ONTARIO POWER GENERATION

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September 10, 2014

VIA RESS AND COURIER

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

Dear Ms. Walli:

Re: EB-2013-0321 – 2014/15 Payment Amounts Application – OPG Reply Argument

Please find attached OPG's Reply Argument for its application for payment amounts for its prescribed generation facilities.

Best Regards,

[Original Signed By]

Colin Anderson
Director, Ontario Regulatory Affairs
Ontario Power Generation

Attach

cc:	Charles Keizer (Torys)	via email
	Crawford Smith (Torys)	via email
	Carlton Mathias	via email
	Intervenors of record	via email

ONTARIO POWER GENERATION

EB-2013-0321

OEB Application

for

Payment Amounts for OPG's Prescribed Facilities

Reply Argument

Ontario Power Generation Inc.

September 10, 2014

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1.0 OVERVIEW

Introduction

In this proceeding, the OEB is confronted with two vastly different visions of OPG. To the intervenors, OPG is “entitled” and “defeatist,” but that is not how the thousands of women and men who work at OPG see it. They recognize that they have been entrusted with the job of operating and renewing the province’s most important electricity assets - safely and for the benefit of the people of Ontario. OPG comes before the OEB respectfully to ask for recovery of the reasonable costs necessary to do this job and the opportunity to earn a fair return on these assets.

The parties argue that OPG’s documented cost control efforts are “too little, too late.” They urge the OEB to cut hundreds of millions in forecast costs and in-service additions to send OPG a strong cost control message. OPG submits that these arguments are a pretext for denying recovery of prudently incurred costs or opposition to nuclear power. OPG has received the cost control message “loud and clear” and is taking every available action to reduce its costs while continuing to operate its facilities safely and make necessary investments to ensure their future operation. No party has identified a single action that is actually available to OPG to reduce costs that OPG is not pursuing.

OPG respectfully submits what the parties call “defeatism” or “entitlement” is simply an unwillingness to pretend. Unlike the parties, OPG cannot simply wish away costs. It cannot ignore its legally binding collective agreements; it cannot reduce accrued pension benefits in contravention of the *Pension Benefits Act* (Ontario); it cannot build a $1.5B tunnel for a billion dollars; it cannot change the size of the Pickering Units or the fact that they use first generation technology. What it can do, and what it is doing is to use attrition to reduce the size of its staff by 20 per cent; bargain aggressively to contain wage increases and benefit costs; work diligently to improve the efficiency of its facilities and supporting operations and invest in the development of assets to benefit Ontarians for the coming decades pursuant to Government policy.

In OPG's view, benchmarking is a valuable tool for measuring relative performance in order to identify potential areas for improvement. This is how OPG uses benchmarking and, in its respectful submission, how the OEB should use it as well. Certain parties selectively read the Memorandum of Agreement between OPG and its shareholder and use it to propose ratemaking via benchmarking. Their views should be rejected as the positions they advocate are contrary to law and lead to absurd results. For example, applying CME's approach to electric distributors would mean that the top quartile performers would see rates that reflected their costs, the next quartile would recover only 75 per cent of their costs, the third quartile would get 50 per cent and those in the bottom quartile would only be allowed to recover 25 per cent of their costs. This is not an approach that could ever lead to just and reasonable rates - simply put, benchmarking is not a formula for setting rates.

The major addition to rate base in this proceeding is the Niagara Tunnel. Board staff's and invervenors' position on the tunnel is paradoxical. On one hand they criticize OPG's design and construction of the project and urge disallowances which range as high as $407M (or about 83 per cent of the $491M at issue). On the other, based on its superior design and construction, they urge the OEB to assign the project a service life of up to 150 years. The Niagara Tunnel was a complex and challenging project that OPG completed safely and is working as designed. OPG submits that the project's costs are prudent and should be approved.

The major ongoing project at OPG is Darlington Refurbishment project ("DRP"). OPG is asking that the OEB approve OPG's proposed contracting strategy. Board staff and certain intervenors state that this request is premature, but OPG submits the opposite is true. Now is the time that changes can be made based on the OEB's views; later will be too late. GEC and ED ask the OEB to reject the proposed strategy and require a fixed price contract. Since the evidence establishes beyond any doubt that a fixed price contract is unavailable, OPG submits that this is nothing more than a back door attempt to use the OEB to achieve what GEC and ED have been unable to do politically – stop Darlington Refurbishment.

OPG's pension and other post employment benefit ("OPEB") costs elicited two significant areas of discussion, only one of which will actually affect test period payment amounts. Parties criticized OPG's pension and OPEB as being too rich, but no party claimed that the amounts

OPG is seeking to recover do not accurately reflect the amounts it is legally obligated to pay. OPG is fully aware of the pension sustainability issue – the Towers Watson Report on pension sustainability was prepared at the request of OPG's Board of Directors based on the recommendation of senior management. The evidence shows that OPG is working to change its plan by introducing changes for management employees and working through the province to achieve a long-term global solution. As the Government's report on the sustainability of the electricity sector pension plans indicates, however, there are complex issues involved that can only be resolved jointly by the companies and their unions.

Through cross-examination, Board staff raised the issue of changing pension and OPEB cost recovery from an accrual to a cash basis. The OEB has twice previously approved accrual accounting for OPG's pension and OPEB costs and should do so again. Accrual is fair to both current and future customers. By regulation, OPG is required to use USGAAP accounting and USGAAP requires the accrual method. Finally, moving to cash would have significant impacts on OPG's earnings and cash flow, which were largely unexplored in this proceeding. If the OEB wishes to consider moving to cash recovery for pension and OPEB or establishing a segregated fund for OPEB costs, it should call a generic proceeding to allow all the complex aspects of these issues to be reviewed and decided on the basis of a complete evidentiary record and to allow the participation of other Ontario utilities which would be impacted by such a move.

<u>Evidence and Evidentiary Updates</u>

OPG recognizes its obligation to produce the evidence necessary to meet its burden of proof to establish that its forecast costs are reasonable and prudently incurred (section 78.1(6) of the *Ontario Energy Board Act*).

The OEB released *A Report with Respect to Decision-Making Processes at the OEB* dated September 2006 (the "Board Process Report"), that addressed the need to rely on evidence. The Board Process Report concluded as follows:

> Thus, in the non-prosecutorial context, the courts' emphasis has been on ensuring <u>that parties have the right to know and answer the case they have to meet</u>. This involves a requirement that a decision maker not base his or

> her decision on facts which are not on the record and parties have the opportunity to respond to legal and policy arguments that are considered by the decision maker. (*emphasis added*) (Board Process Report, p. 26).

For fundamental reasons of procedural fairness, parties must base their submissions on evidence, filed by them, developed through cross-examination or produced by the applicant in response to interrogatories, Technical Conference questions or undertakings. This is necessary to allow an applicant a chance to respond by testing any contrary evidence submitted or introducing additional evidence to demonstrate the reasonableness of its requests. This is a well-established principle of common law.[1]

Unfortunately, in this proceeding, the submissions of Board staff and intervenors urge the OEB to decide matters on the basis of information that was never introduced during the evidentiary portion of the proceeding and, sometimes, based on no evidence at all. Moreover, in the guise of argument, parties offer "expert" opinion evidence on complex technical matters – again opinions that were never put to the relevant witnesses.

Not only are parties required to base their submissions on evidence as set out above, but tribunals, such as the OEB, have a duty to consider the relevant evidence in the proceeding. It is well established that ignoring or failing to consider relevant evidence is an error in law, though rejecting evidence after proper consideration is not. If a tribunal fails to take into account relevant and material facts, the courts will intervene on the grounds that Parliament never intended it to make decisions without considering the relevant facts."[2]

OPG introduced a substantial amount of evidence to discharge its burden of proof as described above. However, little of it was successfully assailed in cross-examination. The expert opinion evidence adduced by OPG has for the most part simply been ignored in Board staff's and intervenors' submissions.

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[1] *Ruby v. Canada (Solicitor General)*, 2002 SCC 75, [2002] 4 SCR 3, at para. 40; Robert W. Macaulay and James L.H. Sprague, *Practice and Procedure before Administrative Tribunals* (Toronto: Carswell, last updated 2013) vol. 2 at 12-38.13-12-39 [Macaulay and Sprague, *Practice and Procedure before Administrative Tribunals*].
[2] Macaulay and Sprague, *Practice and Procedure before Administrative Tribunals* at 17-6.12.

As the OEB appreciates, the experts who testified in this proceeding were required to accept the responsibilities that are imposed on experts by the OEB's Rules of Practice and Procedure and all of the experts in this case did that. This included the responsibility to assist the OEB impartially by giving evidence that is fair and objective. The experts were duly qualified and accepted by the OEB to give opinion evidence as set out in their reports. No parties objected to the experts' qualifications nor to their being accepted by the OEB to give the evidence that they provided.

Other than the evidence from Ms. McShane, little of the experts' evidence was referred to in the submissions of Board staff and the intervenors and the expert's conclusions largely went unchallenged. Mostly, the parties avoided discussing them.

Each of the experts' testimony has been addressed under the relevant issue in OPG's Argument-in-Chief or in the relevant sections in this Reply Argument. As a general submission, OPG says that given the experts' impressive qualifications, their having been accepted by this OEB panel to give opinion evidence and the lack of any serious challenge to their opinions and conclusions by Board staff or the intervenors, the experts' evidence should be given substantial weight by the OEB.

Parties' arguments also were critical of OPG's evidentiary updates, which consisted of two Impact Statements and additional evidence related to Darlington Refurbishment. OPG updates its evidence when it becomes aware of material changes to its costs or significant new information that materially impacts its prior testimony. OPG undertakes evidentiary updates based on its understanding of Rule 11.02 in the OEB's Rules of Practice and Procedure.

OPG puts a substantial amount of work into preparing and verifying its Impact Statements. It does a comprehensive survey throughout its regulated operations for any material changes ($10M per year in revenue requirement up or down) and brings forth everything it finds. Changes below the materiality threshold are not included even if, as was true for Impact Statement #1, their cumulative impact would be quite large. When new information emerges that changes its evidence, OPG brings it forward even if unfavourable.

OPG has provided the OEB with a comprehensive evidentiary showing that fully supports its requested payment amounts. OPG respectfully submits that based on the evidence in this proceeding, these payment amounts should be approved.

2.0 GENERAL

2.1 ISSUE 1.1

Primary - Has OPG responded appropriately to all relevant Board directions from previous proceedings?

OPG set out its responses to prior OEB directions at Ex. A1-11-1 in its prefiled evidence. There were no substantive submissions made by Parties on this issue.

2.2 ISSUE 1.2

Primary - Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

2.2.1 Business Transformation

This section responds to the submissions of SEC and CME on business transformation ("BT") (SEC argument, paras. 1.2.12-1.2.21; CME argument, para. 5). Their submissions are largely directed to redefining the words "cost control" to mean "cost reduction" and to the revision of history. Both submissions are fairly placed in the category of "unhelpful" criticism. Rather than suggesting ways that OPG could improve BT, these submissions merely complain that the reductions should have happened sooner and be larger. OPG submits that these submissions should be given no weight.

BT will reduce OPG's staff by some 1300 employees in its regulated operations by the end of 2015 (Ex. L-1.2-17 SEC-006; Ex. JT2.10; Ex. JT2.33; Ex. J3.1). OPG submits that this is a very large and challenging staffing reduction that has been successfully managed and remains on track (Tr. Vol. 3, p. 8, lines 13-27).

SEC and CME argue that:

- “BT’s goal is “cost control;”
- “Cost control” equals “cost reductions;”
- “OPG’s costs are not going down”
- “Therefore BT is a failure.”

The fallacy here is equating “cost control” with “cost reduction.” OPG has repeatedly explained that many of the drivers of its proposed rate increase are beyond the company’s ability to control. The prime example is the impact of discount rate changes on pension and OPEB costs. Just because the drivers are leading to increased costs does not mean that BT has not reduced costs (Tr. Vol. 11, pp. 123-124). Significant cost savings have been achieved to date, are expected going forward and are built into the test period business plan (Ex. JT2.10 and Ex. J3.1).

SEC also makes much of the fact that the savings inherent in a centre-led organization should have been obvious to OPG. As OPG’s witnesses explained for many years the company followed a “decentralized model” whereby local plant groups were accountable for things like local public affairs because they had greater knowledge of the local community. As it became clear that OPG’s production was going to continue decreasing and the number of plants declined, the benefits of centralization in terms of cost savings outweighed those of decentralization and OPG instituted a centre-led model (Tr. Vol. 3, pp. 85-86).

SEC, after moving to ensure that the KPMG Report would be made part of the record, neglects to mention it in their argument (see Tr. Vol. 1, p. 6). Perhaps this is because KPMG does not share SEC’s view that business transformation is a failure. To the contrary, KPMG regards it as a well structured initiative that captures the bulk of the savings opportunities available (See Ex. A4-1-1, p. 2 and AIC, p. 7).

2.3 ISSUE 1.3

Secondary - Has OPG appropriately applied USGAAP accounting requirements, including identification of all accounting treatment differences from its last payment order proceeding?

SEC asks the OEB to make a retroactive change to the calculation of Bruce Lease net revenues that is inconsistent with both the OEB's decision on how these revenues are to be calculated and the approved settlement in EB-2012-0002 (SEC argument, paras 1.3.2-1.3.5). SEC's requested change should be rejected.

OPG explained the impact on Bruce Lease Base Rent Revenue in EB-2012-0002:

> USGAAP requires the amount of base rent revenue to be recognized on a straight-line basis from the start of the Bruce Lease in 2001. Under CGAAP, the amount of rent revenue recognized is calculated on a straight-line basis effective April 1, 2008 following the OEB's direction that "Bruce lease revenue be calculated in accordance with GAAP for non-regulated businesses" (EB-2007-0905, page 110). The earlier effective date for the purposes of the straight-line calculation under USGAAP results in a lower amount of revenue being recognized over the remaining expected lease term.....so the overall impact is a $1.6M annual reduction in Bruce Lease net revenues. (EB-2012-0002, Ex.A3-1-2, p. 6).

SEC references Ex. L-1.3-17 SEC-019 where it asks OPG to provide references in EB-2011-0432 where the impact of USGAAP on Bruce Lease Net Revenues was discussed. In this proceeding SEC does not argue that there was insufficient evidence in EB-2011-0432 or EB-2012-0002 on the impact of USGAAP on Bruce Lease Net Revenues. Instead, SEC highlights the $59M impact on retained earnings and incorrectly categorizes it as a proposal (SEC argument, para. 1.3.3). It is not a proposal; it was a <u>required</u> transition entry as part of the January 1, 2011 USGAAP opening balance sheet. OPG was obligated to account for this amount as an adjustment to retained earnings.

SEC submits that the OEB should now order that the $59M be credited to a deferral account. OPG disagrees for two reasons. First, SEC's proposal would be inconsistent with the OEB's prior decision that Bruce Lease revenues and costs are to be determined on the basis of GAAP for non-regulated entities. And secondly, because it would be inconsistent with the approved settlement in EB-2012-0002 where the OEB approved OPG's adoption of USGAAP and related account balances that did not reflect the entry that SEC, a party to the settlement, now seeks to add.

The OEB has been very clear about the approach to determining Bruce Lease net revenues. In EB-2007-0905 the OEB found the following:

> In the Board's view, the fact that the net revenues related to OPG's unregulated Bruce lease are intended to mitigate the payment amounts for Pickering and Darlington does not lead to a conclusion that the Province must have intended that the Bruce revenues and costs be calculated as if OPG's investment in Bruce were subject to regulation.
>
> Further, the Board finds that the Bruce net revenues, as a mitigation measure, do not form part of OPG's revenue requirement for the prescribed assets. Rather, the Board concludes that the regulation requires net revenues be used to reduce the payment amounts that would otherwise be set based on the revenue requirement for the prescribed assets. In the Board's view, "revenue requirement" is a concept that is applicable only to rate-regulated activities. (EB-2007-0905, Decision with Reasons, p. 107).

Ultimately, the OEB decided to calculate Bruce Lease costs and revenues on an accounting basis, stating:

> The Board finds that the appropriate method to calculate OPG's test period revenues and costs related to the Bruce stations is to use amounts calculated in accordance with GAAP. OPG's investment in Bruce is not rate regulated. In the Board's view, <u>it would not be a reasonable interpretation of Sections 6(2)9 and 6(2)10 to find that OPG should use an accounting method to determine revenues and costs that an unregulated business would otherwise never use.</u> Had the Province intended the Board to determine revenues and costs related to Bruce in accordance with principles applicable to a regulated business, the regulation would have so stated. *(<u>emphasis added</u>)* (EB-2007-0905, Decision with Reasons, p. 109).

The impact of the OEB's decision on OPG was that the return that was negotiated in establishing the agreements with Bruce Power and consequently reflected in revenues was provided to the benefit of the ratepayer as it is part of OPG's revenues under GAAP. The flip side to that is that the $59M, an adjustment to equity pursuant to GAAP, is neither revenue nor an expense. The $59M adjustment to equity is treated in the same way as OPG's annual return on equity — both are foregone as they do not meet the GAAP definition of cost or revenue. Similarly, the impact is not eligible for inclusion in the Bruce Lease Net Revenues Variance Account as it is neither revenue nor a cost pursuant to GAAP.

The remedy proposed by SEC is effectively to establish a regulatory liability. The OEB establishes regulatory assets and liabilities with respect to the facilities subject to regulation. The Bruce facilities are not regulated. The remedy proposed by SEC is to use an accounting method to determine revenues and costs that an unregulated business would otherwise never use, which is precisely the approach that the OEB has already found to be unreasonable, as noted above.

Despite the above, if the OEB determines that a deferral account should be established, OPG may have to record a liability with a charge to the income statement. This would have a punitive effect on OPG's net income and its ability to earn a fair return on invested capital since the original credit was recognized as an adjustment to retained earnings.

In EB-2012-0002, OPG fully disclosed all the revenue requirement impacts of OPG's adoption of USGAAP, including the impact on Bruce Lease net revenues (Ex. L-1.3-17 SEC-019). The balance in the Impact for USGAAP Deferral Account was agreed to as part of the EB-2012-0002 Settlement Agreement. The OEB approved that Settlement Agreement, authorizing the use of USGAAP by OPG for regulatory accounting, reporting and rate-making purposes (EB-2012-0002, Tr. Vol. 1, p. 25). SEC's proposal is essentially to amend the terms of the EB-2012-0002 Settlement Agreement in a subsequent proceeding. The OEB accepted that settlement and should not entertain SEC's invitation to retroactively amend it.

For all of the reasons provided above and in its evidence and Argument-in-Chief, OPG submits that the OEB should find that OPG has appropriately applied USGAAP accounting requirements, including identification of all accounting treatment differences from its last payment order proceeding.

2.4 ISSUE 1.4

Oral Hearing - Is the overall increase in 2014 and 2015 revenue requirement reasonable given the overall bill impact on customers?

This section addresses the arguments about the size of OPG's overall increase (CCC argument, p. 3; CME argument, para. 13-14, 27; SEC argument, paras. 1.4.13 through 1.4.19). It does not address the "colour commentary" provided by the parties.[3]

In an effort to make the size of the increase appear greater, the parties have combined the payment amounts and the interim period riders in calculating the increase. Thus the later the implementation date they select, the fewer months over which the 24 month revenue requirement is amortized. For example, by selecting an implementation date of December1, 2014, CME spreads the recovery of the 24-month revenue requirement over 13 months.[4] By failing to note that the interim period riders, by their very nature, would cease at the end of 2015 (as noted in Ex. J13.8), CME leaves the false impression that their estimated large increase is an enduring one.

The fact remains that estimated average increases experienced over the test period versus current rates are as depicted in Ex. N2-1-1. For residential consumers this is an increase of about $5.31 per month (about 4.5 per cent) including the newly regulated hydroelectric facilities and assuming they would have otherwise received $30 per MWh (Ex. N2-1-1, p. 11).

SEC creates a straw argument, and then knocks it down by claiming OPG has said that it never receives any money and then demonstrating that there have been increases in revenues (SEC argument, paras. 1.4.14 through 1.4.19). All of the calculations on SEC's table are against the starting point of the temporary payment amounts set by the province in 2005 ($33 per MWh for hydroelectric and $49.50 per MWh for nuclear) (SEC argument, para. 1.4.14). The

[3] For example, SEC provides a flawed recitation of the history of the Ontario Hydro demerger, a redefinition of bankruptcy, a reinterpretation of the purpose of the Global Adjustment, and a mischaracterization of the relative cost of OPG's output (SEC argument, paras. 1.4.4 through 1.4.6). Since SEC itself acknowledges that this is nothing more than background information, and its only apparent purpose is to cast OPG in an unfavourable light, OPG has elected not to respond. Obviously, that should not be taken as agreement.

[4] CME calculates the resulting increase as 61 per cent, but the actual number is 52.4 per cent using the calculation method shown in Ex. J3.10 and monthly production forecasts shown in Ex. E1-1-1, Table 1 and Ex. E1-2-2, Table 2.

problem with this argument is that OPG never said what SEC claims and the chart SEC prepared shows that what OPG actually said, that base rates have not increased since 2008 and in fact have declined slightly since 2010, is absolutely accurate. The increased revenues that SEC shows are due to rate riders approved to recover variance and deferral account balances and changes in production. OPG's base rates have been essentially constant from 2008-2013.

3.0 RATE BASE

3.1 ISSUE 2.1

Primary - Are the amounts proposed for rate base appropriate?

Regulated Hydroelectric Rate Base

A number of intervenors (Board staff, AMPCO, CME, CCC, LPMA, SEC and VECC) have recommended reductions to Hydroelectric in-service amounts during the test period, based on historical trends. Similarly, a number of submissions (Board staff, AMPCO, CME, CCC, EP, LPMA, SEC, and VECC) have called for disallowances to the in-service amounts requested by OPG in relation to the Niagara Tunnel. These items are dealt with in Issues 4.3 and 4.4 respectively. OPG's reply submissions under those issues make it clear that there is no basis for any of the proposed disallowances. As such, and for the reasons set out in its evidence and Argument-in-Chief, OPG submits that the rate base for the regulated Hydroelectric facilities should be accepted by the OEB, as filed.

Nuclear Rate Base

Similar to Hydroelectric, intervenors (Board staff, AMPCO, CME, CCC, LPMA, and SEC) called for reductions to Nuclear in-service amounts during the test period, based on historical trends. Further, a number of submissions (CME, CCC, ED, GEC, SEC and VECC) called for disallowances to the in-service amounts requested by OPG in relation to the Darlington Refurbishment Project that are expected to close to rate base during the test period. There were also submissions that had inventory implications associated with Nuclear Fuel. These items are dealt with in Issue 4.8, 4.9 and 6.5 respectively.

OPG's reply submissions under those issues make it clear that there is no basis for any of the proposed disallowances. As such, and for the reasons set out in its evidence and Argument-in-Chief, OPG submits that the rate base for the regulated Nuclear facilities should be accepted by the OEB as filed, subject to its findings on Nuclear in-service amounts (Issue 4.8), the Darlington Refurbishment Project (Issue 4.9) and Nuclear Fuel (Issue 6.5).

4.0 CAPITAL STRUCTURE AND COST OF CAPITAL

4.1 ISSUE 3.1

Primary - What is the appropriate capital structure and rate of return on equity for the currently regulated facilities and newly regulated facilities?

There are a number of submissions on capital structure and rate of return. OPG has grouped these submissions and its reply to them under the sub-headings set out below.

THERE IS NO BASIS FOR REDUCING THE EQUITY COMPONENT OF OPG'S CAPITAL STRUCTURE

A number of parties made submissions recommending a reduction in the equity component of OPG's capital structure based on the increase in rate base related to hydroelectric assets arising from the inclusion of the Niagara Tunnel in rate base and the regulation of the newly regulated hydroelectric assets.

These equity adjustment proposals suffer from a number of fatal factual and legal errors, as well as errors of regulatory principle, as explained in greater detail below. Accordingly, OPG submits that they should all be rejected and that the OEB should retain the current 47% equity thickness.

Positions

SEC urges the OEB to set aside the expert testimony of Ms. McShane and instead rely on their calculations based on their interpretation of evidence offered by Drs. Kryzanowski and Roberts ("K&R") in EB-2007-0905. SEC's calculations produce an equity thickness of 42.34 per cent (SEC argument, para. 0.2.2), which they acknowledge would change based on the actual hydroelectric and nuclear rate base amounts approved by the OEB (SEC argument, paras. 3.1.37 through 3.1.38). SEC's analysis has the general support of CCC (who says that the equity thickness should be reduced to something in the range of 42 per cent (CCC argument, p. 8) and LPMA (who says that the maximum equity thickness should be 42 per cent (LPMA argument, p. 4).

SEC's proposed 42.34 per cent is based on a flawed methodology and an incorrect premise. In making its calculation, SEC asserts that the 47 per cent equity thickness, established in EB-2007-0905, was based on the OEB's adoption of the K&R methodology and on the basis of that the OEB determined a 50 per cent equity ratio for Nuclear and 40 per cent equity ratio for Hydroelectric. These assertions are both wrong. While the OEB accepted 47 per cent as being appropriate for OPG's operations, there is nothing in either EB-2007-0905 or EB-2010-0008 that says the OEB adopted the equity ratios of 40 per cent and 50 per cent for the two technologies or, as noted in Board staff's argument, there is nothing in the EB-2007-0905 decision that indicates that the OEB accepted the K&R methodology (Board staff argument, p. 8).

Finally, SEC's methodology does not even update for the change made by K&R in EB-2010-0008. In EB-2010-0008, K&R updated their views to conclude that the common equity ratio for hydroelectric assets should be 43 per cent, not the 40 per cent used by SEC (EB-2010-0008, Decision with Reasons, p. 114). As Board staff points out, this significant change by K&R reflected an acceptance by them that their approach in EB-2007-0905 of weighting by production rather than by the net book value of assets was wrong (Board staff argument, p. 7-8).

CCC's support for a common equity ratio of about 42 per cent is particularly odd in that they acknowledge in their argument that Drs. Kryzanowski and Roberts revised their views about the appropriate capital structure for hydroelectric on a stand-alone basis to 43 per cent in EB-2010-0008 (CCC argument, p. 7); while the SEC analysis, that CCC appears to support, is predicated on Drs. Kryzanowski and Roberts' outdated recommendation of 40 per cent from EB-2007-0905.

AMPCO believes that a decrease in equity thickness is appropriate but does not offer a specific adjustment (AMPCO argument, p. 7). VECC supports CME's proposal to adjust the return on equity ("ROE") for the newly regulated hydroelectric assets, but will support a lowering of OPG's equity ratio to 42.5 per cent in the event CME's proposal is not accepted by the OEB (VECC argument, p. 18).

SEP submits that the stand-alone principle should no longer apply as the principle is "a relic of the failed privatization initiative of the Harris government" (SEP argument, p. 3) and, as a consequence, the correct economic return is the social discount rate (SEP argument, p. 7). OPG notes that the validity of the stand-alone principle was determined by the OEB in EB-2007-0905 (pp. 137 and 142) and the application of a social discount rate as the allowed return for OPG was not addressed in this proceeding or the last proceeding, nor was it a topic in the OEB's most recent cost of capital consultation.

Board staff, to their credit, acknowledges two important points in coming to their recommendations on capital structure. First, they acknowledge that the OEB did not accept the methodology of Drs. Kryzanowski and Roberts in previous proceedings (Board staff argument, p. 8). Secondly, they note that Drs. Kryzanowski and Roberts revised their hydroelectric equity thickness to 43 per cent in EB-2010-0008 (Board staff argument, p. 7). They conclude by saying that <u>if</u> the OEB agrees with K&R methodology this time, and <u>if</u> the OEB agrees with SEC that the newly regulated facilities are the same risk as the previously regulated facilities, then an equity thickness of 45 per cent to 46 per cent is reasonable (. p. 8).

EP and the PWU support the current equity thickness of 47 per cent as proposed by OPG.

THE PROPOSED CAPITAL STRUCTURE ADJUSTMENTS HAVE NO EVIDENTIARY BASIS

Parties to this proceeding have proposed dramatic, perhaps unprecedented, adjustments to OPG's capital structure without even bothering to file expert evidence on the issue. This is despite the fact that they had ample opportunity to do so and have known for many months that capital structure would be an issue in this proceeding.

Without expert evidence, these parties have opted to abandon principles of procedural fairness and have instead advocated their submissions on the untested assertions of counsel or on evidence from a proceeding held over six years ago, EB-2007-0905, and which relates to an entirely different factual circumstance. Neither of these approaches is legally acceptable or consistent with good regulatory practice.

Unfortunately, this failure by intervenors to file evidence is not a new concern. In its EB-2010-0008 decision, the OEB gently admonished intervenors for attempting to introduce evidence in their arguments, saying that "Quite a number of very material issues were explored somewhat late in the process; in some cases the arguments themselves contained what could be characterized as evidence." (EB-2010-0008, p. 6). The OEB went on to say that its comments were to "…guide the parties as to the Board's expectations for the next proceeding." (*Ibid*., p.7). It is clear that, in respect of Issue 3.1, the Board's guidance was not followed.

The intervenors would also have been aware of the OEB's requirement to file evidence to support proposed changes in capital structure through their involvement in EB-2011-0210 (a Union Gas case for new rates effective January 1, 2013). In that case, the OEB rejected Union Gas's request for an increase in its equity ratio on the basis that it had not filed evidence to support the arguments it was making in support of its proposed change, specifically noting that Union Gas "…filed no evidence to support this position that the equity ratio was not correct and the Board therefore gives this argument little or no weight" (EB-2011-0210, Decision and Order, p. 48) and that, "The Board acknowledges that there was a general consensus on the Canadian utilities that intervenors and Union say were comparable. The Board notes, however, that neither Union nor the interveners filed analytical evidence that demonstrated that these utilities are of like risk to Union. Rather, what evidence was presented was anecdotal, ad hoc, and incomplete." (*Ibid.*, p. 49).

Unlike the intervenors, OPG did file expert evidence to support its position.

With respect to the intervenors' reliance on evidence from prior cases, OPG notes that the OEB only has jurisdiction to admit evidence from another proceeding into a current proceeding when that other proceeding is being heard at the same time as the current proceeding (*Ontario*

Energy Board Act, s. 21(6.1)). The requirement that the proceedings be heard at the same time is to provide fairness by enabling a party to participate as necessary to challenge or question such evidence based upon the circumstances before the OEB. This is not the case in this proceeding. EB-2010-0008 and EB-2007-0905 are at an end and dealt with different facts.

For these reasons alone (i.e., the lack of expert evidence filed in this proceeding, the reliance on evidence from prior proceedings, and the mischaracterization of the OEB's acceptance of that evidence), OPG submits that the OEB should reject the proposed adjustments to OPG's capital structure.

CHALLENGES TO OPG'S EVIDENCE ARE WITHOUT MERIT

Beyond the legal and evidentiary problems with the intervenor submissions, OPG submits that the offered criticisms of Ms. McShane's evidence are without merit and should be rejected.

Ms. McShane is well known to the OEB and was accepted by the OEB as a cost of capital expert in this hearing (Tr. Vol. 10, p. 6, lines 10-11). She testified in both of OPG's prior rate proceedings and has a well-developed understanding of the business and financial risks that OPG faces and that relate to the determination of cost of capital.

In her report, Ms. McShane provided an analysis and expert opinion on whether the capital structure approved in OPG's last application (EB-2010-0008) was appropriate for the test period, given the completion of the Niagara Tunnel project and the inclusion of additional hydroelectric assets in OPG's regulated rate base (Tr. Vol. 10, pp. 7-8). Her report was filed as Ex. L-3.1-17 SEC-024, Attachment 1 (the "Report").

Ms. McShane concluded that OPG's deemed common equity should, <u>at a minimum</u>, remain at 47 per cent for the reasons set out at pages 2 and 3 of her Report. These reasons included her views that:

1. The business risks specific to OPG's regulated hydroelectric generation operations, including the newly regulated facilities, are somewhat higher than when the OEB issued

its Decision in EB-2010-0008, due largely to the higher operating risks of the newly regulated facilities.

2. The fundamental business risks of the nuclear generation operations have not changed materially. However, the operating leverage has continued to rise, leading to higher potential volatility in earnings for the nuclear generation operations. All other things equal, a thicker equity component would be required to dampen the volatility.

3. The lower end of a reasonable range of equity ratios for the regulated hydroelectric generation operations, including the newly regulated generation, consistent with their relative business risks and the fair return standard is, conservatively, 45 per cent. As such, a 47 per cent common equity ratio for OPG's combined hydroelectric and nuclear operations, given the latter's higher operating risks and increased operating leverage, remains reasonable even with the higher proportion of regulated hydroelectric generation rate base during the test period.

4. The Darlington Refurbishment Project, due to its size, will reverse the relative proportions of the test period hydroelectric and nuclear generation rate base. Capital structure decisions reflect longer-term, not test period, business risks. As the Darlington Refurbishment Project investment is more than double the combined rate base additions from the Niagara Tunnel project and newly regulated hydro facilities, maintaining the approved 47 per cent common equity ratio is a conservative approach that OPG should revisit once a decision on the Darlington Refurbishment Project has been reached.

5. The Darlington Refurbishment Project will require significant capital investment, including approximately $1.5B during the test period. With no additional cash flows to service the corresponding debt financing, credit metrics will be weaker, putting downward pressure on debt ratings. At a minimum, OPG's allowed common equity ratio should remain at the previously approved 47 per cent to avoid further weakening of credit metrics.

6. The OEB is committed to the implementation of incentive regulation for both the regulated hydroelectric and nuclear operations. Although the specifics of the plans have yet to be developed, the characteristics of incentive regulation expose regulated companies to higher risk than cost of service regulation. The higher business risk of the

regulated operations under incentive regulation provides support for, at a minimum, maintaining the approved 47 per cent common equity ratio.

In the interest of keeping its reply to a manageable length, OPG does not propose to reply to every misdirected criticism of Ms. McShane's evidence. Instead it will focus its submissions on the key points raised. However, OPG's lack of response to a specific criticism should not be seen as acceptance.

To begin, SEC submits that her evidence cannot be relied upon because her opinion is premised on the view that the existing equity ratio of 47 per cent is too low (SEC argument, para. 3.1.5). This is incorrect as any fair-minded reading of her Report will make clear. Her analysis took as a point of departure the OEB's previously approved common equity ratio of 47 per cent (Report, p. 7). It considered whether there had been changes in business and financial risk that warranted a change in the capital structure, but did not question whether the 47 per cent previously adopted was appropriate (Tr. Vol. 10, pp. 7-8).

SEC, among others, then goes on to suggest that Ms. McShane's evidence should be discounted because she has no independent knowledge of the circumstances of OPG's newly regulated hydroelectric operations, and is not an expert in their operations, and hence is dependent on information from OPG personnel (SEC argument, para. 3.1.8). However, there is nothing wrong or unusual about using information from experts in the field (i.e., discussions with OPG operations staff who have significant experience with these assets) to make a relative business risk analysis. In fact, none of the cost of capital experts that regularly testify before the OEB, not even Drs. Kryzanowski and Roberts, have expertise in the operation of hydroelectric generation facilities. Ms. McShane had the benefit of a number of discussions with OPG operating personnel as well as her own research and experience in coming to her opinion (Tr. Vol 10, pp. 102 and 109-110). Accordingly, in OPG's submission this criticism should be rejected by the OEB.

SEC then goes on to say that Ms. McShane "probably" had some of her facts wrong and therefore has insufficient knowledge of the actual business risks of the newly regulated operations to form an independent opinion (SEC argument, para. 3.1.10). The net result of which is SEC's submission that in the absence of evidence to the contrary, the OEB should treat the newly regulated assets as having the same business risk as the previously regulated assets (SEC argument, para. 3.1.14).

The main problem with the submission that Ms. McShane "probably" got some facts wrong is the source of the supposed "correct facts". The source of the "correct facts" is nothing more than a number of unsupported assertions by SEC's counsel that are inconsistent with the actual evidence on the record. After criticizing Ms. McShane for not being an expert in hydroelectric operations, SEC's counsel has no difficulty going on to give evidence on how these facilities operate and what constraints they face (SEC argument, para. 3.1.13; and footnotes 42-49).

For example, SEC implies that First Nations issues are bigger with respect to the previously regulated facilities than with respect to the newly regulated facilities (SEC argument, para. 3.1.9). Setting aside the obvious fact, as testified to by Ms. McShane (Tr. Vol. 10, p. 92, lines 7-16), that the newly regulated hydroelectric assets are primarily located in northern Ontario where First Nations communities and related traditional areas are significant, the evidence is that OPG has formal arrangements with 19 First Nations (Ex. A1-4-2, p. 14), only one of which (i.e., the arrangement with the Akwesasne) is related to a previously regulated facility. The remaining 18, as well as several ongoing negotiations, are mostly related to newly regulated facilities and continue to require active management.

SEC is also wrong with respect to the proposition that OPG's previously regulated hydroelectric assets (e.g., Niagara River) have greater operating constraints than the newly regulated stations (e.g., Abitibi River). This is simply not accurate or consistent with the evidence. As described in section 5.1 of Ex. A1-4-2, all of OPG's hydroelectric stations (both previously and newly regulated) operate under externally imposed restrictions. While the six previously regulated facilities are on international rivers and operate under treaties administered by the International Joint Commission, the 48 newly regulated stations are all subject to similar restrictions that prescribe flow and water level elevation limits. The seven stations on interprovincial rivers are regulated by Ottawa River Regulation Planning Board or the Lake of the Woods Control Board. The remaining 41 stations are on 17 interior provincial river systems that are subject to either Ontario Ministry of Natural Resources water management plans or are on federally regulated navigable rivers (i.e. Rideau, Trent, and Severn) (Ex. A1-6-1, pp. 3-5).

And while the newly regulated facilities have more short term storage than the previously regulated facilities (Tr. Vol. 4, page 30, lines 11-24), they also face higher production variability as inflow conditions are both substantially more variable and uncontrollable due to smaller river system drainage basins and weather-related natural inflows (Ex. E1-1-1, section 3.5, and Tables 1 and 2). The previously regulated facilities are largely fed by the Great Lakes and benefit from the stability of an enormous drainage basin, whereas the newly regulated facilities are on various river systems with much smaller drainage basins. Further, the availability of storage can be limited due to high inflows (e.g. during freshet), environmental constraints due to aquatic life or sanitation, navigation requirements, or other restrictions imposed by water management plans. As Ms. McShane testified, production and water availability were some of the factors that she considered in coming to her conclusion on relative risk (Tr. Vol. 10, p. 107).

With respect to the peaking nature of the newly regulated facilities, OPG has testified that peaking operations increase the frequency of stops and starts leading to more wear and tear on the generating units (Tr. Vol. 4, pp. 43-44). And increases in stops and starts related to peaking operations are recognized as a business risk in Hydro-Thermal Operations' Business Plans (Ex. F1-1-1, Attachment 1, Slide 14, Item 10; and Ex. N1-1-1, Attachment 6, Slide 19, Item 9). How these and other production-related risks translate into OPG's availability and EFOR targets for the newly regulated facilities is usefully summarized in Chart 1 of Ex. F1-1-1 on page 25 and Charts 2a and 2b on pages 7-8. OPG submits that these tables show that most of the newly regulated plants are expected to have worse reliability and more operating issues than the previously regulated facilities.

Intervenors seeking a reduction in OPG's equity ratio also submit that the OEB should look at just the business and financial risks in the test period and ignore everything else (SEC argument, para. 3.1.22; CCC argument, p. 7; among others). However, this is not the proper way to examine the business and financial risks facing a utility – one also has to give consideration to longer run risks as Ms. McShane has done (Tr. Vol. 10, pp. 36-37). This is particularly true for a company like OPG which has very long-lived assets like hydroelectric and nuclear generation facilities. Business risks, and their impact on cost of capital and capital structure, are not just test year issues, contrary to CCC's position. Investment funds are not committed to long-term assets based solely on the circumstances in the test year. This has been recognized by the OEB in its EB-2009-0084 Report on the Cost of Capital for Ontario's Regulated Utilities Assets, where it notes that, "the Board is of the view that the capital attraction standard, indeed the FRS [Fair Return Standard] in totality will be met if the cost of capital determined by the Board is sufficient to attract capital on a ***long-run sustainable basis*** given the opportunity cost of capital" (*emphasis added*) (EB-2009-0084, p. 20). Looking at longer run business developments and risks also supports the principles of predictability, transparency and stability that the OEB adopted in their Cost of Capital Policy (EB-2009-0084, p. 32).

In its argument, VECC makes a number of submissions that are premised on OEB having been wrong on OPG's cost of capital since the Cost of Capital Policy was introduced in 2009 (VECC argument, pp. 4-6). On this basis alone, these submissions should be rejected out of hand as they are nothing more than a backdoor way of taking issue with the OEB's 2009 Cost of Capital Policy Report (EB-2009-0084) and the results of implementing that policy. They place a lot of emphasis on comparing OPG's cost of capital and capital structure to other Canadian utilities, particularly Nova Scotia Power ("NSPI"), with its 37.5 per cent equity ratio (VECC argument, pp. 6-8). VECC's argument that OPG's request in this proceeding is egregiously high is partly based on their belief that the capital structure of NSPI (37.5 per cent equity ratio) is the "right" number for an integrated electric utility with 60 per cent of rate base in generation assets. It is important to note that NSPI's equity ratio has not changed since the OEB initially set OPG's equity ratio in EB-2007-0905 (Tr. Vol. 10, p. 28, lines 10-14). So a comparison with NSPI provides no new information that the OEB did not have available to it when OPG's capital structure was initially set.

In considering VECC's submissions it is worth having regard to the OEB's decision in EB-2011-0354, a proceeding to consider an application by Enbridge Gas for new rates effective January 1, 2013. There, the OEB found that Enbridge, by advancing a comparison between its capital structure and those of other utilities, was in effect attempting to argue that the OEB should reconsider the basis for its earlier decision (in EB-2006-0034) on Enbridge's capital structure

(EB-2011-0354, Decision on Equity Ratio and Order, pp. 6-7). This approach was rejected by the OEB which stated that if Enbridge had wanted to review the EB-2006-0034 decision it should have filed a review application but had not done so (*Ibid*., p. 7). The OEB also indicated in that decision, that in assessing whether a utility's risk had changed since its capital structure had last been set, the proper basis for that assessment is a consideration of the utility's access to capital, interest coverage ratios, credit ratings, debt terms and financial results and not a comparison of its capital structure to those of other utilities.

In its submissions on capital structure, VECC makes exactly the same points that Enbridge tried to make in EB-2011-0354. Accordingly, OPG submits that VECC's submissions should be rejected for the same reasons given by the OEB in EB-2011-0354.

In its argument, LPMA asserts its view, without any support, that adding the newly regulated plants adds to the diversity of the hydroelectric operations and thus reduces the risk. This conclusion ignores the fundamental operating differences between the newly regulated and the previously regulated facilities. The fact that there are more newly regulated than previously regulated and those plants are more geographically/weather diversified than the previously regulated plants does not outweigh the higher operating risks of the newly regulated plants (Tr. Vol. 10, p. 5, lines 11-19).

SEC and others attempt to confuse Ms. McShane's evidence on the impact of the Darlington Refurbishment Project on OPG's financial risk and credit metrics, which are key considerations in determining capital structure. They make the point that ratepayers should not be charged today for assets that have not yet gone into rate base (SEC argument, para. 3.1.16). This statement is entirely erroneous.

SEC also makes a related submission that OPG is attempting to include construction work in progress ("CWIP") in rate base (SEC argument, para. 3.1.18). Again this is patently false.

Ms. McShane's evidence on Darlington Refurbishment is straight-forward; namely that one needs to consider both business and financial risks when setting the cost of capital and capital structure for a utility (Tr. Vol. 10, p. 100, lines 14-17). This is well understood and accepted by the OEB (EB-2011-0354, p. 7, as discussed above).

As OPG is planning on spending over $1.5B on the Darlington Refurbishment Project during the test period, and additional billions beginning in 2016, there can be no doubt that these large capital expenditures will increase OPG's financial leverage, lower its already weak credit metrics and increase OPG's overall financial risk (Tr. Vol. 10, pp. 36-37, lines 22-10; Report, pp. 20-23). This increase in financial risk is flagged in the debt rating agency reports where Standard & Poor ("S&P") discusses OPG's significant financial risk profile, low returns on regulated operations and substantial debt-financed projects (Ex. A2-3-1, Attachment 1, pp. 2-3) and notes that "…the company has reached an inflection point in its capital plans where significant expenditures for such things as the Darlington nuclear facility refurbishment and the Lower Mattagami project are required. We believe that these projects will put significant strain on credit metrics for the next two years." These concerns are also echoed by DBRS which noted that "OPG is expected to generate free cash flow deficits over the medium term, driven by higher capital expenditures (capex) requirements to fund hydroelectric and refurbishment projects." (Ex. A2-3-1, Attachment 2, p. 1). The capital structure applicable to the assets in rate base has to provide financial support for all the regulated assets, whether in rate base or not (Tr. Vol 10, pp. 36-37). As Ms. McShane pointed out, Alberta Utilities Commission has allowed thicker common equity ratios (in addition to CWIP in rate base) where there is a major capital build (Report, p. 20).

This fact coupled with the greater risk of the newly regulated hydroelectric assets is inconsistent with the intervenors' position of reduced equity.

SEC and others assert that the future introduction of incentive regulation mechanism ("IRM") to OPG is irrelevant to the consideration of cost of capital since it should reduce business risks and, in any event, is an issue for a future proceeding (SEC argument, para. 3.1.22). The problem with this submission is that there was no evidence adduced that IRM reduces business risks. In fact, Ms. McShane's expert option is just the opposite (Tr. Vol. 10, p. 37, lines 1-4). It is noteworthy that the two independent rating agencies, DBRS and S&P, also view incentive regulation as riskier than cost of service regulation (Report, pp. 17-18). Incentive regulation by its very nature has greater business risk because it typically contemplates a decoupling of rates from the underlying costs. While true that the precise form of incentive regulation is an issue for a future proceeding, it is clear that the OEB intends to introduce incentive regulation for OPG beginning January 1, 2016.

VECC also points to the actual ROEs earned by Enbridge and Union Gas as proof that there is no evidence of higher risk under incentive regulation. However, as Ms. McShane testified, higher returns do not mean that that these utilities were not experiencing higher risks and the experience of the Ontario electricity distributors has been very different (Tr. Vol. 10, p. 52, lines 13-28).

VECC also takes issue with Ms. McShane's reliance on a summary of previous empirical analysis of the impact of incentive regulation on cost of capital found in a paper authored by Camcho and Menezes. VECC considers that, because the assumptions that the authors adopted in developing their own theoretical model are unrealistic, somehow it follows that their summary of others' empirical analysis, which demonstrated "the firm's cost of capital under PC [price cap] regulation is higher than under COS [cost of service] regulation" (Report, p. 18), cannot be relied on. Whether the authors' model is realistic or not is a red herring — it has no bearing on the point Ms. McShane was making (Tr. Vol. 10, p. 55, lines 4-26).

As discussed above, the equity adjustment proposals by intervenors suffer from a number of fatal factual and legal errors, as well as errors of regulatory principle. Accordingly, OPG submits that they should all be rejected and that the OEB should retain the current 47 per cent equity thickness.

THE PREVIOUSLY APPROVED METHODOLOGY FOR SETTING OPG'S ROE SHOULD BE MAINTAINED

While Board staff supports OPG's proposed ROE for 2014 (i.e., 9.36 per cent), they propose a change in methodology for 2015 (Board staff argument, p. 10). They are supported in this requested change by CCC, SEC and LPMA.

For 2015, Board staff proposes that OPG's ROE be set on the same basis as other cost of service applications for 2015. However, OPG's application is not a 2015 cost of service application; it is a two year application covering both 2014 and 2015. The method of determining the second year (2015) return on equity proposed by OPG in this application is the exactly the same methodology adopted by the OEB in OPG's previous application (Ex. C1-1-1, p. 2, s. 4.1). In that case, the OEB decided that ROE for both years should be based on the same vintage of information, albeit from different sources.

Board staff suggests that their proposal would reflect more current data from Consensus Forecasts (Board staff argument, p. 10). While true, this current data would arise after the record in this case has closed and would be a departure from the established methodology for setting OPG's second year ROE. OPG submits that there is a lot of value in maintaining established and approved methodologies, absent compelling new information.

It is worth noting that Board staff made essentially the same submission in the last rates case (EB-2010-0008); that the second year ROE should be updated just prior to 2012 (Decision with Reasons, p. 121). The OEB rejected Board staff's update proposal in that case, saying that OPG's proposed approach was "…consistent with the Board overarching policy and represents the best balance between rate stability, procedural efficiency and accurate forecasting" (*Ibid*. p. 123). Accordingly, OPG submits that the OEB should reject staff's new update proposal for the very same reasons as last time.

PROPOSALS TO APPLY A DEBT RATE TO THE NEWLY REGULATED HYDROELECTRIC ASSETS SHOULD BE REJECTED

ED argues that the re-valued component of the newly regulated hydroelectric assets should only receive the cost of debt and the OEB should consider doing the same for the previously regulated hydroelectric assets (ED argument, paras. 58-59).

The basis of the ED submission is its view that the re-valued component is not capital spending but more akin to taking on debt (*Ibid.*, para. 58).

This submission suffers from a number of problems. First, it is not consistent with the evidence. Second, it would require the OEB to revisit a Government-orchestrated restructuring of Ontario Hydro, something that happened over 15 years ago, and substitute a new interpretation that would be completely inconsistent with what the restructuring of Ontario Hydro was intended to accomplish: a commercial operation that would be viable on a stand-alone basis. Finally, it would be inconsistent with the clear intent of regulation O. Reg. 53/05 and the treatment the OEB afforded the previously regulated hydroelectric facilities in EB-2007-0905.

ED's argument references transcript volume 12, page 130 where ED notes the value of hydroelectric assets in Ontario Hydro's final financial statements, and the value of hydroelectric assets on OPG's 2009 annual report. ED's argument does not reflect the answers OPG provided to ED's follow-up questions explaining the difference. Mr. Barrett provided a high level summary of the financial restructuring of Ontario Hydro (Tr. Vol. 12, p.136) and the implication on OPG: "I think the way that I like to think about this is there was a package of assets that were owned by the government, and they were sold to OPG in exchange for certain debt and equity amounts as part of this government-orchestrated restructuring process." (Tr. Vol. 12, p. 135).

Mr. Mauti confirmed that the package of assets "were assigned debt from OEFC and the Ministry of Energy as their sole shareholder, so they had share capital of, I think it was, approximately $5 billion." (Tr. Vol. 12, p. 135). Mr. Mauti highlights the salient point with regard to cost of capital for OPG: "Well, I think, more importantly, it is the cost to OPG. The purchase -- this was dealt with as sort of a purchase transaction from Ontario Hydro in assigning that purchase price that is establishing the starting cost basis for OPG." (Tr. Vol. 12, p. 133).

As it was a purchase transaction OPG followed accounting requirements to assign asset values. As explained by Mr. Mauti:

> [the] methodology, I guess, that was employed to assign asset values to the different technology streams was to basically apply what was considered at that time Canadian GAAP purchase accounting. So in effect, Ontario Power Generation was established with a revaluation of the value of its assets, and it was financed through a combination of debt and equity as of April 1, '99. You will notice that the nuclear stations went from a $24 billion cost down to a $3 billion cost. (Tr. Vol. 12, pp. 130-131).

In summary, OPG purchased the assets at the transfer values established in 1999, and issued debt and equity to do so. The return that should be allowed to be earned on the debt and equity issued to acquire the assets should be commensurate with the business and financial risks of the underlying assets.

OPG would also note the ED proposal has garnered little support among the other intervenors. In fact, SEC argues against it:

> …we think the government's intent was that on a go-forward basis, they be regulated in the normal way. The ED proposal would have the effect of reaching back into the Ontario Hydro days, taking away some of the benefit of the revaluation of OPG's assets at the time of the restructuring. If that had been intended by the government, in our view they would have said so explicitly. (SEC argument, para. 3.2.6).

CME argues that the capital supporting the newly regulated plants is "stranded debt" and therefore should only receive the cost of debt. VECC believes the "thesis correctly states the appropriate treatment for these assets" (VECC argument, p. 17) while SEC finds the proposal "has merit as a principled alternative." (SEC argument, para. 3.2.9).

This argument is based on a re-telling of the restructuring of Ontario Hydro that is replete with errors (CME argument, para. 34); the premise that since these assets were operating at a loss on December 31, 2013 they somehow became "stranded debt" (CME argument, para. 35); and, the proposition that the OEB should have regard to the sources of capital when determining matters related to capital structure and return on capital (CME argument, para. 31).

With regard to CME's proposition that the OEB should consider the source of capital when determining a utility's capital structure; this is patently incorrect and would be a complete violation of the OEB's long-standing practice and the Stand-Alone Principle. The OEB has to look at the use of funds (i.e., the business and financial risks associated with the investment) to determine the appropriate cost of capital to be applied. In addition, in EB-2007-0905, the OEB has already determined that it would not look at the identity of the shareholder in setting the return for OPG (EB-2007-0905, Decision with Reasons, p. 142). The newly regulated assets are no different than the previously regulated hydroelectric assets in that regard.

