing the project would likely lead to the best result in terms of cost and schedule. Both OPG's senior management and OPG Board supported continued negotiations with Strabag rather than exploring the option of replacing Strabag with a new contractor. OPG also asked the external experts on the CLOC for their views and they too supported continuing to negotiate a revised agreement with Strabag.

8.2 Discussions with Strabag

After receiving the DRB Report, both OPG and Strabag filed arbitration notices, but each confirmed that the notices were filed only to preserve their respective rights under the incorporate a fair cost-sharing approach. The Principles of Agreement and the process of negotiating the ADBA are discussed in the following sections.

9.0 CONTRACT RENEGOTIATION

9.1 Agreed Approach

9.1.1 Principles of Agreement

OPG and Strabag ultimately developed a Principles of Agreement ("Principles") document which was based on a hybrid approach that included resolution of Strabag's claim for DSC in the Queenston formation and renegotiation of the DBA going forward. Both parties committed to complete the project in a safe, environmentally sound and expeditious manner and to reflect the DRB recommendations as they worked toward a revised agreement.

OPG agreed to pay Strabag $40M to resolve all issues to November 30, 2008. This figure reflected an effort to share Strabag's claimed losses of $90M. As a good faith gesture, OPG committed to make the $40M payment within 15 days of the Principles signing, but Strabag was required to provide OPG with a $40M letter of credit to cover the possibility that a final agreement would not be reached. OPG also had the right to audit Strabag's losses and to the extent that the full $90M was not substantiated in the audit, the $40M payment could be reduced proportionately.

Going forward, the tunnel would incorporate revised horizontal and vertical alignments to minimize boring in the Queenston shale.[36] The renegotiated contract would be based on a target cost and schedule. The target cost would be developed on an "open book" basis to reflect the reasonably estimated cost to complete the project. It would not include any profit, but would include a negotiated 5 per cent overhead fee (a reduction from Strabag's 12 per cent proposal) on allowed project costs and also would provide incentives and disincentives, as discussed below in Section 9.2.

[36] As noted above, the horizontal realignment had already begun in early September 2008, some two months before the Principles of Agreement were signed.

The Principles further provided for the development of project management processes that would facilitate greater OPG involvement in project decisions, recognizing that Strabag would continue to direct and be responsible for the design and construction of the tunnel. The document also required that the future design build agreement be supported by adequate financial security and that Strabag maintain the existing design and construction team throughout the duration of the project except where Strabag provides substitute personnel acceptable to OPG. Finally, the document made clear that it was not the parties' intent to have the Principles affect existing performance warranties and guarantees.

In term of next steps, the Principles required that the parties negotiate a Term Sheet further delineating the provisions above.

9.1.2 Term Sheet

The Term Sheet envisioned in the Principles was signed on February 9, 2009. It confirmed and elaborated on the approach outlined in the Principles by making clear that:

- The cost and revenues of all claims for work conducted prior to December 1, 2008 are Strabag's in exchange for OPG's payment of $40M.
- The cost and schedule impact from claims arising from work conducted after December 1, 2008, shall be dealt with under the provisions of the amended agreement, which is to be based on a target cost approach.
- The cost of claims that bridge December 1, 2008, are to be apportioned between the parties in accordance with the first two bullets.

The Term Sheet detailed that the DBA provisions would remain in effect until the amended agreement was signed and that the new agreement would be retroactive to December 1, 2008. For the period between the signing of the amended agreement and December 1, 2008 ("the interim period"), OPG would pay Strabag the amounts necessary to reflect the difference between payments made under the DBA and those due under the amended agreement plus interest at the rate set out in the DBA.

The Term Sheet required that Strabag provide OPG with detailed cost information starting from December 1, 2008 and that it unconditionally open its books to OPG. The Term Sheet also required that Strabag continue its fixed price arrangements with its current sub-contractors and that Strabag obtain OPG's approval for any new subcontracts above a threshold amount.

Under the Term Sheet, the DBA was to be the starting point for the amended agreement and its terms would only be changed to reflect the target cost approach contained in the Principles. The Term Sheet also embodied the parties' agreement to develop protocols on how they will work together to complete the project as well as develop a target cost and target schedule. An important principle agreed in the Term Sheet was that to the extent applicable, the cost and schedule for project activities other than tunnel boring, rock support and profile restoration would not exceed the cost and schedule in the DBA for these other project activities (e.g., work on the intake, outlet and tunnel lining).

Pursuant to the Term Sheet, the parties negotiated a Memorandum of Understanding ("MOU") on the target schedule, signed on February 24, 2009, which established a new Substantial Completion date for the project of June 15, 2013. Based on the target schedule, an MOU on target cost was also negotiated and signed on April 7, 2009, which established a target cost of $985M for Strabag's work.

While the Term Sheet was prepared to facilitate the creation of an amended agreement, it was not itself a complete agreement. Many significant issues remained to be negotiated, such as the target cost and schedule details, the operation of the Steering Committee created to resolve disputes, and whether the occurrence of DSC should lead to a change in the target cost and schedule. Ultimately, these matters were all addressed and resolved in the Amended Design Build Agreement.

9.2 Amended Agreement

The original DBA was used as the base for the Amended Design Build Agreement (“ADBA”). Most DBA provisions were retained unchanged except as necessary to convert the agreement to a target cost contract.[37] Under the ADBA, OPG and Strabag agreed on a Target Cost of $985M, a contract schedule with Substantial Completion by June 15, 2013 and changes to the allocation of risk. Strabag will be entitled to its costs to complete the project and incentives will apply if it completes the project for less than the Target Cost or before the agreed Substantial Completion date. Conversely, disincentives will apply if the costs exceed the Target Cost or the project is late.

The ADBA defines Actual Cost as the $302M paid to Strabag prior to December 1, 2008 plus the accumulated Allowed Costs (defined below) from December 1, 2008 onwards, minus any proceeds from the sale of assets and any insurance payments received by Strabag. Actual Cost will be used to calculate the applicable cost incentives and disincentives which apply to Strabag. Strabag will be reimbursed for all costs it incurs to complete the project (“Allowed Costs”) that are not specified to be Disallowed Costs in the ADBA. Disallowed Costs include items such as costs arising from Strabag’s negligence, wilful misconduct or breach of Applicable Law, head office costs, interest costs, certain insurance deductibles, costs for warranty work, costs to correct or remove a defective part of the project and third party liability. Strabag also will be entitled to apply an overhead recovery fee of 5 per cent to Allowed Costs from December 1, 2008 onwards to cover the costs of head office support. OPG is to make monthly payments under the contract based on anticipated Allowed Costs for the coming month and true up the prior month’s payments.

The Target Cost will be adjusted to reflect changes in costs for certain items, as baseline assumptions were included in the calculation of the Target Cost with the expectation that the Target Cost would be adjusted up or down to reflect actual circumstances such as, for example, changes in the baseline inflation assumption or diesel fuel costs.

---

[37] Capitalized terms in this section are defined in the ADBA, which is included in the CD of NTP Key Documents accompanying this Exhibit.

The Contract Schedule is based on a Substantial Completion date of June 15, 2013 and will be adjusted for certain events set out in the ADBA. The schedule is premised on the horizontal realignment that reduced the tunnel length by approximately 200 metres, and a vertical realignment which allowed the tunnel to exit the Queenston shale and move to the overlying rock formations where tunnelling conditions were expected to, and did in fact, improve. Certain incentive and disincentive payments described below are based on the Target Cost and Substantial Completion date.

Under the ADBA, if OPG's actions impact cost or schedule, then Strabag will be entitled to an adjustment in the Target Cost and Contract Schedule. This is to address provisions in the ADBA that either require Strabag to obtain OPG's consent for certain matters or that impose obligations on OPG, which may impact the Target Cost or Contract Schedule.

In addition to the payments described above, Strabag received an Interim Completion Fee of $10M upon completion of TBM mining activities on March 30, 2011 and was also entitled to a Substantial Completion Fee of $10M on March 9, 2013 upon achieving Substantial Completion. A Cost Performance Incentive/Disincentive will be calculated as 50 per cent of the difference between Actual Cost and the Target Cost as adjusted. A Schedule Performance Incentive of $200,000 per day is due for each day that Substantial Completion occurred before the June 15, 2013 date for Substantial Completion set out in the contract, unless this date is adjusted through a contract amendment.[38] If the project had exceeded the contract schedule, Strabag would have been required to pay OPG a Schedule Performance Disincentive of $67,000 per day for each day that the project exceeded the contract's Substantial Completion date, as adjusted. The agreement limits the maximum aggregate cost and schedule incentives to $40M and the maximum cost and schedule disincentives to $20M.

[38] The Substantial Completion date has been extended by ADBA amendments. ADBA amendments are discussed below in Section 11.3.

Consistent with the original DBA, an incentive or disincentive will be applied to the extent measured flow deviates from the Guaranteed Flow Amount ("GFA") of 500 cubic metres per second by an amount which exceeds the plus or minus two per cent dead band. Strabag also continues to provide the warranties and financial guarantees contained in the DBA, including a parental indemnity, a Letter of Credit and a Maintenance Bond.[39]

The ADBA provides for adjustment to the Target Cost and Contract Schedule should a Major Risk Event occur. The adjustment mechanism is set out in the Major Risk Table in Appendix 5.3C of the ADBA. The Major Risk Events are as follows:

- main TBM bearing failure, except due to negligence;
- conveyor belt damage greater than 1 kilometre, not due to negligence;
- gas concentration above Ontario *Occupational Health and Safety Act* limits;
- water ingress greater than 100 litres/second;
- BTEX levels greater than threshold accepted by Ministry of the Environment
- unexpected subsurface geotechnical conditions requiring a material change to means and methods or having a material impact on cost and schedule;
- measured crown overbreak depth and volume greater than baseline only if progress slower than planned;
- critical marine work at intake area affected by operational constraints at the International Niagara Control Works; and
- unknown subcontractor claims.

The ADBA provides that disputes not settled at the project level are to be brought to a Steering Committee consisting of a senior representative from each of OPG and Strabag. The Steering Committee may resolve the matter itself or seek advice or non-binding recommendations from experts. As was the case in the original DBA, all unresolved disputes go to arbitration under the Rules of Arbitration of the International Chamber of Commerce ("ICC"), with arbitration normally occurring only after Substantial Completion unless the

---

[39] In the ADBA the amount of the Maintenance Bond is set at up to 10 per cent of the Target Cost. Strabag and OPG have agreed to a Maintenance Bond of $50M, or approximately 5 per cent of the Target Cost.

Steering Committee members mutually agree to submit a dispute to ICC arbitration at an earlier date.

10.0 SUPERSEDING BUSINESS CASE AND REVISED PROJECT BUDGET

While the ADBA was being finalized, OPG began preparing a Superseding Business Case Summary ("Superseding BCS") to seek approval from the OPG Board for the target cost and schedule.[40] OPG management had kept OPG Board apprised of the status of negotiations through updates to the OPG Board's Major Projects Committee ("MPC"). The MPC had reviewed the Principles of Agreement prior to their adoption and endorsed management's decision to negotiate a revised agreement with Strabag based on a target cost and schedule. The Superseding BCS was the vehicle to seek formal OPG Board approval of the new contracting approach and the resulting target cost and schedule.[41]

The Superseding BCS included a summary of progress on the project and the difficulties encountered in tunneling, leading to the DSC dispute before the DRB. It then summarized how the project will be executed under the ADBA.

Schedule and cost variance explanations were also provided in the Superseding BCS. Some of the primary drivers cited for the schedule variances are:

- Slower than planned TBM progress due to worse than expected conditions in the Queenston shale once the tunnel passed the St. Davids Gorge.
- Expectation of continuing challenges as the tunnel ascends to higher rock strata and undertakes more mixed-face mining.[42] Some of the rock types in the upper formations are harder and more abrasive, causing greater cutterhead wear and requiring more frequent cutter replacement. The mixed face conditions also produce "eccentric loading"

---

[40] The full OPG Board approval package for the Superseding BCS is contained in the accompanying CD of NTP Key Documents.

[41] The ADBA was signed in mid-June, after OPG Board had reviewed and approved the cost and schedule variances for the project based on the Superseding BCS.

[42] Mixed-face mining occurs when the TBM is boring different rock types at the same time. For example, as the tunnel elevation increased, the top of the TBM was mining Whirlpool Sandstone while the bottom was in Queenston shale. When these rock types differ in hardness, it causes uneven loading on the TBM cutterhead.

18-Aug-2005	**Design Build Agreement ("DBA") Signed with STRABAG AG**
Sept-2005	**STRABAG occupied site and started NTP construction**
17-May-2006 and 19-Jun-2006	**STRABAG Issues Claims for Differing Subsurface Conditions ("DSC") for Underwater Construction at the Intake Channel and Acceleration Wall** • Initiation of a dispute regarding a DSC for excessive overburden on the river bed encountered during construction of the intake channel that was claimed to differ materially from the subsurface conditions described in the Geotechnical Baseline Report ("GBR") • DSC claim related to work at the acceleration wall where conditions (i.e. bedrock elevation and the presence of large boulders) were claimed to differ materially from the GBR
01-Sep-2006	**TBM Excavation Commences** • TBM was acquired and assembled within 12 months according to the schedule proposed by STRABAG and incorporated into the DBA
23-May-2007	**STRABAG Claims DSC for Adverse Conditions in the Queenston Shale** • On or about 16-May-2007 near 840 m, immediately below the Whirlpool sandstone formation, a large block of Queenston shale dropped from the tunnel crown • STRABAG claimed DSC relative to the GBR
20-Sep-2007	**Settlement and Release Agreements Covering the Intake Channel DSC Signed** • Addressed DSC for the Intake Channel and Acceleration Wall underwater construction • Settlement Agreement signed by OPG and STRABAG • Release Agreement signed by OPG, STRABAG, Dufferin Construction and McNally Construction
24-Oct-2007	**STRABAG Initially Proposes a New Tunnel Alignment** • STRABAG suggested a number of benefits of realignment including an improved tunneling process
05-Nov-2007	**STRABAG Delivers Dispute Notice 001** • Dispute Notice 001 delivered to OPG concerning STRABAG's DSC claim associated with "Collapse in the Tunnel Crown," signaling their intent to refer this matter to the Dispute Review Board ("DRB") as a complex dispute triggered by a DSC, under the process contained in DBA s 5.5(a) • OPG countered on 12-Nov-2007 by requesting that Strabag agree to have the DRB first decide whether DBA s 5.5(c) applies. That section states settlement of DSC's concerning differing rock support requirements should be addressed only upon completion of the tunnel excavation
04-Feb-2008	**STRABAG Submits an Optimized Alignment & Revised Schedule Proposal** • Proposal also included information on alleged DSCs, efforts to mitigate DSCs, and implications to TBM drive and costs
14-Feb-2008	**OPG and STRABAG Senior Management Decide to Obtain a Determination from the Dispute Review Board ("DRB")** • Determination requested from DRB concerning the merits and materiality of DSCs alleged by STRABAG • DRB response would be considered by both OPG and STRABAG to pursue further negotiations including finalization of commercial terms of the realignment

13.2 Appendix B – Summary of Geologic Investigations

Beginning in 1983, extensive geotechnical investigations were undertaken during concept and definition phases for the expansion of OPG's Niagara hydroelectric facilities, which at that time contemplated two additional tunnels and a new underground generating station ("Beck 3"). These investigations were heavily focused on the Queenston shale formation because drilling in this formation was required by the plans to excavate the new tunnels under the existing Sir Adam Beck No. 2 tunnels with sufficient separation to allow the use of the existing rights of way (i.e., tunnel at greater depth in the same corridor). Because the plan also involved tunneling under the buried St. Davids Gorge (to reduce excavated material disposal relative to an open canal) and constructing the planned underground powerhouse, the investigations also focused on the buried St. Davids Gorge area and the planned powerhouse area.

As indicated in Table 1 below, the geotechnical investigations were carried out in stages and included a total of 59 boreholes and a geotechnical test adit (small test tunnel). Rock cores were retrieved from the boreholes to determine physical and engineering properties (chemical composition, strength, in-situ stress, joints, swelling potential, etc.). This investigation work involved internal staff, experienced engineering consultants (i.e., Acres, Golder), geotechnical engineering faculty from the University of Western Ontario, University of Toronto, Laurentian University, University of Michigan, and other international geotechnical engineering and construction experts from universities in Florida and Germany who participated through technical review panels (see Table 2 below).

Twenty of the 59 boreholes were along the 10 kilometre tunnel route with the remainder in the area of the proposed powerhouses, along other potential tunnel alignments and around the Pump Generating Station reservoir. Besides core retrieval for testing, in-situ stress measurements were conducted in some boreholes to assess the magnitude and orientation of the horizontal stress regime. Piezometers were also installed in many of the boreholes to assess groundwater conditions.

The geotechnical adit was originally 580 metres long and three metres in diameter. It was subsequently enlarged on a trial basis to 12 metres in diameter over its last 30 metres. The adit was excavated at the Sir Adam Beck complex by Thyssen Mining Corporation of Canada Ltd (subcontractors to Acres Bechtel Canada). Excavation occurred between August 1992 and July 1993 (see Figure 1 below). The adit was tested and observed as part of the investigation program, and monitoring continued through March 1994.