OPG notes that in the EB-2007-0905 Decision, the OEB cited AMPCO's argument that "the ROE should be set to the true cost to the shareholder of having assumed this segment of OPG's debt obligation to the OEFC, namely the interest rate on this debt, which is 5.85%" and cited CME's submission "that the ROE should be between 5.85% and 8.57% (the most recently approved level for Hydro One), and should be set at the lower end of the range." (EB-2007-0905, Decision with Reasons, p. 152). The OEB then found:

> The Board agrees with OPG that it would be inappropriate to set OPG's ROE at 5.85%. This rate does not represent the cost of capital for OPG's regulated facilities; it is the interest rate on OPG's prior debt obligation to the OEFC. The Province may have assumed this debt, but that is related to the shareholder's cost of capital, not OPG's cost of capital. (EB-2007-0905, Decision with Reasons, p. 153).

CME's argument that the newly regulated assets are being financed by stranded debt is also wrong. The newly regulated assets were, prior to becoming prescribed assets, being financed by the debt and equity of the consolidated OPG, not solely by debt. As indicated in the DBRS report, the debt ratio of the consolidated operations of OPG has been less than 40 per cent (Ex. A2-3-1, Attachment 2). With the regulated operations allowed a debt ratio of 53 per cent, it is impossible for the newly regulated operations to have been financed with 100 per cent debt. In fact, the only possible conclusion is that they were being financed with more than 47 per cent equity that has been allowed for the previously regulated hydro and nuclear operations.

CME states that OPG did not raise the capital that is supporting the newly regulated hydroelectric assets. This submission is contrary to the evidence in the proceeding (Tr. Vol. 12, pp. 133-134). OPG raised the capital to support all its assets when it acquired them from the Ontario Hydro in 1999 and over time since then, with a combination of debt and retained earnings.

The fact that the newly regulated assets were not earning their cost of capital on December 31, 2013 does not mean that their cost of capital was equal to the cost of debt and that OPG should be denied a reasonable opportunity to earn the cost of capital.

CME is providing its opinion of the background to the province's decision to prescribe certain OPG assets to set a context for punitive and unrealistic recommendations on cost of capital. Without attempting to correct all of CME's unsupported assertions related to the financial restructuring of Ontario Hydro, as noted above OPG's asset purchase was accomplished through an assignment of debt and issuance of equity; therefore OPG was not financed with stranded debt as alleged by CME (CME argument, para. 34b). CME asserts that none of the capital supporting the newly regulated assets could be serviced because, as of December 31, 2013 OPG was earning nothing to cover the costs of capital (CME argument, para. 34e). The evidence does not support this position. OPG's 2013 audited financial statements which the OEB must rely upon in setting payment amounts for OPG's newly regulated assets do not contain an impairment charge for these assets. Neither do any of OPG's previous audited statements. If CME was correct, OPG would be required to write down the value of its assets. The facts do not support CME's position.

For the reasons set out above, the OEB should reject any submission that OPG's newly regulated assets should earn a debt rate rather than OEB-approved return on equity rate. As the Federal Court of Appeal noted, and as cited by the OEB in its EB-2009-0084 Cost of Capital Report:

> …in the long run, unless a regulated enterprise is allowed to earn its cost of capital, both debt and equity, it will be unable to expand its operations or even maintain its existing ones…This will harm not only its shareholders, but also the customers it will no longer be able to service. (EB-2009-0084, Cost of Capital Report, p. 16).

4.2 ISSUE 3.2

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

No parties took issue with the long-term or short term debt rates proposed by OPG. Accordingly, for the reasons set out in its evidence and summarized in its Argument-in-Chief, OPG submits that these long-term and short term debts rates are appropriate and should be accepted by the OEB for the test period.

OPG acknowledges that the final approved debt costs for the test period will be impacted by the OEB's decisions on capital structure and rate base. OPG has responded to the submissions of Board staff and intervenors on these issues elsewhere in this Reply Argument.

5.0 CAPITAL PROJECTS

5.1 REGULATED HYDROELECTRIC

5.2 ISSUE 4.1

Secondary - Do the costs associated with the regulated hydroelectric projects that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery (excluding the Niagara Tunnel Project), meet the requirements of that section?

This issue will be addressed as part of OPG's reply to Issues 4.2 and 4.3 below.

5.3 ISSUE 4.2

Secondary - Are the proposed regulated hydroelectric capital expenditures and/or financial commitments reasonable?

As set out in OPG's Argument-in-Chief, OPG uses a structured portfolio approach to identify and prioritize projects (AIC, p. 19; Ex. F1-1-1, p. 23, Appendix A). OPG's project management and capital budgeting processes are substantially the same as those reviewed and accepted in EB-2010-0008 (Ex. D1-1-1, p. 15). Notwithstanding this, Board staff submits that a $38M reduction of OPG's test period capital budget is warranted since "…the viability of the Ranney Falls project is undetermined." (Board staff argument, p.12).

Board staff's submission was supported by CME and VECC. Board staff references an exchange that took place during the first Technical Conference and claims that OPG's continuing discussions in respect of federal waterway agreements and the fact that OPG originally considered submitting the project under the feed-in-tariff ("FIT") regime that was in place at the time, implies that the project is not viable (Tr. Tech. Conf. Vol. 1, pp. 67-69). This is incorrect.

Discussions to secure federal approvals are a necessary element of any hydroelectric project that is constructed on a federal waterway, such as the Trent-Severn. Neither the need for those discussions, nor their timing, speaks to the viability of a project. There is nothing to suggest that such approvals will not be forthcoming, nor does the transcript imply that.

Further, the fact that the project was considered as part of a FIT proposal should not be puzzling. The business case summary provided in evidence (Ex. D1-1-2, Attachment 1, Tab 10) is dated December 2011 – almost two years before Ranney Falls GS was prescribed as a regulated facility under O. Reg. 53/05. As a result of that change, and as clearly set out in the same Technical Conference transcript, OPG has no intention of seeking FIT treatment for this project since it is now a regulated facility (Tr. Tech. Conf. Vol. 1, p. 68, lines 18-23). The prior consideration of alternate revenue streams for a project does not impact its current viability. Its viability is determined by its economic evaluation, which was provided in evidence, but ignored by Board staff in its argument.

Board staff also states that OPG has not "…provided a sound reason to increase the level of capital expenditures beyond historical levels." (Board staff argument, p. 12), and has cited the OEB's decision in EB-2005-0001 and EB-2005-0437 as justification. In Ex. F1-1-1, OPG discusses its Hydroelectric Business Plan and references categories of "Ongoing Operations" and "Development Initiatives" (pp. 2-3). Ranney Falls GS is one of the development initiatives specifically set out in this exhibit, as is the Niagara Tunnel and the PGS reservoir rehabilitation project. As such, these types of projects are above and beyond the normal sustaining and regulatory expenditures that are typically covered by the hydroelectric capital budget. However, the capital budget is needed to fund initiatives designed to develop additional long-term energy supply, consistent with OPG's Memorandum of Agreement with its Shareholder (Ex. A1-4-1, Attachment 2).

While the Ranney Falls project does not close to rate base during the test period (and hence, does not impact the revenue requirement), it was highlighted during the Technical Conference that there are certain test period capital expenditures that relate to the project (Tr. Tech. Conf. Vol. 1, p. 67). As shown in Ex. D1-1-2, the definition phase of the project ($6.1M) is included in test period cash flows (Ex. D1-1-2, Attachment 1, Tab 10, p. 1). Accordingly, a simple disallowance of the full amount in OPG's capital budget associated with Ranney Falls is inappropriate, and the OEB should reject this recommendation.

AMPCO also claimed that OPG's historical capital spend was less than forecast. In its submission, AMPCO states that for previously regulated hydroelectric, OPG's historical spend was 81 per cent of budget, whereas for newly regulated hydroelectric it was 85 per cent. According to AMPCO, this should result in a decrease of OPG's regulated hydroelectric capital amounts for the test period of $43.4M.

To simply apply these historical variances forward into both years of the test period ignores all the evidence that was filed in support of the forecast level of capital spend for 2014 and 2015. OPG filed extensive evidence on the projects that form its capital budget (Ex. D1-1-1 and Ex. D1-1-2). AMPCO does not take exception to any of them. Accordingly, there is no basis for this recommendation.

OPG's entire application is based upon a forward looking test period. In general, this allows the regulator to assess costs on a forecast basis, with an understanding of the specific work that is planned during the test period consistent with the utility's business plan. OPG agrees that the regulator should review historical costs, however it would be wrong to simply adopt those costs with no consideration of the differences that exist between the historical period and the test period. On this basis, AMPCO's proposed disallowance should be rejected.

5.4 ISSUE 4.3

Secondary - Are the proposed test period in-service additions for regulated hydroelectric projects (excluding the Niagara Tunnel Project) appropriate?

OPG is seeking approval for previously regulated and newly regulated hydroelectric in-service additions under this Issue 4.3 except for the Niagara Tunnel project, which is addressed under Issues 4.4 and 4.5. The proposed in-service additions are summarized in Table B of OPG's Argument-in-Chief (pp. 20-21). OPG confirms that the amounts included for 2013 are as shown in that table ($46.4M for Previously Regulated and $73.5M for Newly Regulated).

Board staff recommends a reduction in forecast rate base additions for the test period for the previously regulated facilities. This submission is supported by CME and VECC. Board staff's recommendation is based on historical data going back to 2010, and suggests that a $13M disallowance in each year of the test period is appropriate. Board staff also makes the submission on page 14 of its argument that for projects >$5M on average over the 2010-2013 period, forecast in-service amounts have been overstated by about $18M on an annual basis. OPG is unable to verify this figure and it is not clear how it was determined.

While using somewhat different values for the disallowance than Board staff, SEC, AMPCO, LPMA and CCC agreed that some form of disallowance on the basis of historical trends is warranted. OPG disagrees with all such proposed disallowances on the basis of historical trends.

OPG notes that the average in-service addition over-forecast during the 2010-2013 period is only $9.4M when the 2013 under-forecast of $15.9M is included for Newly Regulated Hydroelectric (Ex. L-4.3-17 SEC-030, Table 1).

As set out in evidence (Ex. D1-1-2, section 4.0), historical variances in in-service amounts were due to a number of reasons including project delays, deferrals, cancellations and below-budget completions. OPG recognizes that there have been some variances between historical budget and actual amounts (Ex. D1-1-2, Table 5), but points out that of the four years, two years yielded positive variances and two years yielded negative variances, in a cyclical pattern. This is not unusual since in any given year if actual amounts are materially less than budget, it is often because there was some delay in closing a project to rate base. This will often be followed by a year in which actuals exceed budget. This is precisely the pattern that exists between 2010 and 2013 in previously regulated hydroelectric.

OPG further submits that the magnitude of the 2013 variance is small at $2.1M. In 2013, Previously Regulated Hydroelectric in-service amounts (excluding the Niagara Tunnel) were budgeted at $44.3M and came in at $46.4M. Contrary to Board staff's argument, this indicates an improvement in OPG's forecasting.

In OPG's submission, it would be unfair to disallow significant amounts from hydroelectric rate base based solely on historical averages. And if one is inclined to look at history, then one should give greater weight to 2013, the most recent historic period, where there was a very small difference between forecast and actual in-service amounts.

Further, OPG notes that the major drivers of historical variances cited by Board staff and intervenors relate to projects that are subject to section 6(2)4 of O. Reg. 53/05 (AIC, p. 18) and have therefore been captured in the December 31, 2013 Capacity Refurbishment Variance Account balance OPG proposes to clear in this proceeding (Ex. L-9.1-17 SEC-132, Attachment 1, Table 7, lines 13-15). OPG also notes that the Sir Adam Beck 1 GS Unit 10 Upgrade project, which makes up the vast majority of forecast test period in-service amounts for previously regulated hydroelectric projects greater than $20M (Ex. D1-1-2, Table 1), would similarly be subject to the Capacity Refurbishment Variance Account (AIC, p. 18).

On the strength of all of the evidence that it filed in support of its in-service forecast for the test period, OPG requests approval of the full amounts set out in its evidence (summarized in AIC, pp. 20-21) for regulated hydroelectric in-service additions.

5.5 ISSUE 4.4

Primary - 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?

5.5.1 Introduction

The Niagara Tunnel is the latest addition to Ontario's provincially owned hydroelectric facilities at Niagara Falls. Construction of these facilities began over one hundred years ago and these facilities continue to provide extraordinary value to the people of Ontario. OPG fully expects the Niagara Tunnel to do the same into the next century. Under Issues 4.4 and 4.5, the OEB is being asked to decide on the prudence of $491.4M that OPG spent to complete the Niagara Tunnel. Below are OPG's submissions on the matter.

Given the scope of the issue before the OEB, OPG is frankly surprised at the lack of any evidentiary showing by Board staff and the intervenors. The parties have been aware for many years that the costs of the Niagara Tunnel would exceed the original budget approved by OPG's Board of Directors prior to OEB regulation and that the OEB would conduct a prudence review of these costs once the tunnel went into service.[5] Despite this knowledge, neither Board staff nor a single intervenor chose to provide any evidence on this issue.

Instead of offering the OEB evidence on which to base its decision, the parties have elected to rely on arguments that can be fairly characterized as selective reviews, done with the benefit of hindsight and with little regard for the facts or the standard of reasonableness. These reviews seek to add facts to the evidentiary record for the first time in argument, highlight certain facts to boost their arguments while completely ignoring other contrary facts and assert conclusions that are directly contradicted by the evidence. The parties offer opinion evidence in the guise of argument. None of these opinions were provided by experts in the procurement, design or construction of large and complex tunnels and none of the opinions offered were tested through cross-examination.

The parties all seek a finding of imprudence without pointing to a single action that OPG took or failed to take that was unreasonable based on the information that it knew or should have known at the time. They substitute a standard of perfection for the appropriate reasonableness standard and, with the benefit of hindsight, attempt to second guess the judgments made by OPG management at the time the project was undertaken. Finally, they fail to establish that the OPG actions and decisions that they allege were imprudent had any cost consequences. Their requested disallowances are merely attempts to receive the full benefit of the Niagara Tunnel without paying its full cost.

AMPCO's argument is particularly egregious in regard to offering opinion evidence masquerading as argument. To OPG's knowledge, AMPCO has never procured, designed or

[5] In EB-2010-0008, intervenors, particularly SEC, sought an interim review of the Niagara Tunnel. OPG responded that the appropriate time to review the costs of the Niagara Tunnel would be after it came into service in 2013. The OEB agreed stating: "The Board does not intend to manage the project, nor will it to conduct any sort of intermediate review, or 'mini-hearing'. The appropriate course of action is for the Board to conduct a thorough prudence review at the time that OPG proposes to add the project to rate base." (EB-2010-0008, Decisions with Reasons, pp. 27-28).

constructed a large, complex tunnel through extremely challenging rock conditions. Its counsel certainly was not qualified as an expert in these areas. Yet this lack of experience and expertise has not stopped AMPCO from pronouncing, usually incorrectly, on a variety of very technical matters ranging from rock characteristics to the selection of an appropriate tunnel boring machine ("TBM"). On this latter issue, one of AMPCO's cited sources of expertise on the characteristics and uses of different types of TBMs is material it copied from the website of the Robbins Company, the firm that designed and constructed the TBM used for the Niagara Tunnel (AMPCO argument, p. 26, ft. nt. 77). This material was never introduced into evidence.[6] Does AMPCO really think it is appropriate for the OEB to decide on the prudence of hundreds of millions of dollars in expenditures based on its interpretation of material read on a website?

Most of the parties' opinions were never put to Mr. Roger Ilsley, an acknowledged expert with vast experience. Those that were put to him were uniformly rejected. As is discussed below, SEC and AMPCO have used their arguments to offer opinion evidence on Geotechnical Baseline Reports for Construction – *Suggested Guidelines* ("Suggested GBR Guidelines"), a document that was never filed or put to the witness panel, and which shows up for the first time in the form of a selective one-page excerpt appended to SEC's argument. OPG has addressed this situation by including the full text of the Suggested GBR Guidelines as Appendix A and an Affidavit from Mr. Ilsley discussing the Suggested GBR Guidelines as Appendix B to this Reply Argument.

Against these unsupported assertions and untested conclusions, OPG has presented a comprehensive evidentiary showing. Its initial evidence included a detailed 145-page narrative on the Niagara Tunnel. OPG's initial filing also 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 Niagara Tunnel; AMPCO, for example, asked just two. Any additional project documents that were requested through interrogatories, at the Technical Conference or at the hearing were provided.

[6] While AMPCO did include two pictures from the Robbins Company website in its compendium, the witnesses were never asked about them. In addition, AMPCO's argument cites to descriptions from the website that were not included in its compendium.

OPG adduced evidence from two company witnesses. Mr. Rick Everdell started working on conceptual studies for hydroelectric development, including the Niagara Tunnel, as a staff engineer for Ontario Hydro in 1976 (Ex. L-4.5-17 SEC-035, Attachment 2). He worked on the definition engineering and environmental assessment for the project and rose through positions of increasing responsibility to become the Project Director for the Niagara Tunnel from November 2005 through December 2013. As Project Director he was the OPG employee with direct accountability for the overall execution of the project from the beginning of construction through project closeout. Mr. Everdell retired on December 31, 2013, but OPG asked him to return as a witness so that the OEB panel could hear from the most knowledgeable individual on the history and construction of the Niagara Tunnel.

Dr. Chris Young was Vice President of Hydroelectric and Thermal Project Execution until he retired in 2014 after a long career with OPG and Ontario Hydro (Ex. A1-9-2, p. 60). He was project sponsor for the Niagara Tunnel. As such, he was the OPG senior executive directly responsible for the project and provided project oversight (Ex. D1-2-1, pp. 43-44). In this role he also served as the primary liaison between the project and OPG's senior management team. He provided the OEB panel with insight into the actions and thinking of OPG senior management, particularly as it involved the dispute with Strabag and its resolution (Tr. Vol. 2, pp.133-140).

As noted above, OPG also adduced expert testimony from Mr. Ilsley. Mr. Ilsley has experience in all aspects of tunnel design and construction and has served on at least 16 Dispute Review Boards ("DRB") (Ex. JT1.5, Attachment 1). With over 40 years experience in the tunneling industry, Mr. Ilsley is well qualified to assess OPG's geotechnical investigations for the project and its decision to take its dispute with Strabag to the DRB and renegotiate with Strabag after the DRB decision. His acknowledged expert opinions went unchallenged.

In the sections that follow, OPG refutes the flawed observations, incorrect conclusions, unsupported opinions and hindsight judgments offered by AMPCO, SEC, CME, Board staff, EP, VECC and CCC. As some of these matters are quite technical and the assertions appear in the parties' arguments without proper references to the record, OPG's responsive submissions are, in some instances, necessarily quite detailed. The fact that OPG has taken the time to address these submissions in detail should not be taken to mean that they have any merit. Rather, because of the complexity of this project and the record, OPG wishes to be sure that the OEB has an accurate discussion of the evidence on each matter.

It is paradoxical that the same parties that call the Niagara Tunnel a flawed project, criticize virtually every aspect of the way OPG conducted its design and construction, and seek massive cost disallowances also argue that the Niagara Tunnel should be assigned a service life of 135 to 150 years because of its superior design and construction.

OPG's view overall is that none of the submissions address the uncontroverted evidence before the OEB 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). By itself, this unchallenged fact should cause the OEB to reject the parties' request that the OEB disallow up to $407.4M in project cost (about 83 per cent of cost at issue). The evidence on the record supports only one conclusion. OPG acted reasonably with respect to the procurement, design and construction of the Niagara Tunnel and therefore no disallowance is warranted - the full $491.4M of project cost at issue should be approved.

5.5.2 Organization of the Niagara Tunnel Reply Arguments

OPG's reply begins by discussing the appropriate legal standard for a prudence review of the Niagara Tunnel costs at issue. This discussion includes extensive citation to OEB Decisions, the decisions of other public utilities tribunals and court cases on the appropriate method for conducting a prudence review and the standards to be used in evaluating the prudence of utility actions.

The bulk of OPG's Reply Argument is organized in a section called Reply by Issue under the following headings:

1. Introduction
2. Geotechnical Investigations
3. Design Build Approach

4. Request for Proposal Evaluation
5. Risk Assessment and Mitigation
6. The GBR and the Differing Subsurface Conditions Dispute
7. DRB Process and Findings
8. Contract Renegotiation
9. Fall of Ground
10. Miscellaneous Issues Raised in the Parties' Arguments
11. Disallowance Calculations

All the intervenor arguments related to a particular matter are addressed under that subject. For the most part, the subjects are arranged chronologically beginning with OPG's geotechnical investigations and ending with why the various disallowances recommended by the parties should be rejected.

5.5.3 The Prudence Standard

As explained in OPG's Argument-in-Chief, the issue before the OEB is whether the $491.4M in project cost above the budget originally approved by OPG's Board of Directors prior to OEB regulation was prudently incurred (AIC, p. 22).[7] Under O. Reg. 53/05, if the OEB is satisfied that these costs were prudently incurred, then it must ensure their recovery. This section discusses the appropriate standard for making this determination.

Expenditures are deemed to be prudent in the absence of reasonable grounds to suggest the contrary. The examination of whether expenditures were prudent must be based on the particular circumstances at the time the decision to incur the challenged cost was made. That is so even if, in hindsight, it is apparent that the decision was wrong.[8]

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[7] O.Reg. 53/05 section 6(2)4 requires the OEB to ensure that OPG recovers the capital and non-capital costs of the first $985.2M of Niagara Tunnel Project ("NTP") costs, which were approved by OPG's Board of Directors prior to OEB regulation.

[8] *Violet v. FERC*, 800 F. 2d 280 at p. 282 (1st Cir. 1986), cited with approval in *Enbridge v. Ontario Energy Board* (2005), 75 O.R. (3d) 72 (Div. Ct) at para. 9.

The OEB "has a well-established set of principles" regarding the conduct of a prudence review:

- Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.

- To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.

- Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.

- Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time. (EB-2012-0033, Decision and Order, pp.13-14, quoting Enbridge Gas Distribution, RP-2001-0032, Decision with Reasons, p. 63).

As the Court of Appeal stated in *Enbridge Gas Distribution Inc. v. Ontario Energy Board*:[9]

> The "prudence" inquiry described by the Board has two stages. At the first stage, the decision of Enbridge is presumed to have been made prudently unless those challenging the decision demonstrate reasonable grounds to question the prudence of that decision. At the second stage of the inquiry, reached only if the presumption of prudence is overcome, Enbridge must show that its business decision was reasonable under the circumstances that were known to, or ought to have been known to, Enbridge at the time it made the decision.

The Court went on to say that:

> Hindsight, that is knowledge of facts relevant to the prudence of the business decision gained after the decision was made, [can] not be used at the second stage of the "prudence" inquiry to determine the ultimate question of whether the decision was prudent. Those facts [can], however be taken into consideration at the first stage in determining whether the presumption of prudence had been rebutted.

OPG does not rest its submissions on the presumption of prudence. It has presented evidence that fully supports a finding of prudence under the appropriate standard – were the OPG decisions that gave rise to the costs at issue reasonable based on the information that was known or ought to have been known at the time these decisions were taken. In contrast, the

[9] Enbridge Gas Distribution Inc. v. Ontario Energy Board (2005), 41 Admin. L.R. (4th) 69 at paras. 11-12.

parties seeking to disallow hundreds of millions of dollars in legitimate project costs would have the OEB apply hindsight to second guess the reasonable judgment made by OPG's management and Board of Directors.

A recent article in Public Utilities Fortnightly entitled, "Cost Recovery for Pre-Approved Projects" (June 2013)[10] provides a concise discussion of the appropriate test for prudence as applied over the years by U.S. utility regulators:

> The majority of jurisdictions that conduct prudence reviews have adopted a common test for prudence—the reasonableness of decisions based on all the circumstances known at the time. The Federal Energy Regulatory Commission, for example, assesses whether the costs at issue result from decisions that "reasonable utility management (or that of another jurisdictional entity) would have made, in good faith, under the same circumstances, at the relevant point in time." The Missouri Public Service Commission applies a similar analysis:
>
>> The company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problem prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company…In accepting a reasonable care standard, the Commission does not adopt a standard of perfection. Perfection relies on hindsight. Under a reasonableness standard relevant factors to consider are the manner and timeliness in which problems were recognized and addressed. Perfection would require a trouble-free project. (citing to Union Electric, 1985 Mo. PSC LEXIS 54, *28 (quoting Consolidated Edison Co. of New York, 45 PUR4th 331 (1982) [internal quotations omitted]).
>
> Importantly, as the Missouri commission noted, the analysis must eschew hindsight and a commission may not substitute its judgment for that of the utility. (Case citations omitted)

The Ontario Court of Appeal has applied a similar approach in assessing the actions of business directors. In *Pente Investment Management Ltd. v. Schneider Corp. (1998)*, 42 O.R. (3d) 177 (Ont. C.A.), Weiler J.A. stated, at p. 192:

[10] *Public Utilities Fortnightly* (June 2013), "Cost Recovery for Pre-Approved Projects." p.1, by David Cousineau and Patricia Galloway located at: http://www.fortnightly.com/fortnightly/2013/06/cost-recovery-pre-approved-projects?authkey=3b904a5182815df49fa45cf2f6a98b31386691a414e431a5466ec1c65ab5ef1e.

> The law as it has evolved in Ontario and Delaware has the common requirements that the court must be satisfied that the directors have acted reasonably and fairly. <u>The court looks to see that the directors made a reasonable decision not a perfect decision. Provided the decision taken is within a range of reasonableness, the court ought not to substitute its opinion for that of the board even though subsequent events may have cast doubt on the board's determ</u>ination. As long as the directors have selected one of several reasonable alternatives, deference is accorded to the board's decision [references omitted]. This formulation of deference to the decision of the Board is known as the "business judgment rule". <u>The fact that alternative transactions were rejected by the directors is irrelevant unless it can be shown that a particular alternative was definitely available and clearly more beneficial to the company than the chosen transaction [reference omitted]</u>." (<u>*emphasis added*</u>).

As OPG has demonstrated throughout this Application, when viewed against this standard, the decisions which led to the additional costs to complete the Niagara Tunnel were prudent and, therefore, the OEB should allow recovery of the resulting costs. As will be discussed in the sections that follow, for every single decision that the parties challenge, OPG did a thorough analysis and sought the advice of international experts prior to taking action.

In making their submissions, intervenors and Board staff do not apply the recognized prudence standard. They have second guessed OPG's decisions based on incomplete facts, incorrect analyses and hindsight. OPG submits that, as shown above, is not the standard for prudence reviews. The OEB does not need to find that every decision OPG made with respect to the Niagara Tunnel was perfect. Rather, the OEB must determine whether the decisions OPG made were reasonable under the circumstances that existed at the time and only disallow costs that are found to be unreasonable on this basis.

5.5.4 Reply by Issue

5.5.4.1 Introduction

The parties offer a laundry list of theories to justify proposed disallowances that range from $50M (EP argument, para. 32) to $407.4M (AMPCO argument, para. 139). As is shown in the sections below, not a single one of the parties' recommended disallowances has any merit. The deficiencies claimed have no factual basis in the evidentiary record and many are just wrong. All of them are based on a "hindsight" review of reasonable decisions made years ago by OPG – exactly what the OEB should not do in a prudence review. OPG submits that if the OEB reviews the evidence on the project using its previously articulated prudence standard, it can reach only one conclusion – OPG's expenditures on the Niagara Tunnel were prudent and the entire amount subject to review should be approved

5.5.4.2 Geotechnical Investigations

AMPCO, SEC and Board staff all claim to have found flaws with the extensive geological testing done by OPG (AMPCO argument, para. 78; SEC argument, paras. 4.4.8 through 4.4.10; Board staff argument, pp. 22-23). These claims are not based on any expert evaluation of the sampling and testing OPG did over more than thirteen years. Mr. Ilsley, the only expert that testified, stated unequivocally that the sampling and testing met or exceeded the professional standards applicable to the project (Ex. F5-6-1, p. 3). Instead, these claims are based on the parties unsupported assertions that the testing was completed too long before the project and that the testing was rushed.

In an effort to mitigate a major risk associated with this project, that the subsurface conditions actually encountered would be worse than anticipated, OPG engaged world recognized experts to perform extensive geotechnical investigations.[11] These efforts are summarized in Appendix B to OPG's evidence (Ex. D1-2-1, Appendix B, pp. 136-140). As OPG has already discussed this material in its Argument-in-Chief (pp. 24-26), it will not repeat that discussion here. The sampling and testing done are also discussed in detail in Mr. Ilsley's Report (Ex. F5-6-1, pp. 3-20).

The evidentiary record establishes that OPG's efforts to identify the geotechnical risks associated with this project were appropriate as were its efforts to mitigate these risks. Ultimately, as Board staff concedes, there are risks inherent in tunneling that cannot be eliminated no matter how much testing is done (Board staff argument, p. 22).

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[11] For example, the model for rock mass strength incorporated in the Design Build Agreement is known as the Hoek-Brown Failure Criterion (see e.g., Ex. D1-2-1, Attachment 6, PDF pp. 256-260 and 1739-1740). Dr. Hoek was one of the experts that OPG engaged in the geotechnical investigations for the Niagara Tunnel (Ex. D1-2-1, p. 139).

In trying to make the claim that OPG's geotechnical investigations were in some way inadequate, Board staff states: "When questioned by a Board panel member at the oral hearing, OPG's expert witness was unable to categorically state whether the testing protocol had changed since 1993, the date of the last testing completed by OPG." (Board staff argument, p. 22). SEC makes a similar claim (SEC argument, para. 4.4.10). Both Board staff and SEC misstate the complete span of the geotechnical work. In actuality, while sampling was completed in 1993, as noted in Mr. Ilsley's Report: "Additional laboratory testing was done from 1994 to 1996 on samples of core from the Adit and a final draft report [Report NAW130-P4D-10120-007-00] issued in February 1997." (Ex. F5-6-1, p. 5).

OPG submits that Mr. Ilsley's testimony under cross-examination reaches a clear conclusion that is directly contrary to Board staff and SEC claims that the testing was outdated. As Mr. Ilsley stated, the electronics to record and present results improved, but the tests themselves are unchanged (Tr. Vol. 12, pp. 63-65):

> MR. RUBENSTEIN: But my question is: In your view, there has been no technological or investigative innovation since 1993 that would have given more precise information?
>
> MR. ILSLEY: I think the tests that were done, the field testing was accomplished by Dr. Haimson -- the stress test in particular -- who is a recognized expert in that field. He did that work originally and it still stands. And it was good then, it was good for the -- his techniques are the same.
>
> MR. RUBENSTEIN: But if, say -- let me ask it this way. If you decided to start doing, say, the geotechnical investigation much -- you know, in 2000, 2001, closer to the point of preparing the second geotechnical data report for the preparation of the geotechnical baseline report, would there have been new technological or investigative tools that would have been -- that would have existed for Hatch or whoever was preparing those documents, that would have given you a better sense of what the subsurface conditions were?
>
> MR. ILSLEY: No, I don't believe so. I am currently involved in an investigation for a tunnel where we are using the most up-to-date field testing equipment -- not to say that the ASTMs are not -- with respect to testing, are not revised.
>
> MS. HARE: I'm sorry. ASTMs, could you say --
>
> MR. ILSLEY: The American Society of Testing Methods, American Society -- yeah, they publish the testing standards, and they are revised on occasion.

> For just a quick example, they have now made it mandatory that the test length of the unconfined compression test must be twice the diameter. It used to be they would allow you to adjust if you had a sample which was at a ratio less than 2. You could -- there was a formula for adjusting.
>
> Things like that which are relatively minor, but I don't think would have affected the overall documentation that was presented in the GBR, the geotechnical baseline report.
>
> MR. RUBENSTEIN: So if I can summarize, in your opinion, the standards have not changed much since 1993 when the original -- the latest possible point where samples were being taken out and analyzed?
>
> MR. ILSLEY: That's correct. Wire line, for instance, core recovery, the technique of triple-tube core barrels using wire line recovery to enhance core quality, all of those things were being used since the middle '80s. I am experienced in that work, and that was used on the project. So the stress measurement, in situ stress, the same technique he uses today, Haimson.
>
> The electronics I am sure has changed, in terms of recording; you know, more compact. But the basic technique itself and the purpose of it has not changed.
>
> MR. RUBENSTEIN: So putting aside the standards, is there actually -- recognizing that what's available is not the same thing necessarily as what are the defined standards, out there in the marketplace that are people that are doing geotechnical investigations, can they or are they using better investigative techniques than what was used in 1993? Or at least in 2004, let's say, were they using...
>
> MR. ILSLEY: No I don't perceive that. There is one perhaps area, which is called acoustic televiewer technology, which has been developing over that period, and I am not sure -- considering 2003 versus '93, I think that probably would have been improved potentially over that time because of electronics, the packaging of the instrumentation.

The suggestions that the testing was rushed or limited are also wrong. As shown above, the testing took place over almost 14 years; that is not rushed. In total, Ontario Hydro spent some $57M on the definition phase activities for the original Niagara River Hydroelectric Development project, which included the geotechnical assessments at issue here (Ex. D1-2-1, Attachment 5, p. 2). This amount was written off prior to OPG's formation and is not included in the amounts that OPG now seeks to recover (See Section 5.5.4.10 (Miscellaneous Issues Raised in the Parties' Arguments) below).

Perhaps the best evidence of the adequacy of the geotechnical investigations is the fact OPG conducted two successful solicitations for tunnel construction based on this data. In both cases the experienced tunnelling contractors who responded submitted binding bids worth hundreds of millions of dollars in reliance on this geotechnical work and without any suggestion that more information was required.

In 1998, OPG issued a tender for a design-build contractor to construct a third Niagara tunnel (Ex. D1-2-1, pp. 9-10). OPG reviewed the bids and selected a successful contractor, but decided to defer the project prior to contract award (*Ibid*.). All of the bids received were based on the geotechnical testing done between 1983 and 1997 and OPG was not asked to provide additional geotechnical information.

Again in 2005, three experienced tunneling consortia were willing to prepare binding bids, each worth more than half a billion dollars, on the basis of this geotechnical work. None of these expert firms indicated that they needed more information about the geology of the site in order to prepare their bids, each of which included a preliminary tunnel design based on the anticipated rock characteristics, and none undertook any additional geotechnical investigations prior to submitting their bids.[12]

All of the expert evidence points to a single conclusion – the geotechnical studies that OPG relied on were undertaken by experts and were appropriate; more testing was not done because it was not necessary.

5.5.4.3 Design Build Approach

EP argues that OPG was imprudent in selecting a Design-Build approach for the Niagara Tunnel construction rather than a Design-Bid-Build because the Design-Build approach gave Strabag proprietary knowledge of the project that prevented OPG from terminating Strabag after the DRB findings were received (EP argument, paras. 15-32). As a result, EP

[12] The only additional geotechnical work was performed subsequent to contract award. Strabag drilled seven additional boreholes in the vicinity of the buried St. Davids Gorge to confirm the viability of its proposed tunnel alignment under the Gorge because its proposed alignment was higher than the concept alignment contained in the request for proposals (Ex. D1-2-1, p. 137).

recommends a $50M disallowance. AMPCO argues that, “the design-build contract proposed by OPG as opposed to a design-bid-build contract did not allow for sufficient analysis of and compensation for risk” (AMPCO argument, paras. 33, 49-55). Both these arguments are wrong on the facts and ignore the documented benefits OPG received by choosing a Design-Build contract.

OPG’s evidence explains why it used a Design-Build approach:

> OPG selected the Design-Build approach for the NTP as the preferred risk management strategy to:
>
> - minimize project duration;
> - capture tunnel contractor experience and innovations;
> - fully integrate construction methods and constructability into the design;
> - appropriately allocate project risks; and
> - obtain as much upfront price certainty as possible.
>
> The Design-Build approach also provided OPG with single-point accountability for project execution because the Design-Build team provides all required services including coordination, design, permitting, procurement and construction. OPG had previously selected the Design-Build approach in the 1998 - 1999 RFP process for design and construction of the Niagara Tunnel. (Ex. D1-2-1, pp. 22-23).

EP claims that OPG had no choice but to continue with Strabag rather than hire a new contractor because the use of Design-Build contracting model meant that the tunnel was built using a proprietary design owned by Strabag (EP argument, paras. 19 and 22). The premise of this argument is wrong. Section 2.16 of the Design-Build Agreement entitled “Intellectual Property” grants OPG ownership of the tunnel design which include, “drawings (including as built drawings), inventions, ideas, processes, discoveries, techniques, diagrams, illustrations, schedules, performance charts, brochures, specifications, plans, photographs” etcetera (Ex. D1-2-1, Attachment 6, p. 46 [PDF p. 60]). Thus, contrary to EP’s supposition, OPG could have terminated Strabag and continued the project with another contractor using Strabag’s design, but chose not to for the reasons explained in Section 5.5.4.8 below.

AMPCO, while citing the many benefits of Design-Build contracting for large complex construction projects, nevertheless argues that the use a Design-Build approach here led to misunderstandings between OPG and Strabag that were reflected in the geotechnical baseline report ("GBR") (AMPCO Argument, paras. 52-55). OPG submits that the evidence establishes that the opposite is true. Because OPG and Strabag worked together to develop the GBR included in the contract (GBR-C), the document reflected their mutual understanding of the anticipated rock conditions and the interaction between the expected rock conditions and the means and methods of construction. The Suggested GBR Guidelines (see Section 5.5.4.6, below), describe this advantage as follows: "GBR for Construction (GBR-C) will reflect the physical baselines established by the Owner and its design team (as augmented by any supplemental exploration) and as clarified or modified by the [Design-Build] team, and the behavioral baselines described by the [Design-Build] team consistent with its design approach, equipment, means, and methods." (Appendix A, p. 40).

5.5.4.4 Request for Proposal Evaluation

AMPCO disagrees with the weighting that OPG used in evaluating the responses to its request for proposals (AMPCO argument, paras. 53-60). OPG provided a detailed discussion of the process used to evaluate the responses and select the successful firm (Ex. D1-2-1, pp. 29-33). This process included separate cross-functional teams to evaluate the commercial and technical aspects of the responses, with each team consisting of a mix of OPG personnel and external experts (Ex. D1-2-1, pp. 29-30). The proposals were initially evaluated and then after OPG conducted negotiations with the two leading proponents, they were revaluated (Ex. D1-2-1, pp. 30-33). The work of the evaluation teams was overseen by a Steering Committee consisting of senior OPG personnel and OPG's Owner's Representative Project Manager (Ex. D1-2-1, pp. 30-31). OPG submits that the process used was well-designed, thorough, fair and independent.

AMPCO argues that the weighting given to the proponent's response to the GBR should have been equal to that given to the proponent's design and construction approach (AMPCO argument, para. 59). Even in hindsight this is wrong. The response to the GBR set out the proponent's opening position on the appropriate geotechnical baseline to be used for the project (GBR-B) with the full expectation that the final baseline (GBR-C) would be negotiated and mutually agreed upon, as happened here. In contrast, the design and construction approach sets out how the proponent is proposing to design and build a tunnel through difficult rock conditions that would last 90 years. On its face, the basic design and construction approach is one of the key determinants of the project's ultimate success and OPG appropriately accorded it a weight that reflected this fact.

5.5.4.5 Risk Identification and Mitigation

Board staff, SEC and AMPCO suggest that the risk identification and mitigation measures adopted by OPG were deficient (Board staff argument, pp. 20-23; SEC argument, paras. 4.4.6 through 4.4.7; AMPCO argument, paras. 64-77). These suggestions have no basis in fact, and as will be shown below, the parties appear not to understand the risks identified and the mitigation measures available to address these risks.

OPG's risk identification and mitigation assessment was led initially by an external expert consultant (URS Corporation) "within an overall risk management framework provided by the Code of Practice for Risk Management of Tunnel Works."[13] (Ex. D1-2-1, p. 26). This effort identified the risks associated with the project based on input from OPG staff working on the project and expert tunnelling input from Hatch Mott MacDonald ("Hatch") and quantified these risks. Based on this information, URS prepared detailed qualitative and quantitative risk assessment reports that were included with OPG's pre-filed evidence (Ex. D1-2-1, Attachments 1 and 3).

The URS Qualitative Risk Assessment described the work undertaken as follows:

> The URS scope of work includes identification, assessment and presentation of hazards and risks associated with the Project in a way that provides a clear method of risk management for the Project going forward. The URS approach takes standard tools of expert solicitation, including one-on-one interviews and group workshops and combines these methods within an overall risk management framework provided by the Code of Practice for Risk Management of Tunnel Works (the Code). (Ex. D1-2-1, Attachment 1, p. 1-1).

[13] "This code was issued by The International Tunnelling Insurance Group 'to promote and secure best practice for the minimization and management of risks associated with the design and construction of tunnels.' It can be found at http://www.imia.com/downloads/external_papers/EP24_2006.pdf." (Ex. D1-2-1, p. 26).

An examination of these reports shows that they accurately described the risks faced by the project and the available options for mitigating these risks. The quantitative report attempted to quantify the risk and schedule consequences of the significant risks identified in the qualitative report and estimate a range of their severity using probabilistic simulations. This is described in the URS Quantitative Report as follows:

> The quantitative analysis followed the qualitative analysis. At two of the project's Expert Panel workshops, panel members were asked to quantify risk consequences in terms of cost and schedule delay impacts. Only costs to OPG were considered. (i.e., Where the costs would fall on the contractor, they were not included in the analysis. In some cases this could cause contractor bankruptcy, which is covered as a separate hazard.)
>
> …
>
> The quantitative analysis used a "Chance Method" Monte Carlo methodology with 5000 trials. The analysis used the Crystal Ball software package, which operates within the Microsoft Excel platform. Crystal Ball is commonly used in engineering, financial and other disciplines for risk analysis. A similar software package called "@Risk" is in regular use by OPG for this purpose. Cost and schedule were run simultaneously:
>
> - for each trial an event occurred or did not occur, in proportion to its probability
>
> - if the event occurred during the trial, both its cost and its schedule delays were determined randomly from the log normal distribution describing them. The cost amount was added to the total cost, and the delay amount was added to the total delay. (Ex. D1-2-1, Attachment 3, pp. 5, 7).

Once OPG selected Strabag as the tunnel contractor, OPG updated the risk assessment to identify and quantify the risks associated with Strabag's specific proposal (Ex. D1-2-1, Attachment 4). Again this update was conducted by a mix of OPG personnel and external experts from Hatch, as well Torys LLP (Ex. D1-2-1, Attachment 4, p. 1). A review of OPG's risk assessment shows that it accurately identified the risks associated with the project. The single highest cost risk that OPG identified was an unfavourable decision from the DRB (Ex. D1-2-1, Attachment 4, p. 4). In fact, four of the top five cost risks were the risks that actually materialized (*Ibid.*).

Using statistical techniques (Monte Carlo simulations, as described above), OPG developed a probability distribution for the cost and schedule consequences associated with the identified risks and used these to create the initial cost and schedule contingencies and associated confidence levels for the project.[14] 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.

AMPCO bases its entire argument on the alleged inadequacy of OPG's risk identification on a misunderstanding of the single risk that OPG ranked highly, but that did not materialize: "[Differing Subsurface Conditions ("DSC")] claim due to rock strength." (Ex. D1-2-1, Attachment 4, p. 4). It states: "AMPCO submits it appears that a risk of lower rock strength or weaker rock strength was not identified by the expert panel as a hazard cause; it was not included in the risk matrix. Only the risk of higher rock strength was identified as a hazard and included in the top two contingency risks for the project." (AMPCO argument, para. 72).

AMPCO's argument confuses intact rock strength and rock mass strength. As OPG's Risk Register makes clear, the concern associated with a "DSC claim due to rock strength" was related to "slower penetration by TBM and faster deterioration of cutters" (Ex. D1-2-1, Attachment 4, p. 9, Reference number 47). In other words, OPG identified the risk that the intact rock strength would be greater than anticipated and this would cause the tunnel to take longer to bore and cost more because of the need to frequently replace the TBM disc cutters as they wore out.

The risk that AMPCO characterizes as "weaker rock" and claims that OPG failed to indentify is actually the risk that the rock mass strength would be weaker than anticipated. A review of OPG's Risk Register demonstrates that OPG did not miss this risk as AMPCO claims. To the contrary, it is covered by two of the major risks identified: "DSC claim due to slabbing overbreak (TBM progress)" and "DSC claim due to different rock support requirements" (Ex. D1-2-1, Attachment 4, p. 4). The Risk Register in OPG's Quantitative Assessment explains the

[14] As explained in the OPG's risk update, the Monte Carlo simulations "combined probabilities and consequences by aggregating 10,000 separate, randomly generated trials to generate probability distributions of possible outcomes." (Ex. D1-2-1, Attachment 4, p. 2).

“slabbing overbreak” risk as “Encountering Ground Conditions more adverse than advertised in Contract”, and the “different rock support” risk as “Rock support requirements significantly different from baseline” (Ex. D1-2-1, Attachment 4, p. 10, Reference numbers 61-62).

Both of these risks materialized due to rock mass strength being weaker than expected. “Slabbing overbreak” did occur in the Queenston formation, but to a degree more severe than anticipated (affecting a greater depth of rock above the tunnel arch). This ultimately led to the need for rock support requirements that significantly differed from the baseline.

Given that OPG did identify and include the risk AMPCO characterizes as “weaker rock”, AMPCO’s argument is simply wrong. Moreover, it illustrates why the OEB cannot rely on “expert” submissions of counsel that appear for the first time in argument and were never put to the witnesses.

Board staff suggests that OPG should have done more to mitigate the risks of the project, but fails to suggest a single concrete action that OPG should have taken, but did not, that would have actually mitigated the conditions ultimately encountered by the project.

From the beginning of the project and throughout its duration, OPG continued to consistently work to identify and mitigate risk. URS prepared an initial high-level risk register, which collected and organized the risks identified (Ex. D1-2-1, p. 26). The risk register also indicated the party responsible for control and management of each risk, as well as contingency plans and measures for risk mitigation (*Ibid.*). This risk register was updated throughout the project and formed an essential part of OPG’s Risk Management Plan, which was also periodically updated (Ex. J1.1). This approach has come to be best practice for major construction projects (Tr. Vol. 2, p. 130).

OPG sought to mitigate the major risk of the project primarily through the terms of the Design Build Agreement (“DBA”), including a GBR developed jointly with Strabag, the DRB mechanism, and through the use of contingencies. While the DBA assigned many of the project’s risks to Strabag through the use of a fixed price and liquidated damages, ultimately, the ground conditions and the resulting risk of DSC rested with OPG as the project owner (Tr. Vol. 1, pp. 60-61).

Board staff does not explain how the risk identification and mitigation process was deficient at the time it was undertaken. Nor does Board staff claim that the contingencies OPG originally included failed to accurately reflect the results of its risk analysis. In essence, Board staff's claim is that because in hindsight it is clear that the rock conditions actually encountered were substantially worse than OPG, Strabag, and any of the other numerous experts who reviewed the geotechnical data anticipated, and, as a result, the tunnel cost more to construct, OPG must have acted imprudently. This is precisely the type of conclusory hindsight review that the OEB should reject.

5.5.4.6 The GBR and the DSC Dispute

This section responds to the arguments by AMPCO, Board Staff, SEC and CME about the GBR.

<u>AMPCO's Assessment of the GBR is Flawed and Should be Ignored</u>

AMPCO's argument contains pages and pages providing detailed, though incomplete and often incorrect, descriptions of the alleged defects in GBR A and how those defects could have misled Strabag in its design and construction of the tunnel (AMPCO argument, paras. 78 to 108). Despite AMPCO's repeated reference to GBR A, however, the citations it provides and the pages it has inserted into the middle of its argument are from GBR C (see Ex. D1-2-1, Attachment 6, Appendix 5.4 [PDF pp. 1719-1806]).

Given that GBR A is not part of the evidentiary record, why would AMPCO continue to refer exclusively to it, and not refer to GBR C, which forms part of the DBA and was included with OPG's pre-filed evidence?[15] The explanation is simple. GBR A was drafted initially by Hatch on OPG's behalf and included with the request for proposal for the Niagara Tunnel. Thus, AMPCO

[15] There is an easy explanation for why GBR A is not part of the record. AMPCO asked for and was provided with GBR B, which was Stabag's response to GBR A, but it never asked for GBR A (Ex. L-4.4-2 AMPCO-016, Attachment 1).

wishes to point to GBR A rather than the jointly negotiated and agreed GBR C, so as to establish that the perceived difficulties with the GBR were all OPG's fault. It says as much in its argument: "OPG was responsible for the GBR." (AMPCO argument, para. 94).

The problem with this approach is that once GBR C was jointly created by OPG and Strabag, it became the baseline for the Design Build Agreement. What GBR A said or failed to say is of no consequence because GBR A was superseded by GBR C. That is why the DRB determined that any difficulties with the language in the GBR were the joint responsibility of the parties (see Section 5.5.4.7).

AMPCO's argument has a section entitled "AMPCO Assessment of GBR." (AMPCO argument, paras. 98-105). Under the Amended Design Build Agreement ("ADBA"), GBR C was deleted and replaced by a Geotechnical Report. What AMPCO has done in this section of its argument is take selected quotes from GBR C (though as explained above it presents them as if they are from GBR A) and compare them to similar sections from the Geotechnical Report in the ADBA.[16] Not surprisingly, the Geotechnical Report contains better descriptions of the rock conditions in the Queenston formation – it was written while the tunnel was being bored through the Queenston formation and includes observations made while tunneling.[17] In addition, the Geotechnical Report was not prepared as a baseline.

Below are some examples of the assertions that AMPCO makes that demonstrate it is unqualified to evaluate the GBR. Some of these assertions are wrong on the facts, others are incomplete and misleading. Of course, most of these assertions were never offered on the record and never tested through cross-examination. OPG submits that these serve as another compelling reminder that untested assertions by counsel in argument are not evidence. AMPCO appears to believe that by selectively reading the evidence it has become qualified to

[16] The Geotechnical Report was prepared during the negotiation of the ADBA (Ex. D1-2-1, Attachment 9, Appendix 5.4 – Geotechnical Report [PDF pp. 2036-2116]). The ADBA was a target cost contract and as such did not include a GBR because any changes in subsurface conditions encountered that required changes in construction cost or schedule would be addressed through Project Change Directives and ultimately reflected as Amendments to the ADBA (Ex. D1-2-1, p. 123).

[17] The Geotechnical Report states: "This Geotechnical Report (GR) summarizes information contained in the Geotechnical Data Report (GDR). This GR also contains data obtained during construction of the Niagara Tunnel Facility Project in the period prior to execution of the Agreement." (***emphasis added***) (Ex. D1-2-1, Attachment 9, Appendix 5.4 – Geotechnical Report, p. 5 [PDF p. 2041]).

assess the GBR and offer opinions on the reasonableness of OPG's actions in preparing and negotiating it. Since AMPCO did not submit any evidence, it is based on these opinions alone that it asks the OEB to make findings of imprudence and disallow hundreds of millions of dollars in legitimate project costs. OPG submits that AMPCO's evaluation of the GBR should be ignored.

- AMPCO claims: "Slickenslided: GBR-A prepared solely by OPG did not describe rock joint surfaces as being "slickensided in some instances." (AMPCO argument, para. 98). This claim is untrue. As discussed above, AMPCO's citation is not to GBR A, but rather to the jointly negotiated GBR C, which presents the parties mutual and agreed understanding of the rock conditions.[18] Furthermore, in direct contradiction of AMPCO's claim, GBR C contains the following statements in discussing the characteristics of the Queenston formation: "Division Q10 commonly shows weathered surfaces within which <u>numerous slickensided partings occur</u>.... <u>Some zones contain slickensided compaction</u> features." (<u>*emphasis added*</u>) (Ex. D1-2-1, Attachment 6, Schedule 5.4 – Geotechnical Baseline Report, p. 44 [PDF p. 1763]).[19]

- AMPCO claims: "Massive: *GBR-A prepared solely by OPG described Queenston Formation as being Massive to Blocky*." (AMPCO argument, para. 98). For many of the same reasons discussed in the previous bullet, this claim is inaccurate. Here is what GBR C actually said about construction in the Queenston Shale: "The Queenston Formation is <u>generally</u> massive. However, construction of the tunnel in the Queenston Formation will have to allow for high in situ stresses and variations in rock mass strength." (Ex. D1-2-1, Attachment 6, Appendix 5.4 – Geotechnical Baseline Report, p. 35 [PDF p. 1754]). All AMPCO's citation to the description in the Geotechnical Report

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[18] AMPCO cites to "KT1.1 Pages 69-70" (AMPCO argument, p. 22, ft. nt. 66). Since there is no exhibit KT1.1, OPG assumes that AMPCO meant to cite to its compendium, Ex. K1.1. Page 69 of Ex. K1.1 is an excerpt from GBR C (Ex. D1-2-1, Attachment 5, Appendix 5.4 – Geotechnical Baseline Report, p. 11 [PDF p. 1730]). Page 70 in the AMPCO compendium is an excerpt from the Geotechnical Report in the Amended Design Build agreement (Ex. D1-2-1, Attachment 9, Appendix 5.4 – Geotechnical Report, p. 10 [PDF p. 2046]).

[19] This page from the GBR is actually included as page 72 of Ex. K1.1, the AMPCO Compendium. If AMPCO had taken the time to read the whole page, rather than a single highlighted line, it would have known that the claim it was making was wrong.

shows is that after tunneling in the Queenston formation for about a year and a half, the parties were better able to describe the rock conditions found there.

- AMPCO claims: "Rock of fresh and of excellent quality: GBR-A prepared solely by OPG describes bedrock at the St. David's Gorge below a certain depth as "generally fresh and of excellent quality". Contractor was mislead by this statement; the joint surfaces were more slickensided in some instances." (AMPCO argument, para. 98). A review of the DRB discussion of conditions under the buried St. Davids Gorge confirms that OPG agreed to Strabag's proposal to raise the level of the tunnel under the buried St. Davids Gorge only in exchange for inclusion of section 5.5 (e) in the DBA, which states that there can be no DSC for conditions in vicinity of the gorge (Ex. D1-2-1, Attachment 7, p. 10). On this basis, the DRB rejected Strabag's contention that conditions in the vicinity of the gorge supported a finding of DSC. Rather than being an example of how GBR A misled Strabag as AMPCO contends, it is another example of the parties negotiating baseline conditions based on their agreed understanding of the rock conditions.

- AMPCO claims: "Incorrect Stress Regimes for Design Purposes: GBR-A incorrectly described the tunnel at Station 0+000 to 1+700 in Queenston Formation (subunits Q2 to Q 10) as 'tunnel is nearly parallel to minimum stress' when it should have been 'tunnel is nearly parallel to maximum stresses'. The distinction between minimum and maximum is important and misleading to contractor because the direction of the in situ stresses aligned with the tunnel can cause failure to propagate." (AMPCO argument, para. 98). AMPCO has correctly identified a non-controversial typographical error that OPG and Strabag had recognized, and corrected five years ago when the ADBA was negotiated. As Mr. Ilsley pointed out at the hearings, the drawings included in GBR C, namely, Figure 6.15 "Stress Orientations in Queenston Formation" (Ex. D1-2-1, Attachment 6, Schedule 5.4 – Geotechnical Baseline Report, Figure 6.15 [PDF p. 1803]), made clear that the tunnel would be parallel to maximum stresses (Tr. Vol. 1, pp. 129-131). No one was misled by the typographical error.

AMPCO speculates that statements in the GBR that identified as more consistent with the use of a shielded TBM may have misled Strabag about the selection of design, means and methods (AMPCO argument, para. 95). AMPCO apparently missed the following footnote in OPG's evidence:

> [23] During the 1998 bidding process, all of the qualified contractors had proposed a closed TBM with a precast concrete segmental lining. For this reason, the 2005 Invitation to Submit Design/Build Proposal anticipated a closed TBM with a one-pass concrete liner. Unlike the other respondents, however, Strabag considered both open and closed TBMs before arriving at their proposed approach of using an open TBM with a cast-in-place concrete lining as the most effective method of meeting the requirements of the project including the 90 year life, impermeability and target flow. (*emphasis added*) (Ex. D1-2-1, p. 67, ft. nt. 23; see also Tr. Vol. 1, p. 117).

As this evidence makes clear, Strabag was in no way misled. At the time of its proposal, Strabag considered both types of TBM and explicitly decided to reject a shielded TBM and propose an open TBM because of the advantages associated with its cast-in-place liner that included an impermeable waterproof membrane (Tr. Vol. 1, pp. 117-120). The design and the means and methods Strabag ultimately proposed were those it believed to be appropriate for an open TBM.

AMPCO points to the fact that Strabag made modifications to the TBM as evidence that it was misled by the GBR (AMPCO argument, paras. 115-117). OPG does not dispute that Strabag modified both the TBM and the rock support to address the actual subsurface conditions being encountered and allow the tunneling to proceed safely. In fact, OPG's evidence discusses these changes in some detail (Ex. D1-2-1, pp. 70-72). All these changes evidence, however, is that the rock conditions actually encountered were more adverse than both OPG and Strabag reasonably expected based on the geotechnical data and analysis.

SEC and AMPCO Misuse and Mischaracterize the Suggested GBR Guidelines

SEC and AMPCO both rely on a single page excerpt of the Suggested GBR Guidelines to support their claims that the GBR was defective (SEC argument, paras. 4.4.16 through 4.4.18; AMPCO argument, para. 98). Prior to its appearance as an Appendix to the SEC argument, this document was never entered into evidence. As the Suggested GBR Guidelines are discussed explicitly in the DRB Report, the parties should have been aware of them soon after OPG filed its Application, because the DRB Report was provided with the Application (Ex. D1-2-1, Attachment 7). Yet, no party requested the Suggested GBR Guidelines during interrogatories. When Mr. Ilsley stated that the Suggested GBR Guidelines were one of the documents he considered in forming his opinion during the hearing, SEC did not ask for them as an undertaking.

Based on a single page, both SEC and AMPCO offer opinions on what the Suggested GBR Guidelines say and how they should be used. To allow full consideration of this document, OPG has attached a complete copy of it as Appendix A to this argument. In addition, OPG has attached as Appendix B, an affidavit from Mr. Ilsley, which addresses the opinions offered by SEC and AMPCO in argument, since these opinions were never put to Mr. Ilsley during the hearing. As noted on page ix of the Suggested GBR Guidelines, Mr. Ilsley was a member of the Technical Team that contributed to the first edition of the Suggested GBR Guidelines (Appendix A, p. ix).

The Suggested GBR Guidelines begin by discussing how they are and are not to be used:

> Though the information contained in this document represents a consensus opinion within the industry on a range of issues, the opinions of practitioners vary on a number of topics. <u>The suggestions provided in this document are therefore intended as guidelines, and should not be interpreted as rules, requirements, or standards of care</u>. (<u>*emphasis added*</u>) (Appendix A, p. 1).

SEC and AMPCO fail to mention this clear direction that the Suggested GBR Guidelines are not to be used as a "requirements or standards of care" because that is exactly how these parties have asked the OEB to use the document.

SEC and AMPCO also do not mention that the Suggested GBR Guidelines contains a chapter discussing how GBRs are to be developed in the context of Design-Build contracts that includes a discussion of the Niagara Tunnel (Appendix A, pp. 38-42). The connection between the Suggested GBR Guidelines and the Niagara Tunnel is not surprising. Two members of the Technical Committee that contributed to the second edition, Peter Douglass and P.E. "Joe" Sperry, were members of the DRB for the Niagara Tunnel (Appendix A, p. ix). Moreover the second edition of the Suggested GBR Guidelines was being developed at the same time as the DRB was meeting on the Niagara Tunnel.[20] As an example of this close connection, the TBM shown on the cover page of the Suggested GBR Guidelines is actually "Big Becky", the TBM used to construct the Niagara Tunnel (Appendix A, Cover and Copyright pages).

Section 8.3 of the Suggested GBR Guidelines (pages 39-41) describes a three-step process for developing GBRs for Design-Build contracts. In section 8.4, the Suggested GBR Guidelines discuss how GBRs have been used in Design-Build contracts, including the Niagara Tunnel:

> **The Niagara Tunnel Project** in Ontario is a DB project that closely followed the three-step process described above. A tender document entitled a GBR-A was prepared by the Owner and submitted as a tender document to prequalified DB teams. The GBR-A contained gaps in the form of comment boxes that solicited input from each team. The document included with each team's proposal was referred to as their GBR-B. Though the construction approaches and designs were different among the different teams, the Owner was able to compare the different GBR-B assumptions and assess compatibility with different design and construction approaches. The selected team's GBR-B was discussed, modified, and agreed upon by the parties prior to incorporating it into the Construction Contract as the GBR-C. The Niagara Tunnel Project, which is currently under construction, includes a Disputes Review Board and a form of a Differing Site Conditions clause. (Appendix A, pp. 41-42).

While the parties have spent time criticizing OPG's development of the GBR jointly with Strabag, the creators of the Suggested GBR Guidelines, which included two of the three DRB members, concluded that the Niagara Tunnel GBR development closely followed the recommended three-step process.

One of the criticisms that SEC and AMPCO level against the GBR is that it contains "imprecise" or "overly broad" wording. This matter is addressed in Mr. Ilsley's affidavit (Appendix B, paras. 6, 7 and 8). Contrary to the criticisms of SEC and AMPCO, the Suggested GBR Guidelines recognize that it is not always possible to describe geologic conditions precisely:

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[20] The second edition of the Suggested GBR Guidelines was prepared during 2006 and finalized in 2007 (Appendix A, Copyright page and p. ix). As the DRB Report notes, the first DRB meeting was on February 7, 2006 (Ex. D1-2-1, Attachment 7, p. 5). Under the terms of the Design Build Agreement, the DRB was required to meet at the project site, at least quarterly, to review the project progress, discuss any issues with Strabag and OPG, and tour the project. (Ex. D1-2-1, Attachment 6, Appendix 11.1(a) - Dispute Review Board Agreement, section 6 (e), Progress Meetings). By the time of the DRB Hearing in June 2008, the DRB would have met nine times.

- “The planning, design, and construction of underground projects must cope with uncertain subsurface conditions. ‘Mother Nature’ did not create subsurface conditions in accordance with a materials properties handbook, nor do geologists or geotechnical engineers (or any other participants in the process) have magical predictive powers.” (Appendix A, p. 16).

- “However, some baseline issues may be qualitative, and not definable in quantitative, measurable terms…. In other instances, baselines may be appropriately stated in qualitative terms, but may not be reliably measured during construction.” (Appendix A, p. 17).

- “Baselines are difficult to write without ambiguity. No one can accurately predict the nature and distribution of materials underground and how they will react to excavation.” (Appendix A, p. 27)

SEC and AMPCO argue that OPG should have sued Hatch for the defective GBR and, was imprudent for not so doing (SEC argument, paras. 4.4.24; AMPCO argument, para. 135). As OPG testified, there was no basis for suing Hatch (Tr. Vol. 2, p. 68). The GBR accurately reflected the exploratory boring and testing that was contained in the 12-Volume Geotechnical Data Report. That document presents the results of the work done between 1983 and 1997 by Ontario Hydro, expert consultants and academics (Ex. D1-2-1, Appendix B). Acres, a firm that later became part of Hatch did some of this work. The DRB ultimately determined that the overbreak was materially different than the parties expected, and that was not due to any fault of Hatch

5.5.4.7 The DRB Process and Findings

<u>The DRB Process</u>

The DRB process was included in the DBA as a mechanism to address disputes over DSC through the use of industry experts familiar with the Project and without the time and expense of litigation.[21] As Mr. Ilsley explained, the DRB process is typically included in complex tunneling projects as a risk sharing measure:

> MR. ILSLEY: I think it's good to look at the genesis of the process of dispute review boards, which were developed hand in hand with the geotechnical baseline reports.
>
> And they were perceived by the industry as being means of risk sharing, alternative dispute resolution to avoid litigation.
>
> And the idea was behind it that if you had a panel of three experts on your dispute review board, experienced in the industry, they would be able to examine the evidence and give convincing reasons as to why and recommendations as to resolution of the dispute. ...
>
> MR. RUBENSTEIN: Would you conclude that generally it's non-binding because parties don't have full confidence in the dispute resolution board and want another avenue?
>
> MR. ILSLEY: No, I wouldn't say. I would say that the -- again, the purpose is to lay before the parties, who perhaps too have not been involved directly in the work, but will be responsible for commercial decisions, to give them some clarity in the issues, and look at the sense of how much that they are responsible for what occurred or not, and thereby make informed commercial decisions (Tr. Vol. 2, pp. 50-51).

Board staff, CME, and AMPCO appear to fundamentally misunderstand the nature of the DRB process and the findings of the DRB with regard to the dispute between OPG and Strabag over the project (Board staff argument, p. 24; CME para. 74-75; AMPCO paras. 120-125). There was a single DSC dispute between OPG and Strabag that went to the DRB. 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, <u>individually or collectively</u>, present a valid claim for DSC and recommend to the parties how this claim should be addressed.

[21] As discussed above, in order to be in a position to decide potential disputes, the DRB needed to understand the project. To do so, it received project documents and periodically met with the parties at the project site to keep abreast of its progress (Ex. D1-2-1, p. 96). Thus when the DRB was seized with the dispute, its members were already very familiar with the difficulties being encountered in tunneling.

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).

The DRB summarized the test for DSC in the DBA and the allocation of responsibility among the parties as follows:

> 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."
>
> ...
>
> 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. (Ex. D1-2-1, Attachment 7, pp. 5-6 (emphasis in the original)).

In attempting to convince the DRB that the four factors quoted above existed with respect to the conditions in the Niagara Tunnel, 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. There was not one cost for "large block failures" and another for "inadequate stand up time" because the actions that Strabag took addressed <u>all</u> the conditions it was encountering. In other words, and contrary to the suggestions of CME, AMPCO and Board staff, the additional cost that Strabag was incurring was not attributable to the causes of DSC, but rather to the actions necessary to address them.

While the DRB did not accept that three of the five conditions constituted DSC, 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. Hypothetically, if Strabag had offered 10 reasons why DSC existed and the DRB disagreed with 9 of them, the result would have been the same – if there are differing subsurface conditions encountered, responsibility for them rests with the owner.

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.

<u>The DRB Findings</u>

This section discusses the two findings that the DRB concluded supported a finding of DSC[22], namely the findings of excessive overbreak encountered and an inadequate Table of Rock Conditions (Ex. D1-2-1, Attachment 7, pp. 16-19). Each of these findings is discussed in turn below.

The DBA between OPG and Strabag anticipated that the project would experience a level of overbreak, which would need to be removed from the tunnel and disposed. The GBR, included in the DBA as an appendix, set a baseline amount of 30,000 cubic metres for overbreak (Ex. D1-2-1, Attachment 6, Appendix 5.4 – Geotechnical Baseline Report, p. 36 [PDF p. 1755]). The DBA clearly contemplated that the quantity of overbreak could exceed this baseline and provided for a price of $55 for removal and disposal of each cubic metre above the baseline (Ex. D1-2-1, Attachment 6, Appendix 1.1(j) - Contract Price, p. 4 [PDF p. 168]).

Given this structure of payment, it was entirely logical that OPG would propose a higher baseline for overbreak, making it less likely that it would be subject to additional payments. Strabag had the opposite incentive – propose a lower baseline so it would be more likely to receive additional payments. These are the normal incentives inherent in commercial negotiations.

[22] As noted above, the DRB found that three of the five reasons offered by Strabag did not constitute DSC. [1] Large block failures, [2] conditions under the buried St. Davids Gorge, and [3] insufficient stand-up time (i.e., insufficient time to install initial rock support behind the tunnel boring machine cutterhead).

Given the recognized uncertainty about how much overbreak would ultimately occur, it would be the normal commercial practice that the parties meet somewhere in the middle. And that is what happened. OPG proposed a baseline of 45,000 cubic metres in GBR A, Strabag proposed a baseline of 15,000 in GBR B and the agreed on figure in the final GBR C was a baseline of 30,000.

The following quote from the Suggested GBR Guidelines contains an example for dealing with uncertain conditions that describes precisely the approach used by OPG and Strabag to deal with the uncertain quantity of overbreak:

> Assume that a tunnel project is to be constructed with a tunnel boring machine through two types of rock; one rock type is stronger and more difficult to bore than the other. The relative percentages of the two rock types along the tunnel alignment are unclear. Given the available information, a reasonable interpretation of the stronger rock to be encountered could range between 30% and 60% of the total tunnel length.
>
> It is almost a certainty that the design team would not correctly predict the actual percentage of stronger rock to be encountered along the tunnel alignment. The recommended approach would be to state the possible range of percentage of stronger rock to be encountered (i.e., 30% to 60%), and then state a realistic percentage to be assumed as the baseline. In this example, that baseline might be set at 45% of the tunnel length. By establishing a clear baseline, the Contractor and Owner both understand the risks to be borne by each; the baseline percentage establishes the amount of stronger rock up to which the Contractor is financially responsible, and beyond which the Owner is financially responsible. (Appendix A, p. 19).

The parties criticize OPG for negotiating a lower baseline quantity of overbreak, and suggest it contributed to the DRB finding DSC, but these parties misapprehend the DBR finding with respect to excess overbreak (AMPCO argument, para. 93; Board staff argument, p. 23; SEC argument, para. 4.4.13).

Clearly, if the issue had been solely the <u>quantity</u> of overbreak, the contract had provisions to address it through increased payment. Using the figure of $55 per cubic metre presented above, which is as specified in the contract, and the estimate for total overbreak actually encountered of about 60,000 cubic metres (30,000 more than the baseline), the cost of excess overbreak that occurred would have been $1.65M ($55 x 30,000). It is beyond question that this was not a dispute over less than $2M.

As the DRB found, it was the fact that the nature and extent of the overbreak was different than anticipated by the parties that constituted DSC (Ex. D1-2-1, Attachment 7, pp. 14, 17-18). Where the GBR anticipated that rock would break away all around the circular profile of the tunnel (top, sides and bottom), in actuality the overbreak was much more extensive and was concentrated in the crown (top) of the tunnel (Ex. D1-2-1, Attachment 7, p. 12). This required the contractor to employ different means and methods to contain the overbreak (Ex. D1-2-1, Attachment 7, p. 18). Moreover, the overbreak was not uniform; it included some extremely large voids (Ex. D1-2-1, p. 84).

The type and extent of overbreak had three significant impacts: 1) it slowed the progress of tunneling due to the need to safely address the loose and falling rock, 2) it required new types of rock support to limit and address the loose and falling rock, and 3) it necessitated extensive profile restoration to restore the circular profile of the tunnel as required by the lining design. It is these impacts, and not the removal and disposal of overbreak quantities in excess of the contract baseline that led to the significant cost increase and schedule delays on the project (Ex. D1-2-1, pp. 70-81, 83-87). Ultimately, these impacts led to OPG acquiring additional land rights so that the tunnel could be rerouted to exit the Queenston formation as soon as possible (Ex. D1-2-1, pp. 75-77).

As Mr. Ilsley described it:

> [T]here was considerably more overbreak -- this had ramifications not only in the tunnelling operation itself, but in the placing of the lining, which had to follow the actual excavation of the tunnel.
>
> You had, then, to support it, to provide a safe working place so that the crews could go in and build the lining, which was a complex undertaking in itself, and the lining had certain requirements also in the design documents. That is, it was not to be any excessive loose rock outside the perimeter of the lining.
>
> So the loose rock had two ramifications: one, their direct impact on the mining operation itself, and secondarily, the fact that it had to be removed because of the lining design.

So that was the -- that all led from the fact that there was an excessive overbreak. (Tr. Vol. 2, p. 53).

In evaluating Strabag's claim for DSC, the DRB was critical of the Table of Rock Conditions, which describes the type of support to be used for each type of rock, and noted two issues with this table that rendered the GBR defective (Ex. D1-2-1, Attachment 7, pp. 13-19).[23] First, the DRB found that the requirement that rock conditions be determined based on the closest match created a defect because, if read literally, there could be "no possibility of a DSC because no matter how different the actual conditions may be from the assumed or anticipated conditions described in the GBR, there will always be a 'closest match'." (Ex. D1-2-1, Attachment 7, p. 16). Second, the DRB concluded that the GBR's use of Type 6 as a catchall category to cover all other rock conditions "eliminates the possibility of a DSC since this wording would cover all other possibilities not assumed or anticipated in the GBR." (*Ibid.*).

When confronted with provisions that the DRB interpreted to mean that there could never be a finding of DSC, the DRB decided to look beyond these provisions to the substance of the matter:

> **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. (*emphasis added*) (Ex. D1-2-1, Attachment 7, pp. 18-19).

[23] Mr. Ilsley did not share the view that the GBR was defective. He stated: "I thought it was ambiguous. I didn't think it was defective." (Tr. Vol. 2, pp. 53-54).

Board staff, AMPCO and SEC argue that since the DRB believed that the GBR was defective, OPG must have acted imprudently. Based on this view they recommend that varying amounts of cost should be disallowed. OPG has three responses.

First, this conclusion is based on the DRB's discussion of the GBR and ignores the fact that despite their view of the problems with the GBR, the DRB members were able to issue unanimous findings deciding that DSC existed. The DRB finding on excessive overbreak is clear - overlooking the defective provisions in the GBR, there still are DSC associated with excessive overbreak (Ex. D1-2-1, Attachment 7, p. 18). As noted above, by the time of the DRB Hearing, the DRB had met at the site and toured the tunnel quarterly over a period spanning more than two years (February 2006 to June 2008). The members would have seen the conditions that Strabag was confronting in boring and supporting the tunnel, and the nature and extent of the overbreak. As Mr. Ilsley stated: "But in the end, the overbreak was plain on its face." (Tr. Vol. 2, p. 54).

Second, these parties have not pointed to a single action that OPG took in developing the GBR that was unreasonable. As noted above, the Suggested GBR Guidelines recommend a process for developing a GBR for Design-Build contracts and state that the Niagara Tunnel project closely followed this process (Appendix A, pp. 38-41). OPG engaged one of the world's preeminent tunneling firms to prepare the GBR and then worked with Strabag, another of the world's leading tunneling firms, to modify it based on the proposed tunnel design and construction methods. Both parties had full access to the 12 volume Geotechnical Data Report produced by Ontario Hydro and both had experienced counsel drafting and reviewing the agreement. Thus the GBR was a document prepared, negotiated and reviewed by experts. Notwithstanding all claimed defects that the intervenors and Board staff point to in hindsight, at the time, OPG acted reasonably in negotiating the GBR with Strabag. The DRB criticized aspects of the GBR to be sure, but those criticisms did not ultimately prevent it from deciding that the subsurface conditions were different than the parties expected.

The third reason for rejecting the proposed disallowances is probably the most important. There is not one piece of evidence that the GBR, defective or not, resulted in any additional cost. As Mr. Young and Mr. Everdell testified, the additional costs experienced were entirely due to the rock conditions encountered and the costs would have been the same or more had OPG known the rock conditions with certainty at the time construction began (Tr. Vol. 1, p. 54; Tr. Vol. 2, pp. 43, 119-122).

Board staff, in an effort to find some costs that were directly attributable to the subsurface conditions being much worse than Strabag anticipated offers the following: “Certainly some of the additional costs were caused by the delay surrounding the discovery of the overbreak issue, in particular with respect to the increased interest charges and management attention. Additional costs were further incurred to conduct the Dispute Review Board hearing and to re-negotiate the contract.” (Board staff argument, p. 25).

As OPG’s evidence makes clear, there was no delay due to the dispute with Strabag. From the time that Strabag issued its first claim for differing subsurface conditions in May 2007 until the Amended Design Build Agreement (“ADBA”) was signed in June 2009, construction of the tunnel continued unabated as rapidly as conditions allowed (Ex. D1-2-1, pp. 71,103 and 112). Strabag continued to work safely and advance the project despite the challenging rock conditions being experienced (Ex. D1-2-1, pp. 102-103). Thus, the dispute and contract renegotiation caused no delay in the tunnel’s progress (Tr. Vol. 2, pp. 82-84).

As the DRB commented:

> 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. (Ex. D1-2-1, Attachment 7, p. 19)

While the Niagara Tunnel did command substantial management attention throughout the project, there was no additional cost associated with this as it is senior management’s responsibility to provide executive oversight of all major projects (Ex. D1-2-1, pp. 49-51). The costs of the DRB were included in the project costs from the outset (Ex. D1-2-1, p. 128). OPG did incur some additional costs for the DRB Hearing, but these were relatively small and necessary for OPG to enforce its rights under the DBA (Tr. Vol. 2, 83-84). As far as costs to renegotiate the contract, as explained below (Section 5.5.4.8), OPG correctly determined that this was the best option for completing the tunnel, a view supported by experts and accepted by most parties.

AMPCO similarly claims that there were additional costs as the result of OPG's alleged imprudence (AMPCO argument, paras. 109-125). These claims have been addressed above. The costs associated with profile restoration, rock support are directly related to the rock conditions experienced. The selection of the TBM had no direct cost consequences and, in any event, was required by the lining that Strabag proposed. As for the costs associated with the buried St. Davids Gorge, the evidence is that OPG accepted Strabag's approach because it had cost advantages and improved the tunnel's flow characteristics (Ex. D1-2-1, p. 74, ft. nt. 29). Moreover, while overbreak was substantial under the buried St. Davids Gorge, it was equally bad in other areas of the Queenston formation (Ex. D1-2-1, pp. 70-77). Finally, the DRB finding of DSC was not based on the area under the buried St. Davids Gorge (Ex. D1-2-1, Attachment 7, p. 18).

5.5.4.8 Contract Renegotiation

None of the parties directly challenges OPG's decision to negotiate with Strabag after the DRB issued its findings.[24] Instead most focus on the results of the renegotiation and deem them unacceptable based on nothing more than their unsupported claims about what OPG should have been able to achieve (Board staff argument, pp. 25-26; AMPCO argument, paras. 128-133; CME argument, paras. 75-80; EP argument, paras. 28-32; SEC argument, paras. 4.4.32 through 4.4.39). OPG submits that the OEB should reject the parties' assessments because they are nothing more than wishful thinking. Given the findings of the DRB and the conditions under which the tunnel was being constructed, OPG negotiated a fair deal.

CME advocates $149.5M disallowance on the theory that OPG paid too much to complete the tunnel (CME argument, paras. 75-80). CME postulates that the additional cost to complete the

[24] SEC does claim that OPG should have offered its Board of Directors more alternatives when seeking approval of the ADBA, but the only concrete suggestion that it makes is that OPG should have negotiated a different type of deal with Strabag (SEC argument, para. 4.4.35). This suggestion is another attempt to second guess the results OPG achieved in renegotiation and, as such, is responded to in OPG's argument above.

final 7.2 kilometres of the tunnel should have been no more on a per kilometre basis than the settlement that OPG entered into with Strabag for the additional costs associated with first three kilometres (CME argument, paras. 77-80).[25] OPG submits that this proposal illustrates that CME has failed to understand the progress of the Niagara Tunnel and the record in this proceeding.

As OPG's evidence clearly explains, the settlement with Strabag covered all costs incurred through November 30, 2008 (Ex. D1-2-1, p. 106). At that time, Strabag's costs were all related to mining the tunnel (Ex. D1-2-1, pp. 70-77). The costs of profile restoration for the tunnel had not been included in the original DBA and profile restoration had not yet begun anywhere in the tunnel (Ex. D1-2-1, pp. 83-84). Profile restoration began in September 2009 (Ex. D1-2-1, p. 84). Thus, while the settlement included the cost of mining the first three kilometres, it did not include any costs for profile restoration over that area. It also doesn't account for differing degrees of difficulty associated with mining in different rock formations along the tunnel.

Even if CME's per kilometre approach was to be accepted, its numbers are wrong. Based on the $40M settlement, OPG paid an extra $22.3M per kilometre (not $13.3M per kilometre) for the first 3 kilometres ($13.3M per kilometre for excavation plus $9.0M per kilometre for profile restoration).[26] Based on Strabag's $90M cost claim, the actual extra cost for the first 3 kilometres was $39.0M per kilometre ($30M per kilometre for excavation + $9.0M per kilometre for profile restoration). The comparable extra cost for the last 7.2 kilometres was $29.6M per kilometre ($280.4M incremental tunneling cost - $40M settlement - $27M for the first 3 kilometres of profile restoration = $213.4M / 7.2 kilometres = $29.6M per kilometre).[27] This figure for the last 7.2 kilometres reflects faster TBM progress and less overbreak and, consequently, less profile restoration once the tunnel exited the Queenston formation.

Board staff proposes some $82M in cost disallowance because "In Board staff's view, it is reasonable to expect that OPG could have negotiated a greater "sharing" of the costs

[25] CME uses 7 kilometres, but the correct figure is 7.2 kilometres given the tunnel's total length of 10.2 kilometres.
[26] Actual profile restoration cost was $92M (Ex. J2.1). This represents an average of $9.0M per kilometre for the 10.2 kilometre tunnel.
[27] CME presents the incremental costs as $282.5M. While that was the budgeted incremental cost, the actual incremental cost was $280.4M (Ex. D1-2-1, p. 128).

resulting from the overbreak." (Board staff argument, p. 26). AMPCO, SEC and CME make similar claims (AMPCO argument, para. 132; CME argument, paras. 79-80; SEC argument, paras. 4.4.32 through 4.4.34). With all due respect, the parties' views, formed in hindsight, on a situation that they were not involved in do not constitute evidence, let alone, justify a finding of imprudence.

The facts of this case, as fully explained in OPG's evidence and highlighted below, are that OPG negotiated a settlement of Strabag's $90M cost claim for $40M and an agreement to complete the project at cost with Strabag's only opportunity for profit coming from the potential for it to earn incentives if it completed the project below the negotiated target cost or ahead of the target schedule (Ex. D1-2-1, pp. 106-111).

OPG submits that this result is entirely consistent with the DRB's finding. The DRB stated:

> 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. (Ex. D1-2-1, Attachment 7, pp. 18-19).

OPG's negotiated settlement of $40M for $90M in past claims represents a "fair and equitable sharing of the cost and time impacts resulting from the overbreak conditions that <u>have been encountered</u>." (<u>*emphasis added*</u>) (<u>*Ibid*</u>). OPG also negotiated a new contract for completion of the tunnel under which both parties accepted "responsibility for some portion of the additional cost" but which also gave Strabag "adequate incentives to complete the Work as soon as possible." (<u>*Ibid*</u>). In short, OPG accomplished exactly what the DRB recommended.

While OPG's audit ultimately only accepted some $77M of Strabag's claim as being verified, Strabag continued to maintain that the $90M represented legitimate costs. As Mr. Young explained:

> MR. YOUNG: Strabag believed that they had suffered a $90 million loss. OPG's audit of that really resulted in an accounting dispute as to what was a legitimate cost and what, in OPG's opinion, was not a legitimate cost, and that is where the 77 million came in. 77.44, I believe.
>
> At that point, this was at the time when the contract was just being put in place, new contract being renegotiated.
>
> It was a significant irritant to the relationship between Strabag and OPG, in that Strabag did believe that they suffered the $90 million loss.... (Tr. Vol. 2, p. 75).

SEC and AMPCO criticize OPG for not immediately clawing back the $5.6M (AMPCO argument, para. 131; SEC argument, para. 4.4.34). This amount is the proportionate share of the claimed amount that was left unsubstantiated by OPG's audit [(40/90)*$12.56M] (Ex. L-4.5-SEC-041, Attachments 16 and 17). As explained by Mr. Young above, this was a significant irritant to the relationship with Strabag going forward, just at the time that Strabag was agreeing to a new contract to complete the tunnel at cost with no assurance of any profit. Strabag, having already made what if believed to be a $50M concession, did not want to turn the $40M settlement into a $34.4M settlement by returning $5.6M to OPG. Under these circumstances, OPG reasonably concluded, that it if the project was to move forward it was necessary to remove this impediment. To do so, OPG agreed that if the project met its cost and schedule targets, then OPG would forego recovery of the $5.6M (Ex. L-4.5-17 SEC-041, Attachments 16 and 17).

In terms of sharing costs going forward, Board Staff, AMPCO and SEC all claim that Strabag did not share enough or did not share at all. The facts are to the contrary. Strabag began working on this project in August 2005 when the DBA was signed (Ex. D1-2-1, p. 132). The renegotiated contract meant that Strabag had worked for more than three years to achieve a $90M loss 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).

While the contract did have incentives for completing the project below the target cost and in advance of the target schedule, at the time it was highly uncertain that Strabag could achieve these. When the ADBA was being negotiated (Fall 2008 through Spring 2009), the project was tunneling through difficult rock in the Queenston formation and was falling further behind schedule (Ex. D1-2-1, pp. 75-76). Of course, in hindsight, Strabag was able to complete the project months ahead of the target schedule and did earn incentives as a result.

Using OPG's $77M figure, Strabag earned a profit of $23M on a $985M contract (or 2.3 per cent) for a project lasting almost eight years.[28] This is a very low level of profit for a major construction project of this difficulty, size and duration (Tr. Vol. 2, p. 24). OPG submits that the renegotiated contract resulted in completion of the project in a timely and cost-effective manner and was the appropriate path forward in light of the DRB finding that DSC existed and its recommendations, as discussed above.

Board staff, AMPCO and SEC ignore this fact and also fail to recognize the hundreds of millions of dollars in additional cost that OPG would have incurred if it was forced to terminate the original contract, find a new contractor and negotiate a new contract for completion of the partially completed tunnel. These additional costs would have been subject to the interest charges that would have continued to accrue while OPG engaged a new contractor. The additional costs would also include the full profit that a new contractor would have included in its proposal and the cost of bringing a new contractor up to speed on the project (i.e., relearning all that Strabag had already learned about the tunneling conditions during more than two years). In addition, OPG would have had to pay the costs of resolving the inevitable claims from Strabag over the termination of the contract.

To Mr. Ilsley, with his more than 40 years of tunneling experience, these risks were very real:

> OPG may also have considered termination of Strabag's contract in order to cure the problems. This would have resulted in a long delay to allow preparation of new contract documents and procurement of a new contractor and afterwards a protracted litigation between the parties. All of which would have delayed the contract completion with concomitant revenue loss and the further unknowns of the re-bid amount and the litigation costs and outcomes. (Ex. F5-6-1, p. 26).

[28] This figure is calculated by taking the $60M in performance incentives paid under the contract, adding the $40M that OPG paid to settle Strabag's excess costs under the original contract and subtracting the $77M of these costs that OPG's audit substantiated ($60M + $40M - $77M = $23M) (Tr. Vol. 2, p. 145). Strabag continued to contend that actual excess costs were $90M despite OPG's inability to substantiate them through audit. Under Strabag's view, the actual profit Strabag earned was $10M ($60M + $40M - $90M = $10M) (Tr. Vol. 2, p. 144). Using these two profit figures as a range, Strabag earned a profit of between 1 per cent and 2.3 per cent on this contract (10/985 to 23/985).

The prospect of incurring these additional costs was a significant consideration to OPG. At the time OPG was negotiating a new agreement with Strabag, OPG was following the ongoing dispute over the Seymour Capilano project where the Greater Vancouver Water District had terminated the original contractor and was seeking to engage a new one (Tr. Vol. 2, p. 137). Mr. Ilsley served as a member of the DRB for the Seymour Capilano project (Ex. JT1.5, Attachment 1, p. 4). As he explained the situation:

> Well, Seymour-Capilano, the project in Vancouver, was bid at about 100 million. In that case there was a dispute over ground conditions. The tunnel was stopped for six months, and the owner decided to terminate the contract, which is always, under the contract, you know, an option.
>
> He then re-bid the work about a year later, and the bids were 1.8 times their -- so they came in at 180 million. So even though 60 percent of the work was done, the two tunnel boring machines were in the ground, one shaft was completed, those costs to finish were almost twice what the original cost was for the tunnel.
>
> And then on top of that, they are still dealing, I think, with the litigation in dealing with the contractor who was terminated, because he, of course, said -- he sued for his costs. So -- and that remains unresolved. I think it's now some six or seven years after. (Tr. Vol. 1, pp. 80-81).

Board staff, AMPCO and SEC also claim that there were strong incentives for Strabag to complete the Project in terms of litigation and reputational risk (Board staff argument, pp. 25-26; AMPCO argument, para. 132; SEC argument, para. 4.4.33). OPG does not dispute that Strabag had incentives to negotiate a new agreement along the lines recommended by the DRB – it had committed substantial resources to the project and had already incurred substantial losses. Strabag also said as much in its Arbitration Notice stating that it would place great weight on the DRB recommendations and use them as the basis for further negotiations with OPG (Ex. L-4.5-17 SEC-040, Attachment 2). OPG submits, however, that Strabag had an even stronger incentive to stop losing millions of dollars each month and had no incentive whatsoever to agree to complete the job with further losses and no opportunity for even a small profit as Board staff and intervenors propose.

During the negotiation, Strabag strongly indicated that if its losses were not compensated and a new agreement reached, it would walk off the job (Tr. Vol. 1, pp. 76-77). Despite clear testimony on this point, the parties refuse to recognize <u>that Strabag was losing money every day that tunneling continued under the DBA</u>. As Mr. Everdell and Mr. Young testified:

> 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. (Tr. Vol. 2, p. 126).

In assessing the relative position of the parties in renegotiation, the parties seem to ignore that the renegotiation took place after three independent tunneling experts on the DRB had found that DSC existed and that Strabag was entitled to additional compensation above that provided for in the DBA (see discussion of DRB findings above).[29]

Board staff states that if Strabag walked off the job, it "would have resulted in very significant costs to Strabag – certainly much more 'cost' than the reduced profit it ultimately wound up with." (Board staff argument, pp. 25-26). Board staff's assumption, made without any factual support, is at odds with the record. As discussed above with respect to the Seymour-Capilano project, Strabag would not have just walked away with damage to its reputation, it would have sued OPG. Given that Strabag prevailed before the DRB, it appears more likely than not that Strabag would have prevailed in any subsequent litigation and been entitled to recover its full losses plus damages for breach of contract. Surely, in evaluating OPG's offer against the potential reputational and litigation risks from walking off the job, Strabag would have taken these circumstances into account.

Board staff, AMPCO and SEC do not maintain that OPG's decision to renegotiate the contract with Strabag was imprudent. Rather, they opine, without a shred of evidence that OPG should

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[29] As noted in Mr. Ilsley's report, at the DRB OPG vigorously defended its position that there was no DSC. The Owner's Representative, Hatch Mott MacDonald, led the presentation of OPG's position. In addition, OPG presented three very experienced experts on rock mechanics, tunnel design and constructability and TBM design in support of its position (Ex. F5-6-1, pp. 26-27). Despite OPG's strong presentation, the DRB found that there was DSC.

have done better in the renegotiation. OPG does not agree and submits that all the evidence supports its position.

Using the appropriate prudence standard – did OPG act reasonably given the information it had and the alternatives it faced at the time it negotiated the ADBA with Strabag – OPG submits that it is beyond dispute that its actions in renegotiating the contract were prudent. From the project's inception, OPG recognized the importance of the Niagara Tunnel and therefore it received significant senior management and Board of Directors oversight (Ex. D1-2-1, pp. 49-51). The project status was regularly reviewed at standing senior management meetings (*Ibid.*).

Once the project began to fall behind its original schedule due to the significant overbreak encountered, this oversight changed considerably. The Board of Directors' Major Projects Committee, which was already receiving periodic reports, requested and received weekly reports from senior management on the project's progress and was directly involved in the assessment and resolution of the dispute with Strabag (Ex. D1-2-1, p. 51).

OPG also obtained independent expert advice on the conduct of the dispute through the creation of a Contract Litigation Oversight Committee ("CLOC"). As explained in OPG's evidence, the CLOC was formed:

> 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).

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

Thus, the entire process of resolving the dispute with Strabag and selecting the best path forward for completing the tunnel was subject to intense scrutiny by OPG's senior management and Board of Directors, supported by external experts. All of this effort was directed to a single aim – getting the Niagara Tunnel completed safely at the lowest cost and with the earliest completion date.

5.5.4.9 Fall of Ground

Board staff and AMPCO propose a $2M disallowance associated with the fall of ground that occurred in September 2009 (Board staff argument, p. 26; AMPCO argument, para. 134). OPG submits that this recommended disallowance should be rejected as another example of a disallowance based on hindsight. OPG does not dispute that the failure to grout Boreholes NF-4 and NF-4A earlier was a contributing factor to the fall of ground (Ex. D1-2-1, p. 79). However, with respect to these boreholes, Strabag followed its consistent practice of not grouting them until after the tunnel mining in the area was compete (Ex. JT1.2). The tunnel intersected them on February 27, 2009 and they were grouted soon after in March 2009, some six months before the fall of ground occurred (Ex. D1-2-1, p. 79). Strabag had previously used this same approach without incident on a borehole that had intersected the tunnel (Ex. JT1.2). While in hindsight it would have been better to have grouted these boreholes sooner, Strabag's approach was reasonable based on the information available at the time the action was taken and therefore no disallowance is warranted.

5.5.4.10 Miscellaneous Issues Raised in the Parties' Arguments

<u>Cost of the Energy Produced</u>

Board staff presents the cost of energy produced through the use of the additional water diverted by the Niagara Tunnel as 10.7 cents per kilowatt hour (Board staff argument, p. 15). Board staff calculates this figure by dividing the test year revenue requirement by the test period incremental production. OPG submits that this is an inappropriate way to calculate the cost of production from a facility that is being depreciated over a period of some 95 years (see section 7.16.2 below). Board staff's approach gives the same weight to the revenue requirement that will be paid 95 years from now as to that being paid today. Board staff's calculation also includes $35.6M (Ex. J3.4) of Gross Revenue Charges ("GRC") associated with the project despite the fact that OPG proposed that it retroactively return any GRC savings once the GRC holiday for the project is approved (Ex. JT1.8).

OPG submits that more realistic cost figures for the Niagara Tunnel output are the 6.8 cents per kilowatt hour ($2009) Levelized Unit Energy Cost ("LUEC") and the 8.7 cents per kilowatt hour ($2014) revenue requirement figures presented in the Project's Superseding Business Case (Ex. D1-2-1, Attachment 8, pp. 5-6).[30]

<u>Savings from Mitigation</u>

VECC posed an unanswerable question about mitigation savings and now criticizes OPG for not answering it (VECC argument, p. 19). OPG provided detailed evidence about its settlement of Strabag's $90M claim for excess costs Strabag incurred prior to December 1, 2008 (Ex. D1-2-1, p. 106; Ex. L-4.5-17, SEC-041, Attachments 14-17). Beyond that, the mitigation was built into the contract as a whole and it is simply not possible to compare the savings in the signed contracts with the savings that OPG might have achieved in some hypothetical other contract. OPG is not asking ratepayers to pay separately for mitigation, OPG is seeking to recover the true costs of the Niagara Tunnel that is in operation, delivering the contracted water flow rate and is designed to operate maintenance free for 90 years.

<u>Costs Written Off by Ontario Hydro</u>

VECC appears to blame OPG because years prior to OPG's formation, the early definition phase costs that Ontario Hydro incurred for geotechnical investigations were written off in accordance with accounting rules when Ontario Hydro decided not to pursue the project

[30] In actuality, both the cited figures slightly overstate the actual cost of the Niagara Tunnel energy because while production is about 5.3 per cent lower than assumed in the Superseding Business Case, this is more than offset by the fact that the cost of the project is about 7.7 per cent lower and the project came into service nine months earlier than assumed.

(VECC argument, pp. 18-19; Ex. D1-2-1, Attachment 5, p. 2). It is more than a little odd to have a ratepayer advocate complain that certain costs are not be recovered from ratepayers especially when, as here, the actions taken were proper.

5.5.4.11 Specific Disallowances Recommended

This section discusses the bases on which each party made their specific disallowance recommendations.[31] As appropriate, it references back to the sections above.

Board staff's recommended disallowances (Board staff argument, p. 26) and the reasons to reject them are provided in the list below:

1. "$40M paid to Strabag for overrun as of November 30, 2008" – Reasonable settlement of a $90M claim and consistent with the DRB findings (See Section 5.5.4.8)

2. "$6M in carrying-costs (IDC) on the $40M payment to Strabag" – See previous bullet

3. "$6M in incremental design work" – Design work was necessary to realign the tunnel to exit the Queenston Formation more rapidly thereby increasing tunneling speed and reducing profile restoration costs (Ex. D1-2-1, pp. 76-77, 83-87)

4. "$26M for the profit provided to Strabag on the basis that OPG did not adequately mitigate the possibility that Strabag could in practice withdraw from the project" – Maximum profit was only $23M and was based on Strabag completing tunnel earlier than contract target. Consistent with DRB recommendation. (See Section 5.5.4.8)

5. "$15M in carrying costs on the reasonable expectation that with an amended Design/Build Agreement at the start, there would have been at least a 5% or 3 month improvement in the overall schedule (57 months instead of 60 months)" – Inconsistent with the uncontroverted evidence that tunneling continued without delay during the dispute and the contract renegotiation (See Section 5.5.4.7)

6. "$10M in Office and General cost and Overhead Recovery costs, or 10% of the itemized amount, in that there was no evidence as the amounts which were embedded in the original contract" – OPG settlement of Strabag's claim was based

[31] OPG notes that to the extent any capital disallowance is approved, there will be the tax effects including reductions in benefits of applicable Capital Cost Allowance deductions provided to customers.

on Strabag's actual cost incurred to December 1, 2008; the 5 per cent overhead amount was only applied to costs going forward (Ex. D1-2-1, p. 109).

7. "$2M related to fall of ground when borehole not closed. In September 2009, a fall of ground incident related to failure to grout an open borehole in proximity to excavation occurred. The impact of the incident was a delay of 17 days and $2M" – Consistent with Strabag's practice that had been used without incident (See Section 5.5.4.9)

AMPCO proposes a disallowance of $407.4M, which is about 83 per cent of the costs subject to review (AMPCO argument, para. 139). OPG has addressed most of AMPCO's substantive points above, but the sheer size of the disallowance merits a brief additional response. Nothing in AMPCO's submissions address the point that OPG has made repeatedly - the cost OPG ultimately paid reflects the cost of mining a tunnel 10.2 kilometres through the rock conditions encountered and installing a lining designed to last 90 year. Apparently, AMPCO is asking the OEB to find that OPG was imprudent because the rock conditions were more difficult than reasonably expected and it was unable to convince Strabag to build a tunnel that cost $687M for the original $407M price (Ex. D1-2-1, p. 128, Table 8). AMPCO's submissions on this issue are long on rhetoric and blame, but they fall far short of presenting facts establishing that OPG acted imprudently and that these actions resulted in additional costs.

CCC adopts the disallowance recommended by CME, but does make the point that:

> The Council accepts that the project is delivering benefits to Ontario consumers by increasing the production of the Adam Beck facility in an environmentally sound way. We are not saying it is [a] project that should not have been undertaken. What we question is the extent to which the full costs associated with the project should be borne by Ontario ratepayers. (CCC argument, p. 10).

OPG submits that this question was definitively answered at the hearing through the sworn testimony of Mr. Everdell and Mr. Young that the cost OPG paid represents the true cost of completing the project given the rock conditions encountered (Tr. Vol. 2, pp. 43, 85, 119-122). It is perfectly appropriate that Ontario consumers should pay the full cost of realizing project benefits they will receive into the next century (CCC argument, p. 10).

CME supports a range of disallowance from $208.5M to $375M (CME argument, para. 83). The lower bound of this range is based on CME's miscalculation of how much the tunnel should have cost based on the settlement with Strabag (See Section 5.5.4.8) plus some of Board staff's disallowances. The upper bound is based on CME's interpretation of AMPCO's recommendation.

EP recommends a $40M disallowance based on OPG's use of Design-Build contracting (EP argument, p. 12) (See Section 5.5.4.3).

LPMA adopts AMPCO's submissions, which have already been refuted (LPMA argument, p. 6).

SEC recommends a reduction of 50 per cent of the amount at issue or $245.7M (SEC argument, para. 4.4.39). SEC supplies no rationale for this particular level of disallowance – the number appears to have been plucked from the air. SEC, like AMPCO, fails to address the fact that none of the actions that it alleges were imprudent caused the rock conditions to be much more adverse than anticipated and caused any of the additional costs incurred to complete the project. SEC asked the witnesses what the tunnel would have cost if OPG had perfect foresight of the rock conditions and got the answer - what it actually ended up costing (Tr. Vol. 2, p. 85). That SEC has chosen to ignore this answer in its submissions, does nothing to make the answer less true.

VECC adopts AMPCO's submissions, which have already been refuted (VECC argument, p. 19).

5.5.5 Conclusion

For the reasons previously stated, OPG submits that it acted prudently in its planning, procurement, risk management and project supervision. The cost that OPG seeks to recover accurately represents the true cost of building the Niagara Tunnel with a 90-year design life through the rock conditions experienced. As such, the full project cost should be recovered.

5.6 ISSUE 4.5

Primary - Are the proposed test period in-service additions for the Niagara Tunnel Project reasonable?

As the parties arguments on the Niagara Tunnel were addressed under Issue 4.4, OPG relies on its submissions under that issue and on its AIC (pp. 21-36).

5.7 NUCLEAR

5.8 ISSUE 4.6

Primary (reprioritized) - Do the costs associated with the nuclear projects that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?

This issue will be addressed as part of OPG's reply to Issues 4.7, 4.8 and 6.6 below.

5.9 ISSUE 4.7

Oral Hearing - Are the proposed nuclear capital expenditures and/or financial commitments reasonable?

Board staff (supported by AMPCO, CME, LPMA and SEC) notes that as compared to Budget or OEB approved amounts over the 2010 to 2013 period, actual capital spending was about 9 per cent less. On this basis, Board staff proposes that the OEB should reduce capital expenditures by 10 per cent (Board staff argument, pp. 28-29). CME argues the variance is 20 per cent by ignoring the results of 2013 where OPG actual capital expenditures significantly exceeded budget (CME argument, para. 85).

The principled arguments set out in Issue 4.2 (Hydroelectric capital expenditures) of this Reply Argument are equally applicable here. For brevity, they will not be repeated.

The evidence in Ex. D2-1-2 page 2 is that "most of the projects being undertaken in the test period are sustaining projects, or projects to sustain and/or improve plant reliability at both

Darlington and Pickering." OPG is therefore puzzled by intervenor arguments that OPG should reduce capital expenditures when at the same time they challenge OPG's failure to improve its benchmark performance including reliability. Indeed, no intervenor challenged the merits of any of the nuclear capital projects proposed by OPG, or the necessity to make these investments. Board staff and CME's arguments simply rest on historical trends without any analysis of reasonableness of capital expenditure forecast. While OPG would argue that historical trend is not the determinant of deciding the reasonableness of capital expenditures, OPG would point out that over the four year period 2010-2013, actual expenditures have been on average $172.2M. The average capital expenditure for the test period is $170.M ($196.3M in 2014 and $143.9M in 2015). Therefore on a comparable basis, OPG's test period forecast is reasonable, and should be approved as filed.

5.10 ISSUE 4.8

Primary (reprioritized) - Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Project) appropriate?

The principled arguments set out in Issue 4.3 (Hydroelectric in-service additions) of this Reply Argument are equally applicable here. For brevity, they will not be repeated.

Board staff's position with respect to in-service additions is inconsistent and should not be adopted by the OEB. Board staff asserts that OPG has over-forecasted in-service additions for the test period on the basis that in-service additions were overstated by 12 per cent over the 2010 to 2012 period (Board staff argument, p. 30). However, Board staff selectively ignores 2013 as part of the historical period. For a proper consideration of OPG's forecast, the entire historical period should be considered and not just the part that advantages Board staff's position. If 2013 is included in the period, OPG has actually under forecast in-service additions by the amount of $66.2M. As a result, it is not legitimate for Board staff to assert that in-service additions should be reduced. The OEB should accept the in-service additions as proposed.

5.11 ISSUE 4.9

Primary - Are the proposed test period in-service additions for the Darlington Refurbishment Project appropriate?

OPG’s proposed in-service additions related to Darlington are $18.7M in 2014 and $209.4M in 2015 (Ex. J15.3). The proposed in-service amounts represent facilities that will come into service in the test period and are used or useful.

With respect to in-service additions, the OEB has stated that: "... the traditional and long established test in Ontario has been the ”used or useful rule.” (EB-2012-0064, Partial Reasons for Decision, p. 14). The OEB provided further clarification that in some cases an Applicant's work may have been completed on a project but it is not yet "in-service" as work which is the responsibility of other parties has not been completed. According to the OEB, in these circumstances, the OEB finds “that the applicant may consider the work completed and hence "useful" even if it is not being ”used”. References to ”in-service” should be read to mean that the necessary work has been completed for it to be put into service. Based on the common meaning of the terms, ”used” means to be employed in accomplishing something in the service of rate payers, while ”useful” means being capable of being put to use in the service of the rate payer.

ED and GEC proposed the application of the more restrictive test of used and useful and that the determination related to an asset being useful included the criterion that the asset is required. ED and GEC relied upon an Alberta Court of Appeal decision (GEC Argument, p. 18, ft. nt. 59). The case is not applicable since the Court was undertaking an exercise of statutory interpretation in regard to a provision of the *Public Utility Board Act* (Alberta) in which it considered the phrase ”used or required to be used to provide service to the public”. This is not the established law in Ontario and as such the proposition posed by ED and supported by GEC should not accepted by the OEB.

For the projects related to Darlington under Issue 4.9, OPG submits that the necessary work has or will be completed for the assets to be put into service in the test period and the assets will be used or useful.

Once an asset is established as being used or useful, the addition to rate base will depend on whether OPG had acted reasonably and prudently in constructing the asset for purposes of it being placed into service in whole or in part.