Construction of a geotechnical adit is not typically done for tunnel projects because of the associated time and cost. The trial enlargement was specifically designed and constructed to simulate the excavation of the planned diversion tunnels in the Queenston shale formation using a full-face tunnel boring machine. In consultation with engaged experts on the Specialist Consulting Board, the adit helped OPG conclude that rapid, full-face tunnel excavation in the Queenston shale formation on the planned scale was technically feasible and cost-effective.

The relevant geotechnical parameters were summarized in the draft Geotechnical Baseline Report ("GBR") and included in OPG's Design Build Request for Proposal documents. The contractor, Strabag, refined the GBR to incorporate its interpretation of the data and rock behaviour expected relative to its planned means and methods of construction. The collaboratively negotiated 3-stage GBR was included in the Design Build Agreement as the agreed baseline for expected geotechnical conditions.

After contract award, Strabag drilled seven additional boreholes to verify the rock conditions in the vicinity of the buried St. Davids Gorge. These boreholes confirmed that the Queenston shale was intact and that Strabag's proposed alignment (which was higher than the concept alignment in the RFP) was feasible.

At 14.4 metres in diameter, the Niagara Tunnel is precedent setting for excavation by an open full-face tunnel boring machine in rock. Rock is not a uniform material and subsurface conditions can vary considerably over a short distance. Despite extensive investigations, rock behaviour during tunneling cannot be precisely predicted from boreholes and adits that provide representative data for only a small percentage of the rock to be excavated. Consequently, tunnel designs are based on experience and interpretation of the geotechnical parameters. Actual rock conditions and its behaviour during tunnel construction cannot be fully known before the excavation is complete. Sub-surface conditions always remain a significant risk to both design and construction of tunneling projects.

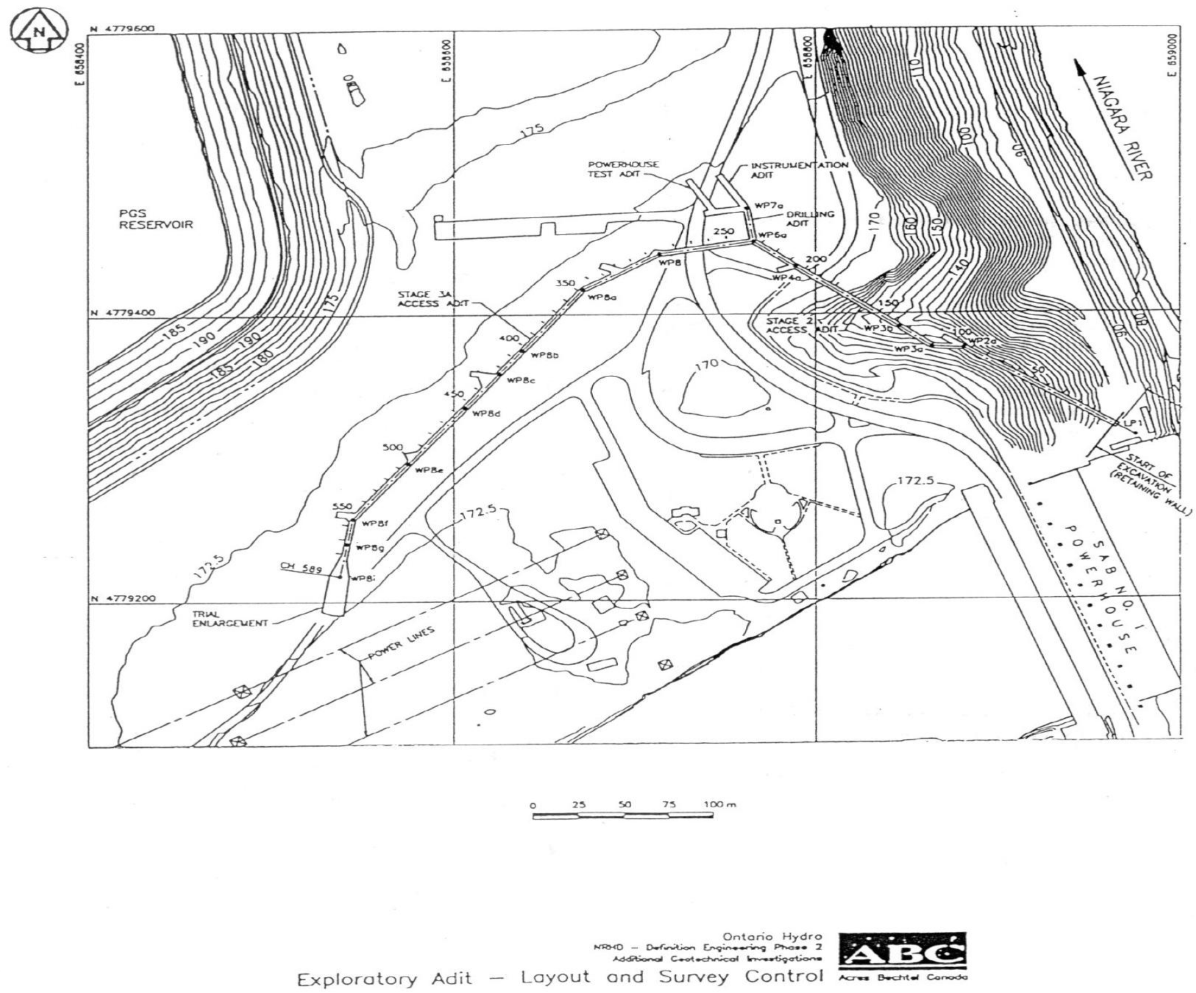
Table 1 - Work Completed During Various Stages of Geotechnical Investigations

Stage / Work Completed	Timeline
Concept Phase • Drilled 5 boreholes (SD-1 to SD-5) in buried St. Davids Gorge • Drilled 25 boreholes (NF-1 to NF-26, excluding NF-16 – was not drilled) along potential tunnel alignments, surface and underground powerhouse locations and around the PGS reservoir	1983 - 1989
Definition Engineering Phase 1 • Drilled 16 boreholes. Five in the Diversion Facilities area (NF-4A, NF-28, NF-30, NF-32 and NF-33), four in the St. Davids Gorge area (SD-6 to SD-9), and seven in the Generation Facilities area (NF-27, NF-29, NF-31, NF-34 to NF-37)	1990
Definition Engineering Phase 2 • Drilled 13 boreholes (NF-38 to NF-50) • Exploratory adit program	1992-1993

Table 2 - Roles of Experts / Consultants

Expert / Engineering Consultant	Role / Area of Expertise
Dr. K.Y. Lo – University of Western Ontario	Swelling Potential in Queenston Shale
Dr. E. Hoek – University of Toronto	Rock Mechanics
Dr. D. McCreath – Laurentian University	Rock Mechanics
Dr. B. Haimson - University of Wisconsin-Madison	In-situ Stress / Hydraulic Fracturing
Dr. Don U. Deere	Member of the Geotechnical Specialist Consulting Board
Dr. Walter Wittke – Beratende Ingenieure fur, Germany	Member of the Geotechnical Specialist Consulting Board
Acres Bechtel Canada (“ABC”)	Engineering Procurement Construction Management (“EPCM”) Consultant
Golder Associates	EPCM Consultant (worked in conjunction with ABC)
Clair. H Murdock Consultants Inc.	Estimating
MultiVIEW Geoservices Inc.	Seismic Survey of St. Davids Gorge

Figure 1 - Geotechnical Adit – Layout and Survey Control



TAB 3

Yes, you are correct, September 2012.

MR. CROCKER: How was this work reflected in the contract?

MR. EVERDELL: This was part of the renegotiated contract, the amended design-build agreement. And this was one of the operations required and built into the target cost and target schedule, when they were established.

And it -- you know, the cost of this work was actual cost that Strabag was reimbursed for.

MR. CROCKER: Can you tell me what that cost was, please?

MR. EVERDELL: I think if...

MR. YOUNG: Just while he is looking for that, just to elaborate a little bit, if you go back to the differing subsurface conditions, and the excessive overbreak, and the DRB finding, this is really one of the actions that was required technically to correct the subsurface -- to correct for the subsurface condition that was found.

MR. CROCKER: While you are looking for the actual cost, this was one of the items that the dispute review board said should be -- said or determined was the responsibility -- was a shared responsibility, wasn't it?

MR. YOUNG: The excessive overbreak was one of the -- was one of the findings that was adverse to OPG of the dispute review board findings.

MR. CROCKER: While you are looking for the price, I can ask you another question.

On what basis then was it determined, in developing this new agreement, that Strabag would be entitled to be compensated for this, in light of the fact that -- well, without my qualifying, why was it decided that Strabag should be compensated?

MR. YOUNG: Well, I mean, the new agreement that was developed was a target priced agreement. Strabag effectively, at the time of renegotiation, had a ninety-million-dollar loss, claimed a ninety-million-dollar loss, and the principle that was put forward by the dispute review board was that the pain should be shared, effectively, associated with this.

The structure of the renegotiated contract effectively was such that Strabag, if they performed well and exceeded targets, could earn a small profit, a very small profit, from the project overall.

So there was -- there was pain on Strabag's part vis-à-vis the entry position to the project overall.

MR. CROCKER: So Strabag then, you are suggesting, didn't suffer any specific pain, to use -- to follow through with your analogy, with respect to this particular incident; it was sort after -- you are suggesting a general pain in completing the --

MR. YOUNG: Well --

MR. CROCKER: Let me finish, please -- in completing the job pursuant to the amended agreement?

MR. YOUNG: What incident are you referring to?

MR. CROCKER: It wasn't an event; the job, I guess, the profile restoration.

MR. YOUNG: Again, profile restoration was part of the work that was necessary to complete the project. And so profile restoration --

MR. CROCKER: But it, again, was the result of something which the board determined was a shared responsibility. It was a response to incidents that were determined by the board to be shared?

MR. YOUNG: Again, I think if you look at the time that the board ruled, when the DRB ruled, the tunnel was about one-third complete. Strabag had suffered a ninety-million-dollar loss, and effectively what was put in place at that point was a contract which, if Strabag performed well going forward, allowed them overall to earn a profit.

Strabag was still sitting in a significant loss position to go forward with, from the time that the contract was restruck. They had to earn their way back out of that.

So the contract, going forward, the ADBA effectively allowed -- gave them an opportunity to earn incentives that would make up the loss. But they were sitting in a loss position at that point, you know, reflecting some pain.

MR. CROCKER: I understand --

MR. EVERDELL: And I think no contractor actually would take on additional losses. So the claim, the DSC -- or dispute review board claim or hearing covering the differing subsurface condition was only for that portion of the tunnel that had been completed by that time, right, the historical, not going forward.

MR. YOUNG: Strabag had done the engineering work, and had done the estimating on it as a starting point.

MR. EVERDELL: Yes, and they worked closely with the OR on what the rates should be -- that should be applied in order to come up with the agreed target.

MR. SMITH: Owner's representative.

MR. RUBENSTEIN: And we would agree -- or you can correct me, but Strabag as the contractor would have more experience than even the owner's representative. They are the one who is are building the --

MR. EVERDELL: Yes, they have the experience building tunnels of this size all over the world.

MR. RUBENSTEIN: So then would we agree they have an incentive because there is -- they have an incentive that the price is -- the target price is higher than what they actually think the actual price would be.

MR. YOUNG: That incentive is always there in a target price contract, in negotiating it.

MR. RUBENSTEIN: And how did you guard against that inherent incentive that is --

MR. YOUNG: You to apply knowledge diligently and look at -- look at scrutinized questions and look at independent information.

MR. RUBENSTEIN: Thank you. I just want to follow-up on a set of questions earlier on by Mr. Stephenson. Mr. Stephenson had asked about what the cost would have been, or -- let me back up.

There was a lot of discussion yesterday that a hundred percent of sort of the overrun costs, the costs in excess of $985,000,000 was because of the differing subsurface conditions and the problems that were encountered; correct?

MR. YOUNG: Correct.

MR. RUBENSTEIN: And the question that I want to understand is: If you knew what the actual subsurface conditions were at the time that you -- at the time of the design-build agreement, what do you think the cost would have been?

MR. YOUNG: I believe that the cost would have been ultimately what the cost was. The project involved -- it was a mining project, and it involved removal of a certain amount of material.

It involved lining the tunnel and filling the voids around that lining, and that was effectively what OPG paid for in this case; so the approximately 1.5 billion cost.

MR. RUBENSTEIN: But would you not agree with me that some of the overrun costs were costs with respect to delays, where you had to wait with respect to -- there was overbreaks and there was scheduling delays because of it. There was the dispute resolution board process, the costs of that, the costs of the experts for those sorts of processes, all the added sort of secondary work that needed to be done to remedy the design issues because of the subsurface, would you agree there is that amount of money that's included in the overrun costs?

MR. YOUNG: First of all -- and I will go down the

MS. HARE: No, please continue.

MR. RUBENSTEIN: And that will be helpful to the Panel.

Was there any materials that you had originally purchased that you needed to purchase different types of materials because of the condition of the rock that you encountered?

MR. EVERDELL: Again, it would be minimal. For instance, they had purchased some of the full ring supports which they weren't able to utilize, so that steel became scrap in the end. But so -- I mean, there was partial recovery on the cost, but, you know -- and it would be, you know, minimal in comparison to the price.

MR. RUBENSTEIN: How about this situation, which -- thinking in terms of the overbreak issue, you were using some type of method and material to deal with that issue, and then at a point you determined that you would use a different type of material or you would use a different type of process. So you might have changed -- there is no wasted material. I'm not saying that, but you sort of changed -- was there any of that situation?

MR. EVERDELL: In that case, Strabag would have -- if it was only minor overbreak, they would have just applied a thicker layer of shotcrete, the sprayed-on shotcrete in that area, but because of the excessive overbreak they needed to apply different procedures.

MR. RUBENSTEIN: Let me just -- one last area. This is with -- essentially it was discussed before, sort of a high-level question.

It was discussed with Mr. Crocker this morning that Strabag, with respect to the amended agreement, made very little profit.

MR. YOUNG: Correct, based on our assessment of where we think they stood on it, yes.

MR. RUBENSTEIN: That's your assessment, not Strabag's assessment?

MR. EVERDELL: We do have Strabag's. We know the actual costs and those were paid to Strabag, and we know what the -- incentives were paid and whatnot, and it adds up to the $100 million, the settlement plus the incentives.

MR. RUBENSTEIN: And is it less profit than they would have made working under the design-build agreement and there were no differing subsurface conditions?

MR. EVERDELL: It is less -- they were taking more of the risk, of course, in that. And we don't know how much they had built into their fixed-price contract -- or fixed-price amount for that, but we believe they would have earned more of a profit under the fixed-price contract if everything had gone according to plan.

MR. RUBENSTEIN: And that -- so then the lower expected profit -- lower actual profit for Strabag, that is something that Strabag and its shareholder, that's their loss, essentially?

MR. EVERDELL: Yes. That was part of their share. They kept the key people on the job for eight years instead of four years, and so there would be a lost opportunity cost for them not being able to the use those people on another job, as well as any profit that they might have achieved.

So they were definitely a team player on this.

MR. RUBENSTEIN: You think that was a fair outcome?

MR. EVERDELL: Pardon?

MR. RUBENSTEIN: That was a fair outcome, all things considered?

MR. EVERDELL: Yes.

MR. RUBENSTEIN: But in this situation, the added costs to OPG, you are seeking that amount entirely from ratepayers?

MR. YOUNG: Yes.

MR. RUBENSTEIN: No amount -- and there should be no amount that the shareholder should have to take on?

MR. YOUNG: Correct.

MR. RUBENSTEIN: Thank you very much. Those are my questions.

MS. HARE: Thank you.

So we will take our lunch break now, then, and we will return at 1:45. It does look like we will start panel 1 today.

MR. SMITH: Okay. That was going to be my question, just to review the bidding. They are available, so if we can start, that would be preferable.

MS. HARE: Okay. Thank you.

--- Luncheon recess taken at 12:36 p.m.

--- On resuming at 1:52 p.m.

MS. HARE: I understand, Mr. MacIntosh, you are up next, and that you are cross-examining on behalf of Energy Probe and then VECC as well; is that correct?

MR. MacINTOSH: Well, actually Dr. Schwartz is going to can the questions of Energy Probe, and I will ask the questions that VECC asked me to put forward.

We will be combining our times, but we don't need all that time.

MS. HARE: Thank you, so we will proceed. Dr. Schwartz?

CROSS-EXAMINATION BY DR. SCHWARTZ:

DR. SCHWARTZ: Thank you, Madam Chair. My name a Larry Schwartz; I am an economist and consultant to Energy Probe in this matter.

I should say that I haven't signed any confidentiality agreements, so I don't think any of my questions will relate to anything confidential. But I will just make that clear in case it arises.

I would like to direct my first question to Mr. Ilsley on the basis of his very considerable expertise on the two contracting modes, design-build and design bid/build that he referred to yesterday.

Mr. Ilsley, if I could ask you for an expert's opinion rather than trying to explain OPG's rationale for what it did; it is well laid out in the report.

My question will then relate to Exhibit D1, tab 2, schedule 1, pages 22 and 23. Here is a discussion of the contracting process, and that is where OPG makes its case.

But looking to your statement, Mr. Ilsley, yesterday that the design bid/build approach was not used in this case, even though it was widely used and perhaps may be even the standard approach in North America, which suggests to me that the design bid/build approach must have some advantages, or it wouldn't be widespread -- so widespread.