In respect of in-service additions related to Darlington, Board staff recommended that the OEB accept the amounts OPG seeks to close to rate base being the amounts of $18.7M and $209.4M for 2014 and 2015 respectively. Included in these amounts are amounts related to OPG's Heavy Water Storage ("D2O") project, but not the amount for the project as a whole. In this regard, Board staff indicated that the OEB's approval should not be considered a finding of prudence for the D2O project.

OPG accepts Board staff's position related to the future consideration of prudence with respect to the remainder of the D2O project to come into service after the test years (Board staff argument, p. 34). OPG fully recognizes that any in-service addition outside the test period will be subject to a future prudence review.

CME supported the position of Board staff related to in-service additions. However, CME recommended a reduction of between 10 per cent and 20 per cent of all in-service additions proposed for the test periods with respect to the D2O project and the Auxiliary Heating System ("AHS") project (CME argument, p. 25). While taking no position with respect to the total in-service additions, CCC also supported the position of CME related to the D2O and AHS projects.

OPG disagrees with CME and CCC's position. The majority of the cost increases related to D2O and AHS are due to maturation of these projects' scope definition, scope management, unforeseen subsurface conditions or revised estimates. In other words, the increased budgets are simply reflective of the true project costs (Ex. D2-2-2, Attachment 1, p. 16). As many of the cost variances are scope based, OPG and ratepayers are actually getting the value of a fully scoped project reflecting the true cost. With respect to the D20 project it was noted in the proceeding:

> MR. REINER: So what has happened on that project is when the initial estimate was submitted by the contractor -- so this goes back to the business case that's filed in evidence -- the scope of work was not well understood. So since that time, there have been a variety of reviews done and they are reviews that include engineering, operations, maintenance, to look at the facility, assess whether it meets the requirements, understand in whole the total scope of that facility, also understood the construction complexities. That facility is being constructed under a new set of seismic requirements that the CNSC has issued. Because it is a nuclear safety facility it contained tritiated heavy water. We have to protect and contain that water in the event of a seismic event.
>
> Those seismic changes were very recent updates from the CNSC, so that has resulted in significant changes in the construction. We have -- so for example, what it has entailed is caissons and pylons down to bedrock for that facility, concrete encasement, tritium removal systems.
>
> So all of those requirements are now fully understood, and that's why we are in process of doing a revision of the estimate and the schedule. (Tr, Tech. Conf., July 8, 2014, p. 62).

Furthermore, the in-service amounts related to D2O are only part of the project and reflect services required for ongoing tritium removal facilities and station operations (Ex. JT3.5, p. 1). These include: relocation of buried services such as a helium line, Tritium Removal Facility Argon and oxygen tank and piping, yard drainage and storm sewers, soil laydown and miscellaneous tie in pipe and valves (Ex. JT3.5, p. 1).

The AHS project replaces an existing boiler house that is beyond its useful life. The current boiler house provides back-up steam to the Darlington station to maintain the station above 10 degrees Celsius when all operating units are shutdown. The project provides a reliable source of steam to support irregular operating conditions when all four units are shut down in the winter to avoid freezing and equipment damage (Ex. JT3.2, Attachment 1).

As a result of scope changes arising from the contractor's original underestimation of scope complexity, a number of material changes have been required to the AHS project, including custom design of boilers and auxiliary equipment to accommodate the building footprint, while maintaining demand output requirements. The AHS project is critical to the Darlington Vacuum Building outage scheduled for April, 2015 (Ex. JT3.2, Attachment 1).

The 10 to 20 per cent reduction to in-service amounts applicable for D2O and AHS are intended to penalize OPG and are without justification. With respect to D2O, the majority of the project costs will be considered in a future proceeding and will consider the management of the project overall at that time. As noted, those aspects that will be in-service in the test period are not the drivers of scope change and are ancillary to the whole project. With respect to AHS, the incremental amount relates primarily to scope and not the mismanagement of a project that was accurately scoped at the outset. The ratepayers are getting the projects required at a cost that provides appropriate value for the now established scope.

SEC submitted that the Water and Sewer Project and the Electrical Distribution Project should be added to rate base. However, the other project in-service amount, should not be disallowed, but should be deferred until further evidence is provided or until the refurbished units are operational (SEC argument, p. 44).

OPG submits that there is sufficient evidence on the record to justify the inclusion of the projects in rate base and that the projects or part of the projects brought into service are or will be used or useful in the test period. In particular, OPG notes the following:

- Darlington Operations Support Building ("OSB") Refurbishment: SEC had no concern as to the timing of the in-service addition as SEC acknowledged that the building, once the refurbishment was completed in 2015, will be used and useful for the benefit of ratepayers in support of energy production from Darlington Nuclear Generating Station. SEC raised a concern about the evidentiary justification for the amount of $47M in project cost (SEC argument, pp. 40-41). As stated in Ex. D2-2-1, the OSB Refurbishment, including non-capital expenditures, was projected to be $46.8M and had a projected in-service amount of $29.7M with an in-service date of September 2015. A full business case of this project was filed as part of Attachment 8 of Ex. D2-2-1. By way of update through Ex. D2-2-2, the in-service date is forecasted to be August 2015 with an in-service amount of $45.1M. This amount reflects the amounts stated in the business case set out in Attachment 8-4 of Ex. D2-2-1 and an accelerated in-service date of August, 2015. As a result, OPG submits that there is sufficient evidence on the record to establish the in-service amount.

- D2O Storage: SEC submits that the costs in respect of this project should only be brought into service as part of the costs of the main project. However, this project is not limited to storing the heavy water that will be removed from the refurbished units (Ex. L-4.9-15 PWU-005). This project will also integrate with the Darlington tritium removal facility to allow the Darlington site to manage tritium emissions and levels and dose levels to workers as part of ongoing operations (Tr. Tech. Conf., July 8, 2014, p. 7, lines 25-28). It also anticipates the requirement for Pickering heavy water to be detritiated at some point in time as part of its final end of service and decommissioning. OPG also provided detritiated water for Bruce Power and Hydro Quebec (Tr. Tech. Conf., July 8, 2014, pp. 70-72). As a result, the D2O storage facility is not wholly related to the DRP and is related to on-going operations as well. As such the OEB should not accept SEC's submissions in this regard.

- Auxiliary Heating System: SEC submits that the in-service amount for the AHS project should not be added to rate base as it relates only to the DRP and does not appear to be required in 2015 when it is projected to be in-service (SEC argument, para. 4.9.7). As noted, the AHS project is essentially a replacement of an old boiler house. It is required in order to protect station systems in the event that there is a power outage and loss of electricity and heating to the power plant on a cold winter day. It is intended to protect the plant systems from damage due to freezing (Tr. Tech. Conf. July 8, 2014, p. 8, lines 1-7). Furthermore, the AHS project is key for the vacuum building outage that is pending for Darlington. At that time, 4 units will be shut down in the spring and during that time there may be cold weather that could require the system to be available (Tr. Tech. Conf., July 9, 2014, pp. 31-32). An updated business case for the AHS project was filed as part of Ex. JT3.2.

- Darlington Energy Complex ("DEC"): While the DEC will provide a full mock-up for training as part of the DRP, the DEC also has an ongoing function to address other business needs, create efficiencies and maximize the occupancy of the facility (Ex. L-9.6-17 SEC-135, part h). The DEC will house other OPG programs and services including the security program for processing new DRP staff and a new information centre to replace the current facility on-site. The DEC will also provide warehouse, office space, and training for the nuclear support, eliminating the need for existing leased facilities (Ex. D2-2-1, p. 23). A full business case for the DEC was filed as part of Attachment 8-1 of Ex. D2-2-1.

- Other Campus Plan Projects: These projects will become used or useful once placed in-service and used to support station projects and outages, in addition to refurbishment work. Leasehold improvements to the GM Building to house nuclear project staff, working on both refurbishment and non-refurbishment projects, are included in this amount. In addition, other facilities include a salt shed, parking improvements, and contractor facility that will support station needs, including outages and Nuclear portfolio projects. A breakdown of the amount reflecting these projects is set out in Attachment A to Ex. JT3.5.

- Safety Improvement Opportunities: SEC submitted that there was no basis in evidence to accept the in-service amounts for safety improvement opportunities. However, as explained by OPG, safety improvement opportunities are projects that OPG must complete prior to the first unit refurbishment as part of the Environmental Assessment ("EA") for the refurbishment as well as for continued operations of Darlington (Ex. JT3.5). These projects will become used or useful by the Darlington station once placed in-service as these are safety enhancements to the existing station. These projects include:

    1. **Third Emergency Power Generator** will be used or useful in meeting an EA commitment to the CNSC by providing improved availability and reliability of the Emergency Power System at the station when it is placed in service in 2015 (Ex. L-4.9-15 PWU-005). It will be able to withstand a higher level seismic event than the Design Basis Earthquake.

    2. **Containment Filtered Venting System** will be used or useful once placed in service in 2015 (Ex. L-4.9-15 PWU-005). Partial in-service amounts of $2M will be used or useful immediately as it allows for a controlled, filtered

release of airborne activity to the environment from containment to prevent failure from over-pressurization in the unlikely event of a severe accident.

3. **Powerhouse Steam Venting System** will be used or useful in meeting the safety improvement EA commitment to CNSC when it is placed in service in 2015. It will improve the reliability of powerhouse venting to prevent damage to safety related systems, structures, and components in the event of a piping failure (Ex. L-4.9-15 PWU-005).

4. **Shield Tank Over Pressure Protection** will be used or useful once placed in service in 2015. Partial in-service amounts of $3.5M will be used or useful immediately as it prevents shield tank failure from over-pressurization under severe Beyond Design Bases Accidents ("BDBA").

5. **Emergency Service Water Buried Services** will be used or useful once placed in service in 2015. The installation of a parallel buried line of piping will continue to supply cooling water to selected safety related systems when normal water supplies are unavailable for the removal of decay heat and prevention of subsequent process failure, which may result in release of radiation to the public.

Therefore, based on the foregoing, there is sufficient evidence for the amounts that relate to Darlington Refurbishment to be placed in-service in the test years and be closed to rate base.

GEC's submissions on the in-service additions related to Darlington focused almost entirely on the D2O and AHS projects. According to GEC, because of what has happened in the past in relation to these projects, OPG should not be entitled to recover any in-service additions even if they are unrelated to D2O or AHS (GEC Argument, pp. 18-19). However, as set out in Attachment 1 to Ex. D-2-2-2, OPG has put in place clear recovery plans to properly scope and schedule for both the D2O and AHS projects in a manner that will add value (pp. 15-21). The submissions of GEC are an over generalization that lack analysis. As noted above, the facts reflect projects that will be used or useful to ongoing operations at an appropriate cost. As such the amounts should be added to rate base.

VECC states that the OEB should order OPG to obtain an independent expert report that addresses what costs were incurred to remedy the managerial errors identified in the BMcD/Modus report along with any costs arising from original decisions (VECC argument, p. 22). According to VECC, no amount for in-service additions should be approved by the OEB, until such a report is filed. OPG disagrees with this suggestion. As noted, most of the projects for which in-service additions are sought do not relate to the D2O or AHS projects and they were not the subject of concerns expressed by BMcD/Modus. As such the restriction suggested by VECC should not apply to those amounts. As noted above, OPG has put in place proper recovery plans for both D2O and AHS.

In any event for the D2O project, OPG will, as part of any justification, have to produce reports and evidence as to why the amounts not sought to be added in this proceeding are appropriate to add to rate base at a later date. As such, not only is VECC's request for such a report irrelevant to most of the in-service additions sought by OPG and unfairly prejudices OPG, it is redundant to the burden OPG will bear in a future proceeding to obtain approval for rate base additions related to D2O.

Based on the foregoing OPG submits the in-service additions OPG seeks to add to rate base in respect of the Darlington Station should be approved by the OEB.

5.12 ISSUE 4.10

Primary - Are the proposed test period capital expenditures associated with the Darlington Refurbishment Project reasonable?

OPG is forecasting capital expenditures on the DRP of $839.9M in 2014 and $842.5M in 2015, an increase from the amounts included in the pre-filed evidence (Ex. D2-2-2, p. 7).

To comply with the Long Term Energy Plan (“LTEP”), to continue its progress to Release Quality Estimate (“RQE”) in the Definition Phase and to be ready to move to the Execution

Phase shortly thereafter, capital expenditures are required over the test period. These capital expenditures include the work required in respect of the Retube and Feeder Replacement ("RFR") work package. In November 2013, an updated DRP Business Case was presented to OPG's Board of Directors as part of an approval of the planned expenditures in 2014 and 2015 (Ex. D2-2-1, p. 13 and Ex. D2-2-1, Attachment 5). There are also a number of prerequisite projects that must be completed from a nuclear regulatory perspective and also on a support basis.

With respect to the approval of the capital expenditures for the test period, GEC indicated that the OEB should first consider the cost-effectiveness of the DRP as a whole, before considering the reasonableness of sub-components (GEC argument, pp. 15-19). This position, however, is contrary to the OEB's decision in EB-2010-0008:

> The Board disagrees with GEC's position that public interest must be determined before a determination on the capital budget. For the purposes of this Decision, the Board's focus is on the reasonableness of the test period expenditures, including a determination as to whether they are supported by the business case. (EB-2010-0008, Decision with Reasons, pp. 71-72).

As a result, the OEB is not required to go through the economic review at this stage before considering the reasonableness of OPG's capital budget.

With respect to an economic review, GEC attempted to challenge the LUEC calculation for the project. Based on that calculation, GEC asserted it is unclear how OPG can maintain that its capital budget is reasonable. ED also considered OPG's LUEC calculation and on that basis stated the capital expenditures were not reasonable.

ED argues that "Based on OPG's current 'high confidence' cost estimate the LUEC from refurbished Darlington units will be 8.9 cents per kWh" (ED argument, p. 14) and cites OPG's response to Ex. J14.4. As shown in OPG's response to J14.4, the 8.9 cents per kWh that ED has quoted for OPG's "high confidence" estimate is a misleading because it combines OPG's very high confidence cost estimate together with the high confidence capability factor. It is technically incorrect to imply that the high confidence LUEC is derived by taking high confidence inputs for all factors and calculating that LUEC. In OPG's view, the technically correct view of the high confidence LUEC is as shown in the LUEC S-curve (Ex. D2-2-1 Attachment 5, pp. 19-20, Fig. 1). The high confidence economic LUEC (70 - 90 per cent confidence) is 7.6 c per kWh to 8.1 cents per kWh (in 2013$) or approximately 7.8 cents per kWh to 8.3 cents per kWh when converted to 2014$. This high confidence LUEC range is derived using probabilistic Monte Carlo simulation techniques applied to the large range of input factors which affect the LUEC.

GEC makes a number of misleading assertions with respect to LUEC (GEC argument, p9. 15-17). GEC refers to a partial LUEC for DRP, excluding externalities of 7.25 cents per kWh, and cites Figure C3 in Attachment 5 of Ex. D2-2-1. It is unclear how GEC derived this number as it is not in evidence. GEC's assertion is that OPG's LUEC does not include externalities is misleading. OPG's costs for the DRP include taking care of all emissions, including all nuclear waste management and decommissioning costs. The statement that nuclear costs should also include an externality amount to reflect "accident risk borne by the public beyond the token amount required by the *Nuclear Liability Act*", is simply a personal opinion (GEC argument, p. 15). GEC's argument that "if the nuclear program were wound down, fixed overheads could be reduced" does not make these costs a part of the economic view of the DRP (GEC argument, p. 16). These costs are past costs for severance, pension and OPEB, which will be incurred regardless of the decision to refurbish or not to refurbish Darlington.

Board staff and others take the position that the OEB should not make a finding on the reasonableness of the proposed capital expenditures as it will be unclear as to what that would mean given costs associated with these projects will not go into service in the test period. OPG believes that the OEB can take guidance from its decision in EB-2010-0008 where the OEB stated:

> However, in the Board's view this does not preclude the Board from assessing the reasonableness of the proposed expenditures before they are made. The Board agrees with OPG that the prudence review of those aspects of the work which are found to be reasonable in this proceeding will be limited to the differential between the proposed expenditures and the actual cost. (EB-2010-0008, Decision with reasons, pp. 70-71).

While agreeing with Board staff, SEC made certain comments to which OPG believes it needs to respond. SEC stated that OPG has had significant cost over runs and have "screwed up" much of what has been done (SEC argument, para. 4.10.5(b)). This is an over statement that is not justified by the evidence. In the context of its capital expenditures, it is clear that most of the cost variances have come from two projects out of a number of projects that OPG is pursuing with respect to the DRP (Ex. D2-2-2, Attachment 1, p. 16). The overall impact on the DRP project is minimal (Ex. D2-2-2, Attachment 1, p. 2). Furthermore, OPG has independent oversight with the expectation of critical review for the continued improvement of the project. This is the key to a successful mega project - critical review and identification of issues so that clear and effective action can be taken. As stated by BMcD/Modus:

> As such, megaprojects' risks need to be viewed at a macro level, **as day-to-day assessments can be misleading and uninformative.** As an example, an owner could chose to mitigate a larger risk to the overall project by accelerating a predecessor project at additional cost. Without the context of the larger project, the cost-benefit analysis to incur the additional cost could not be justified. (*emphasis added*) (Ex. D2-2-2, Attachment 1, p. 8).

BMcD/Modus also indicated that:

> There are three core nuclear industry principles that are essential ingredients to our oversight mission:
>
> (1) In the nuclear community, there is wide acceptance of the need for ***continuous improvement*** based on learning lessons from operational experience ("OPEX"), which provide a basis for judging progress and effectiveness;
>
> (2) Nuclear projects and operations are in a constant search for corrective actions which are specific recommendations for mitigating or recovering from problems; and
>
> (3) When problems are identified and corrective actions attempted, it is essential to establish the extent of the condition to properly characterize the magnitude of any one problem or set of problems. (Ex. D2-2-2, Attachment 1, p. 9).

The key aspect as stated by BMcD/Modus is that OPG is responsive to oversight and is taking direct and appropriate steps to carry out the various projects that make up its capital expenditures and the DRP in general. In particular as stated by BMcD/Modus:

> We meet weekly with DR Team's point of contact who updates the log of recommendations and actions, and meet periodically with the Project's leadership team (the "Refurbishment Project Executive Team" or "RPET") as a whole. To date, we have seen the DR Team take action on many of the items we have raised, including: (1) taking the recommendations as written as well as the prescriptive actions we may have identified; (2) finding a middle ground for response and action; or (3) identifying how the DR Team plans to address such recommendations in the future. In our reports, we identify the team's progress and monitor both the sufficiency and the speed of its responses. Thus far, we have been satisfied with the DR Team and P&M organization's actions or commitments to providing responses to our recommendations. (Ex. D2-2-2, Attachment 1, p. 11).

Based upon the foregoing, the test period capital expenditures associated with the DRP are reasonable.

5.13 ISSUE 4.11 AND ISSUE 4.12

Oral Hearing - Are the commercial and contracting strategies used in the Darlington Refurbishment Project reasonable?

Primary - Does OPG's nuclear refurbishment process align appropriately with the principles stated in the Government of Ontario's Long Term Energy Plan issued on December 2, 2013?

Below, OPG will respond to submissions made by parties with respect to both Issues 4.11 and 4.12. OPG submits that its Commercial and Contracting Strategies with respect to the Darlington Refurbishment Project are reasonable and the OEB has sufficient evidence in this proceeding to make that determination at this time. OPG further submits that OPG's nuclear refurbishment process adheres to the principles of the LTEP.

Ruling as to Reasonableness

Parties such as Board staff, SEC, CCC, and CME have asserted that the OEB should not make a ruling of reasonableness relating to OPG's commercial and contracting strategies at this time. OPG submits that the relief requested and the underlying intent of the request is sufficiently clear for the OEB to rule and to make a determination.

Board staff states that it remains unclear why OPG needs the OEB to make a determination on the issue of whether the commercial and contracting strategies related to the Darlington Refurbishment Project are reasonable (Board staff argument, p. 36). During the course of the proceeding, OPG made very clear what a ruling in this regard includes (AIC, p. 44; Tr. Vol. 16, p. 4). Witnesses further clarified:

> MR. REINER: We'd certainly want to understand if there are areas that are of concern, and we would want to understand why they are of concern. (Tr. Vol. 16, p. 38).

> MR. REINER: …where the Board sits in terms of not being able to see the whole picture, being able to see a partial picture, but I would have to think it's helpful to understand what the approach is that's being utilized, and then to be able to see that as the project progresses and to see how the project is performing relative to those approaches. (Tr. Vol. 16, p. 39).

> MR. REED: The Board would be looking at the reasonableness of the company's decisions in the same context in which the company has had to make those decisions. The company doesn't know what the final project is going to cost. The company doesn't know what's going to happen during execution phase and even what the RQE is. But it does have to make decisions now, and it has for the last three years, as to what the right commercial strategy is and contracting strategy. So in my view, a test of reasonableness is one that bases that evaluation on the circumstances that prevailed at the time those decisions were made. So by examining it now, the Board is able to put itself in the same shoes the company was in in having to make those decisions without knowing the consequences of those decisions, without knowing the results for sure. (Tr. Vol. 16, p. 40).

Consistent with this is OPG's position, stated in its submissions related to the Issues List established in this proceeding:

> [I]t is appropriate to examine whether its proposed commercial and contracting strategies (see Ex. D2-2-1 p 15-17) are reasonable given the long time horizon and significant costs of the project. Such an examination will not be a prudence review, which can occur only after project completion when costs are known. This issue will provide OPG with the benefit of the OEB's view on the reasonableness of proposed commercial and contracting strategies as those strategies are implemented and administered over the Project's life. Project plans at times must adapt to changing circumstances. A review of commercial and contracting strategies at the current stage will provide the OEB with a baseline

> against which to consider the ultimate execution of the project on a future full prudence review. (OPG Draft Issues List Reply Submissions, January 31, 2014, p. 9).

Board staff attempted to draw a parallel with the OEB's consideration of the Niagara Tunnel project in EB-2010-0008 (Board staff argument, p. 36). However, both the nature of the proposed review and its timing distinguish the situation here from the Niagara Tunnel project review proposed in EB-2010-0008. In their EB-2010-0008 submissions on the issues list, SEC, CME and CCC all requested that the OEB examine the prudence of the Niagara Tunnel project before the project was complete and its costs closed to rate base (EB-2010-0008, SEC Opening Submission, p. 2; CME Opening and Reply Submission, p. 2; and CCC Opening Submission, p. 1). OPG properly opposed these requests and the OEB agreed. Here, neither OPG nor any of the parties supporting inclusion of this issue are suggesting that the OEB conduct a prudence review of Darlington Refurbishment. The proposed review involves only OPG's contracting strategies, not the project's cost.

OPG's request is clear and defined. It provides an appropriate structure within which to consider OPG's future activities. A finding of reasonableness will not eliminate the need for a future prudence review and the aspects that will encompass that review. However, it will enable that review to be assessed in the appropriate context.

GEC and ED Ignore the DRP's Complexity

Unlike other intervenors, GEC and ED submitted that OPG's commercial and contracting strategies were not reasonable and that OPG had not satisfied the principles set out in the LTEP.

The ED and GEC submissions are built around two primary aspects. First, an interpretation of the LTEP principles applicable to nuclear refurbishment relating to risk minimization and second, the target pricing mechanism's ability to transfer sufficient risk to contractors.

With respect to the LTEP principles, both ED and GEC focus on the following three of the seven principles of the LTEP applicable to nuclear refurbishment:

1. Minimize commercial risk on the part of ratepayers and the Government.
5. Require OPG to hold its contractors accountable to the nuclear refurbishment schedule and price.
6. Make site, project management, regulatory requirements and supply chain considerations, and cost and risk containment, the primary factors in developing the implementation plan.

Based on these principles, both ED and GEC adhere to the position that the fundamental aspect underlying these principles is the absolute minimization of risk. However, both ED and GEC have a very one dimensional view of what is meant by minimizing risk. That view is wholly focussed on the existence of a fixed price turnkey contract. For both ED and GEC, such a contract is a panacea. In adopting this position, ED and GEC fail to comprehend the complexity of the DRP, overstate the risk mitigation that such contracts provide and ignore the inherent risk associated with fixed price turnkey contracts.

OPG does not disagree that the minimization of risk is key to the success of the DRP. However, OPG disagrees with the singular and narrow perspective of ED and GEC. Although the risk associated with commercial and contracting strategies is important, it has to be considered in conjunction with a broader strategy to minimize risk because of the unique and complex nature of the DRP as a mega project. Because the DRP is a mega project there is no “textbook” or singular approach – it is case-by-case dependent on the circumstances of each project (Tr. Vol. 16, p. 28).

In the case of the DRP, the multi-faceted approach to risk minimization includes:

- OPG retains project management responsibility and design authority for the DRP. This provides OPG with direct and clear visibility into the work plan, schedule and cost of each prime contractor, and enables OPG to discern potential risks and to ensure early corrective action. These actions would include recovery and monitoring plans to adhere to schedule and cost estimates (Tr. Vol. 14, p. 57).
- By the time the release quality estimate (“RQE”) is developed in 2015, OPG will have tested every sequence of work taking place on the critical path, tested all tools

developed, tested the abilities of the workers that will use the tools and will have tested setup, tear down and the execution of work (Tr. Vol. 16, pp. 19-21). This approach will enable OPG to properly scope the project to minimize risk.

- Throughout the project OPG is subject to continuous critical oversight designed to highlight risks and issues to ensure self-assessment and corrective action during the development and execution of the project. This includes internal auditors, internal oversight committee, scope review board, options review board, Blue Ribbon committee on scope, and gate review board on funding releases. There is also the Nuclear Oversight Committee of the Board of Directors with the independent and critical review of activities by Burns & McDonnell/Modus Strategic Solutions. The Ministry of Energy also has its own independent oversight embedded in this project (Tr. Vol. 16, p. 144-145).
- OPG's strategies take into account the significant size and complexity of the DRP and the fact that no one contractor has the knowledge or capacity to execute the project or the financial and commercial wherewithal to fully absorb the financial risk of the project. As such, it has developed an arrangement where the nature of the work and technical clarity results in either a fixed price or target price, together with incentives and disincentives (Tr. Vol. 16, p.4).

Each of these aspects is a fundamental part of minimizing the risk of the project (Ex. D2-2-2, Attachment 1, pp. 8-9); Ex. D2-2-1, Attachments 7-1, p. 6).

ED and GEC, on the other hand, have failed to grasp the complexity of the DRP and its unique aspects. As a result, ED and GEC completely ignore the first three aspects above and erroneously focus on a fixed price arrangement on the misbelief that a fixed price turnkey contract is without risk, is the only means by which risk is managed and minimized and is the only reasonable strategy. As demonstrated below, GEC and ED's assertions and conclusions in this regard are incorrect and should be disregarded by the OEB.

Fixed Price Turnkey Contract is not Viable

GEC and ED have challenged OPG's approach on the basis that a fixed price turnkey contract model should be used and that, under the OPG approach, OPG has not transferred sufficient risk to contractors. However, GEC and ED's assertion that a fixed price contract as the only means to minimize and manage risk is incorrect as they each fail to take into account certain fundamental facts that impair the use of fixed price arrangements.

A fixed price turnkey contract has one contractor responsible for delivering to the owner a completed project. The contractor takes full responsibility for design and execution. As the contractor bears the full risk under the contract, the influence of the owner is limited unless there is a corresponding transfer of risk to the owner from the contractor to account for that influence. The result, assuming risk is to remain fully allocated to the Contractor as proposed by GEC and ED, is that the owner has little ability to monitor risk issues and require recovery or corrective actions. This is an inherent risk found in fixed price turnkey contracts that ED and GEC ignore. In particular, this is a risk relating to schedule that the owner bears and has no ability to mitigate. The owner inevitably carries the risk with schedule delays. It is a risk it cannot shed and a risk it could not mitigate under a fixed price turnkey arrangement (Tr. Vol. 14, p. 55); Tr. Vol. 16, pp. 45-46).

If a project has clearly known and understood technical parameters (perhaps such as a typical construction project) a loss of control over schedule and the project's progress may be acceptable in return for a fixed price turnkey arrangement (Tr. Vol. 16, p. 46, lines 15-25). However, this is not the case for a mega project that has intrinsic risks that lack clarity (such as the condition of the reactor face) and are not within the contractor's management skill set. Mega projects "have a rhythm all their own and typically involve large sums of money, lengthy, multi-year project schedules and significant risks…" (Ex. D2-2-2, Attachment 1, p. 8). This is the circumstance with the DRP. Based on lessons learned by OPG with respect to execution at the Point Lepreau project, OPG is minimizing exposure to schedule risk and related costs by adopting its stated multi-prime contractor approach with target pricing. Unlike a fixed price arrangement, as noted, under its strategies, OPG will be able to actively manage and monitor the project to mitigate its inherent schedule and cost risk through direct and clear visibility into work plans, schedule and cost (Tr. Vol. 14, pp. 57).

GEC incorrectly assumes that the required visibility and transparency for a project like DRP could be merely negotiated into a fixed price turnkey contract (GEC argument, p. 24). However, this assertion is misleading and demonstrates a fundamental misunderstanding of what a fixed price turnkey contract is designed to do. For a contract of this nature that transfers to the contractor risk and responsibility for the project, the contractor will require both (i) a price that reflects the financial risk assumed (dictated by the value, complexity, potential delay related to the project and alternately the contractors financial exposure if things go wrong), and (ii) control in order to manage that risk (Tr. Vol. 16, p. 33, lines 20-27). Under a fixed price arrangement, because the contractor assumes significant risk, the contractor will require significant control as well as a premium monetary return to mitigate and offset that risk. If, as suggested by GEC, there are aspects that provide the owner the ability to affect the course of the project, then there will be corresponding risk mitigation provisions for the benefit of the contractor that will enable the contractor to potentially avoid the responsibility and effectively limit exposure because of enhanced owner involvement. This will limit any benefit of a fixed price and the associated price premium (Tr. Vol. 16, pp. 33-34). In effect, what in concept may have started as a fixed price turnkey arrangement will through negotiation see risk transferred to the owner.

This was referred to in evidence by Mr. Reed of Concentric when he stated that:

> MR. REED: In the wake of the Lepreau experience I can understand that, and I can tell you that from our experience, while it may be easy to attach a label to a contract like lump-sum or turn-key or fixed-price, what happens is you start to peel back in the terms of the agreement the excluded conditions, the limits of liability, the excused performance events, and the owner responsibility events, and it becomes nothing more than essentially a sham, as people start to realize the risks they're undertaking. (Tr. Vol. 14, pp. 46-47).
>
> * * *
>
> MR. REED: Again, it would also come down to contract language. In our experience -- and this was the case with Lepreau, when you have so many opportunities for excused performance, for owner responsibility, for limitations of damages and limitations of liability, very, very quickly you realize that what you thought you were paying for you aren't getting.
>
> So that is not a reasonable strategy. And it stems -- just one quick point of sort of education and background on this. It stems from the fact that so many of the risks are beyond the control of the vendor, of the contractor.
>
> There are huge extrinsic risks here outside of the project or the program that no vendor would be willing to take on, because they are political, social, natural-

> event risks. They are economic and market risks that have nothing to do with the project or how well or poorly construction is being performed.
>
> So under that existence, you can understand why it is impossible to estimate or quantify that risk or to price it, which is why vendors aren't prepared to accept it. And again, we have seen where many parties have thought they had, in fact, shifted risk under a lump-sum turn-key contract, that ends up not being the case. (Tr. Vol. 14, p. 48).

In addition to the protective clauses described above, a contractor will also hedge its financial exposure under a fixed price turnkey contract with a price premium. As stated by Concentric:

> In addition, recent experience with this strategy has demonstrated that although the model proposes to transfer significant risk to a vendor, such risk transfer is largely unachievable in a nuclear safety environment due to exemptions for excused events and force majeure, the owner's liability for nuclear safety, and a lack of complete, detailed designs. As a result, the price premium paid to transfer risk is usually not commensurate with actual risk transferred to a vendor. At Point Lepreau, the fixed price, lump sum, turnkey strategy has largely protected NB Power from cost overruns, but has provided limited protection from schedule slippage and the extensive cost of replacement power that resulted. (Ex. D2-2-1, Attachment 7-1, p. 7).

This was further clarified by Mr. Reed when he stated:

> MR. REED: Two things to remember. Number one, LSTK, or lump-sum turn-key arrangements, are neither lump-sum nor turn-key. Fixed-price is not a fixed price, other than a term used in a contract. And the best example of that is -- that's relevant is Lepreau. Lepreau had more than a billion dollars of delay costs and more than a billion dollars of overrun costs borne by different parties, but still dramatic cost changes on the engagement, even though that was described as an LSTK, or lump-sum turn-key contract, and there is many, many examples I can point to where people have been rudely awakened as to what that term means. (Tr. Vol. 14, p. 45).

Furthermore, potential contractors are not prepared to entertain fixed price turnkey contracts (Ex. D2-2-1, Attachment 7-1, p. 8; Tr. Vol. 16, p. 45).

This is not a cookie cutter exercise (Tr. Vol. 16, p. 28). This is clearly evident from the issues that have occurred at Point Lepreau which have factored into OPG's learning and the need to minimize risk. However, ED and GEC have chosen to be selective in endorsing a fixed price turnkey approach. They have effectively ignored Point Lepreau as a case study applicable to the Canadian market and have pointed to Wolsong as a project that OPG should follow (Tr.

Vol. 16, p. 85). Although OPG has reviewed Wolsong as a basis of lessons learned, GEC's assertion that Wolsong was fixed priced and OPG can accomplish the same result is not correct. A key distinguishing factor was the existence in Canada of unionized labour that requires different treatment than incurred in Korea (Tr. Vol.16, p. 86; Tr. Vol. 16, p. 47).

Both ED and GEC place weight on the fact that a fixed price turnkey contract was not sought from bidders. However, efforts were made by OPG:

> MR. REED: Mr. Elson, if I could add a point on that, which I think is documented in the evidence here, the company did specifically ask for an approach to contracting that was short of LSTK, a form of contracting called JV or joint venture contracting, in which a joint venture would be established that would be owned by OPG, by the multiple contractors performing their work. And collectively, the profit or loss of that JV would determine the profit or loss of the contractors.
>
> That was specifically proposed to all of the bidders, and that is obviously a level of risk that is far, far less than LSTK or lump sum fixed-price contracting.
>
> None of the bidders, not one, agreed that it would submit a bid -- at any price -- under a JV structure.
>
> JV structures actually have a lot more success in other industries, because they -- again, they are short of a fixed-price arrangement, but if the bidders weren't prepared to submit a bid at all under a JV structure, it certainly says to me that they wouldn't be comfortable going beyond that. (Tr. Vol.14, p. 51).

Once again ED and GEC have over simplified something that is very complex. This is a unique project undertaken at considerable costs over many years. It is not comparable to a typical construction project where a fixed price arrangement may be more acceptable. As such the commercial and contracting strategy must match the risks and specific circumstances.

The conclusion based on the above is that a fixed price turnkey contract is not viable (Ex. D2-2-1, Attachment 7-1, p. 7; Tr. Vol. 14, pp. 45, 51). Therefore, based on the foregoing, the OEB should be careful not to accept the assurances by GEC and ED that the arrangements could be different since such assurances are based on oversimplification that reflect limited knowledge and no evidence.

Target Pricing and Oversight

OPG has adopted a target pricing model, which has at its core a contractual mechanism that aligns the party most capable of managing the risk with accountability for that risk. On this basis, where there is a high level of design completion and clarity of scope, the contractor is assumed to be best able to manage the risk. In this circumstance, there is a fixed price provision in the contract and less project oversight (Tr. Vol. 16, p. 4). Where there is less project definition, risk will be allocated between the parties with incentives and disincentives built into the contract that has target pricing (Tr. Vol. 16, p. 21). Therefore, OPG has established a contracting approach that uses fixed pricing where appropriate and has built in incentives to avoid cost overruns and schedule delays. Fundamental to this approach are two key and essential components: (i) appropriate contract incentives and disincentives; and (ii) effective project oversight. Both will be considered below.

For example, with respect to target pricing, the retube and feeder replacement work package reflects approximately 60 per cent of the total DRP cost. Because the conditions that will arise on the actual reactor face are unknown until the reactor is shut down and work commences, there is not sufficient clarity of scope for a contractor to absorb the risk of the work on a fixed price basis given the estimated magnitude of the cost and duration (Tr. Vol. 16, pp. 4, 17-18). As a result, the contract for this work package is based on target pricing.

Under this model, if the contractor's direct cost exceeds the target price, profits and overheads are recovered through a fixed fee, which impacts the contractor's overhead and profit. The contractor could effectively earn no profit and be compensated for costs only. This mechanism provides a clear incentive for the contractor to avoid cost overruns relative to the target price. The profits and overhead earned by the contractor are real and not fantasy as asserted by GEC (GEC argument, p. 22). A contractor has shareholders and is in the business of making a profit and paying a return. The loss of profit on a project that reflects a large transaction and that extends over a significant time period will not provide good financial results or return to its shareholders. Compensation for cost only is not a winning strategy of a for-profit contractor.

Also included in the target pricing arrangement, particularly in that related to retube and feeder replacement, are schedule disincentives for any delays beyond the approved target schedule. These financial penalties are not meaningless and are set in the contract as a fixed amount per day of delay which allows OPG to recover the bulk of the estimated burn rate per day of delay from the contractor. This is in addition to the cost disincentive mechanism which allows OPG to recover any additional cost overruns be it related to schedule or other direct expenses incurred by the Contractor. The contractor is also accountable for all costs related to any rework done because of contractor quality and costs related to rectifying items that fall under a warranty provision.

GEC and ED criticized OPG's strategies on the basis that only 7 per cent of costs were fixed. However, this does not accurately reflect the nature of the costs and the degree to which target pricing applies. As stated by OPG:

> MR. REINER: I'll maybe start, and I'll ask Mr. Rose to chime in. If you look at that estimate and you break it down into its components, and in the confidential filing you can see those components, there is a sizeable cost associated with things that are fairly fixed but we can predict fairly accurately, and it would include things like waste-related cost, fuel-related costs.
>
> The OPG project management costs are essentially time and material. We know what our burden salary rates are and how much time the project will take to execute. There is some uncertainty around that, because there is schedule uncertainty.
>
> But when you peel all of those things away, and then what you are left with is the executable work that the contractors will perform, the refurbishment, scope of work, so to speak, that becomes a smaller number. (*emphasis added*) (Tr. Vol. 16, p. 16)
>
> * * *
>
> MR. REINER: Under the target cost model, in general, cost is paid for, and incentives and disincentives are structured around a target cost.
>
> Now, costs aren't always paid for. There are circumstances where the quality of work, which is risk that clearly lies in the contractor space, if there is a quality of work issue that requires rework to be done, that is the contractor's cost. So that is 100 percent in the contractor's space.

> There are also warranty provisions, that if the work is faulty and the equipment fails, rectification is 100 percent in the contractor's space.
>
> But assuming the job progresses without quality issues and without any warranty issues, then the cost, the cost is paid and the contractor is incentivized to achieve the target cost and target schedule because they would essentially be paying OPG back profits and overheads associated with that cost. (Tr. Vol. 14, p. 53)

The 93 per cent of project costs identified includes OPG internal costs (e.g. OPG project management organization, facilities & infrastructure, insurance, fuel, licensing and permits, waste management, etc.). Only an estimated 27 per cent of the $10B estimate is/will be contracted out on a cost reimbursable or target pricing basis with incentives/disincentives for the five major projects within the DRP. In total, commercial risk applies to approximately 34 per cent of the $10B total DRP estimate, of which approximately 7 per cent is fixed price.

Working in tandem with the contract incentives is project oversight. These two aspects are at the core of OPG's commercial and contracting strategies. As stated during the proceeding[32]:

> MR. REINER: This is why we structured the project in a way that has OPG manage the work and have visibility into schedules and into the specific execution of work that the contractor is performing...and that is why in our particular case we want visibility into the schedule, we want visibility into the work, and the reporting and progress of work will come up through the OPG project management so that when we see a decision like this being contemplated <u>we can intervene and provide direction</u>. <u>(emphasis added)</u> (Tr. Vol. 14, pp. 56-57).

And as was further stated:

> MR. REINER: ... and a means for allocation of risk to the party that's best able to manage that risk through a pricing structure that's tailored to the level of project definition and also to the level of owner oversight that is required. And this means that the use of target pricing where projects are less defined and more oversight is required, or fixed pricing, where there is greater definition with less oversight required. (Tr. Vol. 16, p. 4).

Unlike the approach proposed by GEC and ED, OPG strategies recognize the complexity of the project and provide an allocation of risk and responsibility that is realistic and viable such

[32] Tr. Vol. 16, pp. 58-59 in the <u>confidential</u> transcript provides further evidence on this point.

that risk is minimized. As a result, OPG submits that the assertion of GEC and ED that the commercial and contracting strategies are not reasonable should not be accepted by the OEB.

Adherence to LTEP

With respect to the LTEP, both GEC and ED take the position that OPG has not minimized risk by keeping contractors to their schedule and price estimates. However, by recognizing the nature of the project and the inherent risk, OPG has established an inherent risk minimization approach. It does not (as proposed by ED) vest all the control of the project and its outcome wholly in the hands of a party that is neither regulated nor prepared to accept the risk without a contract that caps that risk but not necessarily the costs because of contractual exclusions. Like any supposed insurance, there will be risk not covered.

However, the province has very clearly indicated that Darlington Refurbishment is a key part of the LTEP. It would not be the intent for this to be accomplished at any cost. The intent is that the refurbishment be accomplished at costs that are economic at minimal risk. OPG has a strategy that accomplishes this end through the mechanism described above. The province is fully engaged in the DRP. As noted in evidence:

> MS. DUFF: And the Minister of Energy, who in the Long Term Energy Plan asked you, as one of the principals, to look at contracting strategies, do you feel that you have received their approval regarding the course that you're taking?
>
> MR. REINER: Yeah. We provide regular updates to the Ministry. And we present each time, as we progress through the contracting process, for example -- prior to making any commitments, updates were provided to the Ministry so they had an opportunity to do their own assessment and determine whether or not they're comfortable with OPG proceeding.
>
> And we do regular business plan updates, and separately, just updates on the refurbishment project.
>
> And they do also have their independent oversight embedded in the project, that provides reports back. (Tr. Vol. 16, pp. 144-145).

To date the province has not raised concerns regarding LTEP compliance.

OPG Past Experience and Intention

Both GEC and ED asserted that because of experiences related to past projects undertaken by OPG, OPG's commercial and contracting strategies should be rejected. OPG rejects this notion. GEC and ED are failing to recognize that past projects are a different set of facts. As noted, the DRP has an unprecedented level of internal and external oversight, preplanning and pre-execution work that incorporates lessons learned on past projects and those of other operators, systems, tools and processes will be tested before execution will commence and by the time RQE is reached, the project will have a very high degree of clarity as to scope (Tr. Vol. 16, p. 4). As indicated by BMcD/Modus, scope definition is a key success factor and OPG has this aspect well in hand: "The Refurbishment Project is appropriately advancing at the time of this assessment toward the goal of producing RQE by October 15, 2015" (Ex. D2-2-2, Attachment 1, p. 10).

ED also questioned OPG's motives and its ability to fairly represent the progress of the project. In this regard, OPG stated in evidence:

> MR. ELSON: Thank you. And in light of that, and in light of the other facts we just discussed, would you agree that OPG or its nuclear staff would have an incentive to underestimate or at least minimize the probability that the Darlington rebuild project would go over budget?
>
> MR. REINER: There is no incentive whatsoever to understate that. Our analysis is based on the way this project is being established, and I think as Mr. Rose earlier indicated, we are working towards a release quality estimate in 2015. That's based upon some very detailed knowledge about what the actual work is going to be that we're going to execute, having engineering completed, having long lead materials ordered, having all of the contracts in place. There's no incentive here to understate the cost. (Tr. Vol. 14, p. 34).

Conclusion

Based on the foregoing, OPG's commercial and contracting strategies are reasonable and should be approved by the OEB. OPG's strategies capture the unique nature of the DRP and set in place the proper and realistic approach to minimize risk in accordance with the LTEP.

6.0 PRODUCTION FORECASTS

6.1 REGULATED HYDROELECTRIC

6.2 ISSUE 5.1

Secondary - Is the proposed regulated hydroelectric production forecast appropriate?

OPG is seeking approval of a test period regulated hydroelectric forecast of 66.0 TWh (32.5 TWh in 2014 and 33.5 TWh in 2015) for the regulated hydroelectric facilities (Ex. E1-1-1, Table 1 and Ex. N1-1-1). With the exception of the treatment of surplus baseload generation ("SBG"), which is considered below, no intervenor objected to OPG's regulated hydroelectric production forecast, and as such, and for the reasons set out in OPG's evidence and AIC, it should be approved as filed.

6.3 ISSUE 5.1(a)

Primary - Could the storage of energy improve the efficiency of hydroelectric generating stations?

In its submission, Sustainability Journal made the following request:

> We submit that the OPG and other organizations in the planning, supply transmission, and distribution fields, and those organizations covered by the OEB's responsibilities for natural gas, should be required to produce public reports that consider these options (SJ argument, p. 3).

Since OPG's prescribed assets do not include any energy storage facilities as described in the materials from Sustainability Journal and since OPG has no plans to build such energy storage facilities, OPG submits that it is unnecessary for it to produce such reports. OPG has no other submissions on this issue.

6.4 ISSUE 5.2

Primary (reprioritized) - Is the estimate of surplus baseload generation appropriate?

Board staff, LPMA and SEC all supported OPG's proposed approach to SBG.

CME, on the other hand, expressed concern regarding the amounts currently included in the SBG variance account and the amounts that would continue to accumulate given the higher levels of SBG that have been forecast for the test period (Ex. J4.2). Accordingly, CME has requested that the OEB embed some level of SBG into the payment amounts by adjusting OPG's production forecast.

While OPG has no specific objection to CME's proposal (in fact, an offset to the regulated hydroelectric production forecast was the approach that was suggested by OPG to account for SBG in EB-2010-0008), OPG reminds CME that the OEB did not approve such an approach at the time of OPG's last payment amounts proceeding. For this reason, OPG's evidence in this Application is consistent with the OEB's direction from EB-2010-0008.

As such, and for the reasons set out in OPG's evidence and Argument-in-Chief, the approach for dealing with SBG should be approved as filed.

6.5 ISSUE 5.3

Secondary - Has the incentive mechanism encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices?

and

6.6 ISSUE 5.4

Primary - Is the proposed new incentive mechanism appropriate?

OPG has proposed modifications to its existing incentive mechanism as a result of the analysis that it conducted after the EB-2010-0008 Decision. As a result of its assessment, OPG elected to propose three basic changes in its proposal. First, the interaction between SBG and the existing incentive structure has been eliminated. Second, the amount that OPG earns has been tied to a forecast of consumer benefit, not to revenues. Third, the revenue requirement offset has been eliminated. Each proposed change is discussed in more detail below.

- OPG notes that the proposed elimination of the unintended SBG interaction going forward was well supported by Board staff and intervenors (CME, CCC, IESO, LPMA and SEC); hence, the question is how to implement this feature rather than whether or not to implement it.

- The tying of the revenues earned by OPG to a forecast of consumer benefits[33] seems inherently fair to OPG since it sets its own incentive revenues equal to the time-shifting benefits that will accrue to consumers.
- Finally, elimination of the revenue requirement offset is reasonable since OPG's incentive revenues are realized at the same time as consumer benefits. In addition, OPG cannot control the amount of incentive revenue that it ultimately realizes because it cannot control the price spreads that exist between on-peak and off-peak periods, which drive incentive mechanism net revenues. Thus forecasting a revenue requirement offset for incentive revenues places risk on OPG that it cannot control. Elimination of the offset will eliminate this risk.

When O. Reg. 53/05 first took effect, the Government saw fit to include a mechanism by which OPG was encouraged to operate its regulated hydroelectric facilities in an economically efficient manner. At that time, a simple production threshold was established, above which market prices would be paid to OPG. There was no financial consequence for not meeting that production threshold. The differential between the regulated rate and hourly Ontario energy price ("HOEP") was retained exclusively by OPG. It was not a revenue requirement offset; it was a pure incentive payment.

Since that time, numerous changes have been made to the incentive mechanism, including elimination of the pre-defined production threshold, inclusion of financial consequences for not achieving threshold, sharing of the incentive payment, inclusion of incentive net revenues within the revenue requirement and establishment of a variance account to facilitate sharing. The majority of these changes are to the benefit of the ratepayer.

Board staff's submissions were generally supported by CME, CCC, LPMA, SEC and VECC. The IESO, in its submission, supported OPG's proposal as filed, stating, "The IESO submits that the proposed [enhanced Hydroelectric Incentive Mechanism] is an improvement relative to

[33] As set out in page 7 of Ex. E1-2-1, the major elements impacting consumer benefits are reductions in payments to gas-fired generators, increased GRC costs and increase in export revenues.

the existing [Hydroelectric Incentive Mechanism] because it would incent OPG to respond to market prices and time-shift their generation as they do today while removing unwarranted incentive revenues arising from SBG spill." (IESO argument, p. 5).

Contrary to Board staff's assertions, the most recent changes that have been proposed (i.e. moving from the Hydroelectric Incentive Mechanism ("HIM") to the enhanced HIM ("eHIM")) are quite simple. The three major changes are set out in the opening paragraphs to this section. The details and justification of each of these changes are set out in evidence (Ex. E1-2-1), supported by an independent third party (Ex. E1-2-1, Attachment 1) and have been tested through interrogatories, technical conference questions and hearing cross-examination. In OPG's submission, for the size of its revenue requirement impact, the incentive mechanism attracts a disproportionate amount of hearing attention, particularly given the OEB's direction found in EB-2010-0008 at Section 1.6[34], and in response to Board staff's recommendation for more onerous Filing Guidelines.

OPG's proposal in EB-2013-0321 is responsive to directions included within the Decision with Reasons received pursuant to EB-2010-0008:

> The Board also directs OPG to **re-address the HIM structure** in its next application. Specifically, the Board expects OPG to **provide a more comprehensive analysis of the benefits of the HIM for ratepayers**, **the interaction between the mechanism and SBG**, and an **assessment of potential alternative approaches** in light of expected future conditions in the contracted and traded market. If OPG is unable to perform this analysis through lack of information, then the company should **seek to have the analysis performed by an agency with access to the necessary information**. It may well be appropriate for OPG to **request that the IESO examine the issue** and provide suitable evidence or for OPG to work with the IESO to prepare the evidence. (*emphasis added*) (EB-2010-0008, Decision with Reasons, pp. 147-148).

These directions, in their entirety, were carried out and are reflected in OPG's proposal in Ex. E1-2-1.

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[34] "It is the Board's conclusion that a number of issues which parties pursued vigorously in cross-examination and argument were not of sufficiently high priority in terms of the dollars or the principle involved."

Board staff appears puzzled by certain evidentiary citations and argues that OPG's position is internally inconsistent (Board staff argument, p. 47). OPG disagrees that its position is in any way inconsistent. At the hearings, OPG set out the approach that OPG proposes (eHIM) and contrasts the payments received in that proposal as opposed to the existing HIM construct (Tr. Vol. 4, pp. 114-120). It is clear from that exchange that in the new proposal OPG's amounts received are tied to <u>a forecast</u> of consumer benefit, where previously they were not. Additionally, there will be no reconciliation between forecast values and actual values (Ex. L-5.4-11 IESO-005). This is entirely consistent with OPG's evidence and the aforementioned transcript exchange. Because there is no reconciliation proposed, it must be recognized that OPG could earn more <u>or less</u> than the forecast amount. This is symmetrical (not biased in OPG's favour) and as such Board staff's concern about OPG retaining excess revenues (Board staff argument, p. 47) is unwarranted.

Further, Board staff also appears confused by OPG's statements on how it will operate its facilities in response to an incentive mechanism. In short, in the absence of any incentive mechanism OPG will operate the facilities consistent with how they are currently operated, but with a flatter production profile than occurs today with less time shifting of water due to the risks involved. OPG has been entirely consistent in its response to this question as set out in a number of evidentiary citations in EB-2013-0321 (including but not limited to Ex. E1-2-1; Ex. L-5.4-22 VECC-004; Ex. L-5.3-1 Staff-062; Tr. Vol. 4 pp. 35; Tr. Vol. 4 p. 47). The IESO in its submission states:

> In OPG's evidence and through further discovery during this proceeding, OPG indicated that under their proposal of a 50/50 consumer benefit sharing mechanism and the proposed enhanced Hydroelectric Incentive Mechanism ("eHIM"), OPG would not change how they operate their previously or newly regulated facilities. (IESO argument, p. 2).

This position was also clearly set out in EB-2010-0008 in OPG's response to VECC Interrogatory 37 (Ex. L-14-37).

Staff later correctly states that OPG's current proposal is dependent upon forecast values. It then goes on to state the following:

> …OPG has sufficient market power and generation time shifting capability to influence the level of HOEP – the basic determinant of HIM revenues. Therefore, OPG may be able to engineer outcomes that could benefit its revenue streams by using its market power to influence HOEP levels. (Board staff argument, p. 47).

Nowhere in the evidence was such an allegation raised, and OPG objects to its inclusion in Board staff's argument. OPG's conduct in the market was never at issue in this proceeding. OPG reminds Board staff that the OEB Market Surveillance Panel ("MSP") and the IESO Market Assessment and Compliance Division ("MACD") exist to monitor and correct for just such activities as is alleged by Board staff above.

In an Interrogatory, Board staff suggested an alternate means of dealing with the interaction between SBG and incentive payments (Ex. L-5.3-1 Staff-061). In Board staff's proposal, the amount of SBG calculated by OPG would be included as an offset to actual production used in calculating the monthly average amount. OPG indicated at that time that the approach was possible, but that additional processes, incremental to those that already exist, would be required by both OPG (financial reporting) and the IESO (settlement tools). This perspective has been echoed by the IESO in its submission at page 3. To use this approach, which ends up at the same point but requires additional effort on the parts of both OPG and IESO to get there, is unnecessary.

Board staff's submission calls for the outright rejection of eHIM, in preference to a continuation of HIM with a post facto adjustment for SBG impacts. OPG submits that the incentive payment adjustment described in eHIM is a post facto adjustment for SBG. The issue, as described above, is where the adjustment takes place. Further, Board staff supports a revenue requirement offset and invites the OEB to consider a graduated sharing mechanism. OPG considers these suggestions to be inferior to the eHIM proposal. If the OEB intends to adopt this approach, it should be modified to improve its workability and fairness. Essentially what Board staff is proposing is a continuation of the existing mechanism with an added step to eliminate any interaction between SBG and the incentive mechanism. OPG wishes to highlight certain issues that exist with the current mechanism, and with Board staff's proposal that, in OPG's view, should cause the OEB to reject Board staff's proposal:

- The revenues realized under the existing mechanism are not tied directly to consumer benefit. This is remedied under eHIM.
- OPG and Board staff share the goal of eliminating SBG interaction with the incentive mechanism, but OPG believes that it is best achieved by the eHIM proposal due to administrative simplicity, as set out above, and agreed to by the IESO.
- The current variance account is asymmetrical. If OPG fails to earn its half of the incentive net revenues, it owns the loss, whereas ratepayers are fully protected. This asymmetry is inherently unfair, since OPG cannot control the price spreads that exist between on-peak and off-peak periods, which are critical to realizing incentive mechanism net revenues. In OPG's submission, should the OEB elect to continue the HIM approach with its revenue requirement offset and variance account, the account should act both ways, thereby protecting both ratepayers and OPG, as is done in other such variance accounts, like the Water Conditions Variance Account.
- Finally, OPG sees no need for a graduated sharing mechanism, or any other decrease in OPG's share of the incentive payments. In his evidence, Mr. Cliff Hamal speaks to the quantum of the sharing, and concludes that "…Simply put, the proposed structure does not provide as strong an incentive as would be found in the open market." (Ex. E1-2-1, Attachment 1, pp. 9-10). Further, Mr. Hamal states "This raises the question of whether the sharing percentage is optimal. The approach adopted by OPG, the equal split of the calculated customer benefit, has the advantage of simplicity and apparent fairness. The recommendation appears reasonable as it falls within a range, where the floor would be the lowest level that still provides OPG benefits after considering its incremental costs and the upper end still provides substantial benefits to customers." (Ex. E1-2-1, Attachment 1, pp. 9-10). To reduce the sharing to less than is currently proposed will have the effect of reducing the amount of time shifting that OPG performs (Tr. Tech. Conf., April 22, 2014, p. 14), which will be to the detriment of both OPG and consumers. Further, the IESO states "The IESO submits that OPG's proposal for a 50/50 sharing mechanism based on consumer benefits is an acceptable incentive that OPG should receive. Under a lesser incentive, it is unknown how OPG's response to market prices (and the resulting time-shifting activity) will change." (IESO argument, p. 4). OPG requests that the OEB reject Board staff's proposal.

There was one other point, raised only by VECC in its submission that requires a response from OPG. VECC asserts that the OEB should consider whether the 2013 balance of the SBG variance account should be adjusted to reflect the financial consequence of the interaction between SBG and the HIM (VECC argument, p. 34) as set out in Ex. J4.7. While unfortunate, this interaction was unintended. The entries in this account were entirely consistent with the decision received pursuant to the EB-2010-0008 case (Tr. Vol. 4, pp. 158-161). So while there may be elements of OPG's Application that do not play out exactly as forecast – some are to the benefit of OPG and some are to the benefit of ratepayers - the OEB cannot simply go back and selectively adjust only those situations that disadvantage ratepayers. VECC's suggestion should be denied. Also see Section 10.2 of this Reply Argument, dealing with Issue 9.4 for additional discussion of this point.

In conclusion, OPG feels that its proposal represents a fair and robust mechanism for encouraging economically efficient behaviour. OPG requests that the OEB approve its proposed incentive mechanism, as filed.

6.7 NUCLEAR

6.8 ISSUE 5.5

Primary - Is the proposed nuclear production forecast appropriate?

OPG is seeking approval of a nuclear production forecast of 48.5 TWh and 46.1 TWh for 2014 and 2015, respectively (Ex. N2-1-1, p. 9, Chart 6). The basis for OPG's forecast for the test period is summarized in OPG's Argument-in-Chief at pages 61-63.

Board staff proposes that OPG's test period production forecast be increased by 1.32 TWh (Board staff argument, p. 56). This submission is supported by CME, LPMA, and SEC. AMPCO goes further and seeks a further increase of 0.23 TWh related to lake water temperatures (AMPCO argument, p. 35).

PWU submits that OPG's nuclear production forecast is appropriate, and that advancing the vacuum building outage ("VBO") to 2015 is reasonable and valid by reference to all operational and financial considerations (PWU argument, paras. 89 – 106).

As will be shown below, there is no proper basis in the evidence for Board staff's and AMPCO's proposed adjustments. The parties' arguments in support of the proposed adjustments are thinly disguised attempts to reduce the payment amounts by arbitrarily increasing the production forecast. These attempts should be rejected by the OEB. OPG submits that the OEB should accept OPG's production forecast because it is the most accurate forecast of test period nuclear production.

Board staff complains that OPG's nuclear production forecast was updated during the course of the proceeding. Board staff submits that most of the reduction related to Darlington, that was included in the update should not be accepted by the OEB because "it was responsive to OPG senior management direction and does not appear to be based on rigorous ground up analysis." (Board staff argument, p. 56). Neither of these points is true or consistent with the evidence.

First, the challenge of the nuclear production forecast by OPG senior management is very much a part of the rigorous review and approval process that all production forecasts go through. Board staff's submission that the process surrounding the update was different in this regard is just wrong.

The evidence in this proceeding (Ex. E2-1-1, p. 4) is that OPG's nuclear production forecasting process has not changed since EB-2010-0008. In response to Ex. L-5.5-2 AMPCO-025, OPG again confirmed that "a Senior Management review is typically conducted in Q3 of the business planning year. A senior management review occurred in Q3 2013 as part of the 2014-2016 business planning process." Therefore, the evidence which Board staff attempts to avoid is that a review and challenge of the nuclear production forecast is a key part of the each business planning cycle. In respect of the 2014-2016 business planning process, this review and challenge occurred in the fall of 2013.

Second, Board staff mischaracterizes the direction from OPG senior management. On page 56 of its argument, Board staff describes the direction as being "to reassess the production forecast to be more in line with actual historical performance" (*emphasis added*). In fact, OPG's evidence is that the direction from OPG's senior management directed generation planning staff to reassess based on OPG's historical performance…" (Ex. N1-1-1, p. 13, ll.1-4). This distinction is important. OPG management did not dictate the outcome of the reassessment as Board staff wrongly implies. As OPG noted:

> Senior Management directed the generation staff to reassess the generation plan. This direction was driven by a concern that the 2014 - 2016 forecast was overstating generation based on OPG's historical performance from 2005 - 2012 where actual generation has been lower than forecast in each year. Senior Management was also aware that as of Q3 2013, the 2013 production forecast was indicating that production would again be below OPG's 2012 - 2014 budget as well as significantly below the generation forecast underpinning OPG's approved rates, resulting in a sizable revenue deficiency. (Ex. L-5.5-17 SEC-074).

In Ex. L-5.5-17 SEC-074, OPG sets out the historical data that Senior Management relied upon in directing the generation planning staff to reassess the forecast, including that,

- Actual Nuclear production for the last several years has come in significantly below the production forecasts.

- Since 2008, over-forecasting production has resulted in over $900M in lost regulated revenue. See Chart 2 in Ex. E2-1-1.

- Actual FLRs have come in well above plan, especially at Pickering.

- Average actual FLR from Year 2005 to Year 2013 is 2.0 per cent for Darlington and 13.2 per cent for Pickering.

- Average FEPO from 2005 to 2013 for Darlington is 0.24 TWh and for Pickering is 0.87 TWh.

While Senior Management wanted to ensure that the forecast presented to them was realistic, the amount of any adjustment was not established by Senior Management. Rather it was an outcome of the rigorous reassessment undertaken by the generation planning staff during

September 2013. Their recommendations, based on this reassessment, were then submitted for approval in November 2013 as part of the overall approval of the 2013-2015 Nuclear Business Plan.

Third, production forecast changes are often made due to such factors as lessons learned from recent OPG outages, internal operating experience, emergent discovery work or short term updates to life cycle management programs. And that was true for the reassessment provided by the outage and generation planners. As described by OPG at Ex. N1-1-1, p. 15, and again at Ex. L-5.5-17 SEC-074, OPG outage planners reviewed and reassessed planned outage days for the VBO/SCO (station containment outage), concluding that there was "a need for 39 additional planned outage days due to the VBO scope being of greater complexity than previously undertaken by OPG and because the VBO outage scope includes life extension activities which have not been part of prior Darlington VBO's. The greater scope includes a 100 per cent increase in electrical equipment maintenance, significant emergency service water ("ESW") piping replacement, a 50 per cent increase in emergency coolant injection ("ECI") valve replacement and the first time implementation of pressure relief valve ("PRV") maintenance."

The 2015 VBO/SCO also differs from previous VBOs in that some tasks will be undertaken for the first time (e.g., the Vacuum Building Pressure Relief Valve seal replacements) (Ex. L-5.5-17 SEC-074). During the oral hearing there was much cross-examination on i) what typically constituted a VBO, ii) the typical difference between a VBO and a station containment outage (SCO), and iii) the timeline around OPG's developed analysis of the regulatory requirements of each including the overlapping critical paths. Ms. Swami clarified that references to "VBO" in the evidence cover the aggregate of station containment work activities, vacuum building activities and electrical replacement (Tr. Vol. 6, pp. 32 - 35).

Neither Board staff nor anyone else was able to impeach OPG's evidence that the planned VBO/SCO work needs to be done, that it makes most economic sense for all of the work to be done through only one four-unit shutdown in 2015, that there is a $48M NPV (Ex. J6.2) benefit by moving the VBO forward into 2015 or that the outage will take the amount of time projected by OPG (Tr. Vol. 7, pp. 25-26).

Fourth, in addition to ignoring the rigorous analysis undertaken to support the VBO forecast, Board staff curiously also ignores OPG's evidence at Ex. N1-1-1, that a component of the 1.32 TWh includes 0.49 TWh (22 outage days) for allowances related to other Darlington planned outages over the two-year test period (p. 16). OPG supported this allowance with analytical evidence. Board staff avoided confronting the substance of this evidence, instead only weakly proffering that it was somehow not "rigorous" (Board staff argument, p. 56). This allowance is in fact based on Darlington's actual performance over the period 2005 - 2013. During this period, OPG's analysis indicated that the average forced extension to planned outages at Darlington was 0.24 TWh per year, amounting to 0.49 TWh over the test period.

Board staff also makes the submission that since OPG did not identify emergency service water piping and emergency coolant injection valve replacement as driving the critical path for the VBO/SCO in its initial pre-filed evidence, OPG must have only become aware of this work during the period May-November 2013 (Board staff argument, pp. 54-55). This inference is just not true. As Ms. Swami explained, the scoping process for an outage is driven by life-cycle management plans. Every outage goes through a multi-year scoping process and it is only in that process that the critical path is determined, which is what drives the length of the outage (Tr. Vol. 7, pp. 27-28).[35]

Board staff states that there is no reference to the critical path work in the outage OM&A evidence although the OPG witnesses described the work as significant (Board staff argument, p. 55). Board staff also questions why OPG did not revise its outage OM&A budget to reflect the additional outage days from the updates. While the specific tasks on the critical path are not discussed in detail in the initial pre-filed evidence, there is a lot of evidence on the complexity and cost of the VBO/SCO outage in 2015. For example, at page 72 of its Argument-in-Chief, OPG states: "The level of forecast outage OM&A spending in 2015 ($330.7M) compared to 2014 $(262.7M) reflects the intent to complete a lengthy and complex combined 4 unit VBO/SCO at Darlington in 2015. OPG anticipates 25 per cent to 75 per cent more work will be required for this outage depending on the particular area (Ex. L-5.5-17 SEC-074)." At Ex. L-5.5-17 SEC-074, p. 1, OPG clearly speaks to the entire outage scope being

[35] OPG filed extensive evidence in EB-2007-0905 at Ex. E2-1-1, page 4 that describes the multi-year outage scoping and yearly update process.

crucial to eliminating the 2021 VBO as set out in Ex. N1-1-1, and at page 4 of the same interrogatory response, OPG clearly references the SCO and VBO being aligned.

In fact, OPG did revise its budget for the VBO/SCO outage. The initial estimate was that the VBO would cost $74.5M in 2015 with $11.1M in preparatory work in 2014. In the 2014 - 2016 Nuclear Business Plan, OPG identified that the VBO execution cost had increased to $84.2M in 2015 with 2014 preparatory work in 2014 of $11.8M. As noted in Ex. N1-1-1, OPG did not update its forecast of OM&A expenses for any increase in outage OM&A costs, and so OPG is not seeking to recover these additional costs from ratepayers.

Board staff's question about the outage budget is also answered by the testimony of Ms. Carmichael. She indicated that when contingency (i.e., forced extensions to planned outages ("FEPO") days in the case of the updated forecast for Darlington) is added to the duration of an outage, there is not typically a corresponding increase in outage OM&A costs (Tr. Vol. 7, pp. 125-126).

Finally, Board staff observes that the total impact of the two updates plus the MUE included in the original forecast is roughly equal to the total MUE proposed in the last application (Board staff argument, p. 55). Given all of the evidence that OPG has provided to explain the technical and operational reasons for its updates to the production forecast, this is a particularly unfair and uninformed submission. OPG also observes that this point was never put to any OPG witness. Based on all of the evidence adduced, OPG submits that this observation should be completely discounted.

With respect to AMPCO's argument that the production forecast be increased by an additional 0.23 TWh relating to lake water temperatures (AMPCO argument, p. 35), OPG submits that the proposed increase should be rejected.

OPG's evidence update in Ex. N1-1-1 at page 15, and Ms. Swami's and Ms. Carmichael's oral testimony (Tr. Vol. 6, pp. 81-82, Ex. L-5.5-17 SEC-077) explain that the updated production forecast for Darlington included the 0.28 TWh reduction to reflect the expectation of higher lake water temperatures than assumed in the 2013-2015 Business Plan. Higher lake water temperatures result in lower generation output due to reduced condenser efficiency.

Ms. Swami explained that production losses related to lake water temperature are not based on predicting what the lake temperature will be in any given year. Instead, an analysis is done by reviewing historical performance over the past number of years. Lake temperatures cannot be predicted, "even based on extremely cold water or extremely warm weather." The estimate that OPG has included in this filing is the best evidence that OPG has (Tr. Vol. 6, p. 82, ll. 22 - 25). AMPCO's suggestion that the production forecast should be increased because AMPCO anecdotally notes, on its own observations, that we did not have warm <u>air</u> temperatures this past summer (AMPCO argument, para. 147) should be given no weight. AMPCO has no evidence correlating air temperatures to lake temperatures to support its submission.

Finally, from a practical perspective, a review of Ex. L-5.5-13 LPMA-006 reveals that OPG's nuclear production has never exceeded 49.0 TWh over the period 2008-2013. While OPG's nuclear production forecast for 2015 of 46.1 TWh is below 49.0 TWh, this is driven by the need to complete an extended four-unit shut down for the VBO/SCO which reduces production by 3.31 TWh (see Ex. L-5.5-2 AMPCO-030). Excluding the impact of completing the VBO/SCO, OPG's 2015 nuclear production forecast is consistent with achieving nuclear production of 49.4 TWh.

Board staff's recommended increase of 1.32 TWh would equate to a production level of 50.7 TWh. This level of production has not been achieved during the period of OEB regulation (Ex. L-5.5-17 SEC-074). It would clearly overstate 2015 production, resulting in a revenue shortfall (approximately $89M) and impact OPG's opportunity to earn its allowed rate of return.

In its Decision with Reasons in EB-2007-0905, the OEB stated at page 174 that it believes, "OPG should be fully incented to produce as accurate a forecast of nuclear production as possible and should be at risk if actual output falls short of forecast." OPG's nuclear production forecast of 48.5 TWh in 2014 and 46.1 TWh in 2015 is a complete and accurate forecast and should be the basis for setting rates for 2014 and 2015.

7.0 OPERATING COSTS

7.1 REGULATED HYDROELECTRIC

7.2 ISSUE 6.1

Oral Hearing - Is the test period operations, maintenance and administration budget for the regulated hydroelectric facilities appropriate?

OPG's total OM&A costs for the test period (including Base OM&A, Project OM&A and GRC related charges) can be found in OPG's Argument-in-Chief, at Table E on page 64.

A number of Intervenors have suggested disallowances in this area. Board staff recommends disallowances of $9.4M in each year of the test period for previously regulated hydroelectric. It also recommends disallowances of $13M in 2014 and $26M in 2015 for newly regulated hydroelectric.[36] SEC (supported by AMPCO, CME and CCC) suggested disallowances of $9.7M in 2014 and $10.0M in 2015 for regulated hydroelectric base and project OM&A. Disallowances almost identical to those suggested by SEC were recommended by LPMA, and on the same basis.

Board staff's proposed disallowances appear to fall into two distinct categories; the first deals with straight reductions to Base and Project OM&A associated with a forecast shown in response to Ex. J3.13 and the second appears to be disallowances targeted at Corporate Costs, Centrally Held Costs and Asset Service Fees based on comparisons of test period costs versus 2013 historical actual costs.

The first category of recommended disallowance results in reductions of $1.3M per year of the test period against Previously Regulated Hydroelectric and $6.9M per year of the test period against Newly Regulated Hydroelectric. OPG understands that these amounts were arrived at by reviewing Undertaking J3.13 which compared 2014 Plan against 2014 Forecast (as of the end of May 2014). Notwithstanding that these were, at the time, OPG's best estimates of where these line items would end up, it is entirely inappropriate to translate these budget versus forecast values into a disallowance. First, the comparison is for only one year, yet Staff has

[36] The $13M represents a half year.

suggested that the differential be withheld from both years of the test period. Second, and more significantly, to cherry-pick this particular line item and deem it a disallowance is unfair. OPG's Application contains many line items. Half way through the year, some of them will show a positive variance against budget and some will show a negative variance. To opportunistically claim these particular variances as disallowances ignores all the others, which could easily work in OPG's favour. Board staff's disallowances based on Ex. J3.13 should be rejected.

The second category of Board staff recommended disallowance above results in reductions of $8.1M per year of the test period against Previously Regulated Hydroelectric and $19.1M per year of the test period against Newly Regulated Hydroelectric. In reviewing Ex. L-1.0-1 Staff-002, Tables 15 and 16, OPG can determine that these amounts reflect the difference between 2013 Budget and 2013 Actual values for the sum of Corporate Costs, Centrally Held Costs and Asset Service Fees. Again, to opportunistically apply these variances for 2013 forward into both years of the test period ignores all the evidence that was filed in support of the forecast level of costs for 2014 and 2015. OPG disagrees with this recommendation. OPG's entire application is based upon a forward looking test period. In general, this allows the regulator to assess costs on a forecast basis, with an understanding of what specific events are planned during the test period consistent with the utility's business plan. OPG agrees that the regulator should absolutely review historical costs, but it cannot simply adopt those costs with no consideration of the differences that exist between the historical period and the test period.

SEC and LPMA apply their proposed disallowances simply on the basis of historical underspends. These disallowances are equally inappropriate, for the reasons already discussed.

Both Board staff and SEC opine that the budget underspends, caused in part by unfilled vacancies, have occurred with "…no operational repercussions…" (Board staff argument, p. 57). This is not supported by evidence. A discussion at hearings between Board Counsel and OPG witnesses yields additional insights (Tr. Vol. 3, p. 161). There, OPG explains that understaffing has indeed had consequences on project delivery – the same delivery problems that would result in budget underspend. OPG manages its business effectively by reprioritizing work and dealing with unfilled vacancies in the short term (Tr. Vol. 3, p. 159). OPG's ability to do so does not imply that "[t]here is no indication that OPG's hydroelectric facilities had any reliability or operational setback because regular employees were not being utilized." (SEC argument, p. 50). It simply means that OPG overcame the issues with only minor impacts to the business.

The proposed disallowances should be rejected.

7.3 ISSUE 6.2

Oral Hearing - Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's hydroelectric facilities reasonable?

OPG has provided benchmarking information for the regulated Hydroelectric facilities for three Applications now (EB-2007-0905, EB-2010-0008 and EB-2013-0321), each time consistent with the OEB's Filing Guidelines (EB-2011-0286) at Section 2.7, page 16. In its Decisions in EB-2007-0905 (page 41) and EB-2010-0008 (page 25), the Board accepted OPG's regulated hydroelectric benchmarking[37].

Board staff, SEC, CME, CCC and LPMA all made submission on this issue. Those submissions were similar in nature and will be dealt with collectively. In its submission, Board staff asserts that OPG's regulated hydroelectric benchmarking is not independent. This was echoed by others. Board staff's assertion is incorrect. While EUCG and Navigant do not produce analysis or reports specific to OPG or other utilities, they do act independently to define, collect, and verify the raw data reported by OPG. This is demonstrated by the Undertaking Responses JT1.10 and J4.1 that define what is to be included in the data submitted for benchmarking. Further, and again in error, Board staff also seem to rely upon the observation offered by KPMG that no external benchmarking reports were available for the purposes of the KPMG review, and thus, it should rightly be interpreted to mean that OPG's

[37] "The Board further finds that the benchmarking methodology and results are reasonable and notes that they have been accepted without challenge by all parties." (Decision, EB-2010-0008, page 25).

hydroelectric benchmarking was not independent. The KPMG report dealing with benchmarking (Ex. K3.1) does not state this.

Board staff and others level a number of criticisms at OPG for its previously accepted hydroelectric benchmarking. However they ignore the fact that the primary purpose of hydroelectric benchmarking is to identify best practices specific to activities in a hydroelectric business (Transcript Vol. 4, p.151, line 15-28). The exclusion of project or corporate costs from hydroelectric benchmarking is not an OPG decision – it represents a consensus of how hydroelectric utilities across North America want the benchmarking data framed because this is what will yield meaningful results for them. The effect of including, for example, certain regulatory costs or other uncontrollable costs that only apply to certain utilities, would dilute the results of any comparisons that can be made through an analysis of the data.

In response to Board Staff's assertion that the Hydroelectric and Nuclear benchmarking is not conducted in an identical fashion (Board staff argument, p. 60), the Hydroelectric and Nuclear benchmarking conducted by EUCG will not and cannot be identical with respect to what costs are included. The two businesses are different (Tr. Vol. 4, p. 151).

The evidence shows that OPG's benchmarking is independent and that the industry has collectively determined that including the selected operating cost items produces the most meaningful results for driving improvements in the business. OPG submits that the additional benchmarking suggested by Staff and Intervenor submissions is unnecessary and likely will not produce useful results at a reasonable cost. In fact, OPG doubts that there would be enough interest by other North American hydroelectric generators such that it could obtain the types of data necessary for such a study.

7.4 NUCLEAR

7.5 ISSUE 6.3

Oral Hearing - Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

7.5.1 Introduction

Board staff's submits that: "The nuclear business and related corporate support OM&A has been significantly improved by BT – OPG's initiative responding to future revenue/generation reductions" (Board staff argument, p. 64). OPG agrees.

Under the BT initiative, a 298.3 FTE reduction in regular staff is incorporated into the test period. This reduction builds on 434.1 FTE reductions between 2010-2013 (Ex. F2-1-1, p.1). The oral evidence is that OPG expects to narrow, if not eliminate altogether, its staffing gaps compared to benchmarks by the end of 2015 (Tr. Vol. 6, pp 19 -20 and 48 – 49).

In its AIC, OPG sets out its justification for the Nuclear OM&A (base, project and outage) costs that are necessary to safely, reliably and efficiently operate and maintain OPG's nuclear stations in the test period (AIC, p. 68). Neither Board staff nor intervenors have challenged OPG's evidence with respect to the work OPG needs to do under these categories of expenditures. However, they have made spurious objections to OPG's benchmarking performance and compensation and staffing levels which are offered in support of an argument that it costs OPG too much money to do the work it needs to do. OPG submits that these arguments should be rejected for the reasons set out under Issues 6.4 and 6.8 below.

PWU submits that the cost of an OM&A program is driven by the size and composition of a utility's work program and the unit cost of labour, material and other components used in the work program (PWU argument, p. 30). PWU states that it is not aware of any criticism that the size or composition of OPG's work program is inappropriate, or that the delivery of that program is inefficient (*Ibid*). It submits that it is also not aware of any criticism of the unit costs for the inputs to the program – other than labour costs. PWU submits that the primary driver of the base OM&A cost increase is the labour escalation and pension and OPEB costs, which increase base OM&A costs by an average of 2.20 per cent per year (Ex. F2-2-2, p. 1). For these reasons, and for the reasons it sets out at pages 31-33 of its argument, PWU submits that the OEB should approve the nuclear OM&A requested by OPG.

Board staff submitted “that in part due to poor benchmarking results (summarized below), reductions of $100M to the proposed OM&A for the test period are appropriate. The reductions are noted in the compensation section of this submission (section 6.7) and the corporate cost section of this submission (section 6.9).” (Board staff argument, p. 64) LPMA agrees with Board staff, but says that the OM&A reductions should be $100M each year, but again, tied to compensation. SEC agrees with Board staff but states that its proposed disallowances under Issue 6.3 are $100M per year reflected in the compensation section, and that Board staff’s proposed disallowances would be subsumed in this figure.

OPG observes that the proposals of Board staff, LPMA and SEC are highly punitive in nature and contrary to the fair return standard. With an OEB decision not expected until the end of 2014, OPG would be left with only 12 months to try and absorb such a substantial compensation disallowance. Given that OPG’s compensation costs for the test period are largely committed costs the legality of Board staff’s, LPMA’s and SEC’s proposals is addressed in section 6.8 below.

CME submits that there should be “significant reductions” to OPG’s forecast nuclear OM&A, but indicates that its submissions are set out in Issue 6.4 with respect to nuclear benchmarking. Accordingly, OPG will respond to CME’s submissions under that issue.

Environmental Defence makes a submission that Pickering’s OM&A costs are unreasonably high. This submission is made on the basis that the costs are apparently higher than “other sources of power (e.g. conservation and hydro imports from Quebec).” (Environmental Defence argument, p. 2) Environmental Defence requests that the OEB disallow a portion of Pickering’s expenses such that its costs “are more in line with the cost of power from other sources” (ED argument, p. 15).

OPG submits that Environmental Defence’s arguments should be wholly rejected. First, it would be improper to determine just and reasonable rates for OPG’s nuclear facilities, which are specific prescribed generators under the *Ontario Energy Board Act*, on the basis of the costs of other sources of power. The setting of just and reasonable rates must provide OPG with an opportunity to recover its prudently incurred costs and earn its allowed rate of return. As Environmental Defence has not made a similar submission with respect to OPG's other prescribed facilities, it must be that it accepts this legal basis for ratemaking.

This proceeding is to set payments amounts that are just and reasonable in accordance with section 78.1 of the *Ontario Energy Board Act* and the accompanying regulation. It is not a supply mix review. As Board staff and others have submitted, it is through the Long Term Energy Plan that the Government sets out the supply mix in Ontario. By its submission, Environmental Defence is essentially asking the OEB to second-guess the LTEP.

Secondly, even if Environmental Defence's proposed cost assessment methodology was legitimate, which it is not, it has not established a sufficient evidentiary record for assessing the costs and practicality of these other sources of power. CDM and hydropower from Quebec sufficient to replace a base load power supply the size of Pickering are far from a reality. Each requires extensive third party participation and, especially in the case of hydro power from Quebec, extensive bilateral negotiation the outcome of which is highly uncertain (Technical Conference April 23, 2014 Tr. pages 22-23).

GEC submits that OPG's "request for full compensation for its operating costs" for Pickering is unsupportable in light of the poor performance of the plant (GEC argument, p. 9). GEC submits that Pickering's 2014-15 O&M requirement should be reduced by $1.225 billion, or if its non-fuel OM&A costs were set at the level Darlington achieves, the disallowance could be only $322.42 million (GEC argument, p. 9). The essence of GEC's arguments for the disallowance of OM&A costs is founded in it submissions on OPG's benchmarking results and so is addressed in Issue 6.4 below. The legal propriety of GEC's submission, being that OPG's compensation costs should be disallowed in light of the poor performance of the Pickering plant, is also addressed, along with similar submissions of other intervenors, under Issue 6.8 below.

7.6 ISSUE 6.4

Oral Hearing - Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for the nuclear facilities reasonable?

7.6.1 Introduction

Board staff and the intervenors misunderstand and misuse the Memorandum of Agreement between OPG and its Shareholder (the "MOA"). Their submissions with respect to Issues 6.3 and 6.4 are premised to a substantial degree on this misunderstanding and misuse. Accordingly, and as explained in greater detail below, these submissions should be wholly rejected.

7.6.1.1 The MOA is Not a Contract to be Enforced by the OEB

The premise of the parties' argument is that the MOA creates obligations for OPG, and if Board staff and the intervenors cannot verify that OPG met those obligations to their satisfaction, this is a proper evidentiary basis for a cost disallowance against OPG. OPG rejects this proposition. OPG says that it would be improper for the OEB to base a cost disallowance on obligations of OPG to its Shareholder under the MOA. And even if it were proper, OPG's Shareholder has no concerns with OPG's performance under the MOA.

With respect to benchmarking and the MOA, the arguments of Board staff and the intervenors are a combination of, (i) OPG being "contractually committed" (CME argument, paras. 5, 6 and 7) to perform to the level of the top quartile; (ii) OPG "required" by its Shareholder to target to achieve top quartile (Board staff argument, pp. 70 – 71), and; (iii) OPG is"required" by its Shareholder to "perform to top quartile standards"(GEC argument, p. 9).

Using this construct, Board staff and the other intervenors have roughly calculated how much could be saved if OPG was at the top quartile in various metrics. They then call for compensation disallowances in the hundreds of millions of dollars on this basis.

OPG says that these submissions are based on a fundamental misunderstanding and misuse of the MOA. OPG is not contractually committed to performance in accordance with top quartile performance standards, as CME and GEC submit. Additionally, OPG is not obliged under the

MOA "to set targets to try and achieve top quartile" as Board staff alleges (Board staff argument, pp. 70–71).

In support of their arguments, the parties have selectively cited provisions of the MOA (Board staff argument, p. 64; GEC argument, p. 4). The provisions cited are sections A3 and C1 of the MOA, as set out respectively, below:

> OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly- owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.
>
> OPG will annually establish 3–5 year performance targets based on operating and financial results as well as major project execution. Key measures are to be agreed upon with the Shareholder and the Minister of Finance. These performance targets will be benchmarked against the performance of the top quartile of electricity generating companies in North America.

The parties have not however, for example, cited section C2 of the MOA which provides, "*Benchmarking will need to take account of key specific operational and technology factors…*" OPG submits that key operational and technology factors would include, for example, accounting for the fact that Pickering uses first generation technology; it consists of comparatively small reactor units and is approaching the end of its operating life (Tr. Vol. 6, p. 15).

The parties also have not cited section A1 of the MOA which provides that: "[OPG] will operate its existing nuclear…assets…within the legislative and regulatory framework of the Province of Ontario and the Government of Canada, in particular, the Canadian Nuclear Safety Commission. OPG will operate these assets in a manner that mitigates the Province's financial and operational risk." OPG submits that this means that OPG must operate within the bounds of applicable statutes and common law, which includes for example, labour laws in Ontario as set out in the section on Issue 6.8 below. It also includes for example, OPG being required to undertake major nuclear plant outages which impact forecast production.

In being mindful of financial risks, OPG must balance performance goals with value-for-money objectives (Tr. Vol. 5, p. 64). OPG submits that it would not be financially prudent for OPG to spend significant sums of money on a plant to have it achieve top quartile benchmarked performance when it is nearing the end of its operating life. In OPG submission, the MOA is not a legitimate basis for determining disallowances. Even if it was, intervenors should at least have regard to <u>all</u> of the provisions of the MOA as set out above, instead of selected excerpts.

The OEB's obligation at law is to set just and reasonable payment amounts for OPG. This standard is not modified by the existence of the MOA. Board staff and intervenors are asking the OEB to impose massive disallowances because OPG is not in top quartile on all benchmarked metrics, or even 'key' metrics. OPG submits that the OEB should reject this argument, as reasonable payment amounts must be based on more than just benchmarking. The role that the OEB plays is that of an expert tribunal. If a mathematical calculation relative to an industry benchmark was is all that is required to set rates, then far less expertise would be required than what the OEB brings to bear. OPG is not aware of any case where the OEB has punished a utility for failure to achieve top quartile performance – this is not consistent with a just and reasonable standard.

The MOA is a bi-lateral contract between OPG and its Shareholder. None of the OEB, Board staff or the intervenors is party to the contract. None of them is called to enforce the contract[38]. The Province could have set out in the MOA that it expected the OEB to enforce the MOA, or that the OEB should have regard to the MOA in setting OPG's rates, but the Province did not do either of these things.

The MOA sets out under its Purpose that: "OPG will operate as a commercial enterprise with an independent Board of Directors, which will at all times exercise its fiduciary responsibility and a duty of care to act in the best interests of OPG." In this context OPG has established appropriate benchmarking targets. In contemplation of OPG's other obligations under the MOA: "OPG has on an annual basis established 3–5 year performance targets based on operating and financial results as well as major project execution. Additionally, key measures have been

[38] This view is supported by the common law. In fact, it is well-established law and has been summarized by the Supreme Court of Canada in *London Drugs Ltd. v. Kuehne & Nagel International Ltd.*, [1992] 3 S.C.R. 299 (S.C.C.).

agreed upon with the Shareholder and the Minister of Finance (see MOA, Section C1). Then: "Once approved by OPG's Board of Directors, OPG's annual performance targets and investment plan are submitted to the shareholder and the Minister of Finance for concurrence" in accordance with section C4 of the MOA.

The evidence in this proceeding is that the Shareholder has concurred with OPG's 2013 – 2015 Business Plan which underpins the application in this proceeding (Tr. Vol. 3, p. 94). The evidence is also that OPG's performance objectives are reviewed by the Shareholder through the submission of the company's business plans and the submission of the business plans of the key business units such as nuclear and hydroelectric as Mr. Mauti testified (Tr. Vol. 3, p. 105). The Shareholder has also concurred with previous period business plans which OPG filed in prior rate case proceedings. All of this confirms that the Shareholder does not require OPG to set targets to achieve top quartile in all metrics and that it is satisfied with OPG performance of its obligations under the MOA.

7.6.1.2 OPG's Benchmarking Results Demonstrate Improved Performance

In its decision in EB-2007-0905, the OEB had the following to say about benchmarking, "While caution should be exercised when reviewing such data, the Board is satisfied that the studies provide meaningful insights into OPG's operations" (EB-2007-0905, Decision with Reasons, p. 30). OPG agrees that benchmarking is a valuable tool for both the company and the OEB and that caution should be used when reviewing the benchmarking data.

In contrast, Board staff and the intervenors seem to believe that OPG should be regulated solely by benchmarking. OPG does not agree with this view and believes instead that benchmarks should be used to gain "meaningful insights." OPG submits that the proper approach is for these insights to be considered along with the other probative written and oral evidence of OPG witnesses and independent experts who are called to testify (Tr. Vol. 5, p. 64; Tr. Vol. 6, pp. 39-45).

With respect to the three key metrics that Board staff references at page 66 of its argument (NPI, TGC and UCF), OPG's evidence was that, "in all three of those metrics, we have improved as a major operator, but in a comparison to the industry we are just stable, because the industry also is changing." (Tr. Vol. 6, p. 14). This of course is the result when Pickering is included. The outcomes are better when only Darlington is assessed (Tr. Vol. 5, p. 73).

Contrary to Board staff's misplaced disappointment about OPG's benchmarking results, these results indicate many positive developments. Most of these relate to Darlington. As for Pickering: "there is an understanding that we will not be able to reach top quartile for value for money metrics with regards to Pickering" (Tr. Vol.5, p. 64; see also EB 2010-0008 Tr. Vol. 3, pp. 124-126). However, OPG does strive for improvement at Pickering. And the results show it. Ms. Swami testified about Pickering that: "if you look at the data over time, we are seeing those improvements. So I did reference the forced loss rate on unit 6 already. I have referenced to the unit 4 forced loss rates. We are seeing very good unit capability factors on our Pickering 5 to 8 units. And so we are seeing that improvement" (Tr. Vol. 5, p. 97).

Board staff argues that "OPG has not achieved the performance set out by ScottMadden. It would appear that the OPG nuclear business no longer considers closing the gap and achieving top quartile to be an objective." (Board staff argument, p. 70). However, Board staff ignores the testimony of Ms. Swami, including the following answer in response to a question from Mr. Millar where Ms. Swami said:

> I would just like to add that when we looked at the cost -- and I talked about this a little bit earlier -- in terms of trying to drive cost improvements, we looked at Pickering and we amalgamated the Pickering site so that we could get benefits, as we discussed earlier, on economies of scale. I also talked about days-based maintenance, looking at how we could achieve our maintenance program with fewer staff, if you will. So we have done a number of things. It's not the performance that we want, certainly, and we are looking for continuing opportunities to make those improvements to drive the total generating costs down, to drive our performance up. And we are right now in the reliability improvement plan, which is referenced in our business plan, so that we can get better generation out of our Pickering facility, which will drive all of these metrics into better performance. (Tr. Vol. 5, p. 95-96)

The evidence in this proceeding is also that Darlington achieved top quartile in Total Generating Cost in 2011 (Ex. F2-1-1 p. 6).

As set out above, Board staff and intervenors have misapprehended the purpose of the MOA and have misused it in this proceeding. They have stubbornly refused (Tr. Vol. 5, p. 73, ll. 7 – 16; Tr. Vol. 6, p. 12, ll. 14 -19) to assess the performance of the Pickering and Darlington plants separately and differently contrary to what the Shareholder does when it concurs with OPG's business plans, and contrary to OPG's testimony. In this manner, Board staff and intervenors have come to the wrong conclusion that OPG's nuclear benchmarking performance has been disappointing. The OEB should not share this view.

In this application, OPG produced a staffing study by Goodnight Consulting (Ex. F5-1-1). Goodnight concluded that because of technology/design/regulatory differences between CANDU and pressurized water reactor (PWR) units, OPG's combined nuclear plants require 400 FTEs more than PWR units for similar functions, and 1031 FTEs for activities that have no equivalent in a similar sized PWR reactor unit plant (Ex. F2-1-1, p. 11; Ex. F5-1-1, part a, slide 14). This evidence was not challenged by Board staff or the intervenors in this proceeding. A rough calculation would suggest OPG CANDU units are operating with unavoidable additional OM&A costs of approximately $184.0M per year (143 FTEs x 176.2K as per Ex. J9.7) as compared to their PWR peers.

While Goodnight eliminated the additional FTEs from its benchmark staffing comparison in order to normalize for these technology/design/regulatory differences, the associated additional OM&A costs are not eliminated when OPG benchmarks its Total Generating Cost to its EUCG PWR peers. In assessing OPG's benchmarking results, this has been overlooked by Board staff and the intervenors. It also makes Darlington's past achievement of top quartile performance on this metric in a significant and impressive outcome (Ex. F2-1-1, pp. 5-6).

Board staff ignores that OPG has successfully pursued initiatives in business transformation to address cost escalation such that the performance gap between Pickering and the rest of the industry is narrowing. The evidence shows that Pickering is able to hold its costs steady while industry costs have escalated (Ex. F2-1-1 Attachment 1, p. 61). Board staff's conclusion that OPG's inability to achieve best quartile on its combined fleet is due to "inefficiency and poor productivity" is simply incorrect. The assertion that OPG should achieve best quartile performance for Pickering without reference to OPG's evidence on such factors as unit size and technology differences is unfair.

As referenced in Issue 6.3 above, in searching to propose a Nuclear OM&A cost disallowance, Board staff has made a calculation of the difference between OPG's forecast costs and what OPG's forecast costs might have been if OPG had achieved either best quartile or the median on the Total Generating Cost benchmarking metric. Board staff calculated some massive numbers. These disallowances were rejected by OPG as being illegitimate under Issue 6.3 and are rejected here again because this approach is not consistent with establishing just and reasonable rates.

With respect to Board staff's conclusion that it is highly unlikely that OPG will achieve ScottMadden's 2014 WANO NPI and UCF performance (Board staff argument, p. 69), OPG notes that with respect to Darlington, the chart set out in Undertaking J5.2 indicates that OPG's current 2014 targets for WANO NPI are actually more demanding than the 2014 ScottMadden targets (WANO NPI of 98.60 as per ScottMadden versus 97.50 as per OPG 2014 target and a UCF of 93.3 as per ScottMadden versus 93.50 as per OPG target).

Pickering's 2014 targets are lower than those set 6 years ago, but Board staff ignores the improvement that has been made during that period of time as described above. OPG's continued drive for improvement at Pickering can also be verified by reference to Undertaking J5.2 which shows Pickering's two-year UCF was 67.65% in 2013 and Pickering's 2014 annual target has been increased to 79.90%.[39] See also Pickering's performance plotted on the Rolling Average Forced Loss Rate chart on page 46 of the 2012 Benchmarking Report at Ex. F2-1-1, Attachment 1.

Similar improvements are being targeted for WANO NPI. In 2008, Darlington's WANO NPI was 95.67, and the 2014 NPI target is 97.90 - a 2.33% improvement. Similarly, Pickering's WANO NPI was 60.90 in 2008 and is targeted to be 72.00 in 2014 - an 18% improvement (Ex. J5.2).

[39] Pickering's 2008 annual UCF of 71.8% is set out in EB 2010-0008, Ex. E2-1-2, Table 1b.

Given that the results for UCF and the WANO NPI metrics will not be determined until year-end 2014, Board staff's assertions that "it seems that OPG will likely not meet the targets for any of the three key metrics at any of its facilities" are uninformed and misleading.

Similarly for the TGC per MWh metric, OPG's performance against the ScottMadden 2009 targets cannot be assessed until year end, and only then on the basis of an actual to forecast variance assessment. As the intervenors and the OEB well know, there can be any number of major unforeseen developments in a nuclear facility, or even deliberate operational changes such as life extensions or changes to production plans (Tr. Vol. 5, p. 96). Furthermore, a comparison of the actual and targeted TGC over the period 2009-2014 provides evidence of continuous improvement by OPG.

That OPG's performance is improving was not challenged by intervenors. In Ex. L 6.3 6 ED-15, non-fuel operating cost at Pickering is targeted to decrease from the current $58.75/MWh to $55.71/MWh in 2014 and $53.34/MWh in 2015 despite cost pressures including labour escalation. Darlington's non-fuel operating cost, already at or close to top quartile, is expected to remain essentially flat over the period 2010 to 2014 ($27.12/MWh to $27.21/MWh) (Ex. L-6.3-6 ED 016), before seeing an increase in 2015 due to the impact of lower production due to the VBO/SCO on the derivation of the unit cost per MWh. These trends are best illustrated by looking at the 3-Year Total Generating Cost per MWh chart and the 3-year Non-Fuel Operating Cost per MWh chart on pages 62 and 65, respectively of Ex. F2-1-1, Attachment 1.

Board staff has stated at page 69 of its argument that it is uncertain how the 90.44% two-year rolling average UCF was determined in Undertaking J5.2, as the 2013 data reported in OPG's financial results was 82.9%. In response, OPG would note that the chart in Undertaking J5.2 was initially prepared by Board staff and updated by OPG. The chart refers to a two-year rolling average. However, Darlington has shifted to a three-year rolling average as explained in Undertaking J5.2 and by Ms. Carmichael in response to a question on the point from Mr. Millar: "MS. CARMICHAEL: It is. However, Darlington has subsequently moved to a three-year rolling average, based on its outage cycle, in future benchmark reports." (Tr. Vol. 5, pp. 70 -71).

Using a three-year rolling average, including 95.2% in 2011 (Ex. E2- 1- 2, Table 1) generates a three-year rolling average of 90.4%. Board staff also incorrectly compares the rolling averages for the period 2010-2013 versus the annual targets in 2014. Darlington achieved an annual 95.2% UCF in 2011 (Ex. E2- 1- 2, Table 1). In OPG's submission, this validates OPG's annual target of 93.4% in 2014.

Contrary to Board staff's assertion at page 72 of its argument, OPG management does accept that there are repercussions for poor performance, and such repercussions have indeed affected OPG management (Tr. Vol. 5, p. 63).

With respect to the cost disallowance proposals that CME and Board staff make, they reference the major operator results set out in OPG's 2012 Benchmarking Report. They cite this report as evidence of OPG's poor performance and therefore the basis for the cost disallowances in 2014-2015 (CME argument, pp. 32-34 and Board staff argument, pp. 67 and 71). These submissions are wrong and should be rejected.

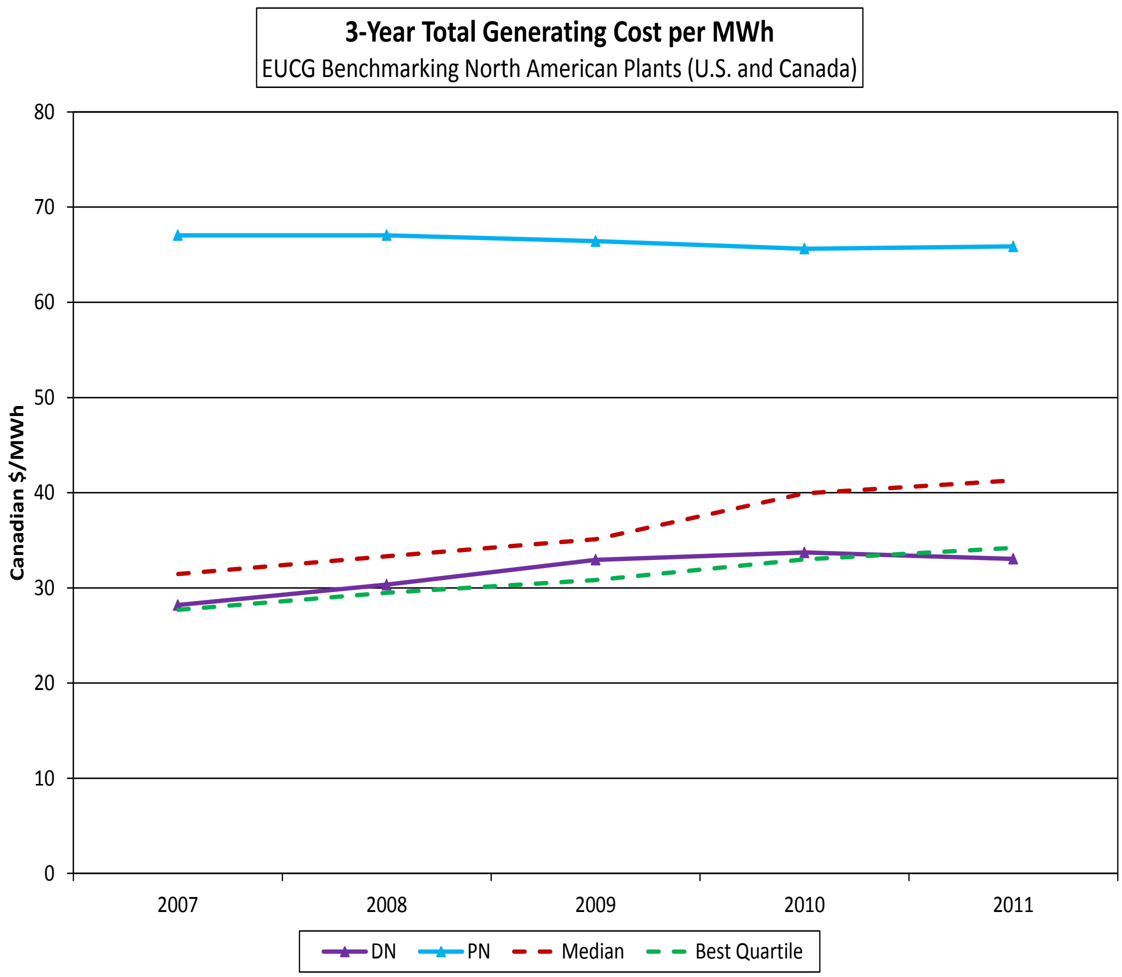
The 2012 Benchmark Report reports on 2011 actual results, it says nothing about 2014 and 2015 costs. For example, the evidence is that in 2011, according to the Goodnight study, OPG's staffing benchmark gap was 17% (Ex. F5-1-1, Part b, p. 4). However, that gap will be effectively eliminated by 2015 (Tr. Vol.6, pp. 19-20, 48-49), This means that intervenors are arguing for cost disallowances in 2014 and 2015 based on benchmarking results from 2011 while ignoring the significant staff reductions that will positively impact OPG's results.

CME states that OPG "shies away from having its performance evaluated against the appropriate benchmarks" (CME argument, para.7). CME provides no evidence for this statement because there is none. The evidence is that OPG annually benchmarks its performance (Tr. Vol. 5, p. 75) against 20 performance metrics and then sets operational, financial and generation performance targets that will move OPG nuclear closer to top quartile industry performance over the business planning period as part of top-down business planning process adopted in response to ScottMadden's work (Ex. F2-1-1, p. 3). This is essentially confirmed by Board staff in its argument at page 67. In addition, OPG undertook a nuclear staffing study initially in response to a direction from the OEB and has continued to update this staffing benchmarking annually.

CME states at page 33 of its argument that it should be of great concern to all ratepayers that the 2013 - 2015 Business Plan filed by OPG in connection with this application projects a Total Generation Cost ("TGC") for Darlington which deteriorates to second quartile in 2014 and third quartile in 2015. Board staff also refers to deterioration of performance at Darlington. OPG disputes any suggestion that Darlington's performance is deteriorating. The higher projected TGC for Darlington in 2015 is clearly the result of the VBO. It will reduce generation by 3.3 TWh. TGC is a measured as $/MWh, and is clearly impacted by this one-time event reducing generation.

For 2014, OPG expects Darlington to be marginally below best quartile. As the graphic in Ex. F2-1-1, Attachment 1, page 62, and copied below, shows, Darlington's TGC has risen at a rate below overall industry cost escalation since 2009. This is not expected to change in the future. It should also be noted that during the same period, Pickering's TGC has decreased due to cost reductions and improved generation at the plant, while industry best quartile has increased (Tr. Vol. 6, p. 15). Therefore, even at Pickering the performance gap has narrowed.

As set out in OPG's AIC, OPG has taken a prudent and reasonable approach to benchmarking its nuclear facilities. The benchmarking results flowing from the approach are reasonable. The resulting targets have been embedded in the 2013 – 2015 Business Plan that was concurred with by the Shareholder and also are reasonable.



7.7 ISSUE 6.5

Secondary - Is the forecast of nuclear fuel costs appropriate? Has OPG responded appropriately to the suggestions and recommendations in the Uranium Procurement Program Assessment report?

Board staff does not take issue with the analysis and findings of the Longenecker study. Further, Board staff takes no issue with OPG's responses to the recommendations of Longenecker, including its position that "off-market" negotiated transactions are not preferred (Board staff argument, p. 73). However, Board staff suggests that OPG be directed to provide a new study demonstrating how its nuclear fuel requirements and cost estimates reflect both appropriate strategies for balancing costs and risks as well as planning for lower nuclear fuel inventory requirements for when Pickering will cease operations. CME and LMPA support Board staff's position.

OPG opposes Board staff's proposal for a further study on nuclear fuel costs. A new study as suggested by Board staff would not be a reasonable expenditure of time and money. The Longenecker study that was completed in 2012 reviewed OPG's nuclear fuel procurement strategy and its risk management approach to balancing risks and costs extensively, and therefore fully addressed the issues that Board staff now seeks to have addressed in a new study. Longenecker notes (Ex. F5-2-1 p. 5) that, "in preparation of this Report, Longenecker has undertaken an extensive assessment of OPG's uranium procurement activities, including reviewing purchasing strategies, contracts, risk limit methodology, and inventory policy". Board staff did not take issue with the analysis and findings of the Longenecker study, nor with OPG's responses to the recommendations of Longenecker (Board staff argument, p. 74), and therefore has not established the need for a new study.