What, may I ask, as you see it, are the advantages to a design bid/build contracting approach -- not specifically with this project in particular, but in general?

MR. ILSLEY: In general, the process -- just to review that quickly, because I think that helps in understanding the differences.

Design bid/build is the approach where the project is completely designed by a selected designer, so the first job of the owner is to find himself a designer who is expert in designing tunnels.

He would then go out do the geotechnical investigation, prepare a geotechnical report, and contract documents, specifications of a one hundred percent design, which he would then put on the street to bid. The low bidder would take the work; that's usually the way that it's done.

Now, with the innovations in tunnelling technology in particular, which are considerable and which allow us to go places that even fifteen years ago, twenty years ago, or ten years ago, you would never even contemplate.

There is a consideration that the people who know most about this process are the contractors. And necessarily walk briefly through my back of the envelope assessment of Strabag's profit on this project, Strabag claimed a $90 million loss when the contract was renegotiated.

That claim -- OPG subsequently agreed that there was at least a $77 million component there. OPG settled with Strabag for $40 million.

MR. MILLAR: So OPG paid 40 million?

MR. YOUNG: OPG paid $40million. So at that point, there was -- Strabag had lost, let's say, $34 million.

Beyond that point in the contract, there were two -- in the new contract, there were two completion incentives that were built into the contract, each worth $10 million. So that would have taken Strabag's to, let's say, $14 million.

And beyond that, there was a $40 million bonus incentive for cost and schedule completion. So that takes Strabag's profit to something in the order of --

MR. MILLAR: Twenty-six?

MR. YOUNG: Twenty-six -- is that correct?

MR. EVERDELL: Yeah, that would be the maximum as well. And you may recall that they claimed $90 million -- actually more than $90 million lost. So when you take that into account, their profit could be under $10 million, even though they earned all the incentives by completing the project, and completing the project ahead of schedule and under the target cost.

MR. MILLAR: Well, profit isn't just incentives earned, isn't that right? When Strabag signed the

contract, let's say originally for 723.6 million, profit
was included in that, right?
     MR. YOUNG: Yes, it was. But effectively, at the
point that they were partway through that contract, they
were seeing a $90 million net loss. So they'd made no
profit; they were claiming to be $90 million under water.
     MR. MILLAR: Of which you gave them 40 million.
     MR. YOUNG: Of which we gave them 40.
     MR. MILLAR: But then they give you a new estimate of
$1.181 billion.
     MR. YOUNG: But that wasn't just an estimate; that was
really a contract that reflected actual cost with
incentives. So the only profit that was in that new
contract was the incentives.
     MR. MILLAR: So their costs don't include profit?
     MR. YOUNG: No, they do not.
     MR. MILLAR: So the original 723 did include --
     MR. YOUNG: Yes, it did.
     MR. MILLAR: -- something for profit in the second --
     MR. YOUNG: Yes, which we don't know.
     MR. MILLAR: Okay. So at the end of the day, they
finished --
     MR. YOUNG: Somewhere in the $10- to $30 million
profit range, on a billion dollars' worth of work.
     MR. MILLAR: And in OPG's opinion, is that a fair
sharing of the costs by Strabag, the additional costs?
     MR. YOUNG: Yes, it is. Again, if you look at when
the settlement was reached, Strabag and OPG effectively had

split those costs, and it really reflected Strabag having an incentive to go forward with the ability to earn a profit.

MR. MILLAR: Why did they have to -- you needed them to finish the project, right?

MR. YOUNG: We needed them to finish the project and ultimately – I mean, this was a negotiated solution. There was -- in our opinion, this was the best available solution and it was achieved at the cheapest possible point.

MR. MILLAR: You didn't think you could squeeze them any --

MR. YOUNG: We could not squeeze them further.

MR. MILLAR: And they would have walked away?

MR. YOUNG: They would have walked away. It was fairly close at the end of the day.

MR. MILLAR: Despite the significant costs they would incur to their bottom line and reputation, they would have walked away rather than accepting less than that, in your view? I know you are not speaking for Strabag, of course.

MR. EVERDELL: They of course wanted to minimize their loss, and they didn't want to incur additional losses going forward from that point.

MR. MILLAR: I have your answer, thank you. Just very quickly -- I don't know if anyone has touched on this or not, but I don't think they have. Could I ask you to turn to page 11 of the compendium, please?

This is part of the second business case, I guess, that went to OPG's board of directors, where you were tunnel by another contractor."

And they refer to alternative number two, which is on the next page.

So alternative number one was proceed under this targeted cost amendment. Alternative number two was engage another contractor. And alternative number three was to cancel the project. Those are the three that were presented to the board of directors, only?

MR. YOUNG: The status quo is there as well. So those three alternatives for the execution of the project, yes.

MS. DUFF: And alternative number one, we know what the cost of that is; it's the additional 615 million.

Alternative number two, is there any financial analysis or review of that?

MR. YOUNG: No, because it would be very, very difficult to cost. There was review of it. There was a lot of discussion around that possibility. The --

MS. DUFF: But there were no numbers to the board of directors about the cost of this? I guess that's --

MR. YOUNG: The comment I was going to make was that one of the things that OPG management did in the process between the contracts was set up a contract litigation oversight committee, with some external representatives on it and some management representatives on it.

That committee was advised on tunnelling by an expert from the United Kingdom, and he specifically advised around that question.

MS. DUFF: Attended the board of directors meeting?

MR. YOUNG: No. No, he did not, but he advised management around that question, and management provided, further, that advice. And that advice was very clearly that this alternative would be an extremely difficult and expensive alternative.

MR. EVERDELL: You may recall as well, just for clarification, that -- Roger mentioned that the tunnelling project in Vancouver that was happening at about the same time, and there the owner -- the contractor stopped work. The owner eventually fired the contractor after a few months, and went out to the street and engaged another contractor. And ultimately, the cost of that project was over two times what the original bid was by the fixed-price contractor.

MS. DUFF: Were either of you in attendance at this board of directors meeting in which this subsequent business case was presented and signed?

MR. YOUNG: No.

MS. DUFF: And the third alternative, which was to cancel the project, that does have a cost. The low likelihood of recovering the -- I guess it's a sunk cost of 563 million?

MR. YOUNG: That's right.

MS. DUFF: And the reason, part is that it's not recommended because there is "a low likelihood of recovering" -- sorry, I am now reading the sentence –- "of the 563 million through regulated rates."

MR. YOUNG: Yes.

And I don't want to put words in your mouth, but I think you were concerned about the financial viability of them being able to continue on in the project; is that fair?

MR. YOUNG: Concerned about the financial incentive of them continuing, given the -- the potential magnitude of the overall loss.

MS. LONG: So you are more concerned about their, perhaps, motivation to continue working, as opposed to any financial risk that OPG was going to incur?

MR. YOUNG: There was concern about how deep their pockets were as well, which was assessed. But there was also concern around whether they, for example, abandoned this project, abandoned any other prospects in North America and effectively said: Sue us. And how difficult that would be.

MS. LONG: As I understood the evidence, you had a contingency amount. I think you had letters of credit from them.

MR. YOUNG: Yes.

MS. LONG: And a parental guarantee and a bond as well to protect you, but you didn't feel that was enough?

MR. YOUNG: Well, I mean, the total loss that they could have been facing, I mean, effectively, had their contract -- had they executed their contract -- you know, they lost $90 million to the that point -- they would have lost an additional 4- or 500 million on the project to complete it. And, you know, clearly the security wouldn't have been enough.

MS. LONG: And my final question for you. I think somebody had asked you a question about the increased costs, and I think -- of the -- after the amended contract, and I think what you had said is substantially most of the costs were due to the rock condition, the overbreak, that sort of thing, but I guess -- can you reconcile for me the incentives? Would those incentives still have had to have been paid if you didn't find yourself in the situation that you did at the time, or you had to renegotiate the contract?

MR. YOUNG: I think if you look at the overall picture, the total picture of a contractor completing this project at the kind of profit level that they completed it at, including the incentives, we would not have found a contractor to complete it at that cost, you know, if you set out -- everybody knowing what they know now, set out to start contracting.

So I think Strabag did effectively almost do us a favour by staying on the job and doing it under the conditions they did it under, versus the kind of conditions and the kind of profit that they would have expected in undertaking the project straight up.

MS. LONG: To just follow-up on that point, though, I just want to be clear and understand you. You didn't approach any other contractors about --

MR. YOUNG: No, we did not. But again, we were clearly advised by experts that the in the situation we were in, the best outcome was to negotiate a target-based contract at that point of renegotiation.

MS. LONG: Thank you, those are my questions.

MS. HARE: I just have a couple of questions, and the first line is following up on the discussion you were having with Ms. Long.

You say that they were losing $90 million; that's based on what they told you. You then did an audit and thought that it was more like 77 million.

How in-depth was that audit? First of all, who did it and how in-depth was it?

MR. YOUNG: It was done by OPG internal audit, and it reflected going through their records, including inter-company transfers, et cetera. And there was a lot of controversy around -- the amounts that the auditors did not recognize reflected some inter-company costs within their organization, for example.

MS. HARE: And does Strabag have a history of walking away from projects?

MR. YOUNG: No, they do not.

MS. HARE: Okay. So you assumed that they might walk away?

MR. YOUNG: We certainly assumed that they might walk away and that -- and very clearly, they were signalling to us that they were having major problems with this, that their loss was hurting them severely and that they couldn't -- they couldn't keep going the way that it was going.

MS. HARE: Were you involved in the renegotiation of

TAB 4

DISPUTE REVIEW BOARD REPORT
Niagara Tunnel Project

Dispute Review Board Dispute No. 1

Differing Subsurface Conditions in Queenston Formation

Hearing Dates: June 23 through 26, 2008 **Report Date: August 30, 2008**

The Dispute Review Board (DRB) met with the Parties and their experts in Niagara Falls, Ontario to hear the Strabag Inc. (Contractor) dispute with Ontario Power Generation (Owner) regarding alleged differing subsurface conditions (DSC) encountered in the Queenston Formation (QF) portion of the tunnel between Stations 0+806 and approximately 2+200. In preparation for the hearing the DRB reviewed the Parties' position papers, reference documents and rebuttal papers, including expert reports and rebuttals to them. The hearing was closed on June 26,2008 following completion of testimony by the Parties and their experts, including their responses to questions from the Board. The Parties provided additional material as requested by the DRB.

1 SUMMARY OF DISPUTE

The following paragraphs summarize the Board's understanding of the Parties positions relative to the pertinent issues in dispute before the DRB and this hearing.

1.1 Large Block Failures

1.1.1 Contractor's Position

Large block failures within the Queenston Formation (QF) that occurred at cutterhead Sta. 0+815 and 0+839 were bounded by the overlying lithological contact with the Whirlpool Formation and natural discontinuities oriented sub parallel and sub perpendicular to the tunnel axis. These failures were structurally controlled, gravity failures with no evidence of any stress-related effects and were not anticipated based on the conditions described in the Geotechnical Baseline Report (GBR). The GBR reference to up to 3 m of slabbing implies progressive failure in layers and not sudden large block failure and these conditions constitute a DSC.

1.1.2 Owner's Position

The Owner maintains that block failure is not due to a geotechnical subsurface condition but a result of inadequate rock support. Further, that although some limited reduction of regional in situ stress field was expected in the QF immediately below the stiffer Whirlpool Sandstone, the stress reduction would not be of a magnitude that would promote block failures in the crown. Rather, the Contractor's failure to install closely spaced steel sets within or immediately behind the shield of the TBM, as agreed to in the Design Build Agreement (DBA) led to the large block failures and no DSC was encountered.

2.2 Chronology

Proposal documents submitted to tenderers	12-22-04
Proposals received from tenderers	5-13-05
Contract awarded to Strabag Inc. and signed	8-18-05
Noticed to Proceed	9-1-05
First DRB meeting	2-7-06
Start tunnel excavation	9-1-06
Large fallout at start of QF	5-16-07
Notice of DSC from Contractor to the Owner	5-23-07
Excavation of St Davids Gorge portion of tunnel	11-07 through 5-08 (approx dates)
Dispute Request from Contractor to DRB	3-5-08
Original Substantial Completion Date	10-9-09

2.3 Pertinent DBA Provisions

Section 2.1 (a) states "The Contractor will ensure that all Work is performed in accordance with and complies with the Owner's Mandatory Requirements, the Contractor's Proposal Documents, Final Submittals, Applicable Law and the other terms of this Agreement."

Section 2.13 (a) states "… The Contractor will be solely responsible for the means, methods, … used to perform the Work, …"

Section 3.3 states "… The Contractor acknowledges exclusive control over and commercial responsibility for any and all means, methods, … to complete the Work for the Contract Price and in accordance with the Contract Schedule."

Section 5.4 states "The Geotechnical Baseline Report (GBR) shall serve as the only basis for determining … differing geotechnical subsurface conditions." The GBR has been developed jointly by the Owner's team and the Contractor and, as such, describes anticipated behaviors and conditions that are dependent on the Contractor's selected designs, means, methods … anticipated or implied at the date of this Agreement. …The Parties acknowledge that such means, methods, … are the sole responsibility of the Contractor, and the Contractor is free to make changes at any time. To the degree that any difference in the behavior of the geotechnical subsurface conditions is attributable to a change or deficiency in the designs, means, methods … then the Contractor will not be entitled to make any claim for the impacts resulting therefrom."

Section 5.5 (b) states that to be a DSC, the subsurface conditions:

(1) Must "… differ materially from the GBR;"
(2) "the material difference in the conditions is not attributable to a change or deficiency in the Contractor's designs, means, methods, sequences, timing and/or level of workmanship;"
(3) Must "… directly and materially impact performance of the Work; and"
(4) "such impact has the effect of materially increasing or decreasing the cost or time of performing the Work."

Section 5.5 (c) (1) states "…the Contractor will record the rock conditions (as defined in the GBR) encountered in the performance of the Work and measure the tunnel lengths thereof and OPG will review and verify such determinations. If the parties cannot agree, the positions of both parties shall be recorded. The resolution of any disagreements will be held in abeyance ..., unless the parties mutually agree that the issue is sufficiently material that the issue should be referred to dispute resolution in which event the matter be resolved in accordance with Section 11;..."

Section 5.5 (e) states "No request by the Contractor for relief for differing subsurface conditions will be allowed in respect of Work under the St. Davids Gorge to the extent that the width of the gorge is within the width defined in the GBR."

2.4 Contract

2.4.1 Design Build

Tunnels in North America have traditionally been constructed using Design-Bid-Build contracts, in which the Contractor has no involvement in preparing the contract documents, including the GBR. All bidders tender to the identical contract provisions, GBR conditions and design.

Design-Build (DB) contracting is becoming a more frequently used form of contract on large, challenging construction projects primarily to reduce the pre-bid time spent on design efforts and equipment procurement, thereby facilitating earlier completion. DB is used on this Project and four main parties are involved: the Owner, the Owner's Representative (OR), the Contractor, and the Designer, ILF Consulting Engineers, of Austria, who is retained by the Contractor. The three contractors that proposed for this Work and their designers prepared preliminary designs, design basis and methods statements, specifications, drawings and payment provisions in general accordance with the Owner's bidding requirements, mandatory requirements and conceptual design. However, after evaluating the conceptual tunnel design, Strabag proposed a different lining design that required a different type of TBM. This was accepted by the Owner and is being used to construct the tunnel.

On this contract the Owner's team prepared an initial GBR, called a GBR-A. Each proposal included a GBR-B, in which the tenderers supplemented and revised GBR-A, to be consistent with the bidder's proposed design approach and planned means and methods of construction. The GBR-C was negotiated with the selected tenderer and became the contractually binding GBR.

The Contractor is responsible for design and construction of the Work. The Owner is responsible for more adverse subsurface conditions than are represented in the GBR. The Owner **and** the Contractor are **jointly** responsible for preparation of the GBR.

2.4.2 Contractor's Proposal

The Contractor proposed a prestressed tunnel lining method, and listed nine hydroelectric tunnels where the method had been used between 1963 and 1988. This lining approach was judged by the Owner's team to be significantly superior, for the unique requirements of the Niagara project, to the methods proposed by the other two tenderers, each of which involved a fully-shielded TBM with a single pass, pre-cast segmental lining. The price and duration of the Strabag proposal, as negotiated, were acceptable. Therefore the Owner contracted with this Contractor to do the Work.

As the DRB understands it, Strabag was not the low bidder and acknowledged in their proposal that using a shielded TBM with a pre-cast segmental liner would make construction easier. However, Strabag considered a segmental liner too unreliable, under the unique site conditions, to meet the required service life of 90-years without unwatering the tunnel for repairs.

hydraulic drills when installing steel channels and rock bolts, even though such loosening was not visually apparent from the L1 area.

The only different Rock Characteristics between Rock Condition 5 and 6 were the addition to type 6 of "closely broken shear and thrust zones" and the catch all "all other conditions requiring greater support than under Conditions 4Q and 5". This explains why all of the QF encountered in the claimed length of the tunnel has been classified by the Owner as Rock Condition 5.

The Contractor refused to record the conditions encountered in the QF in accordance with this Table, even though the DBA (Section 5.5(c)(1) instructed him to do so. The DRB suspects this was because the Rock Characteristics described in this Table were inadequate to define the rock in a manner that would enable identification of a DSC, i.e. mapping in accordance with the Table would force the Contractor into classifying the rock as one of the 3 rock types listed for the QF.