Board staff implies that while OPG was aware of the Longenecker study recommending reduced inventory levels in April 2012, OPG has unreasonably delayed implementing reduced inventory levels (Board staff argument, p. 74). This assertion is without merit.

Ending inventory levels are mathematically the result of opening inventory plus new uranium deliveries less usage. With regard to OPG's ability to reduce new uranium deliveries, as described at Ex. L-6.5-3 CME–008(b), OPG's existing contracts do not have termination for convenience provisions. Therefore, OPG would be in breach of contract if it failed to take delivery of uranium in accordance with the contract provisions in order to achieve lower inventory. The economic consequences of OPG breaching its contracts would be more harmful to ratepayers, together with a negative impact on OPG's supplier relationships. Furthermore, in Ex. L-6.5-1 Staff–093, OPG described the reasons why it did not make sense for it to change its nuclear fuel procurement program as suggested by Board staff's question. OPG needs to ensure that an adequate supply of uranium is available to meet the operational requirements of its nuclear units, while minimizing the price, market and credit risks associated with this supply. If OPG does not manage these risks prudently and things go awry, there would be harm to ratepayers.

CME also argues at para. 158 that the nuclear fuel inventory forecast costs should be reduced by $4.7M in the test period on the basis of OPG's response to a hypothetical question posed by CME (Ex. L-6.5-3 CME 008). However CME ignores OPG's response in Ex. L-6.5-3 CME 008 that also stated that CME's hypothetical reduction was not possible or reasonable:

> If OPG reduced inventory to 30% of its 2015 annual requirement at the commencement of 2014**,** the estimated carrying cost savings would be approximately $4.7M as per Table 4 below. However, drastically reducing inventory levels is an unreasonable approach to inventory management as other variables such as contractual obligations as well as financial and physical risk coverage limits, need to be considered.

CME proposes a second cost disallowance at para. 159 of its argument. OPG believes that para. 159 includes a typo in that where it says that the forecast should be no more than $244.7M for 2014 and 2015, what CME means is that this is the amount it proposes for *each* of 2014 and 2015. Assuming there is a typo, CME is seeking a disallowance of $59.0M over the test period and the proposal is without merit.

CME's request for a disallowance on fuel costs is based on neither facts nor evidence. As such there is no support for the use of 2013 actual fuel costs. Neither CME nor any other intervenor led evidence or adequately challenged OPG's evidence or even argued that OPG's past, or future, fuel procurement is imprudent. The Longenecker study found that OPG's uranium procurements have been undertaken in a professional manner, using evaluation criteria that appropriately consider diversity of supply, the relative capabilities and performance risks of suppliers, and includes an appropriate mix of contracts (spot versus long-term, fixed price versus market-related, etc). Longenecker also found that OPG's procurement strategy is prudent in today's market (Ex. F2-5-1 pp. 2-3). CME cited no evidence that OPG's fuel procurement is imprudent, only making a bald assertion that fuel costs should be reduced.

Establishing OPG's test period fuel cost at 2013 actual expenditure levels would not be consistent with just and reasonable rates, for the following reasons:

- OPG's fuel cost to operations is equal to the cost of fuel multiplied by production. Actual production in 2013 was 44.7 TWh (Ex. L-1.0-1 Staff 002 Attachment 1 Table 14). Forecast production in 2014 is 48.5 TWh and 46.1 TWh in 2015 (Ex. N2-1-1

Table 3). Therefore, CME's alleged "significantly greater" fuel costs for the test period over 2013 are primarily related to the increase in production.

- OPG's uses the weighted average cost accounting which delays and smooths out the impact on costs of nuclear fuel bundle arising from changes in the costs of uranium concentrate, uranium conversion services and fuel bundle manufacturing (Ex. F2-5-1 p. 2). A significant component of 2014 and 2015 fuel costs represents purchases already made and costed within closing 2013 fuel inventory.

- OPG's evidence at Ex. L-6.5-1 Staff 094 is that OPG's existing contracts are a mix of fixed price, market-related and base price escalated contracts. Contracts with fixed prices or base escalated pricing are essentially committed and OPG has no means to reduce fuel costs for purchases in the test period. Contracts with market-related pricing will be subject to market prices in 2014 and 2015. CME has led no evidence, nor challenged OPG's evidence, to suggest that OPG's forecast of fuel prices in 2014 and 2015 is unreliable or invalid. There is no evidentiary basis in this hearing, nor is there any precedent for other commodities such as natural gas, in other OEB proceedings, that dictates that a future commodity price should be set at past price, primarily because the future price of the commodity is significantly greater than it has been in the recent past.

With regard to OPG's ability to increase usage (as a suggested way to reduce inventory levels), there is substantial evidence in OPG's filing that OPG is not only unable to increase production over forecast, but indeed production has been below forecast since 2008. Indeed, OPG updated its test period production forecast based on the 2014-2016 Business Plan, forecasting a 2.6 TWh reduction (Ex. N1-1-1). The update was for material changes (N1-1-1 p. 1 line 10) and did not include any corresponding increase in ending nuclear fuel inventory. There is no revenue requirement impact as a result of the fuel inventory not being updated.

Board staff has submitted that OPG's nuclear fuel costs are appropriate, subject to OPG's answer above about the lack of revenue requirement impact from not updating fuel inventory, and subject to the determination of the production forecast (Board staff argument, p. 74). As OPG has submitted under Issue 5.5, its nuclear production forecast is appropriate and given that there is no revenue requirement impact based on the nuclear fuel inventory, OPG submits that the OEB should accept the position of Board staff and OPG that OPG's nuclear fuel costs are appropriate.

7.8 ISSUE 6.6

Primary - Are the test period expenditures related to continued operations for Pickering Units 5 to 8 appropriate?

OPG is seeking approval of its proposed 2014 expenditures for Pickering Continued Operations and the associated impact on the nuclear production forecast. The test period costs for continued operations are $38.9M (all OM&A), which includes $1.8M related to Pickering Continued Operations' share of the Fuel Channel Life Cycle Management ("FCLM") project expenditures (Ex. F2-2-3, p. 4, Chart 1). The nuclear production forecast also reflects the incremental outage days associated with Pickering Continued Operations, which reduce nuclear production by 0.5 TWh in 2014 (Ex. F2-2-3, p. 1).

Board staff supports OPG's cost levels for Pickering Continued Operations for the test period (Board staff argument, p. 75). Board staff also supports the incremental outage days for this project (Board staff argument, p. 56). Other intervenors, except as referenced below, either support Board staff's submissions or have no specific submissions on this issue.

The Ontario Power Authority supports Pickering Continued Operations. Its written evidence setting out this support, both prior to the oral hearing and elicited through questions by GEC and ED during the oral hearing, is set out further below.

Board staff observes that in 2010, OPG decided to pursue continued operations of Pickering units 5 to 8 rather than refurbishment. The project would extend life from 2015/2016 to 2020. The Decision with Reasons from EB-2010-0008 approved $84.1M in expenses in the 2011-2012 test period for Pickering Continued Operations. Board staff also observes that no project costs are forecast for 2015 and that OPG seeks capacity refurbishment account recovery related to Pickering Continued Operations' 2013 costs. Board staff confirmed the development and provision of an updated business case for Pickering Continued Operations prepared by OPG and takes no issue with these costs (Board staff argument, pp. 74-75).

Board staff observes that several intervenors have questioned the economic merits of continued operations of Pickering. However, Board staff submits that, for the test period, the OEB should rely on the Long Term Energy Plan (Board staff argument, p. 75):

> The continued operation of Pickering facilitates the refurbishment of the first units at Darlington and Bruce by providing replacement capacity and energy without greenhouse gas emissions while managing prices. However, an earlier shutdown of the Pickering units may be possible depending on projected demand, the progress of the fleet refurbishment program, and the timely completion of the Clarington Transformer Station. (Ex. KT2.2, p. 30).

OPG submits that its evidence and arguments on the value of Pickering Continued Operations, and the support in the LTEP summarized by Board Staff above, are a complete answer to AMPCO's objection to any cost recovery for Pickering Continued Operations (AMPCO argument, para. 163). They are also a complete answer to GEC's proposed cost disallowances linked to Pickering Continued Operations (GEC argument, p. 13), as discussed below.

The apparent basis for both AMPCO's and GEC's submissions is their view that the project does not have a positive net present value ("NPV"). However, this view is contrary to the evidence of both OPG and the OPA.[40] Neither AMPCO nor GEC made any discernible challenge to the evidence of OPG or the OPA on this point. Furthermore, both AMPCO and GEC willfully ignore the non-economic benefits of Pickering Continued Operations as highlighted by the OPA's letter of August 15, 2012 (Ex. F2-2-3, Attachment 2) and summarized in OPG's AIC (p. 83).[41] In the face of challenges by GEC, OPA issued a letter to the OEB dated June 9, 2014 (Ex. K6.1) confirming that it continued to stand by its assessment of August 2012 with respect to the positive NPV of Pickering Continued Operations.

[40] OPG's 2012 Business Case Update (Ex. F2-2-3, Attachment 1) derived a positive $520M NPV ($2012). The OPA letter of August 15, 2012 (Ex. F2-2-3, Attachment 2) refers to an expected cost advantage of approximately $100M.
[41] GEC attempted to undermine the letter originally filed by the OPG using information it gained through a Freedom of Information request. This attempt failed and the OPA reaffirmed the support in its earlier letter.

In its argument, GEC references the above-described OPA letter of June 9, 2014, but in referring to it, tries to diminish it by stating parenthetically, "*(which is not evidence tested in this proceeding)*" (GEC argument, p. 11). This is a disingenuous submission by GEC. GEC had every opportunity to test the evidence, but was unable to undermine the conclusions presented in the OPA's two letters and confirmed by the OPA in its responses to the questions of GEC and ED filed with the OEB on July 25, 2014. The OPA's August 2012 letter stated, "The Ontario Power Authority supports Ontario Power Generation's proposals for expenditures in 2013 and 2014 to maintain the options of continued operation at Pickering NGS…" (Ex. F2-2-3, Att. 2)

In an effort to attack the positive NPV of the project, GEC's submission addresses the sensitivity analysis undertaken by both the OPA and OPG in evaluating the project. However, it does not address this analysis in a fair way in OPG's submission. It attempts only to paint the project as uneconomic. GEC does not consider the interrelationship of all factors within the sensitivity analysis, particularly those that drive a positive economic benefit of the project.

GEC argues that OPG has failed to provide the OEB with its current assessment of the overall value of Pickering Continued Operations, including the impact of surplus baseload generation. OPG prepared the updated business case for Pickering Continued Operations in 2012 to confirm the economic value of proceeding with project expenditures for the remaining two years (2013 and 2014). This was consistent with the OEB's desire as set out in the Reasons for Decision in EB-2010-0008.[42] While OPG did not update its analysis after 2012 because by then it had made the decision to proceed with project completion, OPG emphasizes that the OPA has undertaken such an analysis. In the OPA answers to GEC's question two, the OPA stated:

> The OPA's letter dated August 15, 2012 (EB-2013-0321, Exhibit F2-2-3, Attachment 2) was informed by analysis described in the draft report prepared by the OPA entitled "Report on the Integrated Power System Planning Impacts of Pickering NGS Continued Operation" and dated April 16, 2012. Since 2012, the OPA has continued to assess the option of Pickering Continued Operations in light of evolving circumstances and has developed two analyses on the subject

[42] The OEB stated in its Decision with Reasons (p. 52) that it would "consider spending for years beyond the current test period in OPG's next application, at which time there will be examination of the progress to date and an assessment of project economics and the company's confidence level on the basis of that experience and more current information."

> for OPA-internal purposes. These analyses, prepared in 2013 and 2014, incorporate updates to the OPA's outlook for electricity supply and demand and ongoing refinements to OPA modelling as of the time of preparation. The conclusions of the analyses are consistent with those expressed in the OPA's letter of August 15, 2012. The analyses were not documented as formal reports.

With respect to GEC's assertions that the OPA analysis fails to account for surplus baseload generation or provide an update of potential surplus energy ("PSE"), OPG refers the OEB to OPA's response to question number 10 in the GEC interrogatories. There the OPA confirms that PSE was fully examined in the OPA's analysis:

> In EB-2013-0321 Exhibit L Tab 6.6 Schedule 8 GEC-007, the OPA advised OPG that it did not directly assess the costs or benefits of PSE in the context of its assessment of Pickering continued operations. The OPA did, however, consider PSE in a more general sense. For example, the OPA did estimate the potential impacts of Pickering continued operation on projected PSE amounts (TWh per year). Further, when assessing the Pickering continued operation against an alternative, the OPA's analysis effectively credited the alternative for providing only the amount of capacity and energy required to meet resource requirements (i.e. rather than replacing one-for-one the capacity and energy that would have been provided by Pickering continued operations). The effect of this was to reduce the economic value of those portions of Pickering continued operation that would have contributed to potential capacity and/or energy surpluses and therefore increase, all else being equal, the competitiveness of the "no Pickering continued operation" alternative.

In response to GEC interrogatory number 11, the OPA set out that its updated analysis indicates a diminished impact due to PSE:

> The OPA's reduced projections of PSE are mostly for the period up to approximately 2017, after which projected PSE amounts are consistent with those projected in the OPA's 2012 report. Prior to 2017, the OPA's PSE projections are between one third and one-half lower than projected in the OPA's 2012 analysis. All else being equal, a lower demand would tend to increase the potential for surpluses. In consideration of the interplay of a variety of relevant factors, however<u>, the OPA's outlook for PSE has, on net, diminished</u>. (<u>emphasis added</u>).

With respect to the Fuel Channel Life Extension (FCLE) project, GEC argues that the costs allocated to Pickering in the test period for FCLE ($2.6M and $4.0M) should be disallowed or alternatively "reallocated to Darlington" on the basis that the allocation of the costs to Pickering appeared to be "in aid of lowering the apparent costs of the Darlington rebuilding." (GEC argument, p. 13). This submission is directly contrary to OPG's filed evidence. As set out in Ex. L-6.3-1 Staff-77, an objective of the FCLE project is to add additional value by operating all Pickering units to the end of 2020, without a life management outage on any unit. The allocated costs are therefore not related to the Darlington Refurbishment project but rather to Pickering Continued Operations. Furthermore, GEC had an opportunity to cross-examine OPG witnesses on the allocation of costs between Pickering and the DRP, but chose not to do so. As GEC's assertion is without merit, is not substantiated by any evidence, and GEC counsel avoided putting the proposition now being argued to the OPG witness in the hearing, the OEB should approve OPG's FCLE cost for recovery in 2014 and 2015 as submitted.

With respect to GEC's submissions that the OEB should "assume that the government will direct the closure of the A reactors in the near term" because of "how much worse Pickering A's performance is compared to the B units" (GEC argument, p. 14), OPG submits that GEC is asking the OEB to usurp the function of the Government. Pickering is one station. It is Pickering Generating Station, not Pickering A or Pickering B, that is included in the Long Term Energy Plan as remaining in service beyond the test period. The OEB should reject GEC's invitation to revise the LTEP.

GEC also argues that if the OEB does not disallow costs for Pickering in this proceeding, the OEB should require that OPG provide, in the next payment application, a detailed analysis of the net benefit/dis-benefit of continued operation of Pickering units with consideration of shutdowns (GEC argument, p. 14).

The study contemplated by GEC should not be ordered by the OEB. OPG submits that the OEB should rely on the Long Term Energy Plan in respect of the ongoing operation of Pickering. The Long Term Energy Plan contemplates the Pickering station remaining in service until 2020 (KT2.2, pp. 30, 47). The Long Term Energy Plan also references that an earlier shutdown of the Pickering units may be possible depending on projected demand, the progress of the fleet refurbishment program, and the timely completion of the Clarington Transformer Station (KT2.2, p. 30). In response to Ex. L-6.6-8 GEC-006, OPG notes that there will not be clarity on these pre-conditions until after Q3 2017, as this is the IESO's current projected in-service date of the Clarington transformer station (from its March 2014 18 Month Outlook). For these reasons, OPG submits that expending resources on the study requested by GEC would be of no value.

In its argument with respect to Issue 6.6 (GEC argument, pp. 10 -15), it is not really clear what GEC is submitting with respect to the test period expenditures related to continued operations for Pickering Units 5 to 8. On page 13 of its argument, GEC seems resigned that “much of the [Pickering Continued Operations] readiness is sunk”, that while there are “[Pickering Continued Operations] readiness expenses in 2014 of $37.1 million”, the “bulk of avoidable costs” are according to GEC, “the incremental costs of running Pickering for the 2014 – 2020 period.” GEC concludes that these costs (approximately $126M and $310M as set out in OPG’s updated business case summary) should be disallowed as OPG has “failed to demonstrate that the continued operation has economic value to Ontarians.” OPG submits that in fact, with the assistance of the OPA, the entity responsible for long-term system planning in Ontario, OPG has demonstrated the economic value of Pickering Continued Operations. All of GEC’s arguments should be dismissed.

With respect to AMPCO’s submission, AMPCO tries to get to a negative NPV for Pickering Continued Operations by arguing that the project is not cost effective because of potential pressure tube to calandria tube gap concerns. AMPCO points to the mid-cycle outage scheduled in 2014 for pressure tube to calandria gap evaluation as evidence of likely higher costs and lost production for Pickering Continued Operations (AMPCO argument, paras. 158-162).

OPG submits that AMPCO’s argument should be dismissed. As AMPCO notes, the Pickering Continued Operations business case included contingency for this issue of potential gaps, stating that “appropriate activities were built into the Continued Operations planning scenario to mitigate those risks.” (Ex. F2-2-3 Attachment 1, p. 4). AMPCO has provided no evidence that the potential pressure tube to calandria tube gap issue will lead to higher costs other than those already incorporated into the OPG study, nor did AMPCO effectively challenge OPG’s evidence on the matter.

Furthermore, the mid-cycle outage pointed to by AMPCO has been cancelled:

> The projected number of Pickering outage days has increased by a net 21 days (0.26 TWh) from 327.9 days to 348.9 days. This is due to a combination of an increase in forced extension to planned outages for Pickering Units 4 and 8 in spring 2014, and the cancellation of the 23 day mid-cycle Unit 5 outage, which was identified in the first Impact Statement filed in December as being required to address the gap between calandria tubes and pressure tubes (see Ex. N1-1-1, page 14, lines 2-7). The Pickering Unit 4 and 17 Unit 8 outages were extended primarily due to increased discovery work and parts quality issues. The mid-cycle outage has been cancelled following CNSC acceptance of the fuel channel component disposition, which eliminated the requirement for pressure tube inspections for Unit 5 in 2014. (Ex. N2-1-1, p. 7).

All of AMPCO's objections to OPG's approval for recovery of its costs under Issue 6.6 should be rejected by the OEB.

7.9 ISSUE 6.7

Primary - Is the test period Operations, Maintenance and Administration budget for the Darlington Refurbishment Project appropriate?

As OPG has set out in its AIC (p. 84), OPG is seeking approval for OM&A expenditures of $6.6M in 2014 and $18.2M in 2015. All differences between the OEB-approved and the actual OM&A costs incurred in respect of the DRP are subject to the Capacity Refurbishment Variance Account. OPG submitted that the DRP OM&A costs are appropriate and should be accepted. No parties have disputed OPG's submission, but LOW has made brief submissions under this heading of costs to which OPG responds here.

LOW submits that "OPG's proposed costs for the Refurbishment Project should only be deemed reasonable and appropriate if the OEB finds adequate provision has been made for the environment. Such a finding falls under the OEB's public interest mandate, since a healthy Lake Ontario is in the best interests of Ontarians." (LOW argument, para. 5)

It is unclear to what extent LOW's submissions are directed at all of the DRP costs, as opposed to only those falling under this Issue.

OPG disagrees with the notion that the OEB has the jurisdiction or the expertise to make findings that "adequate provision has been made for the environment." The environmental regulatory oversight of OPG rests with the CNSC. The CNSC determines the obligations of OPG with respect to environmental compliance and OPG ensures that compliance with various programs. These programs are costed accordingly to ensure compliance. Costs are sufficient since OPG remains in compliance with the applicable conditions and standards. Therefore, as this is LOW's condition precedent for the OEB determining that OPG's proposed costs are reasonable, OPG submits that the OEB should disregard LOW's submission and accept the only other proper submission that the OEB has received, which is OPG's submission.

LOW's submission on the OEB's jurisdiction to determine whether adequate provision has been made for the environment is premised on the assumption that the public interest mandate of the OEB includes the OEB's consideration of a "healthy Lake Ontario." While a healthy Lake Ontario is important, it does not fall within the scope of the OEB's jurisdiction to determine environmental conditions and programs and the scope of such conditions and requirements. However, even if it did, LOW has not led any evidence of what a "healthy Lake Ontario" is. It is OPG's view that this is not a concept of which the OEB can simply take judicial notice. Doing so would not be proper for an expert environmental tribunal let alone an expert economic regulatory tribunal. OPG expects consideration of this issue would require a substantial body of scientific evidence and expert opinion. Additionally, LOW has not led any evidence that the DRP is in any way incompatible with a "healthy Lake Ontario", nor that the DRP could singularly cause an 'unhealthy' Lake Ontario.

LOW submits that if the OEB finds "the environmental costs to be reasonable" that the OEB require OPG to provide updates concerning the actual costs of the environmental assessment follow-up studies, other Refurbishment environmental monitoring studies and any adaptive management projects (LOW argument, paras. 9-10). LOW also submits that the OEB should require OPG to provide "updates regarding whether any oversight bodies are assessing the cumulative environmental effects of the Darlington operations." (LOW argument, para. 26).

OPG submits that LOW is attempting to obtain discovery and establish a forum to examine OPG on issues that are properly within the jurisdiction of other regulatory bodies and not the

OEB. Since the evaluation of OPG's environmental programs are not within the OEB's scope of review, it make little sense for updated cost information to be filed with the OEB. The OEB's jurisdiction is to establish payment amounts under Section 78.1 of the *Ontario Energy Board Act*. Cost information related to such programs should be filed in the ordinary course of making a rate application to the extent they are material and relevant to the OEB's ultimate determination. There are other forums which are more properly available to LOW to pursue its items of interest at the level of detail it wishes.

For all of the foregoing reasons, LOW's submissions should not be accepted by the OEB.

7.10 CORPORATE COSTS

7.11 ISSUE 6.8

Oral Hearing - Are the 2014 and 2015 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Under Issue 6.8, parties have raised issues with respect to OPG's compensation and pension and other post employment benefit ("OPEB") costs. These two items are addressed separately in this section.

7.11.1 Compensation

In relation to compensation, Board staff recommends a disallowance of $100M to test period nuclear OM&A based primarily on the compensation paid to PWU represented staff and alleged overstaffing (Board staff argument, pp. 86-87). SEC, supported by various other parties, recommends a disallowance of $100M for each of 2014 and 2015, again based on PWU costs (SEC argument, para. 6.8.24). For its part, CME argues that the disallowance should be even greater: $146M in 2014 and $144M in 2015 (CME argument, para. 188). It too points to compensation paid to PWU represented staff while also referring to the compensation paid to Society represented staff and management.

None of these proposed disallowances should be adopted. OPG submits that, properly analyzed, the reductions do not withstand scrutiny. They do not have regard to the correct legal framework, nor to the evidence. A disallowance would be legally unreasonable. OPG has prudently managed its compensation costs which are appropriate for the scope and complexity of the regulated business. In light of the demands placed on OPG's workforce, the skills, education and training that are required to operate, maintain and renew OPG's prescribed facilities, and the unionized environment in which OPG operates, its compensation costs are reasonable and should be approved.

7.11.1.1 The Legal Framework

As set out in OPG's Argument-in-Chief, its regulated staff work in a predominantly unionized environment, with approximately 90 per cent of staff belonging to either the PWU or the Society. OPG's compensation costs are in large measure a function of the binding collective agreements in place with those two unions. The costs are committed and must be assessed through the lens of a prudence review, the essential features of which are set out above in Section 5.5.3 of this Reply. The OEB must assess the prudence of the collective agreements based on the information that was known or ought reasonably to have been known by OPG at the time the agreements were entered into. As the OEB said in RP-2001-0029, a case concerning Union Gas that was released almost contemporaneously with the *Enbridge* case:

> In every circumstance where the Board is required to consider the prudence of any action by a regulated utility, it is engaged in a review of the reasonableness of the utility's action at a given point of time in the past. The retrospective nature of such a review is inescapable. Utilities that are obliged to take action to address operational requirements must be able to do so with some confidence that their actions will be judged on the basis of circumstances obtaining at the time they are compelled to make the decision, not on the basis of circumstances which emerged afterward. (RP-2001-0029, Decision with Reasons, p. 20, para. 2.35).

An essential aspect of any prudence review is consideration of alternatives. As the OEB said, it "must consider the alternatives available" to the utility at the time of its decision. Translated to the present case, the proper legal framework requires consideration of the prudence of OPG's collective agreements having regard to the alternatives and information that were available to OPG when it entered into those agreements.

The Ontario Court of Appeal's decision in *PWU v. Ontario Energy Board*, 2013 ONCA 359 is the leading case on the proper legal framework in which to analyze OPG's compensation costs. Despite the obvious importance of the Court of Appeal's decision, none of the parties that have proposed a disallowance of OPG's compensation costs have made any effort to explain how their proposed disallowance fits within the Court's framework.[43] For the reasons discussed further below, their proposals do not fit within the Court's framework.

7.11.1.2 No Basis for Any Compensation Disallowance

Wages Paid to PWU Staff are Reasonable

The main argument made by parties is that the compensation paid by OPG to its PWU represented staff is higher than 50th percentile as reflected in the AON Hewitt report. SEC puts the matter bluntly, "the Board should disallow PWU compensation costs in excess of the 50th percentile." (SEC argument, para. 6.8.17). Those costs are estimated to make up roughly 95 per cent of the $100M disallowance it seeks.

There is no proper basis for this argument. In practical terms it would mean that OPG would have to have negotiated a substantial wage roll back in collective bargaining. No party has suggested that this was achievable, nor could they. There is simply no evidence that a better result was available in collective bargaining. In fact, Board staff, notwithstanding its proposed disallowance, concedes that OPG could not have achieved such a result; Board staff "accepts that it would not be reasonable for OPG to achieve the 50th percentile as presented in the AON Report." (Board staff argument, p. 79).

In fact, as described in OPG's Argument-in-Chief, OPG was successful in its negotiations. The PWU agreement was negotiated in early 2012 under a Government imposed mandate on OPG to achieve "net zero"; OPG was expected to achieve an agreement with a net zero compensation increase, meaning any increase in compensation had to be offset by corresponding savings elsewhere in the collective agreement. OPG met the Government's expectation; OPG negotiated a number of cost and productivity offsets to the wage increases in the PWU agreement (Ex. F4-3-1, p. 10; Ex. L-6.8-1 Board staff-101, p. 3; see also, Ex. JT2.34). These included:

[43] There is an incomplete discussion of the case in footnote 113 of Board staff's argument (p. 66) in the context of benchmarking and in footnote 181 of SEC's argument (p. 57).

- Elimination of the Goalsharing bonus
- Elimination of Radiation Protection Clothing
- Net savings in health and dental
- Efficiency Gains - MAR and Shift Turnover
- Adding “Radiation Protection Technicians” to the hiring hall
- Hard threshold PSA
- Ability to “claw back” family time taken but not repaid
- Extension of targeted severance provisions (Ex. JT2.34).

The aggregate value of these offsets is equal to approximately $22.0M per year and exceeds the estimated cost of the year over year increase of 2.75 per cent wage increase included in the PWU agreement of $21M. Moreover, the $22M in offsets does not include the large overall savings arising from Business Transformation and the reduction in headcount (Ex. JT2.34).

The calculations associated with the net costs and savings were presented to, and met, the Government’s expectations regarding “net zero” (Ex. JT2.34).

While SEC complains that the AON Hewitt report was not presented by OPG to the PWU in collective bargaining, this fails utterly to recognize the uncontradicted evidence from OPG and Dr. Chaykowski – the only labour relations expert called by any of the parties at the hearing – that, in bargaining, the relevant comparators are other, internal bargaining units and external, comparable bargaining units (“similar union, similar workers, similar line of business etc..”, i.e. the bargaining unit, “across the street”) against whom negotiations are patterned:

> …I was making that distinction the other day between the role of benchmarking studies in both collective and interest arbitration versus this idea of comparable bargaining units. And it is comparable bargaining units that are relevant here. (Tr. Vol. 9, p. 79)

As the PWU correctly observes in its submissions, the evidence is that reports like the AON Hewitt report, however informative, do not impact the outcome of collective bargaining, or the result of interest arbitration.

> MS. HARE: So this is a question to Dr. Chaykowski.
>
> Even in the face of evidence that shows that these workers are paid more than other workers, do you think the arbitrator would rule in favour of the union's position?
>
> DR. CHAYKOWSKI: Well, I think one way of looking at it is that what the parties tend to focus on is the rate of increase. They sort of take where they're at as a given, often.
> Because in the case of some of these surveys, if they were accept them at face value, the employees might be looking at a wage roll-back.
>
> MS. HARE: Right.
>
> DR. CHAYKOWSKI: And I mean, that for many of them is just not on. You may have no choice if you're non-unionized, but if you are unionized, that is one of the central things that a union really must do, is, at least in tough times, protect your wage levels, and in better times, obviously, go after pretty significant pay increases, usually that reflect productivity increases in the industry, and certainly to protect against inflation increases.
>
> So I think that from time to time these surveys probably are presented across the table in a variety of negotiations settings, but I think that it is unlikely that they would be taken seriously by the union because what they're focussed on is, you know, whether the collective agreement next door that they usually compare themselves to got 2 percent or 2 and a half percent or 3 percent. And that's in order to maintain their pay relativities.
> And the interest arbitrators really take the same approach. And, you know, I've gone back to it before, but it really is a nice example. The Albertyn award is pretty, pretty standard fare in terms of what arbitrators look at, so it is a good marker for the kinds of criteria that they will take into account.
>
> And they're very conscious of both internal pay relativities as well as external pay relativities. (Tr. Vol. 8, pp. 102-103).

In fact, the PWU's attitude towards reports like the AON Hewitt study is captured in its argument. There it says, "The AON survey is simply a point-in-time comparison and far from an apples-to-apples comparison and not informative with respect to performance trends." (PWU argument, p. 60).

In any event, SEC's submission glosses over the evidence that OPG regularly provides its unions, throughout the year, with information, such as the AON Hewitt report or the Goodnight study to "educate" the unions and frame negotiations:

> And, Mr. Millar, if I might, what we do with this information [Scott Madden, Goodnight and the Aon Hewitt report] with our unions is -- it is an ongoing process of education, where we try and present the information and how we are being measured, so that they have an appreciation of some of our cost constraints and then in turn the drivers that we have in trying to contain those costs; for instance, staffing and head count. (Tr. Vol. 8, pp. 70-72).[44]

OPG's relative success in negotiations with the PWU is evidenced through comparison to other companies that inherited collective agreements from Ontario Hydro. OPG has negotiated increases that have been at or below most of the successor companies in most years since 2001 resulting in cumulative increases that are below most of the successor companies (Ex. F4-3-1, Table 3). Table 3 is set out below for ease of reference:

[44] However, for the reason set out above, it would be wrong to suggest that the reports can influence the outcome of bargaining.

Table 3 – PWU Increases Compared Among Successor Companies

	PWU General Wage Increases (%)						
	OPG	Bruce Power	Hydro One	Kinectrics	New Horizons	Inergi	IESO
2001	**3.00%**	**3.00%**	**3.00%**	**0.00%**	**3.00%**	**3.00%**	**2.00%**
2002	**2.00%**	**3.10%**	**3.00%**	**5.00%**	**3.00%**	**3.00%**	**2.00%**
2003	**3.00%**	**4.00%**	**3.00%**	**3.00%**	**3.50%**	**2.00%**	**3.00%**
2004	**2.50%**	**3.00%**	**3.00%**	**2.50%**	**3.25%**	**4.00%**	**3.00%**
2005	**2.50%**	**3.00%**	**3.50%**	**3.00%**	**3.00%**	**3.00%**	**2.50%**
2006	**3.00%**	**3.00%**	**3.50%**	**3.00%**	**3.00%**	**2.75%**	**3.00%**
2007	**3.00%**	**3.25%**	**3.00%**	**3.00%**	**3.00%**	**3.00%**	**3.00%**
2008	**3.00%**	**3.20%**	**3.00%**	**3.00%**	**3.00%**	**3.00%**	**3.00%**
2009	**3.00%**	**3.00%**	**3.00%**	**3.00%**	**3.00%**	**3.00%**	**3.00%**
2010	**3.00%**	**3.00%**	**3.00%**	**3.00%**	**3.70%**	**3.00%**	**3.00%**
2011	**3.00%**	**2.75%**	**3.00%**	**3.00%**	**2.70%**	**3.00%**	**3.00%**
2012	**2.75%**	**2.75%**	**3.00%**	**3.00%**	**2.70%**	**2.60%**	**2.50%**
Cumulative	**39.5%**	**44.0%**	**44.0%**	**40.4%**	**43.8%**	**41.7%**	**38.5%**
2013	**2.75%**	**3.50%**	**2.50%**	**3.00%**	**2.60%**	**n/a**	**n/a**
Cumulative	**43.3%**	**49.1%**	**47.6%**	**44.6%**	**47.5%**	**n/a**	**n/a**
2014	**2.75%**	**n/a**	**2.50%**	**n/a**	**2.65%**	**n/a**	**n/a**
Cumulative	**47.3%**	**n/a**	**51.3%**	**n/a**	**51.4%**	**n/a**	**n/a**

In an attempt to buttress their position, Board staff and SEC make two additional related arguments. First, they argue that because ratepayer groups are not represented at the bargaining table there may be misalignment between the interests of OPG's shareholder and ratepayers. Second, they assert that the bargaining incentives may be different in the private sector and the OEB, as "market proxy" should solve for this difference. Each of these arguments is without merit.

With respect to the interests of OPG's shareholder and ratepayers in bargaining, there is no evidence of a lack of alignment; indeed, Board staff and SEC do not even speculate as to what might constitute a lack of alignment, how that might arise or even what tangible impact it might have on bargaining. This is not surprising as all the evidence points the other way - OPG has bargained aggressively with its Unions to limit wage increases. (Tr. Vol. 7, p. 163). It reached an impasse with the PWU that was only resolved after the engagement of a provincially appointed conciliator who was appointed to avert a work stoppage. A similar impasse with the Society resulted in the appointment of an arbitrator to resolve the impasse. (Tr. Vol. 7, p. 163; Ex. L-6.8-17 SEC 110). In sum, the argument amounts to nothing but a bald assertion, leading nowhere. In fact, the very concept is inconsistent with OPG's Mission Statement to be Ontario's low cost generator of choice and was rejected in cross-examination (Tr. Vol. 8, pp. 51-52).

Moreover, there is nothing unique about the fact that ratepayers do not directly participate in collective bargaining which would differentiate compensation costs from other costs at issue in this Application. In fact, substantially all of OPG's costs arise from decisions made by it – either unilaterally or in commercial negotiations – that do not involve other stakeholders. Nothing prevents the OEB from assessing the prudence of these decisions and it is regularly called upon to do so. In so far as its own involvement goes, the OEB has frequently advised that its role is not to manage a utility; that is the role of management (EB-2005-0001, Decision with Reasons p. 9; EB-2007-0905, Decision with Reasons p. 28; EB-2010-0008, Decision with Reasons, p. 28.).

With respect to the market proxy argument, this is misplaced on several fronts. First, the suggestion that OPG is a monopoly service provider, comparable to an electric or gas LDC, is simply wrong. OPG offers its prescribed generation into the Ontario electricity spot market and interconnected markets without any guarantee that its generation offers will be accepted and dispatched. So the comparison to the competitive market is inapposite. As the OEB said in OPG's first payment amounts case:

> This is the first time the Board has set prices for an electricity generator. The Board has considerable experience in setting rates for electricity and natural gas distributors and transmitters that are, in substance if not legally, monopoly providers of energy delivery services. The electricity generation business in Ontario, however, is very different from distribution and transmission of electricity and gas. For example, there is no "market" for distribution of electricity to homes and businesses but there is a market in the electricity commodity that is produced by OPG and other generators. And, unlike the electricity and natural gas distributors that are subject to rate regulation, generators do not have an "obligation to serve." (EB-2007-0905, Decision with Reasons, p. 7).

Further, even accepting for argument's sake that the OEB's function is to act as a market proxy, this does not allow it to avoid the consequences of the *Labour Relations Act*. This statute applies to OPG just as the *Ontario Energy Board Act* does. As a successor company to Ontario Hydro, OPG was required by law to adopt the collective agreements covering staff transferred to OPG from Ontario Hydro and to bargain collectively going forward. The costs arising from that process become subject to review by the OEB for prudence, like any other costs that OPG incurs. If the costs are prudent, then OPG is entitled to recover them.

Finally, on the evidence, the inconvenient truth in respect of this and other arguments in relation to the wages paid to OPG's PWU represented staff is Bruce Power and how it has fared in bargaining with the PWU relative to OPG.

Bruce Power is unregulated. It is a profit maximizing enterprise that operates in the private sector. It competes with OPG for PWU labour. In Board staff's words, private sector firms have "a very strong incentive…to bargain aggressively with unions and attempt to limit increases, or even secure compensation decreases." (Board staff argument, p. 78). And yet, the evidence is that since 2001 OPG has been able to negotiate lower wage increases than Bruce Power. The comparison is set out in Table 3 above. A comparison of 2013 wages by PWU job category is set out in F4-3-1, Table 2, reproduced below for convenience:

Table 2 - 2013 Wage Comparison of PWU Positions between OPG and Bruce Power

PWU Job Category (2013)	OPG	Bruce Power	Difference ($/Hr)	Difference (%)
Civil Maintainer I	$38.95	$52.36	-$13.41	34.43%
Emergency Response Maintainer	$38.95	$47.19	-$8.24	21.16%
Civil Maintainer II	$38.95	$49.04	-$10.09	25.91%
Nuclear Operator	$50.08	$58.32	$-8.24	16.45%
Shift Control Technician	$50.08	$57.27	-$7.19	14.36%
Mechanical Maintainer	$50.08	$57.10	-$7.02	14.02%
Nuclear Security Officer	$38.95	$40.87	-$1.92	4.93%
Business Support Representative (OPG - Office Support Representative II)	$38.95	$46.02	-$7.07	18.15%
Project Tech II – E&C (OPG - Project Technician - E&C)	$50.08	$51.34	-$1.26	2.52%
Chemical Technician	$50.08	$51.99	-$1.91	3.81%
Cost & Scheduling Technician (OPG - Planning $ Cost Control Technician)	$50.08	$52.63	-$2.55	5.09%
Finance Clerk (OPG- Finance & Payroll Representative)	$38.95	$48.74	-$9.79	25.13%

***** Wage comparisons for PWU positions are based on top step of the OPG salary bands and top step of the Bruce Power competency based scales or multi-trade scales (if applicable).

Parties that have proposed a compensation disallowance do not like the evidence comparing OPG to Bruce Power. For the most part, they simply ignore it. Board staff and SEC purport to minimize it, although neither suggests that Bruce Power is not the best comparator. SEC says that it was “revealed during the oral hearing [that] the pay band comparison is not accurate…and that the actual pay gap may not exist at all.” (SEC argument, para. 6.8.22) Charitably, this is a gross distortion of the record. The evidence is that:

> In 2002 and 2006 OPG successfully negotiated reductions to the top bands of its PWU and Society wage schedules. These schedules are therefore the negotiated compensation for unionized employees. At the time of implementation of the schedules in 2002 and 2006, there were a number of employees whose base wages exceeded the new schedules. To accomplish the goal of lowering the upper end of the wage schedules, an agreement was reached to maintain the wages of those employees whose base wages exceeded the new schedules at the point of implementation (i.e. they were “grandfathered.”) This agreement applies by exception only in respect of those employees and ceases to exist if the employee changes a position in which case they adopt a wage from the established wage schedules.
>
> The introduction of new salary bands resulted in future savings as the top of the salary bands were reduced.

> Approximately 89% of OPG's represented employees are covered by the wage schedules with the remaining 11% subject to the grandfathering exception. The number of employees covered by the exception has reduced approximately 20% from 1200 to 972 since the Auditor General's finding and is expected to be negligible by 2020.
> If the 972 grandfathered employees were limited to the top of their salary band, OPG's total base salary costs would be approximately $5.6M lower per year
>
> *   *   *   *
>
> <u>In addition, even if one were to adjust the OPG salary bands by weighting them to take account of overband employees, the central conclusion that OPG pays less than Bruce Power would continue to apply.</u> Table 2 includes PWU positions that cover approximately 45% of the total PWU population across OPG. The annual PWU base wage cost is approximately $550M. So the cost of the PWU overband employees is less than 1% of the total PWU wage bill. (*emphasis added*) (Ex. J8.1).

SEC's complaints about OPG's "attitude" towards collective bargaining are wrong and should be ignored. Coming from a party without any expertise in relation to the subject and which did not challenge the evidence of the only expert who was called at the hearing − Dr. Chaykowski – the submissions should be rejected out of hand.

There is nothing "defeatist" about recognizing the fundamental labour relations realities that OPG faces. To do otherwise would be wrong in fact, and in law. The parties' submissions in effect ask OPG and the OEB to bury their collective heads in the sand. This is unrealistic – OPG must address the labour relations context as it is and not as the parties wish it were. In any event, OPG's performance in collective bargaining has been strong and it stands behind it.

CME argues that compensation costs should be cut by a further $50M to account for compensation levels for Society represented staff and management (CME argument, para. 188).[45] There is absolutely no basis for this argument. With respect to Society compensation, the terms of the Society collective agreement, including as they relate to compensation, were imposed by an Arbitrator Albertyn on OPG after negotiations failed to produce an agreement. There can be no serious suggestion that OPG could have achieved a better, or even different, result. Moreover, CME entirely overlooks the fact that OPG's Application is based upon its

[45] This is on top of the $96M for each of 2014 and 2015 said to be attributable to PWU compensation.

2013-2015 Business Plan, which assumes a zero per cent increase. Finally, CME also overlooks the fact that even if the AON Hewitt report were relevant (which is denied above), it would not assist: Society represented staff already benchmark at the 50th percentile compared to other power generators and nuclear generators, which is the only reasonable comparator group.

For management staff, CME's argument is equally flawed. Management Group ("MG") also benchmarks at the 50th percentile relative to power generators and nuclear generators. OPG's MG compensation band structure and base pay merit budget are reviewed against external benchmarks to ensure that MG compensation is in line with the 50th percentile. The MG band structure has been frozen since 2008 and base pay and merit increases have been restricted through numerous constraints that have been self-imposed by OPG or imposed by Government legislation in the form of Bill 16 and Bill 55. These salary restraint measures have contributed to a reduction in OPG's total cost of MG base salaries since 2010 and have reduced management salaries such that they are now generally at or below the 50th percentile relative to the comparator groups (Ex. F4-3-1, p. 20). As even Board staff acknowledges, "it does not appear that OPG's management is in general overpaid on a per employee basis." (Board staff argument, p. 87).

<u>Staffing Levels are Appropriate</u>

The second main argument made (primarily by Board staff) is in relation to staffing levels. In this respect, Board staff points to the Goodnight study. Reliance on the study is misplaced. OPG's staffing levels are appropriate.

To begin, it is important to recognize what is within OPG's control and what is not. OPG concedes that it has a measure of control over the number of management staff it employs. OPG also has control, within the scope of the needs of its business, to limit the number of employees it hires. However, OPG does not have unfettered control to terminate employees, nor to contract work out. The right to do so, in both cases, is severely circumscribed by the collective agreements with the PWU and the Society. It is, therefore wrong to suggest, as Board staff does, that the collective agreements do not impact staffing levels. The evidence is as follows:

- Both the PWU and Society collective agreements contain clauses that restrict the degree to which OPG can contract out the work of employees who are members of the union. Given the degree of unionization, these clauses capture substantially all of the work at OPG.
- The contracting out clauses in the PWU and Society collective agreements provide for a jointly managed process for determining what work can be contracted out. Where agreement cannot be reached the dispute moves to arbitration for resolution.
- Re-organization of OPG's workforce entails reducing and redistributing staff, and restructuring jobs. Each of these aspects of reorganization is limited by the collective agreement.
- The PWU agreement includes no lay-off clause, the result of which is that excess staff, if any, can only be addressed through staff redistribution or voluntary severance.
- The Society collective agreement contains an employment continuity clause which addresses layoff, voluntary severance and redistribution of employees. Under the agreement with the Society, the parties must jointly match employees' skills to positions in the organization and then identify which employees are excess. Determining which employees are excess involves examining the qualifications of each employee against the qualifications for each job identified in the organization. Where multiple employees are qualified for the same job, seniority applies. As a result, the person currently doing a job may not retain it if another qualified employee has seniority. Once this matching is completed, employees are either laid off or redistributed to other organizations (Ex. F4-3-1, p. 18).

Given the tools available to it, OPG has reasonably chosen attrition to underpin the BT initiative, which is designed to improve efficiency to permit OPG to operate with fewer employees (Ex. A4-1-1, p. 1). As set out previously, under BT, OPG will reduce its year-end 2015 staff level by 2,000 employees with the potential for further reductions in later years. This decreased staff level is expected to reduce OPG's OM&A by $700M between 2011 and 2015 (Ex. A4-1-1). Approximately 1,300 staff and $550M are attributable to regulated operations, including the newly regulated hydroelectric facilities (Ex. A4-1-1; Ex. L-1.2-2 AMPCO-006).

Reducing staff levels by 2,000 employees by the end of 2015 represents close to a 20 per cent reduction in OPG's headcount.

The Goodnight study shows OPG's strong commitment to reducing headcount and managing its costs. The Goodnight study is further discussed in relation to Issue 6.4 above. As set out there, the staffing "gap" identified by Goodnight was just 4.7 per cent as at March 31, 2014 and closing fast (it had been 17 per cent in 2011). By the end of the test period, the gap will be effectively eliminated.

OPG also specifically agrees with and adopts the PWU's submissions in relation to the study at pages 44-49 of its argument. For example, as the PWU correctly observes:

> First it is very important to understand that benchmarking studies or comparison that do not take into account technological differences have little or no value. Valid comparison require a "like for like" comparison, or at least normalization for known difference. The Goodnight report, by taking into account technological differences between CANDU and PWR/BWR nuclear plants and analyzing the nature of the differences has more realistically presented the staffing levels hat is appropriate to the type of the technology used. Moreover, the Goodnight series of updates are more useful because they show OPG's performance trend. (PWU argument, p. 44).

Board staff also points to the results of other nuclear benchmarking generally to support its argument. In addition to the comments relating to benchmarking set out under Issue 6.4 above, there are several flaws with this line of reasoning. First, it amounts to double counting of previous arguments relating to wage levels and staffing. This fact is obvious from Board staff's argument. As it says, benchmarking performance cannot be tracked "directly to any particular budget item, however compensation costs are certainly a major driver." (Board staff argument, p. 87). If compensation is a driver of benchmarking performance, and compensation costs are a function of wages and staffing, it is improper to complain about benchmarking, wages and staffing, all under the heading of compensation.

Second, and more fundamentally, benchmarking information does not assist in resolving the question before the Board; that is, the prudence of OPG's committed compensation costs. More specifically, benchmarking does not address the question of whether, based on information that was available to OPG at the time its collective agreement were prudently entered into, if there was another alternative reasonably available. For the reasons set out above and in OPG's Argument-in-Chief, there was not.

In relation to MG staffing, Board staff says that if nuclear management levels, as a percentage of total regulated staff, were fixed at 2010 levels, the revenue requirement impact would be $20M over test period (Board staff argument, p. 87). Complaints about management staffing levels are misplaced and fail to have regard to significant improvements made by OPG in this respect (Board staff argument, pp. 85-86; SEC argument, para. 6.8.7(c); CME argument, para. 171; CCC argument, pp.15-16; VECC argument, p. 35).

OPG acknowledges the comments made by the Auditor General. However, it is important to bear in mind that the comments were made in relation to prior periods and include staff relating to BT and Darlington Refurbishment (Ex. J9.1). Contrary to Staff's suggestion, there is no good reason to suppose that management levels would decrease through BT in lockstep with overall staffing levels. In fact, in absolute terms there are no director level positions or above forecast for BT in 2015. And, on an FTE basis through the end of the test period, OPG is forecasting an overall reduction in management staffing levels. Finally, in relation to total regulated management cost – the item that parties and the OEB should focus on in relation to management compensation – the evidence is that costs are flat over the test period (Ex. JT2.33).

In OPG's submission, as a result of BT there is no proper basis to complain about OPG's staffing levels.

<u>Other Miscellaneous Arguments Should be Rejected</u>

Board staff and SEC both point to overtime in their discussion of compensation costs. Argument in this respect can safely be ignored by the OEB: there is no substance to the complaints and they do not ground any claimed disallowance in any evidence. Board staff questions whether the Goodnight study met the "OEB's direction with respect to overtime", given that it did not include outage related overtime (Board staff argument, p. 86). SEC makes a similar complaint (SEC argument, para. 6.8.23).

The OEB did not direct OPG to file an analysis of overtime. Rather, the OEB stated that it expected to examine the issue of overtime more closely in the next proceeding and expected OPG to demonstrate that it has optimized the mix of potential staffing resources (EB-2010-0008, Decision with Reasons, p. 84). OPG addressed the mix of potential staffing resources at Ex. F2-2-1 pp. 4-5 (base OM&A); at Ex. F2-4-1 pages 3-5; and variances of actual overtime to budget at Ex. L-6.3-2 AMPCO-044. Specifically in relation to outage related overtime, the evidence is that that there is no means to accurately benchmark outage costs, whether overtime or otherwise and it was for this reason that outage overtime was excluded by Goodnight.[46]

Finally, SEC argues that OPG's oversight and management of its performance evaluation process is inadequate. The centre piece of this argument is the assertion that for unionized staff OPG has no formal requirement for job evaluation. This is hardly surprising. As Dr. Chaykowski testified, job progression in the unionized broader public sector is regularly based on seniority without any formal job evaluation criteria. As he testified, "it is not uncommon to see these kinds of salary grid progression models in the broader public sector." (Tr. Vol. 11, p. 68). In fact, the OEB's own collective agreement with the Society provides for seniority based progression without performance evaluation (Ex. K7.4, Tab D [PDF p. 1467]).

7.11.1.3 Conclusion on Compensation

OPG submits that on the basis of the evidence presented and the discussion of that evidence in OPG's Argument-in-Chief and this Reply Argument, the OEB should approve OPG's compensation request as a reasonable and appropriate forecast of its test period expenses.

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[46] SEC also tries to support its complaints in this respect by, among other things, comments made by respondents to the Auditor General. Respectfully, it is difficult to take this seriously. As Dr. Chaykowski testified: "Well, you know, I'd have to see the survey. To be honest, I'm a little suspicious. There's always a lot of response -- potential for response bias in surveys like this, where people read into it, This is a chance for me to express my concerns about, you know, about the workplace. (Tr. Vol. 8, p. 124).

7.11.2 Pension and Other Post Employment Benefits

OPG's pension and benefit plans are substantially the same as the plans that were before the OEB and approved in EB-2010-0008.[47] Importantly, they are plans that OPG inherited and was legally required to continue on the demerger of Ontario Hydro (Tr. Vol. 7, pp. 152-153). The "richness" of the plans results from decisions made by Ontario Hydro over 20 years ago or more; not OPG. It should not be punished for something it did not do, and which, as set out further below, is now largely beyond its control. As described in OPG's Argument-in-Chief, there have been no increases by OPG in the benefits offered under the pension plan since it was last considered by the OEB. Similarly, there has been no increase in other benefits. On the contrary, the evidence is that OPG has been taking steps to stabilize benefit costs and has implemented a number of changes to better align its benefit provisions with those of the external market (Ex. F4-3-1, p. 24). Those initiatives are detailed in OPG's Argument-in-Chief at pages 94-95. It is also worth noting that, based on the most recent actuarial funding valuation of the OPG pension plan, the plan is 99 per cent funded on a solvency basis (Ex. J9.6, Attachment 1, p. 2) and 90.5 per cent funded on a going concern basis (*Ibid*, p. 7) as at January 1, 2014.

It bears repeating that for OPG's unionized employees, 90 per cent of OPG's workforce, pension and benefit provisions can only be changed through the collective bargaining process or arbitration (if the collective agreement provides for it, or the Government imposes it through legislation (see Ex. L-6.8-2 AMPCO- 058(J)). They cannot be changed unilaterally by OPG (Ex. F4-3-1, p. 7; Tr. Vol. 8, p. 19).