The DRB agrees that the Table of Rock Conditions and Rock Characteristics is inadequate to be used for the identification of DSCs and, further, that the inclusion of such terms as the "closest match" and "all other conditions" essentially renders the concept of DSCs meaningless and makes the GBR defective. Other contract language has been used in the U.S. in Design-Bid-Build contracts in an effort to avoid DSC claims. Such disclaimer language is contrary to case law and has consistently been thrown out by the U.S. courts. In this DB contract, both Parties jointly developed the GBR document and both Parties should share the shortcomings of the resulting documents.

4 CONCLUSIONS AND RECOMMENDATIONS

4.1 Large Block Failures

There is no DSC. The actual conditions were adequately described in the GBR.

4.2 St. Davids Gorge

Given the provision of the DBA Section 5.5 (e), the Contractor has no claim for any DSC in this 800m long section of QF.

4.3 Insufficient Stand-Up Time

There is no DSC based on insufficient stand-up time, as the Contractor's reported reliance on RMR values stated in the GBR was inappropriate.

4.4 Excessive Overbreak

There is a DSC with respect to the excessive overbreak, provided the defective provisions of the GBR are overlooked, because the GBR contained potentially misleading statements that make the Contractor's position reasonable. Any substantial changes in the designs, means and methods of the support (i.e. Type 4S) were the result of DSCs encountered and not vice versa. Since the development of the GBR was the mutual responsibility of both Parties, we recommend that the Parties negotiate a reasonable resolution based on a fair and equitable sharing of the cost and time impacts resulting from the overbreak conditions that have been encountered and the support measures that have been employed. Both Parties must accept responsibility for some portion of the additional cost, but at the same time the Contractor must have adequate incentives to complete the Work as soon as possible.

4.5 Inadequate Table of Rock Conditions and Rock Characteristics

The Table of Rock Conditions and Rock Characteristics is inadequate to define the subsurface conditions that were encountered. More importantly, the classification of support types based on the "closest match" to rock conditions and rock characteristics given in this Table, together with rock characteristics defined as "all other conditions", renders the concept of DSCs essentially meaningless and the GBR defective. The DRB recommends that the Parties jointly revise the Table of Rock Conditions and Rock Characteristics in such a manner that it describes the rock characteristics to be assumed in terms that are mappable (or otherwise quantifiable) so that it can serve as a clear basis for defining DSCs throughout the remainder of the tunnel excavation. The DRB also recommends that the terms "closest match" and "all other conditions" be removed from the GBR.

This report and the Conclusions and Recommendations presented herein reflect the unanimous views of the Dispute Review Board.

Additional Comment:

The DRB members have rarely experienced such an excellent, cooperative atmosphere between the Parties on a tunnel project. This is especially impressive considering the pioneering nature of the Work and the problems and issues encountered. The Board is confident that the Parties can negotiate an amendment(s) to the DBA that, while not commercially optimum for either Party, will allow the Project to proceed to optimum completion.

Respectfully submitted,

Date: 8/30/08

Peter M. Douglass

Peter M. Douglass, DRB Chair

Date: 8/30/08

D. McCarry

Dennis McCarry, DRB Member

Date: 8-30-08

P.E. Sperry

P.E. Sperry, DRB Member

TAB 5

1 INTRODUCTION

1 Ontario Power Generation Inc. (OPG) is implementing the Niagara Tunnel Facility Project, the key element being a water delivery tunnel. The project will be constructed following the Design/Build delivery method.

2 This Geotechnical Baseline Report (GBR) includes descriptions of the tunnel and other underground works to be constructed; interpretations of the geological and geotechnical information obtained for the Project, and a summary of expected geotechnical and groundwater conditions to be encountered.

3 The designs, means, methods, sequences, timing or level of workmanship required to construct the project in accordance with the Contractor's design will influence the behaviour of the subsurface materials during construction. This GBR is intended to assist the Contractor in evaluating the requirements for excavating and supporting the ground, and in preparing the design.

4 The GBR will be used during the execution of the Contract for comparison of the assumed subsurface conditions with actual subsurface conditions as encountered during construction. Consequences associated with subsurface conditions consistent with, or less adverse than, the baseline conditions represented in the Contract Documents are the responsibility of the Contractor. Those consequences associated with subsurface conditions more adverse than the baseline conditions are accepted by OPG. The GBR is intended to assist the parties in the resolution of contractual disputes.

5 Documents and reports that were prepared during the development of the project and other studies in the project area, including the GDR, are reference documents for information only. None of the information contained in these reference documents constitutes a representation by OPG or any Person (whether in tort or contract), and the Contractor must make its own assessment of the relevance and validity of such information.

6 This GBR presents the soil, rock and groundwater conditions expected to be encountered in the surface and subsurface excavations. While the actual conditions encountered in the field are expected to be within the ranges as given in the GBR, the distribution of geologic conditions encountered will likely vary from those presented in this GBR. Where an average value is given without a range or histogram, the given value shall be considered to be the 50% probability of occurrence averages, and the range shall include extreme values at 10% probability of occurrence that are 30% greater and 30% lower than the average.

7 Where the values are presented as a range, the range shall be considered to include all values at 25% probability or higher. The extreme values in the range shall be increased or decreased by 10% to address values at 10% probability of occurrence for a normal distribution. The distribution will be assumed to be skewed so that the

TAB 6

AMPCO Interrogatory #016

Ref: Exhibit D1, tab 2, Schedule 1 Niagara Tunnel Project (NTP)

Issue Number: 4.4
Issue: Do the costs associated with the Niagara Tunnel Project that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?

Interrogatory

a) Pages 24 – OPG indicates the five proponents were invited to present their views in a 2004 meeting with OPG on the Geotechnical Baseline Report (GBR) provided. Please summarize Strabag AG's comments or concerns related to the GBR and how they were considered by OPG.

b) Page 25 – OPG indicates that in Ed. Zublin AG's view, building such a large tunnel would be a significant challenge. Please identify any challenges identified by Ed. Zublin AG related to the subsurface conditions and how they were considered by OPG.

c) Page 28 – OPG estimated a $96 M cost contingency and 36 week schedule contingency for the tunnel portion of Strabag !G's proposal to achieve a 90 per cent probability that the project would remain within budget and schedule. Please discuss how OPGs contingencies for the tunnel portion of the other four proponents differed from Strabag !G's and why.

d) Page 28 – OPG indicates five amendments to the invitation documents were issued in response to issues raised by the proponents. Please indicate if any amendments were related to issues raised regarding the GBR and subsurface conditions.

e) Page 29 -As part of the RFP process proponents were asked to include a response to the GBR. The RFP score for the response to the GBR was 45 points which represented 9% of the RFP evaluation. Please summarize Strabag AG's response to the GBR.

f) Page 45 – OPG indicates the subsurface risks were investigated and analyzed by Acres and Hatch. Please provide this analysis.

g) Page 113 –Chart 6 Cost Changes between the DBA and the ADBA – The Chart shows a variance of $614.8 M. i) Please provide the percentage of the variance that is associated with the cost overrun due to the adverse subsurface condition issue. ii) Please add a column to the Chart that shows a breakdown of the costs associated with the adverse subsurface condition issue.

h) Page 129 – OPG concludes that the entire amount of project costs should be recovered by ratepayers. Please discuss if OPG considered any cost sharing arrangements regarding the

$614.8 M in additional costs compared to the original budget as shown in Chart 6 on Page 113.

Response

a) During the November 2004 meeting, Strabag AG identified that they had no major comments with the draft GBR. There was discussion about the need for more information. OPG identified its intent to complete the GBR for the contract. For the RFP process, OPG also made available additional information in the form of the Geotechnical Data Report ("GDR") to proponents in the data room.

b) Ed. Zublin AG did not raise specific concerns with subsurface conditions, but did express concern about the TBM size, tunnelling logistics and tunnelling schedule.

c) OPG did not specifically assess contingencies for proponents other than Strabag. OPG's quantitative risk assessment process was conducted in two stages. The initial risk assessment (conducted by consultant URS – Ex. D1-2-1, Attachment 3) was performed concurrently with the RFP process and was based on the reference tunnel concept included in the RFP. This was followed by a specific risk assessment based on Strabag's proposal, which was performed after Strabag had been identified as the preferred proponent (Ex. D1-2-1, Attachment 4).

d) Amendments 3 and 4 to the invitation documents, included changes to the GBR that were related to questions raised by proponents. Specifically, in response to a proponent question that asked "What is the bottom elevation of [the] St. David Gorge at the centerline of the tunnel alignment?", the following was added to the GBR in Amendment 3:
    a. Figure 4.3 *"Buried St. David's Gorge – Baseline Elevations for Bottom of Gorge*".
    b. Section 4.4.4.3 *"Bedrock at St. Davids Gorge*" to describe Figure 4.3 and to provide a more detailed explanation about the elevations.

   Amendment 4 modified section 8.1.2.1 of the GBR to remove the requirement for a shielded tunnel boring machine for the tunnel excavation in response to the following proponent question: "Chapter 9.1 of the Owner's Mandatory Requirements calls for a shielded Tunnel Boring Machine suitable for safely excavating the ground conditions as described in the GBR. It is our understanding that an open type TBM equipped with roof support shield, finger shield and side support shields can equally or better meet the requirements. Please confirm."

e) Strabag's response, GBR-B (ILF Consulting Engineers document dated May 2, 2005), is attached (Attachment 1).

f) Beginning in 1988, Ontario Hydro (now OPG) engaged Acres (now Hatch) to provide engineering services that included geotechnical investigations and analysis as outlined in Ex. D1-2-1 Appendix B – Summary of Geological Investigations and in Ex. F5-6-1 Niagara Diversion Tunnel Report prepared by Roger Ilsley. Based on these geotechnical investigations and analysis, Hatch (formerly Acres) prepared the Geotechnical Baseline Report ("GBR") included in the Design Build Agreement (Ex. D1-2-1 Attachment 6). The GBR captures the results of the extensive geotechnical investigations and analysis to detail the subsurface conditions expected to be encountered during design and construction of the Niagara Tunnel.

g) OPG considers that 100% of the variance relative to the originally approved budget of $985.2M is due to the more adverse subsurface conditions experienced during the tunnel construction. This includes direct increases in tunnel contract costs and additional time related costs in categories such as interest during construction, OPG Project Management and Owner's Representative costs.

Project Cost Flow Estimate ($M) **(including Contingency)**	**Original Approval (DBA)**	**Revised Estimate (ADBA)**	**Estimated Capital Cost at Completion [1]**	**Costs Associated with Adverse Subsurface Conditions**
OPG Project Management	4.4	6.0	5.0	0.6
Owner's Representative	25.4	40.4	36.2	10.8
Other Consultants	4.0	5.9	6.5	2.5
Environmental / Compensation	12.0	9.6	8.7	(3.3)
Tunnel Contract (including Incentives)	723.6	1,181.7	1,112.9	389.3
Other Contracts / Costs	78.9	69.8	68.4	(10.5)
Interest	136.8	286.6	234.5	97.7
Total Project Capital	985.2	1,600.0	1,472.0	486.8

Notes: 1) Estimated Capital Cost at Completion as noted in response to Board Staff Interrogatory #28.
2) Numbers may not calculate due to rounding.

h) OPG did not consider any cost sharing arrangements for the costs above the $985.2 M approved by OPG's Board of Directors prior to OEB regulation. As fully documented in the evidence, the amount OPG spent on the NTP represents the true cost of completing the project given the subsurface conditions actually encountered. OPG acted prudently in planning and executing this project and in addressing the differing subsurface conditions encountered. Since any cost sharing arrangements would amount to a disallowance of prudently incurred costs, OPG did not consider them.

TAB 7

UNDERTAKING JT1.5

Undertaking

To provide CV of Richard Ilsley.

Response

Please see Attachment 1.

R I GEOTECHNICAL, INC.

2670 Topanga Skyline Drive
Topanga, CA 90290
Tel. 310.455.3860
Fax. 310.455.3670
email: roktek@aol.com

ROGER C. ILSLEY
TUNNEL & GEOTEOCHNICAL CONSULTANT

Education

M.Sc., Engineering Rock Mechanics, Imperial College, University of London, England
B.Sc., Engineering Geology, Newcastle University, England
Assoc. Deg., Civil Engineering, Mid-Essex College, England

Registration

Professional Geologist—Wisconsin, Indiana, Illinois

Experience and Background

Mr. Ilsley's educational background and his broad construction and consulting experience have allowed a synthesis of the related fields of rock and soil mechanics, engineering geology, hydrogeology, and construction methodologies in both soil and rock. He has more than 40 years experience in the field of design and construction of underground construction projects; 12 years working for construction companies and the remaining years in the consulting engineering field. He can provide leadership and technical input to projects that require multi-disciplinary expertise and the ability to combine the qualitative and quantitative aspects of geotechnical engineering with the practical aspects of design and construction.

Representative Underground Excavation Project Experience

- Member of Peer Review Board for the Washington DC Water and Sewer Authority for the Anacostia CSO Control Plan Design. The project entails the design of 13 miles of CSO conveyance and storage tunnels up to 26 feet in excavated diameter in soil and 17 shafts ranging up to 132 feet in diameter. Over 150 borings, including about 50% sonic, have been completed. He has provided peer constructability and geotechnical review of the preliminary engineering plans including exploration plans, field and laboratory testing and data interpretations and the GBR. The majority of the initial 35,000 foot long Blue Plains Tunnel Contract is being constructed beneath the Potomac and Anacostia Rivers and a Design Build project delivery has been used. The tunnels will be excavated using EPB TBM's and supported with a one pass, bolted and gasketed, SFR concrete segment lining system, with water pressure heads up to about 4 bars. He participated in preparation of the completed 30, 60 and 100% project documents; in the preparation of the SOQ and the Design Build RFP issued July 1, 2010; in workshops on Design Build project delivery; in identification of Risk Register construction activities and their potential cost and schedule impacts. Conducted peer review of plans and specifications. Served on the committee for the selection of the DB team for the Blue Plains Tunnel and Anacostia River Tunnel segments; the former is under construction. Currently participating in the design review of the third phase of the work, the Northern Boundary Tunnel and review of the conceptual phase of the Potomac rock tunnels.

- Member of Design Review Board for Northeast Ohio Regional Sewer District's Dugway Storage Tunnel which consists of a 26 ft mined diameter, 6.25 miles long rock tunnel with six drop shafts and near surface ancillary work. Tunnel support and lining will be provided by FRC segments. The 30 and 60% level design review have been completed. Consultant to the Bouyges and Jacobs Engineering Design Build team for the Port of Miami Tunnels contract consisting of twin, 42 foot diameter finished highway tunnels, about 8,000 feet total length beneath the main shipping channel, with gasketed bolted SFR concrete segments for support. The tunnel was excavated using an EPB TBM through ground consisting of very weak to moderately strong limestone with sand layers. He participated in the evaluation of the supplementary geotechnical investigations including sonic and SPT borings and CPT explorations; also a comprehensive laboratory testing program to further characterize the ground conditions, lithology and stratigraphy for design and construction purposes.

Provided peer review of the resulting geotechnical reports for the approach works and the channel tunnel crossing.

- Consultant to the Federal Transit Authority for design readiness review for the Los Angeles Metro West Extension. Reviewed conceptual and later preliminary design drawings, specifications, tunnel alignment, station locations and geotechnical reports for the Purple Line, regarding constructability and design level, in order to release federal funds to the project.

- Consultant to the design team (Parsons Brinckherhoff, et. al.) for the Los Angeles Metro System. Duties included resolution of constructability issues arising during construction of the twin, 21-foot diameter Lankershim Blvd. Tunnels (Contract 331) which were constructed in alluvial soils and the Puente Formation using digger shields and the twin Hollywood Hills Tunnels (Contract 311) in rock, using Tunnel Boring Machines (TBMs). Also participated in the design of the Eastside Extension tunnels that examined the use of Earth Pressure Balance TBM's and evaluations of the potential settlement to buildings and its mitigation. Contract 331 required extensive soil modification using silica based chemical grouts to control ground settlement. Compaction grouting was used as the shield passed beneath existing buildings to minimize settlement. Contract 311 required a 400-foot long fault zone to be grouted with micro-fine cement to reduce permeability and strengthen the rock.

- Member of Board of Consultants for the Metropolitan Water District of Southern California's Inland Feeder Project consisting of 90,000 feet of 17-foot diameter tunnel in rock and soil; participated in a comprehensive review of the re-design of the Arrowhead and Badlands Tunnels. A pre-excavation grouting program using ultrafine and regular OPC cement grouts was implemented. A very strict inflow criterion was met as part of a U.S. Forest Service's permit. Gasketed, bolted segments were designed for 900-foot heads.

- Member of Design Review Board for Hatch Mott/ CDM on the Staten Island Subsea Siphon Crossing consisting of about 10,000 feet of 13 foot excavated diameter tunnel. The tunnel is being excavated using an EPB TBM through a varied geology including fresh and extremely weathered rock; glacial soils including sands and gravels with occasional cobble and boulder zones and recent marine sediments including fine and coarse grained soils. Conducted constructability review at 90% design level of GDR, Geotechnical Design Report, GBR, specifications and drawings.