The uncontradicted evidence is that challenges associated with pension plans in particular are not unique to OPG. Rather they are widespread across the Ontario broader public sector. As Dr. Chaykowski testified, the issues are "amongst the most difficult" to resolve (Tr. Vol. 11, p. 53). In fact, OPG attempted to make headway on the issue of its pension plan during the last round of negotiations with the PWU. However, the PWU refused to even agree to a committee to discuss the issues. To the same effect, Arbitrator Albertyn refused, despite OPG's request,

[47] Pension refers to the OPG registered pension plan. OPEB refers to other post retirement benefits, the supplementary pension plan, and the long-term disability benefit plan.

to make changes to pension and OPEB for Society represented staff leaving the matter status quo (Tr. Vol. 8, p. 140).

The Towers Watson report relied on so heavily by these parties makes this same point. It points out that any strategy in relation to OPG's pension plan, "needs to recognize the reality of labour negotiation dynamics and related bargaining capital required for implementing changes." (Ex. JT2.12, Attachment 1, p. 11). While Board staff and SEC may not like this evidence, it is undisputed and reflects the reality within which OPG must operate.

The Report on the Sustainability of Electricity Sector Pension Plans to the Minister of Finance ("Leech Report"), which is frequently referenced to by Board staff and SEC, also makes these points. With respect to collective bargaining it says: "all elements of the pension plans at these companies are determined in collective bargaining. Notwithstanding the fact that the employers are the plan sponsors and bear all of the risks, the collective agreements contain language providing that terms can only be altered with the consent of both parties." (Leech Report, p. 14). The report goes on further to make a blunt observation that "collective bargaining process, on its own, is not an optimal process to ensure that the pension plans are sustainable and affordable on an ongoing basis." (Leech Report, p. 24).

Discussing arbitration, the Leech Report says:

> A request to shift the pension obligation from the employer to the employee is likely to be seen by arbitrators as a form of compensation reduction unless it is offset by an increase in wages. In addition, arbitrators tend to direct parties to resolve significant pension-related decisions through subsequent rounds of bargaining and have not made significant changes to pension plan design. (Leech Report, p. 15).

In the face of this evidence, Board staff's observation that "there is no doubt in Board staff's view that OPG can control some of the costs related to various components and features of the plan such as employee contribution, indexing, spousal plans, etc." (Board staff argument, p. 90) lacks any air of reality. No evidence is cited in support of this "view", nor could there be. The evidence is diametrically opposed to the statement. Each of the items identified by Board staff is a matter which would require union consent, which manifestly was not forthcoming.

Indeed, Board staff's view is impossible to reconcile with its own admission (immediately beforehand) that it "does not disagree with OPG" that significant reductions in pension costs can only result from: an increase in actual discount rates; higher mortality rates; and significant legislative amendments.

SEC's argument is in the same vein. It similarly utterly fails to acknowledge the uncontradicted evidence above, including that the PWU and Society were absolutely unprepared to negotiate any changes to the terms of the plans.

SEC also makes numerous incorrect statements about the value of potential changes to OPG's pension plan. Rather than correcting all of them, OPG responds only to SEC assertions that OPG has provided misleading information or misleading argument. SEC states that the calculations OPG provided were based on the 2008 valuation of the pension plan and accuses OPG of presenting a misleading figure (SEC argument, para. 6.8.40-6.8.42). This is incorrect.

The January 1, 2008 valuation applies to just three of the items, totalling just $4M, that appear to be included in SEC's $118M amount. As explained in Ex J9.10, p.1, lines 17-24, SEC figure itself is a mixture of cash and accounting impacts, some of different vintages. Further, as noted in Ex. J9.10, p. 1, lines 24-26, "the estimated savings are not additive as the various plan changes are likely to be interrelated, resulting in a total impact that is different from the sum of the individual impacts." It is SEC's conclusion that "a full set of the changes would reduce pension costs alone by $118 million per year" (SEC argument, para. 6.8.40) that is misleading.

In comparing the OPG single-employer plan to the Ontario Public Service jointly-sponsored pension plan and citing the Leech report recommendation to move to a 50/50 contribution target, Board staff claims that there are "savings" of up to $140M available if both current service (normal cost) contributions and special payment (for past shortfalls) to the OPG registered pension plan were equally shared with employees.[48] Not only does the suggestion of these "savings" completely ignore the collective bargaining reality outlined above, but it is also based on a premise, which is contrary to the law, that special payments related to past service

[48] Given its completely speculative nature, OPG has not corrected Board staff's calculation, which is a total OPG figure, to reflect the regulated portion only.

could be equally shared with employees. At law, any changes to the pension plan can only be made prospectively, in respect of future service. In referring to the Leech report recommendation, Board staff neglects to mention that the Leech report recommends the move to a 50/50 current service contribution target over a period of time, not immediately as implied by Board staff's "savings". Specifically, the report states:

> It is recommended that employer/employee contribution move to the target of 50/50 on an agreed timeline. The government has suggested five years to reach that target which would appear to be a reasonable phase in period. (emphasis added) (Leech Report, p. 24).

For all these reasons, the "savings" identified by Board staff at page 90 of its argument are completely illusory. And, in any event, Board staff's calculations based on Ex. J9.6 are not direct "savings" against the revenue requirement because they are cash, not accrual, amounts. A detailed calculation would need to be undertaken by the actuaries on the various components of the USGAAP pension costs (explained in Ex. F4-3-1, section 6.3.1) to assess the hypothetical impact of holding employees at risk for past shortfalls.

7.11.2.1 Proper Basis of Cost Recovery: Accrual

As set out above, the main argument made by parties is that OPG should be required to move from an accrual basis of cost recovery to a cash basis of cost recovery for pension and OPEB costs. In EB-2010-0008 the OEB denied a similar suggestion, holding:

> OPG correctly points out that there is currently no consistency amongst utilities in the use of either the cash or accrual method to setting pension and other post employment benefit expenses. Both methodologies have been approved by the Board. The Board in this case sees no compelling reason to change OPG's existing approach of using the accrual method. Consistency in accounting treatment, in order to compare results year to year, is advantageous for purposes of assessing the level of costs for reasonable. A consistent approach over time also ensures a greater level of fairness of ratepayers and the company. (EB-2010-0008, Decision with Reasons, p. 91).

In OPG's submission, while the figures may be different, the circumstances with respect to its pension and OPEB-related costs and their recovery have not changed since EB-2010-0008; recovery should continue to be determined on an accrual basis in accordance with generally accepted accounting principles. Canadian GAAP applied at the time of EB-2010-0008 required the use of accrual accounting for pension and OPEB; USGAAP does as well.

As discussed in OPG's Argument-in-Chief, in the case of pension and OPEB-related costs, costs are recognized when the related employee service is considered to be rendered and the benefit is considered to be earned, not when the actual benefit payments are made to retirees in the future. All companies make accruals during a reporting period, whether for wages employees have earned (but not paid), services received (but not paid) for external contractors, or revenues earned (but not received) for production of electricity. In fundamental financial statement terms, the income statement depicts the revenues earned for cost incurred to produce a product or service. Revenues are matched to costs and benefits, thereby avoiding intergenerational equity issues (discussed further below).

Specifically with respect to other post retirement benefits, the Federal Energy Regulatory Commission found that accrual accounting is appropriate for regulatory purposes, as articulated in their Statement of Policy on Post-Employment Benefits Other Than Pensions ("FERC OPEB Policy") (docket no. PL93-1-000) referred to by Board staff (Ex. K13.2):

> It is self-evident that where a jurisdictional company's rates are to be judged just and reasonable based upon its cost of providing service, the Commission must prescribe the accounting principles it will use to define and measure the cost to track ratemaking... The Commission has examined SFAS 106 [Statement of Financial Accounting Standards No. 106, Employers' Accounting for Post-retirement Benefits Other Than Pensions][49] in this regard and finds the following:
>
> a) PBOPs [Post-Employment Benefits Other Than Pensions] are a form of deferred compensation to employees for the services that they provide during their working years. <u>Therefore, the costs of providing these benefits are properly included in the cost of service during the period that the benefits are earned.</u>
> b) Measurement of PBOPs for a given rate test period is a process of allocating accrued costs between periods in a rational manner <u>so that each period bears its equitable portion of such costs.</u> SFAS 106 provides a reasonable convention for measurement of accrued costs including the transitional treatment of prior service costs.

[49] SFAS 106 was subsequently codified within US GAAP as part of Accounting Standards Codification Subtopic 715-60 Compensation – Retirement Benefits, Defined Benefit Plans – Other Postretirement

c) Uniform principles of cost measurement between similarly situated regulated companies and between time periods are beneficial for carrying out the Commission's regulatory programs. (emphasis added) (FERC OPEB Policy, pp. 6-7).

FERC's findings are consistent with the strong policy reasons to favour accrual accounting. Accounting standards require entities to reflect the true cost of doing business in their financial statements. Transparency in relation to the true cost of electricity generation (or any regulated service) favours the same result. As the OEB has said many times, it is in the public interest for consumers to know the true cost of electricity (or gas) so that they may make informed consumption decisions. The OEB has also previously articulated its preference for regulatory accounting to follow financial accounting where not inconsistent with sound rate making principles (EB-2008-0408, Report of the Board, p. 7). As such, Board staff's submission that it is paramount for the OEB to make sure that costs are paid in the test period if they are accrued in the test period (Board staff argument, p. 97) is at odds with what the OEB does in most cases.

At present, most regulated utilities in Ontario recover their pension-related costs on an accrual basis. SEC's statement to the contrary is simply incorrect (SEC argument, para. 6.8.55). It misunderstands that the situation for electric LDCs is different because of their participation in the OMERS plan. OMERS uses the accrual method to determine the amount of pension costs it must recover from its members and bills each member utility its appropriate share of these costs. While the invoice each utilities sees and pays is a cash amount, the amount of each utility's invoice is based on costs that have been determined using the accrual method.

7.11.2.2 Response to Proposal to Move to Cash Recovery

As the material above clearly sets out, OPG continues to believe that pension and OPEB costs are appropriately recovered on an accrual basis. In OPG's view, this matter was considered by the OEB and decided in the last payment amounts proceeding (EB-2010-0008, Decision with Reasons, p. 91). No party raised this issue at Issues Day and, as a result, it was not included on the Issues List for this proceeding. On this basis, OPG did not present any evidence on this issue.

In the current proceeding, Board staff asked a few interrogatories on cash versus accrual and the possibility of setting up a segregated fund for OPEB (Ex. L-6.8-1 Board staff-122 to Board staff-124), asked some questions about OPG's position on these issues (Tr. Tech. Conf. April 23, 2014, p. 198-99; Tr. Vol. 13, pp. 5-25) and asked for an update to one of OPG's responses (Ex. JT2.40).

Based on this limited discovery, some cross-examination and through its arguments, Board staff has offered analysis and calculations intended to show the benefits of moving to cash accounting, but as fully discussed below, many of these analyses and calculations are incomplete or contrary to accounting and actuarial practices, and some are just wrong. As this proceeding has clearly demonstrated, the calculation of pension and OPEB costs is exceedingly complex and involves hundreds of millions of dollars. OPG submits that the record in this proceeding is inadequate to support any radical change. As is discussed more fully in the next section, if the OEB believes that there is merit in examining the issues of cash accounting, it should create a generic proceeding or joint working group, where a thorough and evidence-based examination can occur. As Mr. Barrett testified:

> But again, if the Board wishes to pursue this, our advice would be that since this touches all of the utilities in the province, it is best done through a generic proceeding, where some of these very complicated legal and tax issues and accounting issues can be dug into with some degree of diligence and experts can be brought forward.
>
> As Mr. Kogan indicated, we've had some very preliminary discussions within the company as a consequence of this issue getting raised in this proceeding.
>
> And my takeaway -- again, not as an expert -- is that this is very, very complicated, and it would take some time and effort to figure out exactly how it is best done and what the consequences of it would be. (Tr. Vol. 13, pp. 24-25).

Similarly, if the OEB wishes a full examination of the issues associated with creating a segregated fund for OPEB, then it should either order OPG to conduct a full study of the issue, as Mr. Barrett suggested (Tr. Vol. 13, p. 134), or roll this issue into the proceeding suggested above to consider moving from cash to accrual.[50]

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[50] OPG notes that a generic process led to the development of the FERC policy on the issue (FERC OPEB Policy, p. 3), which utilities then had three years to adopt (Ibid, p. 5). OPG also notes that, in EB-2010-0008, on another

An examination of the record shows that Board staff's statement that there is extensive evidence on this issue is incorrect (Board staff argument, p. 100). Examples of issues that were not explored or reviewed incompletely include impacts of a move to a cash basis on the equity ratio and USGAAP accounting impacts, as discussed in Ex. J13.7. In fact, one of the purposes of that undertaking was to identify the issues that would need to be further evaluated in considering a change in recovery methodology (Tr. Vol. 13, pp. 98-99). Similarly, there is insufficient analysis in this proceeding to support Board staff's centerpiece claim that pension cash amounts are more stable than accounting amounts (Board staff argument, pp. 100-102).

Before turning to the specific claims made by Board staff and SEC in support of recovering pension and OPEB costs on a cash basis, it is important to correct Board staff's and SEC's claims that OPG has allegedly collected large sums of money from ratepayers since 2008 for pension and OPEB which it has used for "general corporate purposes" (Board staff) or "additional cash profits" (SEC) (Board staff argument, pp. 94-95; SEC argument, para. 6.8.62).

What Board staff has completely ignored is the fact that, as of December 31, 2013, OPG has not collected $667M of pension and OPEB costs, including related tax effects, for the 2011 to 2013 period. In a massive understatement, Board staff mentions in passing that "there are some amounts in the variance account as at December 31, 2012 being collected over a 12-year period and some further amounts in the variance account that have been approved for tracking and will be disposed in a future proceeding." (Board staff argument, p. 96). Board staff also ignores the fact that all of the OPG evidence and argument that they reference (Ex. JT2.40, Ex. J13.7 and Chart 4 of the Argument-in-Chief), includes amounts recorded in the variance account that have not yet been recovered, or in some cases authorized for recovery. Board staff continues to ignore this fact despite OPG having brought it up numerous times (Ex. L-6.8-1 Staff-124; Tr. Tech. Conf. April 23, 2014, pp. 199-200; Tr. Vol. 13 pp. 9-11). Once Board staff's and SEC's claim is adjusted for this significant omission, it becomes clear that OPG has not yet seen the cash that they argue has been used already.

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complicated pension and OPEB issue that came up late in the proceeding (Board staff's submission), the Board ordered OPG to produce, for the next payment amounts proceeding, an analysis of alternatives to using discount rates based on AA corporate bond yields to determine pension and OPEB costs. OPG produced a comprehensive analysis (Ex. F4-3-1, s. 6.3.3), which was accompanied by material from the Canadian Institute of Actuaries and independent actuaries (Ex. F4-3-1, Attachments 3-5).

Board staff has proposed several options as to how the OEB might address recovery of OPG's pension and OPEB-related costs on a cash basis. The first option that Board staff proposes is to apply the cash method of cost recovery, but approve $0 in revenue requirement for OPEB (Board staff argument, p. 98). OPG assumes that this option is proposed first to make the subsequent options look more reasonable. Staff claims that this option should be considered because during the 2008 to 2013 period, had the OEB approved the cash method, OPEB recovery from ratepayers would have been lower.

The fundamental problem with this proposal, as Board staff must recognize, is that the OEB adopted the accrual method and set rates for 2008-2013 on that basis. Board staff's attempt to bob and weave around this fact must fail. Reducing current payment amounts to "claw back" amounts recovered in a prior period based on approved final payment amounts is the definition of retroactive ratemaking.

As this option was not discussed during the hearing, it is not surprising that the calculation Board staff offers is incorrect. The basis for Board staff's claw back relates specifically to previously regulated hydroelectric assets and nuclear assets. Board staff's proposed option overlooks, at the minimum, that cash amounts for the newly regulated hydroelectric must be included because none of the past collections incorporated newly regulated hydroelectric (See Ex. JT2.40, p. 2, note 1; Ex. J11.15, Table 1, line 16).

7.11.2.3 Responses to Specific Arguments in Support of a Move to Cash Recovery

Beginning at page 96 of its argument, Board staff begins in earnest to set out its argument for the OEB to order that OPG recover its pension and OPEB-related costs on a cash basis. The arguments advanced contain numerous errors: OEB's decisions have been mischaracterized; evidence in relation to pensions has been wrongly applied to OPEB and vice versa; inconsistent assertions have been advanced; extrapolations have been made that cannot be justified and misstatements made with respect to accounting requirements and actuarial methods, to name just a few. SEC's argument, while much shorter, makes many of the same mistakes. Because of the large number of errors, OPG's response does not highlight them all and is limited to some of the bigger items. Because of the complexity of this material, the following responses are necessarily quite detailed. OPG's silence on a point should not be interpreted as agreement.

Board Staff Mischaracterizes the OEB's EB-2007-0905 Decision and O.Reg. 53/05

Board staff misrepresents the Board's past decisions by stating that, in EB-2007-0905, "the Board approved recovery [on an accrual basis] in the absence of sufficient evidence to the support the cash basis." (Board staff argument, p.107). The incorrect implication here is that the reason the OEB approved the accrual method was that the evidence was insufficient to support the move to a cash basis. In fact, in EB-2007-0905 OPG proposed to recover pension and OPEB costs on an accrual basis (EB-2007-0905, Ex. F3-4-1 pp. 22 -28) and no party disagreed. OPG's evidence in EB-2007-0905 was clear, consistent and comprehensive. A review of the Board Staff and intervenor arguments reveals that no one even raised the issue of the cost recovery methodology for either pension or OPEB. The EB-2007-0905 decision did not indicate that the OEB had any concerns with accrual or that it was considering the cash method and desired more information.

Board staff also attempts to twist the application of clear O.Reg. 53/05 requirements. Board staff claims that the OPEB liability disclosed in OPG's financial statements is overstated for regulatory purposes because it is not offset by amounts collected from ratepayers. Board staff then suggests that this may somehow affect the O.Reg. 53/05 requirements for the OEB to accept OPG's assets and liability values. (Board staff argument, p. 98). OPG notes that there is no basis in USGAAP for the proposition that the unfunded OPG liability should be offset by a portion of general cash revenue collection. The liability is properly reflected in the financial statements as it represents an obligation incurred by OPG in relation to service rendered by employees. As OPG's witnesses explained, the accounting for OPEB costs and obligations and the accounting for OPG's revenues are separate, in accordance with USGAAP (Tr. Vol. 13, p. 16-17). The regulation requires the OEB to accept asset and liability values as set out in OPG's audited financial statements, which are currently in accordance with USGAAP and previously followed Canadian GAAP (see discussion in Section 7.18 of this Reply Argument (Deferred Taxes)).

Board Staff's Claims on Future Accrual-to-Cash Differences Are Speculative and Inaccurate

Board staff's submission on this issue misinterprets OPG's argument and witness testimony by applying information on OPEB to pension and vice versa. As an example, the evidence cited from Mr. Mauti relates solely to OPEB (Board staff argument, p. 97). Board Member Long asked about benefits and Mr. Mauti responded about benefits; when Presiding Member Hare then asked a follow up question, Mr. Mauti's response continued to address OPEB (Tr. Vol. 13, pp. 134, 139).

While OPG witnesses were not asked about pension-related differences between accrual and cash costs, Chart 4 (AIC, p. 105) shows that in 5 out of 6 historical years, cash costs were greater than accrual costs. Had OPG been asked about pension, it would have responded that there is no basis for making generic claims or predictions, with any precision, regarding the magnitude or direction of differences between future pension cash contributions and accrual costs, as explained below.

Accounting pension amounts and pension funding requirements are determined using different bases, USGAAP and Pension Benefits Act (Ontario), respectively. There are some key differences between these calculations, involving discount rates (discussed below), application of smoothing mechanisms, and amortization of accumulated gains or losses/deficits, to name a few. As such, cash amounts can be higher or lower than accrued cost in a given year; this cannot be predicted with certainty as implied by Board staff.

With respect to OPEB, Board staff appears to project the impact of differences between accounting costs and payments for the next 10 years assuming 2014 and 2015 differences continue. There is no basis for this and, in fact, it is wrong to do so. As Board staff correctly points out elsewhere, accounting costs can fluctuate as a result of changes in assumptions, such as discount rates. For instance, as set out in the first line of the chart in JT2.40, OPEB costs have been or are projected to be as low as approximately $120M and as high as about $230M (for the nuclear and previously regulated hydroelectric assets) over the 2008-2015 period.

In contrast, cash benefit payments have been steadily increasing over the same period and are expected to continue to increase steadily due to the growth and aging of the retiree population. Mr. Mauti's testimony, quoted by Board staff (p. 97), reinforces this point, as it specifically notes that the accrual expense is higher than cash, "based on current accounting estimates and things like discount rates as they exist today." (Tr. Vol. 13, p 139). As such, the gap between recent OPEB accrual and cash amounts could narrow significantly, particularly as interest rates increase.

<u>Board Staff's Assertions Regarding Discount Rates are Inaccurate and Inconsistent</u>

Board staff states: "And staff notes that if discount rates for example rise, the cash amounts would be affected in the same direction, in any event given that the discount rates would also affect the actuaries' valuations establishing the minimum contributions." (Board staff argument, p. 98). This is a sweeping generalization for pension and is wrong for OPEB. OPEB cash payments, by their nature, are not directly affected by changes in discount rate levels. Put simply, if the discount rates increase, ratepayers would not see a rate reduction on account of OPEB under a cash basis of recovery. For pension, accounting amounts calculated using discount rates based on AA corporate bond yields (Ex. F4-3-1, s. 6.3.3) in accordance with US GAAP. Funding requirements are calculated as prescribed by the Pension Benefits Act using a combination of discount rates (for solvency valuations) and expected asset return levels (for going concern valuations).[51]

While it is reasonable to suggest that a change in macroeconomic interest rate levels would affect all of these rates in the same direction, Board staff fails to acknowledge that the extent of such changes could be very different for pension accounting costs and cash amounts. Furthermore, Board staff has not recognized that there are likely to be differences between when an increase in discount rates (and expected asset returns) is reflected in accrual accounting costs and cash amounts.

[51] A detailed discussion of the discount rate used in the going concern funding valuation can be found at Ex. J9.6, Attachment 1, p. 44. Solvency valuation rates are found at p. 49 of the same document.

Board staff's confusion regarding accounting and funding discount rates is also apparent at the bottom of page 102 of their argument. There Board staff compares the 4.3% discount rate, at June 30, 2014, determined in accordance with USGAAP for purposes of calculating accrual costs with a discount rate of 5.6% from January 1, 2014, which is used for purposes of calculating going concern funding requirements per the Pension Benefits Act. Putting aside the different points in time, as discussed above they are not comparable rates and are used for different purposes. This was explained by OPG witnesses (Tr. Vol. 12, pp. 91-93; Tr. Vol. 13, pp. 38-39). The discount rate of 4.3% is actually equivalent to the accounting pension discount rates shown in Board staff Table 27, but at a different point in time.

In the section of their argument titled, "Volatility caused by the selection of the discount rates," Board staff appears to suggest that fluctuations in discount rates and expected rates of return reflected in accrual pension cost calculations result in volatility of costs that is not exhibited in pension contributions. (Board staff argument, p. 102).

Board staff's argument cannot be reconciled with its own later observation, in relation to its Table 28, that the going concern discount rate for funding purposes dropped by 70 basis points between the January 1, 2011 and January 1, 2014 funding valuations (Board staff argument, p. 104, Table 28). Indeed, Board staff states that "if discount rates for example rise, the cash amounts would be affected in the same direction, in any event given that the discount rates would also affect the actuaries' valuations establishing the minimum contributions." (Board staff argument, p. 98)

SEC also suggests OPG is unintentionally misleading the OEB on the advantages of the accrual method. SEC claims that while the accrual method "matches costs to the work being done," it "also matches costs to market volatility, and interest rate volatility" (SEC argument, para. 6.8.59). Similarly, SEC states: "Accrual amounts are shifted immediately by changes in plan returns, discount rates, and mortality assumptions, among others." (SEC argument, para. 6.8.48). This statement is wrong. Period costs under the accrual method are not shifted immediately as smoothing mechanisms spread this volatility over many years based on employees estimated service lives (Ex. F4-3-1, pp.26-28).

Claims of Errors or Inconsistencies in OPG's Calculations are Not Appropriate

Board staff's re-calculation of OPG's evidence on the difference between the 2015 accrual and cash cost for the registered pension plan is not appropriate. As such, Board staff's figure of $113.8M at page 96 of their argument is incorrect. Similarly, OPG does not confirm Board staff's calculations (at p. 102) and SEC's claim (para. 6.8.49) that suggest Chart 4 in OPG's AIC contains an error.

These errors result because Board staff is not using the correct forecast 2015 contribution, which is the $405.3M, as originally provided by OPG in the N2 impact statement and not the $329.6M which is based on the 2015 minimum contribution shown in Ex. J9.6 (see ft. nt. 2). As explained in Ex. J11.9, p.1, the impact of the funding valuation filed in Ex. J9.6 on the 2015 contribution cannot be estimated with any precision because the 2015 contribution is not expected to be finalized until 2015. The actuarial funding valuation provides only the estimated minimum contribution amounts. As such, the correct figure for the projected cumulative difference between cash and accrual pension amounts for 2008-2015 remains $35.8M per AIC Chart 4. As noted in AIC, this total is not a significant amount in the context of the amounts and period of time involved.

As Board staff points out, OPG's contributions may exceed the estimated minimum amounts (Board staff argument, p. 100). OPG expects that Board staff and intervenors would support such additional contributions, given their concern with the financial sustainability of the OPG pension plan and their focus on funding liabilities. Additionally, actual contributions for the year need to reflect actual base pensionable earnings of the employees.

Board staff also questions the differences between JT2.40 amounts and J13.7 amounts with respect to cash and accrual amounts for OPEB. (Board staff argument, p. 99) Ex. JT2.40 excludes the long-term disability benefit plan while J13.7 includes it. Ex. JT2.40 specifically refers to supplementary pension plan and other post retirement benefit (OPRB) costs. This is because that undertaking was given as an update to Ex. L-6.8-1 Staff-124, which in turn asked for information about retirees. Employees on the long-term disability benefit plan are not retirees. This was explained in footnote 1 in Ex. L-6.8-1 Staff 124. As such, any amounts sourced by Board staff from JT2.40 excluded the long-term disability benefit plan. This distinction was specifically clarified in cross-examination on the matter. (Tr. Vol. 13, p. 8-9).

7.11.2.4 Inter-generational Equity

OPG fundamentally disagrees with Board staff's application of the inter-generational equity principle and related observations that, among other things, ignore the requirements of O. Reg. 53/05. Board staff begins their observations by saying that "ratepayers today are paying OPG's pension and OPEB costs that have arisen over the last several decades." (Board staff argument, p. 108). OPG addressed this supposition, in the context of the newly regulated hydroelectric assets, in its Argument-in-Chief (AIC, pp. 102-104) as well as in Ex. J11.7. In short, OPG submits that section 6(2)11(ii) of the regulation means that the OEB must ensure recovery of the cost impacts flowing from OPG's pension and OPEB obligations (and the funded status of the pension plan) that initially arose prior to regulation and which are reflected in the financial statement liability values. As these liability values include those for inactive members, the costs associated with these members flow from them. This is also discussed in Section 7.18 (Deferred Taxes) of this Reply Argument.

Putting aside the legal constraints, Board staff's complaint is simply irreconcilable with its proposal to move to a cash basis of recovery. Cash amounts for OPEB (excluding the long term disability benefit plan) are paid to retirees or dependents exclusively. If anything, Board staff's own proposal would exacerbate their inter-generational equity complaint. With respect to pension, both cash contributions and accrual costs would include elements related to the existing retiree population since pension obligations (whether calculated on a funding or accrual accounting basis) and fund assets are for both retirees and active plan members.

Board staff then goes on to say that "it is inequitable for today's ratepayers to pay for pension and OPEB costs that OPG will have to find the cash to pay for decades in the future." (Board staff argument, p. 108). Board staff sees inequity in this because they believe this is "exposing ratepayers to future risks for amounts already paid now." (*Ibid.*) In a related statement earlier in their submission, Board staff notes that "the money collected today to fund liabilities tomorrow is already gone, and will not be available to actually fund those liabilities." (Board staff argument, p. 94). Board staff then asserts that "OPG does not appear to have any clear plan, other than "managing its cash flows" on where it will get the money to fund these liabilities" (Board staff argument, p. 95). This line of argument is fundamentally flawed and unfounded, as it follows that Board staff believes that OPG is somehow spending cash received for OPEB today on expenditures that it otherwise would not undertake. There is no evidence of this.

In reality, if OPG receives less cash today or sets some of the cash received in a segregated fund, it would have to increase borrowings. This simply means that, at some point in the future, OPG will have higher debt, which is just another obligation, like OPEB. The "risks" associated with making OPEB payments to retirees would be replaced with risks associated with paying off the debt. Of course, this "risk" is inherent for any company that has operations with a finite life and has nothing to do with a properly formulated inter-generational equity principle. This is because this "risk" is inherently borne by the Shareholder. Said differently, whether amounts collected for OPEB are set aside in a segregated fund or not, the apparent "risk" to future ratepayers is unchanged. Similarly, monies that are being set aside for the registered pension plan are not there to mitigate risks for ratepayers/customers but rather the risk for employees and pensioners.

As discussed earlier, the proper application of the inter-generational equity principle indicates that ratepayers who are consuming electricity generated today should pay their fair share of the associated pension and OPEB costs for employee service that produced this electricity. The inter-generational inequity that would arise under a cash basis of recovery, most directly for OPEB, is very real and particularly acute for a business, like OPG, which is not required to replace assets that have reached end of life. This is particularly true for OPG's nuclear plants, which are the majority of OPG's generation assets. OPG, unlike a transmission or distribution company, is not a quasi monopoly service provider with an obligation to serve that must constantly replace the assets used to meet this obligation.

As Board staff acknowledges, commercial operations at Pickering are currently expected to close by the end of the decade (Board staff argument, p. 109). Under a cash basis of recovery, this likely means that OPEB payments to employees who exit the organization (and eventually retire) after Pickering shuts down would be recovered as a cost of Darlington generation. And when Darlington units shut down at the end of their post-refurbishment life, OPEB payments to all retired nuclear employees, which will only grow over time, will need be recovered as a significant additional cost of future generation and thus drive up rates.

Board staff appears to recognize the risk that a business with a finite life assets is particularly vulnerable to a cash basis of recovery in noting that “if OPG were to be in danger of ceasing operations in the short to mid-term [...] then staff would agree that the accrual method would be preferred to smooth out the rate impact.” (Board staff argument, pp. 108-109). While Board staff dismisses this critical consideration with the statement “the underlying assumption is that OPG is a going concern,” (Board staff argument, p.109) as demonstrated above, the fact that OPG’s largest assets have a finite life should be a significant concern for the OEB when considering the cash method for OPEB.

7.11.2.5 Financial Impacts to OPG

As set out in OPG’s Argument-in-Chief (AIC, p. 106), there are significant financial ramifications associated with a change to the cash basis of cost recovery. These include initial impacts at the time that there is a change from the accrual recovery method, as well as test period (ongoing) income and cash impacts that, as summarized in the Argument-in-Chief, will have implications for OPG’s credit and other financial metrics and financial risk. The weakening metrics and increased risk that would result are expected to require an upward adjustment in OPG’s equity ratio to ensure a fair return (Ex. J13.7).

In Ex. J13.7 and its argument, OPG highlighted a possibility that it may have to reverse up to $3 billion in regulatory assets related to pension and OPEB, if the OEB moves away from an accrual basis of recovery. Since then, OPG has determined that in accordance with US GAAP, a move away from the accrual basis will result in an immediate reversal of pension and OPEB regulatory assets. OPG’s external auditor, Ernst & Young LLP, concurs that this accounting treatment is required upon transition. OPG determined that it will need to reverse pension and OPEB regulatory assets of either approximately $1 billion or $3 billion, depending on the manner in which the OEB implements such a change.[52] The reversal will result in a reduction in OPG's equity through a charge to other comprehensive income.

Board staff's suggestion that OPG's submissions in the Argument-in-Chief and Ex. J13.7 are not consistent with the testimony of its witnesses is wrong, as is the allegation that "there is some leeway in USGAAP not identified by OPG for the OEB's consideration that will allow the cash basis for recovery for pension and OPEBs." (Board staff argument, p. 106). Mr. Kogan clearly distinguished between USGAAP requirements for pensions and other post-retirement benefits during the hearing:

> MR. KOGAN: I think we would -- this would be a complicated analysis, based on the specific facts and circumstances that would surround any such transition. So I just want to caveat that. And obviously anything we do, our auditors, given the magnitudes that we would be talking about, would be scrutinizing this very much.
>
> So that is the first point I want to make.
>
> The second point is, <u>specifically with other post-retirement benefits</u>, there is a prohibition under U.S. GAAP for -- to recognize this kind of, what I will call an accounting regulatory asset for the difference between cash amounts and accounting amounts.
>
> And so that would be a major consideration and I think a major risk impact to us and our financial results that could arise.
>
> With respect to the pensions, which -- we would need to analyze the specific facts and circumstances to see if this kind of an asset would be appropriate. (emphasis added) (Tr. Vol. 13, pp. 57-58).

Following the above exchange, Mr. Kogan provided the specific USGAAP technical reference related to the above prohibition of regulatory assets for other post retirement benefits (Tr. Vol. 13, pp. 58-59).

When Ex. J13.7 and the AIC were being prepared, consistent with the above testimony, OPG had not yet concluded its analysis of the appropriate treatment for the pension regulatory asset

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[52] Including newly regulated hydroelectric assets and assuming effective dates for new payment amounts as requested by OPG.

under a cash recovery regime. As such, OPG did not characterize the $3B write-off as a certainty. Since then, OPG completed the analysis and confirms the results as presented here.

In accordance with US GAAP, there will also not be a regulatory asset offset recognized for the difference between test period revenue amounts reflecting costs on a cash basis and corresponding registered pension plan and OPRB expenses recognized in the income statement on an accrual basis. OPG has discussed the accounting treatment with its external auditor, Ernst & Young LLP, who concurs that this treatment is in accordance with US GAAP. OPG determined that under Board staff's recommended option, the reduction in the forecast revenue requirement during the test period would be reflected in a reduction of over $350M in OPG's cash flow and income. The test period income impact would be even greater, in excess of $400M, if one were to reflect in payment amounts a lower pension contribution of $329.6M for 2015, as advanced by Board staff and SEC. These kinds of impacts would be expected to continue to erode OPG's financial results beyond the test period under a cash basis of recovery.

Under Board staff's option that sets OPEB recoveries at $0M for the test period, the income impact would be even greater at over $500M. As indicated by OPG witnesses, these kinds of impacts would translate into corresponding reductions in income to the Shareholder (Tr. Vol. 13, p. 102).

Contrary to Board staff's view, impacts of this kind of magnitude would do nothing but magnify the very sustainability concerns that Board staff expresses with respect to OPG's pension plan (Board staff argument, pp. 91-92). This also refutes SEC's assertion that OPG will not "disadvantaged" and "is not at risk" if the OEB moves away from the accrual basis (SEC argument, paras. 6.8.60, 6.8.67). There will be serious implications on OPG's financial results and cash flow, including deterioration of OPG's already weak financial ratios as highlighted in Ex. J13.7. For perspective, the reduction in income of $350M would erode about 40 per cent of the requested test period return on equity (Ex. J11.12, Attachment 1, line 1a). Other possible options suggested by Board staff would erode over 60 per cent of return. Clearly reductions of this nature will not afford OPG a reasonable opportunity to earn its authorized rate of return.

In relation to the financial impacts of moving to a cash recovery methodology, Board's staff's statement (Board staff argument, p. 107) that OPG has not provided evidence that it would receive a qualified audit opinion misunderstands what a qualified audit opinion is and when it is given.

First and foremost, a qualified audit opinion is not an option for OPG. OPG's governing principle is to ensure that its financial statements comply with USGAAP, as required by law. Specifically, OPG would be in breach of the *Ontario Business Corporations Act* and O. Reg. 395/11, a regulation under the *Financial Administration Act*, which specifically requires OPG to adopt USGAAP and prepare its financial statements in accordance with USGAAP. OPG also would be in violation of certain credit facilities, lending agreements and associated covenants. OPG's credit agreements are predicated on the fact that OPG provide audited financial statements that are prepared in accordance with USGAAP.

To comply with USGAAP, OPG will recognize the impact of the OEB's decision. In other words, if the OEB requires OPG to recover its pension and OPEB costs on a cash basis, OPG will reflect the consequences of that decision in its financial statements as described above. An auditors' report expressing an unqualified opinion provides assurance to users that OPG's financial statements present fairly, in all material respects, the financial position of OPG and the results of its operations in accordance with USGAAP. A qualified opinion would only arise if OPG's financial statements failed to reflect the impact of the OEB's decision in accordance with USGAAP – something OPG would not do.

Board staff also alludes to the fact that Hydro One is able to recognize, in accordance with USGAAP, a regulatory asset for the difference between cash pension contributions reflected in revenues and accrual pension expenses (Board staff argument, p. 106). Although OPG is not privy to the details of Hydro One's accounting rationale, OPG believes that a key distinction is that Hydro One effectively has been on a cash basis of recovery for pension costs since its inception. The fact that OPG's recovery methodology would be changed to a cash basis on a prospective basis would result in a different amount being recovered by OPG going forward, relative to the accrual method.

With respect to OPG's recognition of a regulatory asset for deferred income taxes cited by Board staff (Board staff argument, pp. 106-107), OPG notes that Board staff's proposal to change the recovery method for pension would result in a different set of circumstances than exists for income taxes. For income taxes, the OEB has been applying a consistent recovery methodology since OPG has been regulated. It is the change in recovery for pension that would give rise to the consequences discussed above.

7.11.2.6 A Generic Proceeding May be Appropriate

Board staff and OPG are in complete agreement that "there are complex, legal, tax and accounting issues to consider" in relation to the choice of the appropriate cost recovery methodology (Board staff argument, p. 95).

As noted above, the record in this proceeding was compiled piecemeal and is incomplete. Based on the OEB's treatment of the issue in EB-2007-0905 and EB-2010-0008, it was, fairly, not an issue from OPG's perspective. There is substantially no pre-filed evidence in relation to the issue. Board staff performed limited discovery and also asked OPG if it was aware of the issue having been raised in the then pending Enbridge proceeding (the real genesis of the issue) and OPG's view as to whether this was a generic issue, to which OPG replied that it was (Tr. Tech. Conf. Vol. 2, p. 198). No party prefiled any evidence in relation to the issue. OPG submits that it is fair to say that the record on this issue is incomplete and, as demonstrated above, poorly understood.

In OPG's respectful submission, the issue impacts all regulated utilities across the province; none of the issues raised are unique to OPG. Indeed, as set out above, all utilities recover OPEB on an accrual basis. If it is an issue for OPG, it is similarly an issue for everyone else. To the extent the OEB wishes to consider the issue further, in OPG's respectful submission, it should do so in a generic proceeding where the OEB would have an opportunity to consider any expert testimony on the complex issues associated with such a move. To put it plainly, the financial ramifications to OPG and its shareholder, as well as other utilities and their shareholders, are too great for the matter to be decided without a comprehensive analysis and complete record.

OPG addressed the segregated fund issue in its Argument-in-Chief (AIC, pp. 99-101) and continues to believe that it would be beyond the OEB's jurisdiction to order the establishment of such a fund. Nothing in Board staff's argument changes OPG's view of the jurisdictional issue (Board staff argument, pp. 92-95).[53] However, if the OEB were to establish a generic proceeding on the issues associated with moving to recovery on a cash basis, then OPG suggests that the segregated fund issue be included in the scope of the proceeding, so that its tax, accounting and regulatory implications can be considered.

7.12 ISSUE 6.9

Oral Hearing - Are the corporate costs allocated to the regulated hydroelectric and nuclear businesses appropriate?

Board staff proposes a revenue requirement disallowance of $25M for each of 2014 and 2015 on the basis of "benchmarking results and historical spending." (Board staff argument, p. 115) These figures are said to already be reflected in its proposed compensation disallowance. CME (CME argument, para. 201) and VECC (VECC argument, p. 35) take the same position. SEC proposes a disallowance of $35M per year (SEC argument, para. 6.10.2) for the same reasons as Board staff. LPMA proposes the greatest disallowance: $39.6M in 2014 and $38.0M in 2015 (LPMA argument, p. 13). It relies entirely on historical forecasting variances. In OPG's submission, all of the proposed disallowances should be rejected by the OEB.

Board staff's submissions begin at p. 112 by reference to the Auditor General's report and the AON Hewitt report, observing that the majority of administrative, finance and human resources staff at OPG are "overpaid" relative to the 50th percentile. Staff goes on to cite Dr. Chaykowski's conclusion that "unions disproportionately increase the wages of lower skilled-workers at the bottom of the wage distribution within a firm." (Ex. F4-3-1, Attachment 1, section 1).

[53] Board staff's argument hinges on the Toronto Hydro case. Its reliance is misplaced. That case concerned section 23 of the *Ontario Energy Board Act*. However, s. 23 is not applicable here. That general section applies to gas and electricity distributors. However, the more particular section 78.1(4) applies to OPG. That section more narrowly circumscribes the OEB's power to impose conditions as part of any order. This section cannot be overridden by reference to the objectives section (s. 2) of the Act.

With respect, these references do not justify any disallowance. On the contrary: Dr. Chaykowski's uncontradicted statement reflects the reality faced by OPG in collective bargaining. Even if Staff were correct to equate OPG's finance and other staff with "lower skilled workers" (which is denied), the benchmarking results evidence nothing other than the accuracy of Dr. Chaykowski's statement. These committed costs cannot be further reduced by OPG.

Board staff's singular focus on benchmarking is reflected in the balance of its discussion of Issue 6.9. This is best exemplified in its discussion of IT and HR resources (Board Staff argument, pp. 113-114). In relation to IT, Staff observes that when OPG renewed its New Horizon IT contract in 2009, it did not use a competitive tendering process. Staff next states that OPG's IT function benchmarks in the second and third quartiles, while noting what the revenue requirement impact would be if OPG were in the top quartile[54]. However, Board staff fails to mention the evidence (it elicited) in relation to the New Horizon contract: OPG sought and obtained expert, independent assistance in relation to the contract.[55] OPG was advised that its costs would be lower if it engaged in a leveraged re-negotiation (as it did) rather than a competitive tender. As Ms. Ladak testified:

> And Everest recommended we do what is called leveraged negotiation. And there's benefits to that approach, in which you have your incumbent, you negotiate with your incumbent, and if those negotiations fail then you go and do, like, a competitive process. And at that point the incumbent cannot participate in the process.
>
> So there is a real advantage to that approach. And Everest, actually, the company we had hired to assist us, had said if we did just the regular competitive process, we would probably only save about 5 to $7 million, but doing the leveraged negotiation would result in additional higher savings, which is what we achieved through this contract. (Tr. Vol. 9, p 14).

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[54] Ignoring Ex. L-6.9-2 AMPCO 064 part d) which says "The target for OPG is to achieve second quartile EUCG standing by 2015 for both metrics."

[55] Ex. L-6.9-1 Staff-135 "As described in EB-2010-0008 Ex. L-4-26, prior to entering into re-negotiation discussions with NHSS, independent consultants provided OPG with market-based cost savings targets. Cost savings achieved through re-negotiation were greater than these targets and enabled OPG to avoid significant transition costs and service disruption risks. Independent consultants also reviewed the final results of the re-negotiation and confirmed that the benefits articulated in the business case objectives were achieved. As noted at Ex. F3-3-1, page 2 of this application, OPG's procurement process allows for a single source process when a competitive process would be impractical. In light of the cost savings realized and given the transition costs and service disruption risks associated with changing suppliers, OPG determined that a competitive process would have been impractical for this contract."

With respect to HR, Board staff's argument at page 114 says:

> In Interrogatory response Exh L6.9-1 Staff-131, OPG indicated that 2012 HR expenses would be reduced by $14.9M if OPG were in the top quartile for both HR metrics. OPG noted that no utilities achieve top quartile for both metrics.

In other words, Board staff believes that it is appropriate to cut OPG's revenue requirement for failure to meet a standard that no other utility has met. For obvious reasons, OPG disagrees.

SEC submissions are addressed in relation to Issue 1.2. They do not justify any disallowance.

Finally, with respect to parties' reliance on forecasting variances, this reflects nothing more than a fundamental unwillingness to address the evidence in relation to the test period costs. In fact, none of the parties refer to that evidence (Ex. F3-1-1) or discuss the reasons for the variances (Ex. F3-1-2). One is left to wonder why any cross-examination was conducted at all.

For the reasons set out above and in OPG's argument in chief at pp. 108-113 OPG submits that its corporate costs are reasonable and should be approved by the OEB.

7.13 ISSUE 6.10

Oral Hearing - Are the centrally held costs allocated to the regulated hydroelectric business and nuclear business appropriate?

This issue is covered under Issues 6.8 and 6.9 above.

7.14 DEPRECIATION

7.15 ISSUE 6.11

Secondary - Is the proposed test period depreciation expense appropriate?

This issue is addressed under Issue 6.12.

7.16 ISSUE 6.12

Secondary - Are the depreciation studies and associated proposed changes to depreciation expense appropriate?

7.16.1 Board staff's Request for Another Depreciation Study Should be Rejected

Board staff submitted that OPG should be directed to file an independent depreciation study in its next payment amounts proceeding based on asset useful lives determined using the equal life group (ELG) method and statistical analysis (Board staff argument, p. 117). CME, AMPCO, SEC and LPMA support Board staff's recommendation.

In its EB-2010-0008 Decision with Reasons (p. 97), the OEB ordered OPG to file an independent depreciation study in this proceeding noting that:

> it is important to also have an independent assessment of the assets. As noted in several submissions, an independent study is a typical requirement of utilities, conducted periodically. Given the level of depreciation expense involved, the Board concludes there is merit in OPG also providing such a study. Such a study provides assurance to the Board and all parties that the depreciation and amortization expenses, which are significant, are reasonable.

In this proceeding, OPG not only complied with the OEB's direction and submitted an independent depreciation study by Gannett Fleming, but also had Gannett Fleming undertake an updated study to account for recent material changes in its assets.[56] Board staff acknowledges this, but now recommends that OPG be ordered to conduct yet another independent depreciation study.

The OEB should reject Board staff's recommendation. The depreciation studies filed in this proceeding fully support the adequacy of the service lives and depreciation methods used by OPG (Ex. F4-1-1, Attachment 1; Ex. F5-3-1). Nothing would be gained by another study. As Gannett Fleming has clearly stated (see quotation below), OPG lacks the data to use the ELG method and the costs of developing this data, if it could be done at all, would be prohibitive and, therefore, it is not worth doing (EB-2007-0905, Ex. F4-2-1, p. II-7).

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[56] Gannett Fleming, OPG's independent depreciation consultant, is a world recognized expert on depreciation. Board staff raised no concerns with the firm's expert qualifications or the quality of its reports submitted in this or previous cases.

Board staff's representation of Gannett Fleming's position on the merits of the ELG method versus the Average Life Group ("ALG") method is, at best, incomplete (Board staff argument, p. 116). As stated in Ex. L-6.12-1 Staff-147(b), Gannett Fleming's actual position is:

> It is the view of Gannett Fleming that the ELG Procedure provides a superior match of the consumption of service values of the assets to the depreciation expense, in the circumstances where sufficient information exists to prepare mortality studies with the selection of retirement dispersion curves (Iowa curves), and where the original vintage of the investment is known.

Gannett Fleming noted in their reviews of OPG's asset service lives that these are not OPG's circumstances, as follows:

> In the specific circumstances of the OPG average service life estimation, the volume of historic retirement transactions available to be analyzed is not sufficient to undertake a detailed study of retirement history. As such, a retirement rate analysis was not completed by Gannett Fleming. However, all of the remaining life estimate tools were available and were used to develop appropriate average service life estimates. (Ex. F5-3-1, p. II-11 and Ex. F4-1-1, Attachment 1, p. II-9)

Gannett Fleming provided a similar assessment in their review of OPG's depreciation review process dated March 1, 2007, noting the following:

> […] a number of OPG's generation assets, which may normally lend themselves to statistical retirement analysis, are not studied using statistical methods by OPG due, in large part, to the fact that these assets have been re-valued for financial and regulatory reporting purposes as at April 1, 1999 (the date on which OPG was formed and effectively purchased the assets from the former Ontario Hydro). As such, much of the original cost and retirement history that would be required in order to perform a statistical retirement analysis would need to be re-created. Even in the circumstances that this data could be re-created, the development of this data would be cost prohibitive, and, in the view of Gannett Fleming, would not provide sufficient additional benefit to warrant the cost associated with its development. (EB-2007-0905, Ex. F4-2-1, p. II-7 and Ex. L-6.12-1 Staff-147(b). (emphasis added).

Gannett Fleming concluded that OPG's continued use of ALG is appropriate as follows:

> Gannett Fleming is also of the view that a review of depreciation procedures should consider the historical practices of the regulatory jurisdiction and practices of the utility. A number of utilities regulated by the OEB, including Enbridge Gas Distribution and Union Gas, and utilities in a number of other North American jurisdictions use the ALG Procedure. OPG has used this procedure since its

> inception and, in Gannett Fleming's view, given the considerations cited above, it is appropriate for OPG to continue doing so. Gannett Fleming is not aware of any specific regulatory, operational or legislative reason to recommend a change to OPG's procedure at this time. (Ex. L-6.12-1 Staff-147(b)). (emphasis added).

At the Technical Conference, Board staff asked OPG to provide the asset lives that Ontario Hydro used prior to the formation of OPG more than 15 years ago (Tr. Tech Conf. Vol. 2, pp. 213-214). This request was properly refused as the information requested has no potential relevance to the current depreciation of OPG's assets because the OEB must accept the asset and liability values approved by OPG's Board of Directors prior to the commencement of regulation. That this is the correct view was confirmed by the OEB's ruling on Environmental Defence's motion that requested OPG be required to provide similar information for the newly regulated hydroelectric assets. In ruling on this motion, the OEB stated: "As the requirements of O. Reg 53/05 are very clear about the valuation of assets and liabilities that the Board must accept upon regulating the newly regulated hydroelectric facilities, no further disclosure is required by the Board at this time." (EB-2013-0321, Decision and Order On Motions, Issues List and Confidentiality and Procedural Order No. 9, p. 7).

Board staff does not dispute that OPG does not have the information necessary to perform an ELG study, but assumes, without any basis in fact, that various unnamed statistical techniques can be used to supply the missing data (Board staff argument, p. 117). Since Board staff offered no evidence on these statistical techniques; no explanation of what these techniques are; and no cite to an authoritative supporting document, OPG submits that this submission should be given no weight by the OEB.

There are good practical reasons for the OEB to not accept Board staff's study proposal. The proposed study would require OPG and its consultant to go back to whatever records exist from 15 years ago and attempt to "cooper up" a set of asset retirement and asset vintage data in the hopes that it will produce a more "vigorous and objective review" of asset service lives. Board staff's assumption that such a study is possible and would be worthwhile is directly contradicted by Gannett Fleming who, in the quote above, expresses doubt about whether this information can be re-created and unambiguously states that such an effort would not be worth the cost.

Board staff fails to provide a single reason why OPG's current depreciation method is inadequate and should be changed. The OEB has repeatedly approved this method for OPG and other large Ontario utilities. Both OPG's depreciation methodology and the resulting asset lives have been validated by independent studies.

For all of the reasons set out above, OPG submits that the OEB should not direct OPG to go to the considerable expense of attempting to undertake an ELG depreciation study. In addition, for all the reasons set out in its evidence and in its Argument-in-Chief and Reply Argument, OPG submits that the OEB should find that OPG's depreciation expense, depreciation studies and proposed changes to depreciation expense are appropriate.

7.16.2 Niagara Tunnel Service Life

Board staff argues that OPG should use a service life of 135 years for the Niagara Tunnel (Board staff argument, p. 118). SEC argues for a service life of 150 years (SEC argument, para. 6.11.1). LPMA recommends 138 years (LPMA argument, p. 14). The depreciation life for the Niagara Tunnel as a whole that OPG proposes based on Gannett Fleming's recommendation is about 95 years (weighted average of the recommended 100 years for the tunnel and 90 years for the tunnel lining) (Ex. L-6.11-1 Staff-143). By any measure, 95 years is an extraordinarily long period over which to depreciate for any asset.

Gannett Fleming's recommended service lives were based on a thorough review of the Niagara Tunnel (Ex. F5-3-1, pp. II-15-II-16 and Appendix 1). To establish these service lives, Gannett Fleming visited the tunnel site during construction and reviewed all relevant tunnel documentation (Ex. F5-3-1, Appendix 1). Gannett Fleming's opinion is also based on the design life of the tunnel lining (Ex. L-6.12-1 Staff-161). Gannett Fleming notes that the linings of the two Sir Adam Beck Tunnels have service lives of 75 years, which is consistent with industry practice, while the Niagara Tunnel has a 90 year service life because of its design and construction characteristics (Ex. F5-3-1, Appendix 1). As noted in Ex. L-6.12-1 Staff-161, this is the best estimate of the service life based on available evidence and there is no empirical data or evidence whatsoever to support a tunnel lining life of longer than 90 years.