- Consultant to Fugro West Inc. who is providing geotechnical engineering services for the LA County Sewerage Districts Tunnel and Ocean Outfall. The tunnel length is about 7 miles long and up to 20 feet in diameter. He has participated in setting up the GIS data base for existing and new data, exploration plans for onshore exploration and an extensive field and laboratory testing program to provide index and engineering properties for tunnel corridor evaluation and preliminary design. Also assisted with initial project stratigraphy assessments and fault relations. The Outfall Tunnel will be constructed in Quaternary soil deposits and very weak to weak rock of Miocene/Pliocene age.

- Participated with a group of experts in a series of workshops for the NYCDEP in order to evaluate alternative construction methods for the proposed Bypass Tunnel beneath the Hudson River on the Rondout-West Branch Tunnel of the NYC aqueduct. Prepared report describing his suggested approach consisting of a new diversion tunnel beneath the existing tunnel with a lake-tap type connection in order to control inflows and allow subsequent permanent connections; this alternative was adopted by the current designer for the project.

- Project Manager and Engineer for numerous geotechnical engineering studies for tunnels in soil and rock for the Milwaukee Water Pollution Abatement Program. The Program included approximately 35 miles of 6- to 15 foot diameter tunnels in generally poor soil conditions below the water table. Also constructed were approximately 17 miles of 12- to 32-foot diameter TBM tunnels in rock up to 300 feet deep. The deepest shafts had up to 135 feet of variable soil conditions with the groundwater level five feet below the ground surface. As Project Manager he supervised 26 geotechnical engineers and engineering geologists tasked with exploration planning and field inspection of over 400 borings, field and laboratory testing, installation of piezometers and recording of water level data, interpretation and summaries of all data and preparation of Geotechnical Data Reports. Studies included evaluations of settlement and effects upon buildings and utilities; design of instrumentation and construction monitoring program; constructability reports. Also responsible for the preparation of numerous Geotechnical Design Summary Reports.

Among the pressure faced soil TBMs used were Lovat, Hitachi EPB, and Mitsubishi Slurry Shield. The tunnel support systems included ribs and lagging, jacked pipe, gasketed and bolted concrete segments. During construction, he evaluated contractor's temporary support designs for excavations and control of water in soil and rock. Support and water control systems included slurry diaphragm walls, frozen soil, soldier pile and lagging, steel sheet piling, soil and rock anchors, rock reinforcement and cementitious and chemical grouting of rock.

- Consultant to Lake Forest Park Water District, Seattle regarding excavation of the Brightwater Central Contract tunnel beneath their aquifer. Reviewed Slurry and EPB performance data and results of laboratory analysis of tunnel spoil in order to assess criteria for identifying soil types and thereby evaluating if the aquifer has been breached. Recently conducted inspection of the completed tunnel beneath the aquifer.

- Member of a two person Design Review Board for Black and Veatch on the Las Vegas SCOP project. The project consists of 44,000 feet of 16 foot diameter mined tunnel under the River Mountains with a hydro-power station at the Lake Mead end. The geology is comprised primarily of lava flows, dykes, pyroclastic deposits, with vesicular and weathered surfaces, flanked with Tertiary sedimentary rock and Quaternary alluvium.

- Consultant to Brown and Caldwell and responsible for the geological engineering aspects of the final design and authorship of the GBR for the North 27th Street ISS Tunnel, Milwaukee, WI. The 10,800 foot long, 23-foot mined diameter rock tunnel is for conveyance and storage of combined storm and sewerage overflow. Supervised geological mapping of the shafts and tunnels.

- Consultant to Jacobs Engineering for the design of the Detroit Upper Rouge CSO tunnels consisting of about 10 miles of 32 foot diameter tunnel, ten drop shafts and a 60 foot finished diameter pump station shaft. The alignment geology generally consists of shale with limestone and dolomite. Identified fissility of shales as a controlling ground behavior characteristic requiring the immediate placement of ground support.

- Member of the tunnel Design Review Board for Black and Veatch on the Ashley River Tunnel Project in Charleston, South Carolina. The seven-foot finished diameter tunnels are 12,500 feet long, about 120 feet deep and will initially be supported by ribs and lagging. The upper 65 feet of soils includes significant thickness of very weak, organic clays with zero blow counts. Of the six planned deep shafts, varying in diameter from 12 to 30 feet, five were constructed using the sinking caisson method and one was a drilled shaft with casing. Five micro-tunneled sections totaling about 2,300 feet, mostly located within the organic clays, were completed. The proximity of historic buildings adjacent to shaft and tunnel excavation was a particular concern.

- As a member of the Technical Review Board for MWH on the Brightwater Project in Seattle, participated in peer review of the East Tunnel 90% design contract documents and Central Tunnel 30% design contract documents. The 15-foot diameter tunnels are about 50,000 feet long in soil conditions, including peat, glacial outwash and boulder tills. The tunnels were constructed using both EPB and Slurry pressure faced TBMs.

- Project Engineer for contractor for six years on rock and soil tunnels and station construction for Washington DC Metro System. Designed tunnel blasting diagrams for 22-foot high by 30-foot wide, twin-track tunnel and associated shafts and portal. Designed and detailed shaft excavation support, concrete formwork, drill jumbo and shotcrete equipment. Other duties included evaluations of contract modifications, preparation of claims, and estimating for bids on Metro System construction projects.

- Project Engineer for contractor for two years on urban storm drainage project, including a six-foot diameter tunnel in silt requiring compressed air, jacked pipe interceptors and culverts in open cuts, pumping station and an earth embankment. Duties included line and grade in tunnel; job planning for materials procurement, sequence of work, equipment selection and design, progress payments and bonus payments to crews.
  I contributed to the preliminary drafting of the ASCE Publication, "Geotechnical Baseline Reports for Underground Construction, Guidelines and Practices," (edited by R.J. Essex and published by ASCE, see acknowledgements) in which the groundwork for the GBR content was laid out. Subsequently, I have participated in the preparation of GBRs and interpreted them for the purpose of presenting geotechnical issues to Dispute Resolution Boards and in expert testimony in litigation.

- I contributed to the preliminary drafting of the ASCE Publication, "Geotechnical Baseline Reports for Underground Construction, Guidelines and Practices," (edited by R.J. Essex and published by ASCE, see acknowledgements) in which the groundwork for the GBR content was laid out. Subsequently, I have participated in the preparation of GBRs and interpreted them for the purpose of presenting geotechnical issues to Dispute Resolution Boards and in expert testimony in litigation.

SUMMARY OF DISPUTE RESOLUTION BOARD (DRB) EXPERIENCE

DRB Experience

- I am currently serving on a DRB for the San Francisco PUC, New Irvington Tunnel and the completed Bay Division Pipeline #5 as chairman; also two DRBs for the Toronto Spadina Subway Extension. I have served on 16 DRBs and was the chairman of three of these boards. I was selected as the third person by the two appointed members in five instances to provide tunnel design and geotechnical expertise. This has allowed me the opportunity to carefully review and evaluate Differing Site Condition claims using the GBR and other contract documents.

- Currently serving on the DRB for the Vaughan Station of the North Extension Toronto-Spadina Subway. The contract is valued at $200 million and consist of a 1,200 foot long station, crossover and tail tunnel structure complete, excavated in glacial soils with a slurry cut-off wall all round and tied – back secant pile and soldier pile with lagging support.

- Currently serving on the DRB for the Northern Tunnels of the North Extension of the Toronto-Spadina Subway. The contract is valued at $400 million and consists of 4.7 kms of twin track 6.4 m diameter tunnel constructed using Earth Pressure Balance (EPB) TBMs (with one-pass bolted gasketed segments for support); the Highway 407 and York Stations; a 200 m Sequential Excavation Method (SEM) tunnel section in soil.

- Served as a member of the DRB for the Seymour-Capilano Twin Water Supply Tunnels consisting of twin, 24,000-feet long, 12 feet diameter rock tunnels with two shafts of 590 and 880 feet depth. The client was the Greater Vancouver Water District, B.C., Canada.

- DRB Chairman for the underground construction for the Stanford Linear Accelerator Center in Menlo Park, CA, consisting of about 1,700 feet of tunnel and caverns up to 50 feet wide in weak rock.

Sequential methods of excavation with road headers were used and the support consisted of dowels and shotcrete.

- Served as a member of five DRBs for the LNWI project for the Sacramento Regional County Sanitation District. These projects included 144-inch diameter gravity sewers and 60-inch diameter force mains constructed in open cut with extensive dewatering and two 15-foot diameter 2,000-foot long EPB TBM tunnel crossings of the Sacramento River with bolted, gasketed segments for support. Also a 3-foot diameter directional drilled crossing of the Sacramento River.

- Third person nominated to serve on DRB for Washington D.C. Metro Contract IE-0032 Greenbelt and Park Road tunnels consisting of 7,000 feet of approximately 21-foot mined diameter tunnels in soil using digger shields. Ground modification using silicate grouts was required for the total length of the tunnels.

- Third person and Chairman nominated to serve on DRB for Sacramento Regional County Sanitation District Contract 3114, Bradshaw Interceptor, Section 5A tunnel consisting of approximately 10,000 feet of 13-foot mined diameter tunnel in soil with ribs and lagging using Lovat TBM. Final lining consisted of RCP with T-lock lining.

- DRB member for the Sacramento Regional District County Sanitation District Contract No. 3908, Upper Northwest Interceptor 3 & 4 Project consisting of about 18,500 feet of tunnel construction methods including 11,000 feet of Slurry TBM micro-tunnel; 6,000 feet of two-pass tunnel with ribs and lagging using a Lovat TBM and 1,500 feet of pipe jack.

- DRB member for Corps of Engineers, Cadey Marsh Flood Relief Tunnel, Griffith, Indiana, consisting of 6,500 feet of 13 foot excavated diameter tunnel with ribs and lagging for initial support and CIP final lining. Extensive dewatering was required.

DRB member for the Santa Clara Valley Water District Lenihan Dam Outlet Modifications Contract No. 91904005 consisting of about 2,500 feet of horseshoe tunnel, 16 feet wide by 13 feet high excavated using drill and blast and a road header through the San Franciscan Formation and supported with ribs and shotcrete. The tunnel traverses a dam abutment from the downstream side and connects to a new intake/dropshaft within the reservoir. An intake structure constructed on the reservoir bank connects to the dropshaft.

Presentation of Position Papers to DRB

- Presented position papers to the DRBs for LA Metro Contract C331 consisting of 10,000 feet of 21-foot diameter tunnel in soil with temporary segments for primary support and an extensive chemical grouting program conducted from the surface. Six major hearings were held.

- Presented position papers to the DRB during hearings of claims on LA Metro Contract C311 which consisted of 15,000 feet of 21-foot diameter tunnel in weak rock with ribs and steel mat lagging for primary support. Two major hearings were held.

- Assisted with presenting geotechnical issues to the DRB on the MWD Southern California, Badlands Tunnel and Arrowhead Tunnels of the Inland Feeder Project in San Bernadino.

- Presented position papers to the DRB for the 9.5 mile long, 26-foot diameter MWDRC Boston Outfall Tunnel. Three separate hearings were held, each of one week duration. I also participated in the information exchange/negotiation sessions between the parties prior to the commencement of the DRB hearings.

LITIGATION AND ALTERNATIVE DISPUTES RESOLUTION EXPERIENCE

Project Name and Description: Contract 331, Los Angeles Metro
Twin, 21-foot diameter tunnels, 10,000 feet long in alluvial soils and weak rock. Excavated with digger shields using temporary concrete segments for support with an extensive chemical grouting program.

Date: 1996 to 2002

Client: Los Angeles Metropolitan Transit Authority Claim Amount: $24,000,000
At Issue: Differing site conditions regarding soils encountered and their behavior; defective specifications and failure to implement the contract.

My Role: Presented position papers to the DRB on soil conditions and behavior, constructability issues arising out of tunnel machine performance and the use of chemical grout.

Dispute Resolution Method: Dispute Review Board/Litigation

Outcome: There were four separate hearings on these related issues over a period of one year. No merit was found on three issues and partial merit on one issue. I was retained as an expert witness by the LA-MTA when they were subsequently sued. The case settled for $6,000,000.

Project Name and Description: Washington, DC Metro, Section E-2c
12,000 feet of 21-foot diameter tunnel in soil excavated with digger shields and extensive chemical grouting and dewatering.

Date: 2001

Client: Washington Metropolitan Transit Authority Claim Amount: $37,000,000

At Issue: The owner and designer misled the contractor in that the design was defective; the selected tunneling method was inappropriate and there was a differing site condition in regard to the soils and their behavior.

My Role: Expert Witness. Selection of the tunneling method and tunnel design was appropriate. The soil and groundwater conditions and soil behavior was not different to that which could have been anticipated.

Dispute Resolution Method: Litigation; jury in Federal Court, Washington D.C.

Outcome: $0 awarded to contractor. The issue went to the Appeals Court with the same result.

Project Name and Description: East Side Reservoir
800,000 acre feet with two rock fill dams. East dam was 6,000 feet long. West dam was 4,000 feet long.

Date: 2000

Client: Metropolitan Water District of Southern California

Claim Amount: $29,000,000

At Issue: Rock Borrow hill was excessively faulted and sheared which severely impacted blasting and excavation efficiency.

My Role: Engineering geological mapping of hillside benches, preparation of report and graphics to portray actual conditions regarding shears and faults and to demonstrate encountered conditions were as portrayed in contract documents.

Dispute Resolution Method: Mediation

Outcome: Awarded $9,000,000
`

Project Name and Description: Boston Outfall Tunnel
50,000 feet of sub-ocean rock tunnel, 26.5 feet in diameter, lined with pre-cast segments secured with dowels but without gaskets.

Date: 1995 to 1998

Client: Massachusetts Water Resource Authority

Claim Amount: $70,000,000

At Issue: Rock conditions were different for the entire tunnel length which caused the TBM to have a reduced penetration rate.

My Role: Attended meetings between selected groups from contractor, owner and engineer to attempt resolution. Prepared expert report and presented position papers at three separate one-week long DRB hearings on rock conditions and impact on TBM performance.

Dispute Resolution Method: Dispute Review Board

Outcome: Partial merit contractor awarded $20,000,000, which was accepted.

Project Name and Description: NS-8 Dropshaft and Ancillary Structures
20-foot finished diameter shaft, 285 feet deep in soil and rock. The soil portion was frozen and the rock grouted with cement and chemical grouts.

Date: 1993

Client: Milwaukee Metropolitan Sewerage District

Claim Amount: $1,900,000

At Issue: Grouting designed by owner was ineffective causing excessive inflows into the rock portion of the shaft and led to windows in the freeze wall because of increased hydraulic gradients.

My Role: Expert witness on issues of grouting design for rock portions of shafts and hydrogeology issues relating to groundwater movement in the rock and overlying soil.

Dispute Resolution Method: Litigation; jury in Federal Court.
Outcome: Contractor awarded $1,900,000

Project Name and Description: Contract 311 Los Angeles Metro
Twin, 21-foot diameter tunnels 16,000 feet long in weak rock (under Santa Monica Mountains). Excavated simultaneously with two TBMs.

Date: 1997

Client: Los Angeles Metropolitan Transit Authority

Claim Amount: $9,000,000

At Issue: Squeezing ground caused tunnel support to collapse behind shield, trapping TBM.

My Role: Presented position paper showing ground movement was predictable and that contractor initial support selection was at fault.

Dispute Resolution Method: Disputes Review Board

Outcome: Awarded $7,000,000 by DRB accepted by contractor.

Project Name and Description: Root River Interceptor
Four miles of two to four feet diameter pipe in open-cut adjacent to river.

Date: 1991

Client: Milwaukee Sanitary District

Claim Amount: $750,000 (against Touche-Ross Accountants)

At Issue: Negligent audit and reporting of contractor's financial condition to the owner in bid documents. Contractor was unable to capitalize the necessary "up front" dewatering work necessary.

My Role: Expert Witness: Geotechnical, dewatering, constructability, blasting

Dispute Resolution Method: Litigation in Wisconsin State Court, jury trial

Result: Client awarded $750,000

Publications

Ilsley, R.C. and Costello, M.J., 1983. Discontinuity Characterization for Underground Openings for the Milwaukee Water Pollution Abatement Program. Underground Space Vol 7.3, Pergamon Press, Ltd.

Ilsley, R.C., Fradkin, S., McBee, J.M., 1984. Characterization of Rock Conditions for the Deep Tunnel Project in Milwaukee, 25th U.S. Symposium on Rock Mechanics, Chicago, IL.

Ilsley, R.C., Fradkin, S., Shorey, E.F., 1988. Evaluation of the Site Investigation and Construction Related Aspects of the Milwaukee Crosstown Deep Tunnel, 2nd International Conference on Case Histories in Geotechnical Engineering, St. Louis, MO.

Rose, J.P., Ilsley, R.C., Pre-grouting of the North Shore Tunnel, Milwaukee, WI, 1989. Ohio River Valley Seminar on Construction in Rock. Louisville, KY.

Ilsley, R.C., Doyle, B.R., Ramage, J., 1989. Approach for the Design of Tunnels in Weak Soils. R.E.T.C. Proceedings, Los Angeles, CA.

Donnelly, T., Ilsley, R.C., 1991. Remote Vibration Monitoring at Historic Structures. Society of Explosives Engineers, Conference Proceedings, Las Vegas, NV.

Ilsley, R.C., Powers, J.P., Hunt, S.W., 1991. Use of Recharge Wells to Maintain Groundwater Levels During Excavation of the Milwaukee Deep Tunnels. R.E.T.C. Proceedings, Seattle, WA.

Ilsley, R.C., et al., 1991. Ground Movements Around Slurry Shield and Earth Pressure Balance Driven Tunnels in Milwaukee, Wisconsin, 4th International Conference on Ground Movements and Structures, Cardiff, U.K.

Pennock, E.S., Fradkin, S.B., Ilsley, R.C., 1991. Impacts of Solution Features on Mining of the North Shore Tunnel, Milwaukee, WI. 34th AEG Meeting, Chicago, IL.

Hunt, S.W., Ilsley, R.C., Santacroce, P.U., 1993. Pre-Excavation Grouting Effectiveness on Shaft Inflows in Rock. R.E.T.C. Proceedings, Boston, MA

Ilsley, R.C., 1994. Engineering Geological Mapping of Rock Slopes Using a Laser Transit. International Congress of I.A.E.G., Lisbon, Portugal.

Tinucci, J.P., Ilsley, R.C, 2001. Mapping, Seepage and Stability Analysis of a 300-foot High Quarry Wall used as a Dam, 38th U.S. Rock Mechanics Symposium, Washington, D.C.

Halim,I.S., Chen,N., Ilsley R.C., 2008. Initial Support design for Tunnels in Horizontally Bedded Sedimentary Rock, North American Tunneling Proceedings, San Francisco, CA.

Ponti, M.A., Fradkin, S.B., Wone, M. Wang, X, Bizzari, R.E., Cording, E.J., Ilsley, R.C., 2009. Subsurface Characterization for CSO Tunnels in Washington, D.C.; R.E.T.C. Proceedings, Las Vegas, NV.

TAB 8

Table 1
(Updated version of Ex. I1-1-1 Table 1)
Summary of Revenue Requirement ($M)
Years Ending December 31, 2014 and 2015

Line No.	Description	Note	Previously Regulated Hydroelectric 2014	Previously Regulated Hydroelectric 2015	Previously Regulated Hydroelectric Total	Newly Regulated Hydroelectric 2014[1]	Newly Regulated Hydroelectric 2015	Newly Regulated Hydroelectric Total	Nuclear 2014	Nuclear 2015	Nuclear Total
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Rate Base										
1	**Net Fixed Assets**	2	5,105.6	5,062.2	N/A	2,502.5	2,519.2	N/A	2,963.8	2,930.6	N/A
2	**Working Capital**	2	0.7	0.7	N/A	0.7	0.7	N/A	710.8	696.4	N/A
3	**Cash Working Capital**	2	21.7	21.7	N/A	8.3	8.3	N/A	32.0	32.0	N/A
4	**Total Rate Base**		5,128.0	5,084.6	N/A	2,511.5	2,528.2	N/A	3,706.7	3,659.0	N/A
	Capitalization										
5	**Short-term Debt**	3	99.0	98.1	N/A	48.5	48.8	N/A	44.7	45.3	N/A
6	**Long-Term Debt**	3	2,618.8	2,596.7	N/A	1,282.6	1,291.1	N/A	1,183.4	1,200.3	N/A
7	**Common Equity**	3	2,410.1	2,389.8	N/A	1,180.4	1,188.2	N/A	1,089.1	1,104.6	N/A
8	**Adjustment for Lesser of UNL or ARC**	3	N/A	N/A	N/A	N/A	N/A	N/A	1,389.5	1,308.8	N/A
9	**Total Capital**		5,128.0	5,084.6	N/A	2,511.5	2,528.2	N/A	3,706.7	3,659.0	N/A
	Cost of Capital										
10	**Short-term Debt**	4	3.6	4.6	8.2	1.8	2.3	4.0	1.6	2.1	3.7
11	**Long-Term Debt**	4	127.0	126.2	253.2	62.2	62.7	125.0	57.4	58.3	115.7
12	**Return on Equity**	4	225.6	227.7	453.3	110.5	113.2	223.7	101.9	105.3	207.2
13	**Adjustment for Lesser of UNL or ARC**	4	N/A	N/A	N/A	N/A	N/A	N/A	74.6	70.3	144.9
14	**Total Cost of Capital**		356.2	358.5	714.7	174.5	178.3	352.7	235.6	236.0	471.6
	Expenses:										
15	**OM&A**	5	145.1	140.0	285.2	234.9	237.3	472.3	2,401.4	2,419.8	4,821.1
16	**Fuel and GRC**	6	267.2	280.8	548.0	75.6	77.5	153.1	266.5	260.5	526.9
17	**Depreciation & Amortization**	7	82.1	81.9	164.0	62.2	63.1	125.3	273.7	288.5	562.3
18	**Property Tax**	8	0.3	0.3	0.6	0.1	0.1	0.2	15.9	16.4	32.4
19	**Total Expenses**		494.7	503.0	997.8	372.9	378.0	750.9	2,957.5	2,985.2	5,942.7
	Less:										
	Other Revenues										
20	**Bruce Lease Revenues Net of Direct Costs**	9	N/A	N/A	N/A	N/A	N/A	N/A	39.7	40.6	80.3
21	**Ancillary and Other Revenue**	10	34.0	34.6	68.6	22.7	23.1	45.8	33.2	30.5	63.7
22	**Total Other Revenues**		34.0	34.6	68.6	22.7	23.1	45.8	72.9	71.1	144.0
23	**Income Tax**	8	49.7	64.2	113.9	29.9	42.7	72.6	108.3	16.8	125.2
24	**Revenue Requirement**		866.6	891.2	1,757.8	554.6	575.9	1,130.5	3,228.5	3,166.9	6,395.4
	(line 14 + line 19 - line 22 + line 23)										
25	**Amortization of Variance & Deferral Account Amounts**	11	0.0	70.6	70.6	N/A	N/A	N/A	0.0	62.2	62.2
26	**Revenue Requirement Plus Variance & Deferral Account Amounts** (line 24 + line 25)		866.6	961.8	1,828.4	554.6	575.9	1,130.5	3,228.5	3,229.1	6,457.6

Notes:
1 Although regulation of Newly Regulated Hydroelectric facilities is expected to begin on July 1, 2014, full year amounts are shown for comparison purposes.
2 From Ex. B2-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro), Ex. B1-1-1 Table 2 (Nuclear).
3 Totals from Exhibit C1-1-1 Tables 1 and 2 (col. (a)).
Capitalization is allocated to Previously Regulated Hydroelectric, Newly Regulated Hydroelectric and Nuclear operations using rate base financed by capital structure.
Capital Structure for OPG's combined regulated operations is provided in Ex. C1-1-1 Tables 1 and 2.
4 Totals from Exhibit C1-1-1 Tables 1 and 2 (col. (d)), updated to reflect changes in Ex. N2-1-1.
Cost of Capital is allocated to Previously Regulated Hydroelectric, Newly Regulated Hydroelectric and Nuclear operations using rate base financed by capital structure.
Capital Structure for OPG's combined regulated operations is provided in Ex. C1-1-1 Tables 1 and 2, updated to reflect changes in Ex. N2-1-1.
5 From Ex. F1-1-1 Table 1 (Prev. Reg. Hydro), Ex. F1-1-1 Table 2 (Newly Reg. Hydro), Ex. F2-1-1 Table 1 (Nuclear), updated to reflect changes described in Ex. N1-1-1 and Ex. N2-1-1.
6 From Ex. F1-4-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro), Ex. F2-5-1 Table 1 (Nuclear), updated to reflect changes described in Ex. N1-1-1 and Ex. N2-1-1.
7 From Ex. F4-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro); Ex. F4-1-1 Table 2 (Nuclear).
8 Ex. F4-2-1 Table 1 (Prev. Reg. Hydro), Ex. F4-2-1 Table 2 (Newly Reg. Hydro), Ex. F4-2-1 Table 3 (Nuclear), updated to reflect changes described in Ex. N1-1-1 and Ex. N2-1-1.
9 From Ex. G2-2-1 Table 1.
10 From Ex. G1-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro), Ex. G2-1-1 Table 1 (Nuclear), updated to reflect changes described in Ex. N1-1-1.
Other Revenues included in the determination of the Nuclear revenue requirement are adjusted for sharing of 50 percent of
net revenue from sales of heavy water per the OEB Decision in EB-2010-0008, (see Ex. G2-1-2 Table 1, Note 1).
11 From Ex. N2-1-1 Table 9 (Prev. Reg. Hydro) and Ex. N2-1-1 Table 10 (Nuclear).

TAB 9

UNDERTAKING J13.4

Undertaking

Update Table 6 of Exhibit F4, tab 2, schedule 1 to include information from the tax return.

Response

Undertaking J13.3 was to file OPG's 2013 tax returns in confidence. Attachment 1 provides a reconciliation of the tax return to the regulatory tax calculation for 2013 in the form provided in Ex F4-2-1 Table 6.

Ex J13.4 Attachment 1: Updated Ex F4-2-1 Table 6
Reconciliation of Tax Return to Regulatory Tax Calculation ($M)
Year Ending December 31, 2013

		2013 Tax Return					Adjustments		(5) - (6) - (7)
Line No.	Particulars	OPG Parent [i]	Subsidiaries [ii]	(1) + (2) Total [iii]	Unregulated [iv]	(3) - (4) Regulated [v]	Bruce Lease [vi]	Other Adjustments [vii]	Regulatory Tax Calc'n
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Determination of Taxable Income								
1	**Earnings Before Tax**	255.1	(88.9)	166.2	(9.9)	176.0	3.3	229.4	(56.7)
	Additions for Tax Purposes:								
2	**Depreciation and Amortization**	543.2	104.0	647.2	192.1	455.1	104.5	31.5	319.1
3	**Nuclear Waste Management Expenses (incl Accretion Expense)**	920.7	0.0	920.7	0.0	920.7	425.8	469.8	25.1
4	**Receipts from Nuclear Segregated Funds**	75.1	0.0	75.1	0.0	75.1	30.4	0.0	44.7
5	**Pension and OPEB/SPP Accrual**	762.2	0.0	762.2	144.9	617.3	0.0	312.0	305.3
6	**Regulatory Asset Amortization - Nuclear Development and Capacity Refurbishment Variance Accounts**	7.0	0.0	7.0	0.0	7.0	0.0	7.0	0.0
7	**Regulatory Asset Amortization - Nuclear Liability Deferral Account**	74.9	0.0	74.9	0.0	74.9	0.0	74.9	0.0
8	**Regulatory Asset and Liability Amortization - Other Variance Accounts**	131.3	0.0	131.3	0.0	131.3	0.0	131.3	0.0
9	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**	(21.1)	0.0	(21.1)	0.0	(21.1)	0.0	(2.4)	(18.7)
10	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account**	62.9	0.0	62.9	0.0	62.9	0.0	0.0	62.9
11	**Regulatory Asset Amortization - Tax Loss Variance Account**	180.9	0.0	180.9	0.0	180.9	0.0	180.9	0.0
12	**Reversal of Bruce Lease Net Revenues Variance Account Additions**	(150.8)	0.0	(150.8)	0.0	(150.8)	0.0	(150.8)	0.0
13	**Adjustment Related to Financing Cost for Nuclear Liabilities**	0.0	0.0	0.0	0.0	0.0	0.0	(76.8)	76.8
14	**Taxable SR&ED Investment Tax Credits**	39.9	0.0	39.9	2.7	37.2	0.0	8.8	28.4
15	**Materials and Supplies Inventory Obsolescence**	30.9	0.0	30.9	22.0	8.9	0.0	0.0	8.9
16	**Other**	139.3	(0.2)	139.1	43.5	95.6	79.3	5.0	11.3
17	**Total Additions**	2,796.8	103.8	2,900.6	405.3	2,495.3	640.1	991.4	863.8
	Deductions for Tax Purposes:								
18	**CCA**	474.6	5.6	480.2	166.9	313.3	5.6	(0.0)	307.7
19	**Cash Expenditures for Nuclear Waste & Decommissioning**	199.6	0.0	199.6	3.4	196.2	91.3	0.3	104.7
20	**Contributions to, and Earnings on Nuclear Segregated Funds**	854.0	0.0	854.0	0.0	854.0	423.0	332.9	98.1
21	**Pension Plan Contributions**	300.0	0.0	300.0	57.1	242.9	0.0	0.0	242.9
22	**OPEB/SPP Payments**	101.1	0.0	101.1	19.2	81.9	0.0	0.0	81.9
23	**Reversal of Nuclear Liability Deferral Account Additions**	79.0	0.0	79.0	0.0	79.0	0.0	79.0	0.0
24	**Reversal of Pension and OPEB Cost Variance Account Additions**	312.5	0.0	312.5	0.0	312.5	0.0	312.5	0.0
25	**Reversal of Impact of USGAAP Deferral Account Additions**	0.7	0.0	0.7	0.0	0.7	0.0	0.7	0.0
26	**Reversal of Other Variance Account Additions**	77.0	0.0	77.0	0.0	77.0	0.0	77.0	0.0
27	**Reversal of Nuclear Development and Capacity Refurbishment Variance Account Additions**	100.9	0.0	100.9	0.0	100.9	0.0	100.9	0.0
28	**Reversal of Return on Rate Base Recorded in Capacity Refurbishment Variance Account**	0.0	0.0	0.0	0.0	0.0	0.0	(50.9)	50.9
29	**SR&ED Qualifying Capital Expenditures**	137.9	0.0	137.9	7.0	130.9	0.0	(0.0)	130.9
30	**Construction In Progress Interest Capitalized**	54.1	0.0	54.1	6.8	47.3	0.0	47.3	0.0
31	**Other**	248.5	0.0	248.5	154.0	94.5	92.9	(0.0)	1.6
32	**Total Deductions**	2,939.8	5.6	2,945.4	414.2	2,531.1	612.7	899.7	1,018.7
33	**Taxable Income** (line 1 + line 17 - line 32)	112.1	9.3	121.4	(18.8)	140.2	30.7	321.1	(211.6)

Notes:
Columns:
- i Amounts are as per the OPG Inc. legal entity tax return.
- ii Amounts are as per the income tax returns for OPG Inc. subsidiaries.
- iii Represents the OPG consolidated amounts. Earnings Before Tax is as reported in OPG's 2013 audited consolidated audited financial statements.
- iv Represents amounts relating to OPG's unregulated operations. Newly regulated hydroelectric amounts are included in this column, while Bruce Lease net revenue items are not.
- v Represents amounts reported in the "regulated" segment of OPG's audited consolidated financial statements in accordance with generally accepted accounting principles.
- vi Represents Bruce Lease net revenue items included in col. (5). Bruce Lease income tax details are provided in Ex. L-1.0-1 Staff-002 Table 38, as updated for the information in OPG's 2013 income tax returns, and are included in Bruce Lease net revenues; therefore Bruce Lease income tax amounts are removed in determining income taxes for prescribed facilities.
- vii Represents the followings:
  (1) items of income and expenses reflected in OPG's income tax returns that do not form part of the regulatory income tax calculation as per the OEB-approved methodology, and vice versa. Examples include: accretion expense for nuclear waste management and decommissioning liabilities an earnings on related segregated funds which do not form part of the OEB-approved recovery methodology for these liabilities, and deemed interest expense that replaces OPG's actual interest expense for regulatory purposes.
  (2) line item presentation differences between OPG's income tax returns and the regulatory income tax calculation that do not impact taxable income.

TAB 10

Board Staff Interrogatory #166

Ref: Exh. F4-2-1 and Table 5

Issue Number: 6.13
Issue: Are the amounts proposed to be included in the test period revenue requirement for income and property taxes appropriate?

Interrogatory

Table 5 at Line 21 in "Regulatory Taxable Income" shows a negative amount of $39.2M (net loss) for 2013 Budget.

a) Please update the 2013 Budget amount to reflect the actual amount for 2013 as at December 31.

b) If the actual amount for 2013 remains as a net loss, is the amount being applied as a loss carry forward to reduce the Regulatory Taxable Income for 2014? If not, please explain.

Response

a) The 2013 actual regulatory tax loss is $153.8M, as shown at Ex. L-1.0-1 Staff-002, Table 29, line 21.

b) No. The 2013 regulatory tax loss is not applied to reduce the forecast 2014 regulatory taxable income because the loss arises as a result of a 2013 nuclear operating loss, as discussed below. As OPG incurred the operating loss, it should receive the benefit of the associated tax loss. This principle of attributing the tax cost or benefit between the ratepayers and OPG's Shareholder was established by the Board in EB-2007-0905 (Decision with Reasons, page 170) and applied in OPG's analysis of tax losses reflected in the balance of the Tax Loss Variance Account approved by the Board in EB-2010-0008 (EB-2010-0008, Ex. F4-2-1, section 4.3.3).

   As determined below, the shortfall in 2013 nuclear production is approximately $325M, which is substantially higher than the regulatory tax loss of $153.8M. Most of the operating loss is related to production. OPG is at risk for production variances. A comparison of actual 2013 nuclear production of 44.7 TWh (Ex. L-1.0-1 Staff-002, Table 14, line 3, col. (d)) to the average of approximately 51.0 TWh of 2011 and 2012 production (50.4 TWh and 51.5 TWh, respectively), approved by the OEB in EB-2010-0008 Payment Amounts Order, Appendix A, Table 3 results in a production shortfall of approximately 6.3 TWh. Using the nuclear base payment amount of $51.52/MWh, the shortfall in production results in a reduction to revenue in 2013 of approximately $325M. As OPG has incurred the operating loss it should retain the benefit of the associated tax losses.

TAB 11

Ontario Energy Board
Commission de l'Énergie de l'Ontario

2006 ELECTRICITY DISTRIBUTION RATE HANDBOOK

May 11, 2005

Chapter 7

7 Taxes / PILs

7.0 Introduction

The 2006 OEB Tax Model and its principles will only be applicable to the 2006 rate year. The Board has not determined the process for the 2007 rate year, including whether or not the tax calculation will be revisited for that rate year.

The tax model has been designed for a distributor using a historical test year as the basis of its application. A distributor filing on an historical test year basis must use the 2006 OEB Tax Model. A distributor filing on a forward test year basis does not have to use the 2006 OEB Tax Model, but must file an equivalent level of detail. The principles set out below, however, remain applicable to all applicants.

7.1 General Methodology Underlying the 2006 Tax Calculation

<u>Application of 2006 Handbook and 2006 OEB Tax Model</u>

Most distributors will pay income and capital taxes in the form of proxy tax payments (PILs) to the Province under section 93 of the *Electricity Act*. A small number of distributors, however, may pay section 89 proxy taxes, or as taxable corporations be subject to normal provincial and federal taxation.

A distributor required to pay PILs under section 93 must complete the 2006 OEB Tax Model without amendments. Any distributor submitting its own tax filing calculation, eg. distributors filing a forward test year application, will, in that calculation, follow the same basic principles, methodology and level of detail outlined in the 2006 Handbook and set forth in the 2006 OEB Tax Model. Any variations from the 2006 OEB Tax Model must be identified and described in the summary of the application.

A distributor not required to pay PILs under section 93 shall do the following:

- in the summary of the application, describe the basis of its tax or PILs payments

- explain all variances between the alternative tax calculation and the methodology of the 2006 OEB Tax Model in the summary of the application

Prudent management of taxes

The Board expects all distributors to take prudent steps to manage their tax costs with reasonable diligence, as they would with other distribution expenses.

OEB 2006 regulatory taxes expense methodology

The specific instructions set out below explain how the Board expects an applicant to calculate regulatory taxes payable for inclusion in 2006 rates.

The tax amount included in rates reflects taxes payable as a result of operating the distribution-only business, rather than taxes calculated for accounting purposes, and hence future/deferred taxes will not be recovered through rates as a result of this filing.

The 2006 OEB Tax Model calculates regulatory tax expense based upon the principles set out in this Chapter.

The organization of the OEB tax model takes into account the standard format of corporate tax returns to be submitted to tax authorities. An applicant may wish to review its filed and assessed 2004 Federal T2 and Ontario CT23 tax returns before starting to complete the 2006 OEB Tax Model.

Use of historical data and future estimates to calculate 2006 tax expense

Revenues, expenses, capital items and all other operating numbers are calculated using the 2006 EDR Model based upon 2004 historical data plus or minus allowed or required adjustments. The 2006 OEB Tax Model automatically includes data from the 2006 EDR Model.

A distributor must make the adjustments described in the instructions to the OEB tax model. The OEB tax model then automatically calculates the recoverable 2006 PILs amount for inclusion in the main model.

Tax rates and exemptions to be used in the 2006 EDR Model

The 2006 OEB Tax Model and the 2006 Handbook guidelines relating to PILs are based upon tax rates and rules that, as of May 1, 2005, are reasonably expected by the Board to be in effect during the 2006 rate year.

Disclosure of PILs tax administration and tax rulings

To calculate the tax expense to be allowed in the 2006 revenue requirement, a distributor must follow the Board's regulatory tax principles set out in the 2006 Handbook and in the 2006 OEB Tax Model.

If a specific tax ruling or assessment policy applies to the distributor in a manner inconsistent with the 2006 OEB Tax Model, a summary of the ruling/policy shall be disclosed in the summary of the application. As well, the distributor's 2006 application must disclose if it has objected to the tax ruling or assessment policy where the effect of the dispute would be a significant change in taxes otherwise payable.

As part of the approval of a rate application, the Board will determine whether to require a variation in the regulatory tax calculation or to establish a variance account.

Partial true-up of 2006 actual taxes paid to taxes recovered in rates

The Board will establish a 2006 PILs/taxes variance account in the Accounting Procedures Handbook to capture the tax impact of the following differences:

- any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the 2006 OEB Tax Model

- any differences that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities

- any differences in 2006 PILs that result in changes in a distributor's "opening" 2006 balances for tax accounts due to changes in debits and credits to those accounts arising from a tax re-assessment:

    - received by the distributor after its 2006 rate application is filed, and before May 1, 2007
    - relating to any tax year ending prior to May 1, 2006

Where the re-assessment of a prior year results in an amount expensed in that prior year being treated as a depreciable property, the resulting increase in 2006 depreciation may reduce 2006 PILs, and the difference must be recorded in the 2006 PILs/taxes variance account. Similarly, if a re-assessment of a prior year results in income reported in that prior year being deferred and becoming taxable in 2006, the difference in tax in 2006 must be recorded in the 2006 PILs/taxes variance account.

Any true-up under this heading is to be implemented consistent with the further comments below on treatment of tax re-assessments.

Differences between actual taxes paid in 2006, and taxes recovered in rates resulting from any causes other than the three identified above, will not be credited or debited to the 2006 PILs/taxes variance account.

The above rules apply only to the 2006 PILs/taxes variance account. Any 2007 PILs/taxes variance account will be dealt with in subsequent Board decision or communication.

Tax re-assessments

No amount of tax relating to any prior year arising from a reassessment shall be included in rates for 2006. The true-up of 2006 taxes relating to re-assessments of taxation years ending prior to May 1, 2006, as set forth above, deals only with the impact on 2006 taxes of those re-assessments.

Account 1562 will remain available for entries affecting prior periods until all re-assessments of those prior years have been received, or the years have become statute-barred.

7.2 Principles Applicable to Specific Components of the Calculation

7.2.1 Non-recoverable and disallowed expenses

There may be some distribution-only expenses incurred by a distributor that are deductible for general tax purposes, but for which recovery in 2006 distribution rates is partially or fully disallowed.

The 2006 OEB regulatory tax methodology considers treatment of both non-recoverable and disallowed expenses. Specifically, the following are addressed:

- non-recoverable expenses known and taken into account at time of filing the 2006 EDR Model (for example, in respect of any expense disallowed under Chapter 6, but which will still be paid by the applicant)

- any distribution expenses disallowed after regulatory review, so that to capture the tax impact of such disallowed expenses, the 2006 EDR Model will need to be re-run using approved figures

Where an expense incurred by a distributor is non-recoverable in the revenue requirement or disallowed for 2006 OEB regulatory purposes, such amounts will also be excluded from the 2006 regulatory tax calculation (unless provided otherwise below for a specific item).

7.2.2 Capital tax exemptions

i) Federal Large Corporation Tax (LCT) Exemption

Where the applicant is the only regulated entity in a corporate group, the full LCT exemption must be claimed by the applicant for purposes of its 2006 OEB tax calculation.

Where the distributor is a member of a larger corporate group that includes other regulated entities, the exemptions will be prorated among the regulated entities.

ii) Ontario Capital Tax Exemption

Where the applicant is the only regulated entity in a corporate group, the full OCT exemption must be claimed by the applicant for purposes of its 2006 OEB tax calculation.

Where the applicant is a member of a larger corporate group, the full provincial capital tax exemption will be prorated among the regulated entities in that group.

iii) Non-distribution activities within an applicant

When distribution and non-distribution functions are being undertaken in the same legal entity by an applicant, the full federal LCT exemption and provincial capital tax exemptions must be claimed by the applicant for purposes of its 2006 OEB tax calculation.

7.2.3 Loss carry-forwards

A distributor expecting to have any loss carry-forwards still available on December 31, 2005 must disclose the amount of those loss carry-forwards in the 2006 application, and apply them in full to reduce the taxable income calculated in the 2006 regulatory tax calculation. These amounts are to be entered in the 2006 OEB Tax Model.

If a distributor has within its legal entity a business other than a distribution business, loss carry-forwards must be allocated between the distribution and the non-distribution business on a reasonable basis. The applicant shall include in Schedule 7-1 a description and justification of that allocation method and calculation.

7.2.4 Undepreciated capital cost (UCC) and capital cost allowance (CCA)

UCC for the test year will be calculated as follows. The closing year-end 2004 actual UCC balances by class from the distributor's actual tax return will be used. To these balances by class, the distributor will add any Tier 1 and Tier 2 capital expenditure adjustments allocated to the appropriate UCC class for each type of asset and its component parts. The half-year rule will be used for any Tier 1 and Tier 2 capital expenditures added to rate base.

Maximum CCA must be claimed when computing taxes payable for purposes of the 2006 OEB Tax Model. The OEB regulatory tax calculation will not take into account any increase in capital cost allowance when distribution assets are purchased above book value.

The effects of the 2001 Fair Market Value "bump" are to be included in the 2006 OEB regulatory tax calculations either as CCA or as the cumulative eligible capital deduction depending on its tax treatment in the distributor's tax return as filed with the Ministry of Finance.

An applicant must complete Schedule 7-2 to provide information about the fair market value "bump".

7.2.5 Regulatory tax treatment of Eligible Capital Expenditures (ECE):

Subject to the statements below, the maximum amortization of ECE must be claimed in computing taxes payable for purposes of the 2006 OEB Tax Model.

i) In respect of ECE arising from adjustments to fair market value at October 1, 2001

   To the extent that the adjustment ("bump") in fair market value at October 1, 2001 is included in a distributor's Cumulative Eligible Capital Amounts, the value of such adjustments must be allocated to the applicant's ratepayers for purposes of its 2006 OEB PILs calculation. These adjustments will be factored into 2006 OEB Tax Model with appropriate instructions.

   An applicant must complete Schedule 7-2 to provide information about the fair market value "bump".

ii) In respect of ECE related to other disallowed or non-recoverable expense

Subject to the above, where a distributor's Cumulative Eligible Capital Amounts includes purchased goodwill or other intangible assets that are non-recoverable or disallowed for regulatory purposes, such amounts will also be excluded from the 2006 regulatory tax calculation. The OEB regulatory tax calculation will not take into account any increase in capital cost allowance when distribution assets are purchased above book value.

7.2.6 Interest deduction

For purposes of the 2006 OEB regulatory tax calculation, the greater of the amount of the actual 2004 interest expense (taking into account the interest effect of any Tier 1 and Tier 2 adjustments proposed in the application), and the deemed interest expense calculated by the main model must be treated as a deduction for the purpose of calculating PILs/taxes.

At its starting point, the 2006 OEB Tax Model will automatically provide for the deduction of an amount of interest equal to the interest rate amount calculated by the main model.

The 2006 OEB Tax Model, however, also provides for any additional amount of actual interest expense due to the following:

- a higher actual interest rate than the calculated rate
- a higher ratio of debt to equity than the deemed ratio
- capitalized interest amounts

The distributor shall enter in the 2006 OEB Tax Model the amount of additional interest deduction expected for tax purposes in 2006 due to either of those causes. In addition, the applicant must complete Schedule 7-3.

7.2.7 Interest capitalized for accounting, but deducted for tax purposes

The applicant must identify the amount of any interest capitalized for accounting purposes in 2004. If a distributor elected to capitalize interest incurred on construction work in progress for tax purposes, any such amounts must also be identified. This election must be disclosed on Schedule 7-3.

7.2.8 Overlapping year-ends

The 2006 rate year runs from May 1, 2006 to April 30, 2007. The rate year is not contiguous with the calendar tax year. In order to calculate the approved regulatory tax payable for the 2006 rate year, however, the rate year will be assumed to be the same as the tax year. Thus any stub period issues (e.g. loss carry-forwards or CCA) will be ignored when completing the 2006 OEB Tax Model.

The only exception to this principle is in the tax rates to be applied. The tax rates anticipated to be in effect during 2006, at the time that the 2006 Handbook is issued, will be used in the 2006 OEB Tax Model. No further action by distributors is required.

7.2.9 Estimating taxable capital

When calculating 2006 regulatory Ontario Capital Tax and the federal LCT, the applied-for 2006 rate base in the application should be used as the proxy for 2006 taxable capital for OEB purposes.

The applicant has the option of substituting its estimated 2006 taxable capital for the rate base proxy. In such cases, the following information must be provided:

- full details of the capital tax calculation, including balance sheet assumptions
- the estimate calculated using rate base as a proxy

The 2006 OEB Tax Model incorporates the estimated 2006 taxable capital exemptions.

7.2.10 Ontario Corporate Minimum Tax

The 2006 regulatory tax calculation does not include the Ontario Corporate Minimum Tax. As this tax can be carried forward for ten years, it is expected that a distributor will recover this tax as it becomes taxable.

7.2.11 Non-distribution elimination

The 2006 OEB Tax Model will require that the applicant exclude any non-distribution costs and revenues. This elimination must be consistent with the definition of distribution-only activity contained within the 2006 Handbook.

7.2.12 Tax credits

Back-up calculations must include an estimate of any tax credits claimed in 2004, such as research and development credits.

7.2.13 Impact of CDM expenditures and Smart Meter expenditures

CDM and Smart Meter amounts are included in the revenue requirement upon which 2006 rates are set, and no special tax treatment is required.

7.2.14 Property Taxes

The OEB Tax Model addresses corporate income tax and capital taxes.

A distributor is also allowed to claim recovery of property taxes payable, including any "proxy" property taxes. Property tax expense is part of the other distribution expenses included in the 2006 EDR Model.

7.2.15 Capital Leases

Adjustments for leases that are capitalized for accounting purposes and deducted for tax purposes must be made in the 2006 OEB Tax Model.

7.3 Tax Payable Filings

7.3.1 Information to be Provided with 2006 OEB Tax Model Filings

An applicant must file, in its summary of the application, the taxes it actually paid for the years 2002, 2003, and 2004 with respect to the distribution business of the applicant. The summary of the application must also include a description of any variances between taxes actually paid in 2004, and the tax expense recovered in 2006 distribution rates, where such variances exceed 25% of 2004 taxes actually paid.

7.3.2 Tax Information Disclosure in Future

As part of its future regulatory filings, the distributor will be required to disclose the actual corporate PILs/taxes paid in 2006 and the amount collected in 2006 distribution rates.

If the difference between the two amounts is greater than 10%, that difference will be explained in that future filing. A distributor must keep appropriate records of the actual versus the recovered PILs/taxes for 2006, and the reasons for any differences.

7.3.3 Supporting Documentation

In some instances, disclosure of back-up information or calculations has been mandated, either in the form of a separate Schedule or at a designated place in the spreadsheet. A complete application must include the supporting information requested in filing instructions.

Where disclosure is not requested as part of the initial filing, an applicant should still maintain reasonable supporting documentation in case enquiries are made during the regulatory review process.

TAB 12

EB-2007-0744

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

AND IN THE MATTER OF an application by Great Lakes Power Limited for an Order or Orders approving just and reasonable rates and other service charges for the distribution of electricity, effective September 1, 2007.

BEFORE: Paul Sommerville
Presiding Member

Bill Rupert
Member

Cathy Spoel
Member

DECISION AND ORDER

THE APPLICATION

Great Lakes Power Limited ("GLPL", the "Applicant" or the "Company") filed an application under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15 (Schedule B) with the Ontario Energy Board (the "Board"), received on August 31, 2007, seeking approval for changes to the rates that GLPL charges for electricity distribution, to be made effective September 1, 2007. In addition, GLPL requested the Board to make the current distribution rates interim as of September 1, 2007 and to authorize the establishment of a deferral account to record revenue requirement deficiencies incurred from September 1, 2007 until new distribution rates are implemented.

setting rates for regulated service. To abandon the stand-alone principle in this case would give rise to the inappropriate result that rates for regulated service would be affected by the income or loss of a non-regulated business.

Benefit of pre-2007 tax losses in GLPL's regulated business

As noted earlier, GLPL's evidence is that there are no pre-2007 loss carry forwards in the distribution business on a stand-alone basis. The reason for that result appears to be that, in years before 2007, GLPL included in its calculation of taxable income the annual increase in deferral account 1574. Board staff submitted that "if the values accumulated in account 1574 are not permitted for recovery in rates, it appears the GLPL distribution division would have incurred operating losses in years prior to the test year." In the staff's opinion, the existence of such prior year regulatory tax losses would make it unnecessary for a tax allowance to be recovered from customers in 2007. [26]

The second tax issue raised by staff is whether, in the event the Board disallows recovery of a deferral account balance, the regulated distribution business itself would have pre-2007 losses that should be used to eliminate any 2007 tax provision.

GLPL argued that, in the event the Board disallows recovery of the balance in account 1574, loss carry-forwards arising pre-2007 should be for the benefit of GLPL's shareholder. GLPL noted that any pre-2007 losses that arise in the event of the Board's denial of recovery of account 1574 must be due to variations in load or expenses compared to the amounts on which GLPL's then existing rates were based. Ratepayers would not have paid any amount due to unfavourable variations in load or expenses. Based on the stand-alone principle, GLPL argued that ratepayers should not be entitled to any benefit of those losses and that applying such pre-2007 losses to reduce the 2007 regulatory tax provision would constitute retroactive ratemaking. Board staff did not comment in its submission on whether the reason for the pre-2007 losses is relevant to whether the losses should be used to eliminate 2007 taxes.

---

[26] In its submission, Board staff also argued that GLPL has overstated its regulatory tax provisions in 2006 and earlier years by voluntarily including the annual increase in account 1574 in taxable income. Staff submitted that GLPL's action of recognizing the increase in account 1574 as taxable income in 2006 and earlier years is not something a stand-alone business would consider necessary or would consider to be prudent tax management. In effect, the staff seemed to be arguing that GLPL should be considered to have loss carry-forwards for regulatory purposes whether or not the Board disallows recovery of account 1574. Because the Board has determined that GLPL will not be permitted to recover the balance in account 1574, it is not necessary to consider and make a finding on this alternative staff argument.

Board Findings

Given that GLPL has included the annual accruals to account 1574 in its taxable income for 2006 and earlier years, the Board's decision to disallow recovery, as set out earlier in this decision, will affect GLPL's tax returns. Board staff and, it appears, GLPL as well, assume that a Board decision to disallow recovery would require GLPL to file revised tax returns for 2006 and earlier years that exclude the account 1574 accruals. That would result in a higher pre-2007 loss carry-forward than has been reported by GLPL to date. The Board has accepted that assumption in its analysis and findings on this issue. However, whether that is the required tax treatment, or whether the earlier tax returns will be left unchanged and the disallowance deducted in 2007 or 2008 tax returns as a loss, would have no effect on the Board's findings on this issue.

The 2006 DRH sets out for electricity distributors how the Board generally intended to address applications for 2006 distribution rates. Among other issues, it dealt with how loss carry-forwards would be treated in setting the 2006 revenue requirements of distributors. The DRH sets out the consensus view of the working group as to how loss carry-forwards should be treated:

> *A distributor expecting to have any loss carry-forwards still available on December 31, 2005 must disclose the amount of those loss carry-forwards in the 2006 application, apply them in full to reduce the taxable income calculated in the 2006 regulatory tax calculation.*[27]

The Report of the Board that accompanied the 2006 DRH discussed the Board's rationale for approving this treatment of loss carry forwards:

> *The Draft Handbook requires the distributor to take into account the potential reduction in actual taxes payable where a loss carry-forward is applicable.*
>
> *Hydro One submitted that any loss carry-forward resulting from revenue or expense variations in prior years was irrelevant for the 2006 calculation. It argued that the ratepayer has not contributed to the prior loss and therefore is not entitled to the future tax savings. Hydro Ottawa made similar submissions.*

[27] 2006 Electricity Distribution Handbook, May 11, 2005, p. 61.

> *Conclusions*
>
> *The Board has no evidence before it to determine whether loss carry-forwards are the result of revenue or expense variations or whether the loss carry-forwards arise for reasons that may be related to ratepayers.* *The Board notes that the consensus approach [take loss carry-forwards into account when setting 2006 rates] will reduce the variance between taxes collected in rates and actual taxes paid. The Board will accept this approach in the Handbook.*[28] *[emphasis added]*

Although the Board accepted the position in the 2006 DRH that loss carry-forwards should be taken into account in setting 2006 rates, the Board does not believe that position is applicable in all rates cases before the Board. It is clear from the highlighted sentence in the Report of the Board that the Board attaches some significance to the reasons for losses. It is also clear from that sentence that approval of the 2006 DRH position on loss carry-forwards was taken without the opportunity to hear any evidence on what might have led to the losses.

The balance in account 1574 as at December 31, 2006 was over $12 million. That amount is more than 50% of the capital account (owner's equity) shown in GLPL's 2006 audited financial statements. Since the Board has denied recovery of a major portion of account 1574, the amount denied would be excluded from GLPL's pre-2007 financial results thereby indicating that GLPL would have incurred significant operating losses for the period 2002 to 2006. It is highly unlikely, in the Board's view, that GLPL's customers absorbed any of those losses. Except for some increases in rates authorized by the Board to collect certain regulatory assets, GLPL's distribution rates have not increased since May 2002, when GLPL's rates first became subject to Board oversight. In fact, in June 2003, the Minister of Energy directed the Board to reduce rates for GLPL's residential and certain other customers.

The Board finds that pre-2007 losses of the distribution business should not be used to eliminate the tax provision for the 2007 test period. The Board reiterates its view that the benefits of a tax loss should be realized by the party – shareholders or ratepayers – that bore the expenses or losses that gave rise to the tax loss. Since the Board has denied recovery of the amount accrued for rate mitigation in account 1574, the resulting

[28] RP-2004-0188, Report of the Board, May 11, 2005, p. 57.

losses should not be attributed to ratepayers but rather to GLPL, which sustained those losses and should retain the related tax benefits.

DEFERRAL AND VARIANCE ACCOUNTS

In addition to account 1574, Deferred Rate Impact Amounts, which has been discussed earlier in this Decision, the Company proposed to dispose of balances in certain deferral/variance accounts and to establish two new accounts.

Existing Deferral and Variance Accounts

The following additional accounts were requested for clearance as per GLPL's Argument-in-Chief:

1508 Other Regulatory Assets $207,609
1562 Deferred Payments In Lieu of Taxes ($103,338)
1570 Qualifying Transition Costs $1,103,217
1580 RSVA – Wholesale Market Service Charge $211,882
1584 RSVA – Retail Transmission Network Charge $(2,893)
1586 RSVA – Retail Transmission Connection Charge ($298,501)
1588 RSVA – Power $179,341
1590 Recovery of Regulatory Balances ($3,057,670)

1508 Other Regulatory Assets

GLPL has requested recovery of account 1508 sub-account OEB Cost Assessments. This balance is related to the difference between OEB cost assessments for 2004/05 and 2005/06 up to April 30, 2006 and the amount of OEB costs included in GLPL's current rates.

Intervenors had no comments on this balance.

Board Findings

The Board approves disposal of the balance in Account 1508 in the manner described in the section, Implementation of Clearance of Deferral and Variance Accounts, later in this decision.

TAB 13

Ontario Energy Board

Commission de l'Énergie de l'Ontario

RP-2004-0188

2006 ELECTRICITY DISTRIBUTION RATE HANDBOOK

REPORT OF THE BOARD

2005 MAY 11

ratepayers as well. However, the Board has no evidence as to how frequently or to what extent this recapture will take place.

While the Board cannot address the recapture at this point, it can address the current tax savings. The Board has determined that the 2006 tax calculation will incorporate the impact of the FMV Bump. If at some point a related tax liability arises from a sale of assets or change in tax status, then the distributor will be able to apply to the Board for relief, at which point the issue will be determined. The Board notes that this approach will reduce the variance between actual taxes and the tax provision in rates, that it will not disadvantage the shareholder because the shareholder incurred no cost, and, if there is subsequent recapture, the distributor may apply to the Board for relief.

Loss carry-forwards

The Draft Handbook requires the distributor to take into account the potential reduction in actual taxes payable where a loss carry-forward is applicable.

Hydro One submitted that any loss carry-forward resulting from revenue or expense variations in prior years was irrelevant for the 2006 tax calculation. It argued that the ratepayer has not contributed to the prior loss and therefore is not entitled to the future tax savings. Hydro Ottawa made similar submissions.

<u>Conclusions</u>

The Board has no evidence before it to determine whether loss carry-forwards are the result of revenue or expense variations or whether the loss carry-forwards arise for other reasons that may be related to ratepayers. The Board notes that the consensus approach will reduce the variance between taxes collected in rates and actual taxes paid. The Board will adopt this approach in the Handbook. However, the Board has concluded that a projection of this factor to 2006 will not be required as this represents unnecessary complexity for purposes of 2006 rates.

Interest deduction

TAB 14

Ontario Energy Board | Commission de l'énergie de l'Ontario

EB-2007-0905

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES

DECISION WITH REASONS

November 3, 2008

- OPG made substantial tax-deductible contributions to the segregated nuclear funds (contributions during the period were $888 million, including a special one-time payment of $334 million in 2007 related to the Bruce facilities);
- the deduction in 2005 of $258 million in Pickering A return to service costs; and
- a loss before income tax from the prescribed facilities in 2007.

OPG referred to its accumulated loss carry forwards as “regulatory tax losses” to distinguish them from actual tax loss carry forwards that are recognized by the tax authorities. In fact, OPG’s witnesses noted that OPG did not have any actual tax loss carry forwards at the end of 2007. The benefit of all tax losses that were generated by the prescribed facilities during the period 2005 to 2007 were used to reduce PILs payable by OPG in respect of its unregulated operations. OPG’s witnesses also noted that in its consolidated financial statements for 2005 through 2007, OPG recorded the benefit of those “regulatory tax losses” in earnings; it did not credit any of the benefit of those losses to a deferral account to be used to reduce the payment amounts for the prescribed assets after April 1, 2008.

In its argument, OPG submitted that: “While an argument could be made that these tax losses belong to OPG and not to ratepayers since they arose in a period prior to Board regulation, OPG has decided that it is appropriate that they be returned to ratepayers.”[131]

Only a few intervenors commented on OPG’s proposed mitigation and its elimination of a tax provision for 2008 and 2009. CCC, CME and SEC supported OPG’s approach. CCC and SEC noted that, absent the mitigating effect of the tax losses, the increase in payment amounts sought by OPG would be much higher than proposed in its application. CME supported OPG’s approach and noted that OPG was not obliged to allocate the benefit of the prior period tax losses to consumers.

Board Findings

OPG’s proposals to exclude a tax provision from the revenue requirement and to reduce the revenue requirement by a further $228 million mitigation amount are both linked to the $990.2 million of “regulatory tax losses” that OPG claims existed at December 31, 2007.

[131] OPG Argument-in-Chief, page 109.

OPG's tax calculations did not receive much scrutiny during this proceeding. Although intervenors supported OPG's proposals (or were silent on the issues), the Board is not convinced that OPG has taken the right approach to income tax issues in its application.

The Board is not convinced that there are any "regulatory tax losses" to be carried forward to 2008 and later years, or if there are any, that the amount calculated by OPG is correct. Reasons for the Board's concerns about OPG's treatment of taxes include:

- OPG's calculation of regulatory tax losses for 2005 to 2007 includes revenues and expenses related to OPG's Bruce lease. The Bruce stations are not prescribed facilities and OPG's Bruce lease is not regulated by the Board. In the Board's view, any calculation of tax losses in respect of the prescribed facilities should exclude revenues and expenses related to the Bruce lease.[132]
- OPG did not have any tax loss carry forwards at the end of 2007. OPG's witnesses confirmed that OPG was able to use the tax losses generated by the prescribed facilities for period 2005 to 2007 to reduce the income taxes that OPG would otherwise have paid in respect of its unregulated businesses. That is, the benefit of the tax losses related to OPG's regulated assets for 2005 to 2007 has already been realized by OPG.
- OPG witnesses confirmed that the benefit of the pre-2008 tax losses in respect of the regulated assets was recorded in OPG's audited financial statements in the form of a lower tax expense. Those witnesses also confirmed that OPG did not establish a deferral account at the end of 2007 to capture the tax benefits it claimed should be used to reduce regulatory taxes for 2008 and later periods in its application. The treatment of tax losses adopted in OPG's financial statements appears to conflict with the position taken in OPG's application to the Board.
- OPG stated that an argument could be made that the regulatory tax losses belong to OPG and not to customers since they arose in a period prior to Board regulation. Nonetheless, OPG submitted it was appropriate that the tax benefits be credited to customers although it offered no reasons why it was considered to be appropriate.

[132] As noted in Chapter 8, the Board has determined that revenues and costs related to the Bruce stations should be calculated for purposes of section 6(2)10 of Regulation 53/05 in accordance with GAAP (not regulatory accounting) and that a tax provision should be included in the Bruce costs.

Although the Board is not convinced that regulatory tax loss carry forwards existed at the end of 2007, or that OPG's treatment of taxes is appropriate, the Board is not making a finding that all of the tax benefits of pre-2008 tax losses should accrue to OPG's shareholder. The Board believes that the benefit of tax deductions and losses that arose before the date of the Board's first order should be apportioned between electricity consumers and OPG based on the principle that the party who bears a cost should be entitled to any related tax savings or benefits. The Board has adopted this principle in other cases where a company owns both regulated and unregulated businesses.

The practical consequences of this principle can be illustrated by reference to two of the items that OPG cites as causes for the 2005 to 2007 regulatory tax loss.

- In 2005, OPG deducted $258 million of Pickering A return to service costs in computing taxable income for that year. For accounting purposes, OPG recorded those costs in the PARTS deferral account. As noted in Chapter 7 of this decision, the remaining deferral account balance at December 31, 2007 of $183.8 million will be recovered through future payment amounts for the nuclear facilities. In the Board's view, the majority of the tax benefit realized by OPG in 2005 should be for the account of consumers given that the nuclear revenue requirement after 2007 will include $183.8 million to recover the deferral account balance.
- OPG's evidence indicated that in 2007 its regulated operations incurred an $84 million loss before income taxes (how much of that loss, if any, that relates to Bruce is unclear). It would appear that the operating loss in 2007 was borne completely by OPG's shareholder. Consumers have not been required to absorb that loss because the payment amounts for 2007 were set in 2005 and did not change. Accordingly, in the Board's view, none of the tax benefit of that loss should accrue to consumers.

The Board does not have the information necessary to determine the tax benefits which should be carried forward to offset payment amounts in 2008 and later periods. The Board has therefore examined the proposed level of mitigation within the context of OPG's overall application.

With respect to 2008 and 2009, the Board is not able to agree, for the reasons outlined above, with OPG's position that "regulatory tax losses" permit it to eliminate an income tax provision. Because there is no evidence about the amount of pre-2008 tax benefits that appropriately should be carried forward to offset 2008 and 2009 PILs, the Board views OPG's proposal to eliminate an income tax provision in the test period as simply mitigation. OPG has effectively agreed to absorb whatever tax provision would otherwise be required for those years. The Board finds that this mitigation should be retained in OPG's calculation of the revenue requirement and payment amounts that flow from the Board's findings in this decision. That is, OPG should not include any tax provision for 2008 and 2009 in respect of the prescribed assets.

As for OPG's proposed $228 million mitigation amount, the Board also does not accept that there is any connection between that amount and any regulatory tax losses. OPG's offer of $228 million of mitigation was made in the context of the revenue requirement, before mitigation, shown in OPG's application. The revenue requirement that results from the Board's findings in this decision will be lower than that proposed by OPG. The Board concludes that it would be unreasonable to hold OPG to its original offer of mitigation. The mitigation amount of $228 million was about 22% of the $1,025.7 million revenue deficiency shown in OPG's application. The amount of mitigation the Board will require OPG to provide for the test period will be equal to 22% of the revenue deficiency calculated based on the Board's findings in the decision. The Board estimates that this amount will be about $170 million, compared to the $228 million in OPG's application.

In its next application for payment amounts for the prescribed assets, the Board will require OPG to file better information on its forecast of the test period income tax provision. To that end, the income tax provision for the prescribed facilities in future applications should not include any income or loss in respect of the Bruce lease. The Board also expects OPG to file an analysis of its prior period tax returns that identifies all items (income inclusions, deductions, losses) in those returns that should be taken into account in the tax provision for the prescribed facilities. That analysis should be based on the principle that if OPG is proposing that electricity consumers should bear a cost (or should benefit from revenues) they will receive the related tax benefit (or will be charged the related income taxes).

The Board also believes that its assessment of income taxes (and other elements of OPG's proposed revenue requirement) would be improved if OPG were to file a complete set of audited financial statements, including a balance sheet, for the prescribed facilities. The Board regulates the rates of a few utilities that are owned by entities that also own substantial unregulated businesses. Those regulated utilities do file separate audited financial statements as part of their applications. The Board directs OPG to file such audited financial statements for the prescribed facilities. Assuming that OPG's next application is filed in mid-2009, the Board expects OPG to file financial statements as at and for the year ended December 31, 2008.

9.2 Nuclear Payment Structure

9.2.1 OPG's fixed payment of $1.2 billion

OPG requested a change in the structure of payments for the nuclear facilities. The current nuclear payment amount is $49.50 per MWh, with OPG being fully at risk for outages at Pickering and Darlington. OPG proposed that the Board approve a fixed payment of $1,221.6 million (25% of OPG's proposed revenue requirement, net of variance and deferral account amortization), payable in equal monthly instalments. The balance of OPG's proposed nuclear revenue requirement would be recovered through a variable payment amount of $41.50 per MWh and a further $1.45 per MWh to cover clearance of variance and deferral accounts.

OPG argued that it should be awarded a significant fixed payment for the nuclear facilities because over 90 percent of nuclear costs are fixed, and because generators in Ontario and other jurisdictions receive some form of fixed payment. It also noted that the rates for utilities that provide regulated distribution services include a fixed component. OPG acknowledged that receiving a significant fixed payment for nuclear facilities would reduce OPG's risk. It submitted that the variable component of the proposed payment structure would still provide a strong incentive to maximize nuclear unit availability, avoid outages, and bring units back from an outage as quickly as possible.

Intervenors were split on the merits of OPG's proposal. CCC, PWU, SEC supported, or did not object to, a fixed component for nuclear payments. CCC submitted that it is more important to mitigate OPG's risk than to provide a meaningful incentive to avoid unscheduled outages. It recommended that the fixed portion of the nuclear payments be set at 50% of the revenue requirement. PWU and SEC supported OPG's proposed 25% fixed payment.