Sir Adam Beck Tunnels 1 and 2 have significantly different characteristics from the Niagara Tunnel, which make comparisons between them inapposite. These two tunnels were constructed by different means through much less challenging rock conditions, were not excavated below the buried St. Davids Gorge and have significantly different linings (Ex. L-4.4-1 Staff-021; Ex. L-6.12-1 Staff-160).

At the time that it was established that the Sir Adam Beck Tunnels 1 and 2 would be depreciated to 2074 on the basis of a 75-year service-life estimate (in 1999, when OPG was formed) both tunnels had operated successfully for approximately 45 years. In contrast, given that the Niagara Tunnel has operated for less than two years, it is premature to consider a similar extension to the Niagara Tunnel service life.

Board staff's recommended overall service life of 135 years, an increase of over 40 per cent, is based on nothing more than Board staff's view that this figure "seems reasonable" in light of the fact that the two Sir Adam Beck Tunnels have operated for almost 60 years (Board staff argument, p. 118). In a transparent attempt to make the Board staff figure seem reasonable, SEC argues for an even higher 150-year service life based on its view of comparability between the Niagara and the Sir Adam Beck Tunnels, while LPMA seeks a 138 year service on the basis of the superior materials and construction practices used in the Niagara Tunnel (SEC argument, para. 6.11.1; LPMA argument, p. 14). These recommendations should be rejected because they are: 1) not based on any evidence, 2) inconsistent with the design life of the tunnel lining, and 3) contrary to the uncontroverted opinion of Gannett Fleming, the only depreciation experts to provide evidence.

7.17 INCOME AND PROPERTY TAXES

7.18 ISSUE 6.13

Primary (reprioritized) - Are the amounts proposed to be included in the test period revenue requirement for income and property taxes appropriate?

Loss Carry Forward

In 2013, there was a regulatory tax loss of $211.6M, due to a shortfall in nuclear production (Ex. J13.4, Attachment 1). The 2013 regulatory tax loss is not applied to reduce the forecast

2014 regulatory taxable income because the loss arose as a result of a 2013 nuclear operating loss. As OPG and its shareholder had to bear the operating loss and not ratepayers, OPG is entitled to receive the benefit of the associated tax loss (Ex. L-6.13-1 Staff-166). As noted below, this principle of attributing the tax cost or benefit between the ratepayers and the shareholder is well established by the OEB.

Board staff incorrectly asserts that the loss should be carried forward and utilized in the calculation of the test period PILs provision. Board Staff takes this position on the basis that the payment amounts in effect in 2013 included an amount for PILs as established in the Board's final order for the 2011 and 2012 test period. According to Board Staff, because ratepayers have borne the costs associated with PILs in 2013 they are entitled to the 2013 tax loss which should be used to offset regulatory taxable income in 2014.

Similarly, SEC asserts certain conclusions related to the benefits follow costs principle which are incorrect. SEC states that the principle was never intended to allow a utility to recover PILS and retain the amounts recovered because the utility operated at a loss. (SEC argument, para. 6.13.11). However, this is a fundamental misstatement of the Board's application of the principle and is incorrect for the reasons set out below.

To be clear, the principle of benefits should follow the costs was succinctly stated in the authoritative text Accounting for Public Utilities, Hachne, Robert, Aliff, Gregory, (Part V, Chapter 7, Sept 17.05) where it was stated:

> Income tax normalization is consistent with a fundamental principal of the cost of service approach to ratemaking; **the principle that consumers should only bear the costs for which they are responsible**. Under this principle, there is a well-reasoned, and widely recognized, postulate that taxes follow the events they give rise to. **Thus, 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**. (<u>*emphasis added*</u>).

However, although Board Staff references the Board's decision in EB-2007-0905, Board Staff incorrectly applies the principle. As noted above, the loss arose because of an operating loss.

OPG and its shareholder had to bear the operating loss and not ratepayers. As a result, the shareholder is entitled to receive the benefit of the associated tax loss.

In referencing the EB-2007-0905 decision, Board Staff failed to highlight a key part of the OEB decision in EB-2007-0905. In the context of applying the aforementioned principle, the Board states at page 170 of its argument:

> 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 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.

OPG notes that payment amounts in existence in 2007 (i.e., set by O. Reg 53/05) were similarly based on forecast information that contained amounts for PILs for both hydroelectric and nuclear operations, for each of 2005, 2006 and 2007. The OEB's website posting of November 3, 2008 for Ontario Power Generation is found at: (http://www.ontarioenergyboard.ca/documents/cases/EB-2006-0064/forecast_facilities_opg_20070213.pdf).

The posting states that "OPG provided forecast information to the Government in support of the development of O.Reg. 53/05. The forecast information was developed in Q3 2004… This information was the basis upon which the Government established the payment amounts in the Regulation."

Similar to 2007, the current approved rates contain an amount for PILs and the payment amounts in 2013 did not change to account for the operating loss and consumers did not bear the burden of that loss and therefore should not have the benefit of the related tax loss.

The actual costs in any year can vary from those that were included in the calculation of payment amounts for the test period and reflected in the final order. The actual income earned in that year may also not reflect the PILs included in the approved rates. The payment of the PILs provision by ratepayers as part of the payment amounts is part of the ordinary course application of a final rate order and is not the expense directly giving rise to the tax loss in this circumstance. Therefore, the ratepayer is not entitled to the benefit of the tax loss. In addition, the OEB cannot adjust the rates in future periods to account for cost differences during the term of the final rate order without a variance or deferral account. To do so would be retroactive rate making and the resulting rates would not be just and reasonable.

In support of its position, Board Staff also relied on the 2006 Electricity Distribution Rate Handbook. On this basis, Board Staff indicated that the OEB had a long established policy with respect to the utilization of tax loss carry-forwards. However, Board Staff over generalizes with respect to the use of the Electricity Distribution Rate Handbook and does not apply it as it was intended.

Board Staff specifically asked OPG about this policy during the hearing (Tr. Vol. 13, p. 64). Mr Barrett clarified that this pronouncement for electric distribution utilities existed at the time the Board made their decision in respect of OPG's 2007 tax loss, and it applied the benefits-follows-costs principle, so in OPG’s circumstances the OEB obviously did not apply that policy. Mr. Barrett also observed that the RP-2004-0188 Report of the Board which gave rise to the Electricity Distribution Rate Handbook had a section which discusses tax-loss carry-forwards which “explains how the Board landed on the rules that are set out in the Board's Handbook. And I think it -- my reading of that part of the report is that the Board did not really turn its mind to the question of how tax losses were arising. I think it consciously said that -- I will just read that section of the report:

> The OEB has no evidence before it to determine whether the 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.

In considering the application of the Electricity Distribution Rate Handbook in the circumstances of Great Lakes Power Limited (EB-2007-0744 Decision with Reasons, pp. 43-44), the OEB determined with respect to the pre-2007 tax losses as follows:

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

That decision specifically highlights and emphasizes the paragraph referenced by Mr. Barrett. In reference to that paragraph, the Board found that:

> 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." (EB-2007-0744 p. 43).

For the reasons set out above, Board Staff's submissions in respect of the tax loss carry-forward should be rejected.

SEC incorrectly states that the benefits follow the costs principle was used by the OEB to ensure that there was a way to allocate costs and benefits to regulated and unregulated periods. SEC provides no basis for this assertion. The benefits follows costs principle is not about a transition between regulated and unregulated periods. It is about setting just and reasonable rates consistent with a cost of service approach where the benefits corresponding to costs incurred are enjoyed by the party that incurred the cost. OPG's shareholder incurred the costs associated with the loss. It received no compensation for it and was then and is now fully at risk for the negative consequences of a loss. As such, the loss carried forward should not be applied to 2014 regulatory taxable income and the calculation of the tax provision applicable for the 2014 test year.

Deferred Taxes

Contrary to the submissions of SEC (SEC argument, paras. 6.13.13 – 6.13.44), OPG submits that the amendments to Ontario Regulation 53/05 (the "Regulation") mean that the deferred income taxes amount on OPG's financial statements at December 31, 2014 is to be excluded from the revenue requirement impacts associated with regulating the newly regulated hydroelectric assets.

Paragraph 11 of section 6(2) of O. Reg 53/05 states the following:

> 11. ***In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc.*** that is effective on or after July 1, 2014, ***the following rules apply:***
>
> i. The order shall provide for the payment of amounts with respect to output that is generated at a generation facility referred to in paragraph 6 of section 2 during the period from July 1, 2014 to the day before the effective date of the order.
>
> 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.*** (*emphasis added)*.

In coming to its incorrect interpretation of the Regulation, SEC only considers two parts of the provision. First, that the OEB must accept "values relating to the income tax effects of timing differences" and second, "the revenue requirement impact of accounting and tax policy decisions reflected in those financial statements." With respect to the former, SEC limits its meaning to the fact that the OEB must accept the amounts as stated in the financial statement and not look behind those amounts. With respect to the latter wording, SEC again restricts the meaning and asserts that this wording merely stands for the fact that if OPG made an accounting decision or took a tax position, the OEB cannot second guess the decision.

Using its interpretation, SEC argues that it would be unfair for OPG's Shareholder to retain the benefit of tax deductions taken in the pre-2014 period and reflected as timing differences in the deferred tax liability, and for the Shareholder also to recover income taxes, on a taxes payable basis, post-2014 through rates. SEC states that to conclude otherwise the regulation would have to have been explicit that the impact of timing differences reflected in the pre-2014 deferred tax expense would be recoverable in the future without taking into account any of the benefits of timing differences prior to 2014.

SEC's parsing of the regulation is too restrictive and not consistent with modern statutory interpretation. The Supreme Court of Canada has consistently held that the "modern rule" of Statutory interpretation requires that the "words of an Act are to be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act and the intention of Parliament" (Re Rizzo: Rizzo Shoes Ltd. [1998] 1 S.C.R. 27). SEC's interpretation ignores that particular aspect of the regulation that explicitly provides that the regulation requires the OEB to ignore the benefits of timing differences prior to 2014 and to establish future rates in the normal course, thereby ultimately permitting OPG to recover income taxes over time through the OEB approved taxes payable approach for including taxes in rates.

OPG submits that SEC ignores the key phrase: "In making its first order under section 78.1 . . . the following rules apply:" This wording explicitly provides that the OEB in making its order must accept the assets and liabilities approved by the board of directors, including values relating to income tax timing differences and the revenue requirement impact of accounting and tax policy decisions. Deferred tax liabilities relate wholly to income tax timing differences. The regulation is clear and explicit. Its purpose is to delineate a starting point for a new regime and the completion of another. Said differently, the Regulation limits the OEB's ability to look back at what happened prior to regulation to adjust amounts that would otherwise be reflected in future rates using the typical OEB approved approach.

This idea of the implementation of the regulation as a means to delineate a starting point was accepted by the Board in EB-2007-0905. In its EB-2007-0905 Decision (p. 79), the OEB stated that "Section 6(2)5 requires the Board to accept the amounts of certain items as set out in OPG's financial statements. In the Board's view, the purpose of this section was to limit the extent to which the OEB and intervenors could go back in history and question the impact of OPG's past accounting decisions on amounts that were determined before the OEB took over the responsibility for setting payment amounts." This is exactly the interpretation that OPG is advancing in this case. By extension of the above interpretation, the Regulation similarly limits the extent to which the impact of OPG's past tax policy decisions can be questioned, as discussed below. OPG reiterated this in Ex. J11.11:

> The Referenced Section [of the Regulation] requires the OEB to accept the tax values, such as the Undepreciated Capital Cost Allowance, reflected in the audited financial statements and, therefore, limit future deductions reflected in the revenue requirement to these amounts. In other words, the Referenced Section requires the OEB to accept that past income tax deductions (e.g., CCA) giving rise to the timing differences have been used up in reducing OPG's pre-regulation taxable income and are not available to reduce income taxes included in the revenue requirement going forward.

Essentially, the OEB's own interpretation means that what has happened in the past remains in the past. For taxes, it means that CCA deductions taken in the past are no longer available to be taken in the future. OPG's tax policy decision to maximize the use of CCA deductions, as discussed in EB-2010-0008 (Tr. Technical Conference, p. 115), applies to all assets, regardless of whether they are regulated. In Ex. J11.11, OPG also stated that "with respect to tax policy decisions, OPG's approach has been to minimize its income taxes payable by claiming maximum allowable deductions, such as Capital Cost Allowance." The Undepreciated Capital Cost (UCC) values reflect these tax policy decisions. The regulation requires the OEB to accept these accounting and tax policy decisions.

OPG submits that SEC's position in paragraph 6.13.27 (b) of its argument that "taking allowed amounts of CCA expense is neither an accounting or a tax policy decision" is disingenuous. If this is not an example of a tax policy decision, OPG is unsure of what meaning SEC would ascribe to "tax policy decisions." SEC is silent on this matter.

It is also important to note that the government prior to the creation of the regulation was aware of the deferred tax liability and its reflection in OPG's business plan in accordance with the approach explicitly contemplated in Regulation 53/05. As a result, contrary to SEC's assertion, by approving OPG's 2013-2015 Business Plan, the government clearly was aware of the approach and consequences set out in the Business Plan and the Regulation. As Mr. Barrett noted: "They were certainly aware of the issue. And we set it out in our business plan, which they concurred with." (Tr. Vol. 11, p. 147)

In SEC argument, para. 6.13.27, SEC does correctly state, regarding accounting and tax policy decisions, that "the Board cannot reach back into the pre-2014 period and second-guess that decision." However, then SEC goes on to read into the regulation a transitional regime where one does not exist. Under SEC's regime, a series of assumptions and considerations have to be made in interpreting and applying the regulation as opposed to accepting the assets, liabilities and timing differences as stated. As the intent of the regulation was to create a rule that the OEB is obliged to follow, the creation of a transitional regime as suggested by SEC would itself have to be explicit, which it is not. In any event, SEC's regime is premised on the notion that ratepayers paid the tax in the period prior to 2014. Specifically, SEC assumes that ratepayers paid this tax on a deferred taxes basis prior to 2014 and somehow reads into the regulation a basis for the OEB to make this assumption. However, there was no rate applicable to the newly prescribed hydroelectric assets set by regulation that would include a tax provision payable by ratepayers. Prior to 2014, OPG recovered the HOEP for the production from the newly prescribed hydroelectric assets. No tax provision was provided for in the market price (which was beyond OPG's control to set) and there is no way of knowing whether energy consumers paid any part of OPG’s corporate tax liability related to those assets. As a result, SEC's assertion that the acceptance by the OEB of the timing differences and deferred taxes as stated in the assets and liabilities somehow resulting in OPG collecting income taxes twice is a wholly theoretical speculation without foundation.

OPG observes that SEC’s position on the interpretation of the regulation is consistent with OPG’s when it comes to the ED proposal to adjust the return on equity for the newly regulated hydroelectric assets on account of the alleged “fair market value bump”. Specifically, at para. 3.2.6 of its argument, SEC basically says that the regulation prevents the OEB from “reaching back into the Ontario Hydro days, taking away some of the benefit of the revaluation of OPG’s assets at the time of restructuring.” This is essentially the same as OPG’s position that the OEB cannot reach back into the pre-2014 period and bring forward the benefit of tax deductions that have been used up. SEC says in para. 3.2.6, regarding a different cost of capital treatment for a portion of the newly regulated hydroelectric asset values, that “if that had been intended by the government, in our view they would have said so explicitly”. Similarly, had the government intended that past tax deductions be applied against tax expenses in future rates, the government would have also said so explicitly.

SEC also makes reference to the OEB's decision in EB-2010-0008 and the OEB's characterization of SEC's submissions in that proceeding (SEC argument, para. 6.13.32).

Contrary to SEC's belief, the OEB rejected both SEC's calculations and the rate payer as beneficiary of timing differences. Timing differences were integral to the calculations put forward by SEC. If the rejection of SEC's position was purely a miscalculation and not the approach to timing differences, it would have been reasonable to expect to OEB to request a recalculation as part of the final order as opposed to a rejection of the scheme as a whole. SEC goes on to suggest that there is some kind of inconsistency or ambiguity in OPG's interpretation of the regulation as it relates to the OEB having to accept the asset and liability values related to pension and OPEB (SEC argument, paras. 6.13.38-40) and as it relates to debt (Ibid., para. 6.13.42). In OPG's submission, there is no inconsistency or ambiguity despite SEC's attempts to muddy the waters.

For the assets and liabilities related to pension and OPEB, the regulation requires the OEB to accept those values as the starting point when setting future rates and not reach back in time to consider how those asset and liability values arose. It also means that amounts recognized as liabilities and expensed on an accrual basis prior to 2014 will not be included in future rates set on an accrual basis. It also means that, going forward, expenses in the normal course, like future pension and OPEB costs charged to the income statement on an accrual basis, will be recoverable in rates under the normal rate making processes, whether they be related to service from active or inactive employees.

With respect to the treatment of the $621M of debt raised by SEC (SEC argument, para. 6.13.42), this amount of debt must be accepted by the OEB and like all of OPG's other actual debt allocated to the regulated assets; it forms part of the capital structure supporting these assets. The determination of actual debt and the impact of the inclusion of newly regulated hydroelectric operations are discussed in Ex. C1-1-2.

Because these assets are regulated, OPG has applied the deemed capital structure approved by the OEB and endorsed by OPG's cost of capital expert, Ms. McShane. This is the exact approach OPG followed in EB-2007-0905, and OPG submits that it is entirely consistent with both the requirements of the regulation and the deemed capital structure approach approved by the OEB in EB-2007-0905 and EB-2010-0008.

7.19 OTHER COSTS

7.20 ISSUE 6.14

Secondary - Are the asset service fee amounts charged to the regulated hydroelectric business and nuclear business appropriate?

No party objected to OPG's regulated hydroelectric and nuclear asset service fees, and as such, and for the reasons set out in OPG's evidence and AIC, they should be approved as filed.

7.21 ISSUE 6.15

Secondary - Are the amounts proposed to be included in the test period revenue requirement for other operating cost items appropriate?

There were no submissions on this issue.

8.0 OTHER REVENUES

8.1 REGULATED HYDROELECTRIC

8.2 ISSUE 7.1

Secondary - Are the proposed test period revenues from ancillary services, segregated mode of operation and water transactions appropriate?

As set out in its AIC (p. 120), OPG earns other, non-energy revenues from its prescribed hydroelectric facilities (Ex. G1-1-1, p. 1). The amounts included in its application for previously regulated hydroelectric facilities are $34M in 2014 and $34.6M in 2015. The amounts included in its application for newly regulated hydroelectric facilities are $22.7M in 2014 and $23.1M in 2015. These amounts are reflected in Ex. N1-1-1, Table 1.

Board staff, in its submission, accepted OPG's regulated hydroelectric other revenues as filed. AMPCO, CME and LPMA all filed submissions recommending alternate means of determining the appropriate levels of test period regulated hydroelectric other revenues. Various treatments were suggested, based on the different line items that make up "other revenues".

In regards to ancillary services, each of AMPCO, CME and LPMA proposed forecasting revenues on the basis of historical actual values. AMPCO (argument, para. 171) and LPMA (argument, p. 17) suggested that 2014 should be set equal to 2013 actual (plus 2 per cent escalation), with 2015 being 2014 values, again escalated at 2 per cent. CME (argument, para. 209) preferred 2014 to be the average of 2011, 2012 and 2013 (escalated at 2 per cent), with 2015 being 2014 values, again escalated at 2 per cent.

OPG's forecast of these revenues considers the components that make up the category of ancillary services – namely, Black Start Capability, Reactive Support/Voltage Control, Regulation Service and Operating Reserve. Some of these services are market based and some are contractual. OPG considers each in coming to its forecast and provides the OEB with the most accurate value, based on what OPG expects will happen with each of the services over the test period.

OPG enters into contract negotiations with the IESO for Black Start Capability, Reactive Support/Voltage Control and Regulation Service. The current contracts for each ancillary service came into effect in 2013 and extend by varying terms into the test period (Ex. G1-1-1, pp. 2-4). Operating reserve is a market based product (Ex. G1-1-1, p. 4). OPG's forecasts of operating reserve are based on OPG's considerable experience supplying the IESO administered operating reserve market. Quite frankly, this requires considerably more rigour than setting values equal to a previous year's amount or a rolling average. Negotiating ancillary service contracts requires OPG and the IESO to come to terms on various fixed and variable payment amounts for availability, use-of-service, and unit starts that change with the resource or resources that are available (Ex. L-7.1-1 Staff-176). OPG submits that only OPG and the IESO are intimately familiar with the operation of OPG's resources within the IESO administered markets and both parties aptly and ably negotiate contracts for ancillary services based on this knowledge.

Differences between forecast and actual revenues are recorded in the Ancillary Services Net Revenue Variance Account - Hydroelectric Sub Account. OPG is not indifferent to the accuracy of its forecasts regardless of whether or not it can utilize a variance account. In a situation where the forecast of ancillary service revenues was less than the amount arrived at by using

OPG's preferred forecast methodology, this would mean a smaller offset to the revenue requirement and directionally higher rates. If actual revenues exceeded this forecast, OPG would credit the difference back to ratepayers through the account. The process would work in reverse were the forecast too high. It is in OPG's interest to ensure that its costs of providing each of these services are covered by the forecast revenue on a service-by-service basis, and hence, OPG prefers its more rigorous forecast of the revenues over the simple extension of historical values. OPG requests approval of its forecast amounts for ancillary services.

8.2.1 Segregated Mode of Operation

In its evidence, OPG proposed to continue with the same revenue offset mechanism approved by the OEB in EB-2010-0008; using a three-year rolling average to calculate the test period forecast. Based on the timing of OPG's application (September 27, 2013), those three years were 2010, 2011 and 2012.

AMPCO, CME and LPMA all filed submissions recommending that the OEB use 2011, 2012 and 2013 as the three years under consideration. Due to the passage of time associated with processing this application, these are now the three most recent historical years though they do not comprise the period upon which OPG brought forward its payment amounts application. While OPG cannot disagree with the methodology (since it is exactly what was proposed), it cannot help but feel this adjustment is opportunistic, and would not have been proposed if the 2013 actuals had reduced the three year rolling average.

8.2.2 Water Transactions

AMPCO, CME and LPMA all filed submissions which accepted OPG's proposed approach for water transaction revenues. As such, OPG requests that the OEB approve its proposed water transaction revenues for the test period, as filed.

8.2.3 HIM Revenue Requirement

This issue has been fully addressed as part of OPG's reply to Issues 5.3 and 5.4 above.

8.3 NUCLEAR

8.4 ISSUE 7.2

Secondary - Are the forecasts of nuclear business non-energy revenues appropriate?

OPG earns other, non-energy revenues from its nuclear facilities (Ex. G2-1-1). The amounts included in its application for nuclear facilities are $33.2M in 2014 and $30.5M in 2015. These amounts are reflected in Ex. G2-1-1, Table 1.

Board staff's submission is supported by CME. In its proposal, Board staff recommends basing test period amounts for nuclear non-energy revenues on 2013 actual levels (Board staff argument, p. 122). OPG disagrees with this recommendation. OPG's entire application is based upon a forward looking test period. In general, this allows the regulator to assess costs and revenues on a forecast basis, with an understanding of what specific events are planned during the test period, consistent with the utility's business plan. OPG agrees that the regulator should absolutely review historical costs and revenue, but it cannot simply adopt those costs and revenues with no consideration of the differences that exist between the historical period and the test period.

Essentially the only justification for adopting this approach advanced by Board staff is with respect to the heavy water related revenues. In its argument (Table 33, p. 122), Board staff incorrectly labels the revenues in line 1 as "Heavy Water Sales". The values set out in the table are actually reflective of "Heavy Water Sales <u>and Processing</u>" (emphasis added) as shown in Ex. G2-1-1, Table 1 and Ex. L-1.0-1 Staff-002, Table 35. This distinction is relevant. As discussed in OPG's evidence (Ex. G2-1-1, p. 2) and Argument-in-Chief (p. 123), much of the volatility associated with this line item historically has to do with heavy water services that have been provided to external parties and to the maintenance cycles associated with OPG's Tritium Removal Facility ("TRF"), which have been built into OPG's forecast of revenues. Board staff's recommendation completely ignores the availability of the TRF and fails to acknowledge the volatility of the market's demand for services – a demand that in many ways depends on others' activities and options for service provision – something Board staff has no knowledge of. It is wrong to ignore these realities and simply apply historical levels to future test periods. Board staff's recommendation should be rejected.

Both LPMA and AMPCO (supported by SEC) make submissions dealing exclusively with revenues associated with Heavy Water Sales and Processing. The submissions generally call for a change in forecast methodology to one which is based on historical actual values. LPMA calls for the test period amounts to be based on a three year average (LPMA argument, p. 18). In its submission, LPMA has set 2015 revenues equal to 2014, contradicting its own recommendation to use a three year average. AMPCO, on the other hand, proposes a four year average (AMPCO argument, para. 183), however, OPG cannot reconcile AMPCO's numbers. Regardless, both of the recommendations are flawed and should be rejected by the OEB for the same reasons as set out above for Board Staff.

History is not necessarily an accurate predictor of the future. With respect to heavy water sales and processing, OPG understands this, while Board Staff, LPMA, and AMPCO do not. There is no pent-up demand for heavy water sales and processing. The increased revenue OPG realized in 2011 and 2012 for heavy water and detritiation was unexpected and was related to the restart of Bruce Nuclear and Point Lepreau reactors (Ex. G2-1-2, p. 2). This will not be repeated and both OPG's 2013 actuals (Ex. L1.0-1 Staff-002, Table 35) and test period forecasts (Ex. G2-1-1, Table 1) reflect this. OPG's understanding of heavy water sales opportunities as well as the market for provision of service (and the availability of its own TRF) make its forecasting methodology superior than simply relying on the past.

8.5 BRUCE NUCLEAR GENERATING STATION

8.6 ISSUE 7.3

Secondary - Are the test period costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease appropriate?

OPG's submissions with respect to this issue are set out at pages 123-124 of its AIC. Consistent with EB-2012-0002 and EB-2010-0008, the revenues and costs associated with the Bruce lease are calculated based on the OEB's decision in EB-2007-0905. Board Staff has reviewed the current application and agreed that OPG's test period forecast for the Bruce lease is appropriate (Board Staff argument, p. 123).

No other intervenors (except AMPCO to some extent as described below) made submissions with respect to the calculation of the net amounts of Bruce lease revenues and costs. OPG submits that the net amounts of the Bruce lease revenues and costs of $39.7M for 2014 and $40.6M for 2015, as shown in Ex. G2-2-1, Table 1, is the appropriate forecast for the test period and should be accepted by the OEB as filed, but, in any event, these forecast amounts will be tracked against actual revenues and costs and trued up via the Bruce Lease Net Revenues Variance Account. These net amounts are an offset to the nuclear revenue requirement (Ex. G2-2-1, p. 1).

SEC proposed that OPG be required to file the cost of generation from the Bruce Generating Stations on a regulatory basis in future payment amount applications, as if the Bruce Generating Stations were subject to cost of service regulation (SEC argument, para. 7.3.4). OPG submits that SEC's proposal is an inappropriate request that runs contrary to the Board's Decision in EB-2007-0905. There the OEB determined that regulatory constructs are not to be used to calculate revenues from an unregulated activity such as the Bruce Lease revenues or costs (EB-2007-0905 Decision with Reasons, p. 110). The OEB's decision also recognized that the Bruce Generating Stations are not prescribed generation facilities under O. Reg. 53/05, and that the OEB does not have the authority to either review the terms of the lease between OPG and Bruce Power, or regulate the prices of engineering and other services provided to Bruce Power by OPG (EB-2007-0905 Decision with Reasons, p. 99). The Bruce Generating Stations' cost of generation is not relevant to calculating OPG's test period costs related to the Bruce Generating Stations and the net amounts of the Bruce lease revenues and costs. Furthermore, and importantly, OPG is not privy to Bruce Power's cost of generation information. OPG submits that the Board should reject SEC's proposal.

AMPCO submits that if the OEB accepts its proposal under Issues 8.1 and 8.2, that the Bruce lease revenue should be adjusted accordingly (AMPCO argument, para. 185). OPG rejects AMPCO's proposal and addresses AMPCO's argument below in Section 9.0 dealing with Nuclear Waste Management and Decommissioning Liabilities.

9.0 NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

9.1 ISSUE 8.1

Primary (reprioritized) - Is the revenue requirement methodology for recovering nuclear liabilities in relation to nuclear waste management and decommissioning costs appropriate? If not, what alternative methodology should be considered?

9.2 ISSUE 8.2

Primary (reprioritized) - Is the revenue requirement impact of the nuclear liabilities appropriately determined?

AMPCO spends more than a third of its argument (paragraphs 186-245 plus Appendix D) providing a convoluted submission that in its essence involves two simple questions:

1) Is the OEB going to follow the provisions of O. Reg. 53.05 s.6 (2)8 and ensure that OPG recovers its liabilities under ONFA.

2) Having determined in EB-2007-0905 that Bruce Lease net revenues should be determined in accordance with generally accepted accounting principles for non-regulated entities, should this consistently applied approach continue to be used in this proceeding?

OPG submits that the answers to both these questions are related: the treatment adopted by OPG reflects the ONFA provisions and USGAAP (as well as Canadian GAAP) requires that OPG's treatment reflect the economic reality of the ONFA. AMPCO's recommended disallowance of $28.5M should be rejected because its acceptance would require the OEB to re-write ONFA and repudiate GAAP accounting for the Bruce facilities.

OPG submits that its treatment of the "Due to Province" amount in the Decommissioning Fund properly reflects that OPG does not have the right or access to the Due to Province amount pursuant to ONFA. As OPG has previously described, ONFA details the required use of the Decommissioning Funds and the circumstances under which OPG can access these funds. (AIC pp. 126-129).

During the course of the hearing, OPG provided Ex. J11.8, which contains a detailed explanation of ONFA sections 2.2, 4.7.3 and 8.2, the specific ONFA provisions that are reflected in OPG's accounting treatment. AMPCO's response to this material is a single sentence: "AMPCO disagrees that these sections of ONFA require OPG to treat these funds in this way." (AMPCO argument, para. 194). OPG submits that AMPCO fails to offer a single reason why it disagrees with OPG's interpretation of the relevant ONFA sections because it has none. OPG's interpretation of these sections, which forms the basis of the accounting treatment reflected in OPG's audited Financial Statements in accordance with USGAAP, is correct.

Below OPG has reproduced the material from Ex.J11.8, which it believes fully supports its interpretation of the ONFA requirement that limit OPG's use of the "Due to Province" amounts:

> Specifically, sections 2.2, 4.7.3 and 8.2 of the ONFA address the incorrect premise of the undertaking. First, section 2.2 restricts access to and use of the nuclear segregated funds to circumstances required or permitted by the ONFA, as follows:
>
> > *"The assets of the Segregated Funds may not be held, used, paid, distributed, Disbursed, managed, encumbered in any way or transferred except as required or expressly permitted by the terms of this Agreement…"*
>
> Second, section 4.7.3 of the ONFA stipulates that, <u>only</u> in circumstances where the market value of the Decommissioning Segregated Fund is more than 120% of the Decommissioning Balance to Complete Cost Estimate, OPG has the right to direct 50% of the amount in excess of the 120% of the Decommissioning Balance to Complete Cost Estimate to be transferred to the Used Fuel Segregated Fund.[57] As noted by the OPG witness at the Technical Conference (Tr. Vol. 2, p. 158, lines 6-17), this is also described in OPG's audited consolidated financial statements (for example, Ex. L-2.1-6 ED-003, Att. 1, p. 36 of the financial statements). The OPG witness also stated at Tr. Vol. 11 (redacted version), p. 110 lines 16-20 that the 120% threshold is not expected to be reached during the test period.
>
> Finally, section 8.2 of the ONFA stipulates that, upon termination of the ONFA, the Province "shall then have the right to requisition a Disbursement to it and/or to OEFC (as the Province may determine)" for the amount by which the market

[57] Section 4.7.3 refers to the term Surplus. At paragraph 1.117 of the ONFA, Surplus is specifically defined as the amount by which the market value of the Decommissioning Segregated Fund exceeds 120% of the Decommissioning Balance to Complete Cost Estimate.

> value of the Decommissioning Segregated Fund exceeds the Decommissioning Balance to Complete Cost Estimate.[58]
>
> Based on the above provisions, unless the Decommissioning Segregated Fund is more than 120% overfunded, at no point does OPG have the right or access to the amount by which the market value of the Decommissioning Segregated Fund exceeds the Decommissioning Balance to Complete Cost Estimate. As such, any attribution of the Due to Province amount to the prescribed facilities is purely hypothetical.

As AMPCO correctly states, when certain events occur, either failure of the segregated funds to earn their targeted return or change in the value of fund liabilities due to the approval of a new ONFA Reference plan, OPG may gain the right to access the "Due to Province" amounts to address any shortfall in the segregated funds. What AMPCO fails to recognize is that the corollary is equally true – unless and until these triggering events occur, OPG cannot access the "Due to Province" amounts. In this case the evidence is clear that neither of the events has occurred. Thus OPG has no right to access these funds and the treatment that OPG has proposed is correct.

OPG's consistent treatment of the "Due to Province" amounts associated with the Bruce facilities is in accordance with GAAP for non-regulated businesses. In contrast to AMPCO's claims, OPG's treatment of the Due to Province amounts is entirely consistent with the OEB approved methodology in EB-2007-0905.

Under the heading "Transfer of Funds" AMPCO proposes that the OEB establish a deferral account to track when the Decommissioning Fund achieved 120 per cent over-funded status and then treat 50 per cent of the excess as the "amount the Used Fuel Fund is entitled to, and be applied in accordance with the EB-2007-0905 OEB approved methodology for recovering nuclear liabilities in a future application." (AMPCO Argument, paras. 240-241). OPG does not believe such a deferral account is necessary as the existing operation of the Bruce Lease Net Variance Account already serves to afford ratepayers the same protections. Should any earnings on the segregated funds be recognized by OPG as having a right to be accessed,

[58] Section 8.1 of the ONFA stipulates that the agreement may be terminated only at the earlier of: a written agreement of both OPG and the Province to this effect; or when substantially all of the costs for the nuclear waste management and decommissioning programs covered by the ONFA have been discharged.

then the normal, OEB endorsed methodology of allocating such segregated fund earnings would naturally assign a portion to the Bruce facilities. It would not be a fixed 50 per cent. Therefore, the earnings related to the Bruce facilities (including associated income tax impacts) would form part of Bruce Lease net revenues in accordance with GAAP for non-regulated entities and therefore be subject to the existing Bruce Lease Net Revenues Variance Account. This would effectively achieve the same results that AMPCO seeks in its proposal for the deferral account. Establishing a separate account would therefore require the OEB to modify the scope of the Bruce Lease Net Revenues Variance Account in order to avoid having the same amount captured twice, in both accounts.

AMPCO makes no reference in its argument to the prescribed facilities. OPG notes that there is currently no account to capture differences between the revenue requirement impact of differences between actual and forecast segregated fund earnings for the prescribed facilities. OPG also notes that, as outlined in Ex. J13.6, higher segregated fund balances and earnings for the prescribed nuclear facilities serve to increase the revenue requirement and thus would result in the deferral account carrying a debit balance to be recovered from ratepayers. We suspect that is the reason such a deferral account proposal from AMPCO is one sided only.

While the material above fully responds to the substance of AMPCO's argument, that argument also contains some errors and misrepresentations that should not stand unchallenged:

- AMPCO para. 189 – "The Decommissioning Fund had excess earnings for the first time in 2012 and, therefore, this is the first time that the OEB has had before it the issue of how these excess funds are to be treated." This statement is incorrect. OPG's first payments application showed the Decommissioning Fund as being overfunded and this was recognized in the OEB's decision as follows: "The decommissioning fund had a fair value of approximately $5.1 billion at December 31, 2007 and is considered to be overfunded under the provisions of the ONFA." (EB-2007-0905, Decision with Reasons, p. 66).
- AMPCO para. 193 – AMPCO's suggestion that OPG has changed the rationale for its proposed treatment of the Decommissioning Fund balances is wrong. OPG has consistently treated the Decommissioning Fund in accordance with USGAAP (and

previously Canadian GAAP), which has reflected OPG's consistent interpretation of the ONFA provisions. For example, OPG's 2007 audited Financial Statements also recognized a "Due to the Province" for the Decommissioning Fund.[59]

- AMPCO paras. 215, 225 – AMPCO implies that OPG attempted to mislead the OEB by not updating the Bruce portion of the calculation in Ex. J13.6. This is simply untrue. As a review of the discussion that led to this undertaking reveals, both Mr. Kogan and Mr. Mauti clearly indicated repeatedly that they were discussing the impacts on the prescribed facilities (Tr. Vol. 13, pp. 75 (L.16-17, 22-23), 77 (L.6)). Mr. Millar then asked them to calculate the impacts that they were discussing as Undertaking J13.6 and that is exactly what OPG did. Under the OEB-approved GAAP methodology for the recovery of nuclear liabilities associated with the Bruce facilities there is no impact on the Bruce facilities and so none was shown.

10.0 DEFERRAL AND VARIANCE ACCOUNTS

10.1 ISSUE 9.1

Secondary - Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

Only four parties made submissions on this specific issue. Two parties – Board staff and LPMA – have indicated that they have no concerns with the nature of the costs recorded in these accounts as the recorded costs are consistent with the purpose of the accounts (Board staff argument, p. 124; LPMA argument, p. 18).

Board staff reserved the right to re-examine the accounts that are not being disposed of in this proceeding and is supported on this point by CME (Board staff argument, p. 124; CME argument, para. 213). OPG accepts that these accounts should be re-examined in the proceeding dealing with their disposition and therefore has no submissions on this point.

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[59] See, for example, pp. 31-32 of OPG's 2007 audited financial statements appended to Ex. A2-1-1 in EB-2007-0905.

SEC raised an objection to the audited December 31, 2013 balance in the Capacity Refurbishment Variance Account ("CRVA"). In paragraph 9.1.2 of its argument, SEC submits that in-service amounts claimed by OPG for the DRP for the 2011 to 2013 period are incorrect. The reader is then directed back to SEC's submissions under Issue 4.9.

Similarly, OPG has provided its reply to SEC's submission on the balance in the Capacity Refurbishment Variance Account under Issue 4.9.

As can be seen from OPG's submissions under Issue 4.9, there is no real basis to SEC's objections and no reason to conclude that the audited balance in this account is incorrect. Therefore, for the reasons set out in its evidence and Argument-in-Chief, and in recognition that Board staff and LPMA expressed support for the audited balance in the CRVA, OPG submits that the OEB should find that the nature or type of costs in the CRVA are appropriate and approve their disposition as proposed by OPG.

10.2 ISSUES 9.2 - 9.4

9.2 Secondary - Are the balances for recovery in each of the deferral and variance accounts appropriate?

9.3 Secondary - Are the proposed disposition amounts appropriate?

9.4 Secondary - Is the disposition methodology appropriate?

OPG has grouped its submissions on these three issues since they are inextricably linked to calculation of the proposed rate riders.

In its Application, OPG proposes to clear the audited December 31, 2013 balances in the four deferral and variance accounts that were deferred from the EB-2012-0002 proceeding. The four accounts are: 1) the Hydroelectric Incentive Mechanism Variance Account, 2) the Hydroelectric Surplus Baseload Generation Variance Account, 3) portions of the Capacity Refurbishment Variance Account, and 4) the Nuclear Development Variance Account (collectively, the "brought forward accounts").

The total year-end audited 2013 debit balance in these four accounts is $126.9M for the previously regulated hydroelectric facilities and $62.2M for the nuclear facilities (Ex. N2-1-1, Tables 9 and 10). A detailed explanation of the proposed account clearance and calculation of riders is presented in Ex. H1-2-1 and Ex. N2-1-1, Tables 9 and 10.

Board staff and four intervenors made submissions on these three linked issues.

Board staff and the CCC indicated that they have no concerns with respect to the balances for disposition in these four accounts and OPG's proposed disposition methodology (Board staff argument, p. 125; CCC argument, p. 18). Similarly, LPMA had made submissions indicating that the proposed disposition amounts and methodology are appropriate (LPMA argument, p. 19). Board staff and LPMA also noted that if the OEB adjusted OPG's production forecasts then the rider calculation would have to be updated (Board staff argument, p. 125; LPMA argument, p. 19). Finally, LPMA noted that if the Board thought mitigation was necessary then one option would be to extend the amortization period, thereby reducing the proposed rider (LPMA argument, p. 19).

SEC made submissions relating to the balance in the CRVA. These are summarized and replied to under Issue 9.1 above.

CME submissions under these issues were limited to their request that the December 31, 2013 balance in the SBG Variance Account be reduced by $6.8M to account for the unintended interaction between this account and the HIM (CME argument, paras. 215-216).

OPG submits that the OEB should reject CME's improper adjustment to the balance in the SBG Variance Account, an adjustment that is supported by no other intervenor and is implicitly rejected by Board staff and others through their acceptance of the balance in this account.

The unintended interaction between the HIM and the SBG Variance Account came to light during OPG's analysis of alternatives to the HIM. This unintended interaction means that an unintended "double count" amount is included within the balance in the SBG Variance Account totalling $6.8M (as explained in Ex. J4.7, at Tr. Vol. 13, p. 125 and Tr. Vol. 4, p. 158-161).

OPG submits that CME's proposed adjustment is improper because it would violate the finality of the OEB's Order in EB-2010-0008 that established the terms for calculating entries into the SBG Variance Account and amounts to retroactive ratemaking. The audited balance in the account, $19.2M (Ex. L-9.1-17 SEC-132, Table 1 and Ex. N2-1-1, Table 9), is calculated correctly in accordance with the terms of the OEB's Order and there is no proper reason for it to be adjusted. OPG notes that no party suggested that the balance in this account was not calculated accurately or in accordance with the terms of the OEB's Order.

In its original pre-filed evidence, OPG noted its discovery of the unintended interaction and was clear that it had developed its eHIM proposals to ensure that it was corrected on a going forward basis (Ex. E-1-2-1, p. 9, lines 14-16).

Adjusting the balance in the SBG Variance Account as proposed by CME would also be a bad precedent in OPG's submission. It would significantly complicate the process for finalizing and disposing of deferral and variance balances in the future. It would create an environment where it would be permissible for parties (either utilities or intervenors) to argue for an adjustment to the scope and/or operation of an account to address new developments or new information that arose after the order establishing the account was issued (Tr. Vol. 13, p. 125, lines 9-14). OPG submits that such an environment would undermine the ability of utilities to book regulatory assets and liabilities in their financial statements related to these accounts and have them accepted by their auditors, since there would be additional uncertainty as to how the balances would be subsequently treated by the OEB.

It is also worth noting, in OPG's submission, that OPG deferred seeking a rate increase in 2013 and earned well below its allowed return on equity for that year (Ex. L-1.0-1 Staff-002, Attachment 1, Table 1, line 12). In this light, CME's attempt to engage in retroactive ratemaking is even more egregious.

OPG has provided its submission on the need for mitigation under Issue 10.1 and will not repeat them here.

Board staff expresses a concern that OPG filed an application that includes a forecast of its December 31, 2013 balances rather than final audited balances (Board staff argument, pp. 125-126). Board staff goes on to submit that the OEB may wish to consider whether it should allow OPG to file on this basis in future.

OPG submits that even a superficial examination of Board staff's concerns reveals that there is no substance to their complaints. First, they express concern that the bill impacts included in the public notice is based on "estimates" (Board staff argument, p. 126). However, this point ignores the obvious fact that much of the revenue requirement, which drives the calculation of the bill impact, is based on forecasts and that the methodology used to calculate bill impacts is itself based on a series of estimates; including estimates of a typical customer's consumption, an estimate of their usage of OPG's generation, and an estimate of overall provincial demand (Ex. I1-1-2, Section 2, Table 1). Board staff assigns a level of precision to customer bill impact calculation that does not exist.

Board staff also says that using a forecast of balances creates inefficiencies without identifying what those inefficiencies are in this case. In this application, the audited balances were provided along with the responses to the interrogatories. The forecast balances were within 1 per cent (Ex. H1-1-1, Table 1 vs. Ex. L-9.1-17 SEC-132, Table 1) of the final audited balances. In terms of the accounts proposed for disposition, the difference was only $4M (Ex. H1-2-1, Tables 1 and 2 versus Ex. N2-1-1, Tables 9 and 10), a very small amount when compared to the revenue requirement that was over $9B.

OPG submits that the filing of forecast balances and the provision of final audit balances was appropriate in this case.

For all of the reasons provided in OPG's evidence and AIC, and in recognition of the support from Board staff and other intervenors, OPG submits that the proposed balances, the amounts for disposition and the disposition methodology should be accepted by the OEB.

10.3 ISSUE 9.5

Secondary - Is the proposed continuation of deferral and variance accounts appropriate?

No party objected to the continuation of the deferral and variance accounts that OPG proposes for continuation.

Three parties (Board staff argument, p. 126, CME argument, para. 217 and LPMA argument, p. 19) sought continuation of the HIM variance account. OPG notes that it had proposed that the HIM variance account continue in order to record interest and amortization of the year-end 2013 account balance (Ex. H1-3-1, p. 5). OPG agrees that it would be appropriate to continue the operation of the account, beyond simply interest and amortization, if the OEB decides to keep the current HIM, as some parties have proposed.

For all of the reasons set out in its evidence and Argument-in-Chief, and in recognition that no one objected to its continuation proposals, OPG submits that the OEB should find that the proposed continuation of the existing deferral and variance accounts is appropriate.

10.4 ISSUE 9.6

Oral Hearing - Is OPG's proposal to not clear deferral and variance account balances in this proceeding (other than the four accounts directed for clearance in EB-2012-0002) appropriate?

Under Issue 9.6, Board staff expresses some concerns with OPG's proposal to clear just four accounts in this proceeding (Board staff argument, p. 127). Elsewhere in their argument, under Issues 9.2 through 9.4, Board staff supports OPG's proposed disposition methodology and proposed disposition amounts (*Ibid.*, p. 125).

While Board staff makes no specific submissions, they encourage the OEB to consider whether OPG's approach in this case is the most effective and efficient means of assessing deferral and variance account balances (*Ibid*., p. 127). They are joined in this by CME, CCC and LPMA. LPMA goes further, suggesting that OPG should be allowed no interest on the accounts not proposed for clearance (LPMA argument, p. 19).

In their submission, Board staff relies on a comment by OPG's corporate cost witness, Ms. Ladak, to infer that OPG believes that separate applications are the norm. In OPG's view, this is an unhelpful submission. OPG presented a regulatory witness. If Board staff really wanted to test OPG's understanding of typical regulatory practice in Ontario they could have questioned that witness – but they chose not to.

OPG submits that its approach was sensible and appropriate in the circumstances. As indicated in Exhibit H1-1-1 sections 4.3, 4.4, 4.7 and 4.12 and in Exhibit L-9.6-1 Staff-191, OPG had just concluded a hearing to review and dispose of the balances in all of the other accounts. The Board's Order in that application (EB-2012-0002) was issued in April 2013, just five months before the filing of the current application. Further, that order generally set the recovery period for 2013 and 2014 so it was reasonable to contemplate a separate hearing for new amortization amounts effective January 2015. In OPG's submission, given the recent Board Decision and Order in EB-2012-0002, it would not have made sense to return to a consideration of the same accounts again as part of this Application.

Given the size, duration and complexity of the current Application, OPG's approach provided additional benefits to all parties in making the current case somewhat more manageable (Tr. Vol. 13, pp. 88-92).

As for LPMA's proposal, which was never put to one of OPG's deferral and variance account witnesses, OPG submits that this submission is inappropriately punitive. It should be rejected out of hand.

For all of the reasons provided above and in its evidence and AIC, OPG submits that the OEB should find that OPG's proposal to clear only four accounts in this Application was appropriate in the circumstances.

10.5 ISSUE 9.7

Primary (reprioritized) - Is OPG's proposal to make existing hydroelectric variance accounts applicable to the newly regulated hydroelectric generation facilities appropriate?

No party objected to OPG's proposal to extend the existing hydroelectric variance accounts to the newly regulated assets.

Accordingly, for all of the reasons set out in its evidence and Argument-in-Chief, and in recognition that there were no objections, OPG submits that the OEB should find that extending the existing variance and deferral accounts to the newly regulated hydroelectric facilities is appropriate.

10.6 ISSUE 9.8

Secondary - Is the proposal to discontinue the Hydroelectric Incentive Mechanism Variance Account appropriate?

Please see OPG's submissions under Issue 9.5.

10.7 ISSUE 9.9

Primary (reprioritized) - What other deferral accounts, if any, should be established for OPG?

While OPG did not propose any new deferral or variance accounts, a total of four additional accounts have been proposed by Board staff and various intervenors. The proposals are summarized below:

1) Board staff proposed that a new deferral account be established to capture GRC savings that would arise if the Ministry of Natural Resources ("MNR") was to grant OPG a GRC payment holiday during the test period (Board staff argument, p. 129). This proposal was supported by AMPCO, CME, EP, LPMA and SEC.

2) Board staff also proposed that a new variance account be established to capture differences between forecast cash payments for pension and OPEB and the actual cash payments (*Ibid.*) This account would only be needed if the OEB was to approve a move to cash basis for pension and OPEB. This proposal was supported by CME, EP and LPMA.

3) AMPCO has proposed that a deferral account be established to record 50 per cent of the amount in excess of the 120 per cent of the Decommissioning Balance to Complete Cost Estimate. The balance in this account would then be recorded in the Used Fuel Fund (AMPCO argument, paras. 239-241).

4) SEC has proposed that a Bruce Lease Net Revenues US GAAP deferral account be created to record a credit to customers of $59M that would be drawn down at an appropriate rate each year (SEC argument, para. 1.3.5).

OPG responds to these proposed accounts in its submissions below.

OPG has no objection to Board staff's proposed account to capture customer credits that would arise if the MNR approves OPG's application for a GRC holiday for the Niagara Tunnel production. OPG indicated as much in its response to Undertaking JT1.8. However, OPG does not expect any decision from the MNR on its application for a GRC holiday during the test period (Ex. JT1.8).

Elsewhere is this Reply Argument (Section 7.1.2), OPG has set out its serious concerns with respect to proposals that the pension and OPEB cost recovery method be moved to a cash basis from the current accrual-based method. However, if the OEB does adopt the cash method then an account of the type proposed by Board staff should be approved by the OEB. The account would be required given variability between forecast and actual cash amounts for pension and OPEB.

OPG does not support either of the other two proposed accounts. As explained elsewhere in this Reply Argument (see Issue 8.2 for the account proposed by AMPCO and Issue 1.3 for the account proposed by SEC), there is no basis for making the adjustments that are at the root of these two proposed accounts. Accordingly, for the reasons set out above, OPG submits that the OEB should reject these two proposed accounts.

11.0 REPORTING AND RECORD KEEPING REQUIREMENTS

11.1 ISSUE 10.1

Secondary - What additional reporting and record keeping requirements should be established for OPG?

Board staff has proposed that OPG be required to obtain advance approval from the OEB of any "regulatory accounting change". They have proposed a $20M materiality threshold before this new obligation would apply (Board staff argument, p. 5). This proposal was supported by several other intervenors (CME, CCC, LPMA, SEC, VECC), including some that did not support a materiality threshold (LPMA, SEC).

Aside from being unnecessary, as discussed below, OPG submits that there are significant problems with Board staff's proposal. First and foremost, they have not specified exactly what kinds of accounting changes would be captured by their proposal.

There are two broad categories of "accounting changes". These are (1) changes in accounting policies (also known under USGAAP as changes in accounting principles), and (2) changes in estimates. Staff's proposal appears to encompass both categories. This broad definition would create immense practical challenges for all participants in the regulatory process.

Under US GAAP (and similarly Canadian GAAP and IFRS), voluntary changes in accounting policies or principles must be applied retrospectively to reflect the cumulative effect of the change on prior periods, as though the new policy or principle had been applied from the inception.[60] For example, absent a change in circumstances, new information or a new

[60] See US Financial Accounting Standards Board Accounting Standards Codification Topic 250, *Accounting Changes and Error Corrections* ("ASC 250") at para. 250-10-45-5. This was discussed by Mr. Kogan at Day 2 of the Technical Conference (Tr. pp. 204-205).

accounting pronouncement, a change from a straight-line method of depreciation to a declining-balance method would be considered a change in accounting policy.

The effects of a change to a significant accounting policy must be disclosed in a company's financial statements. As can be corroborated by a review of OPG's audited financial statements, OPG has only made one change in accounting policy related to the prescribed assets since it became regulated by the OEB – the adoption of US GAAP. And the adoption of US GAAP for regulatory purposes was addressed through an application to the OEB for approval to adopt US GAAP for rate-making purposes in EB-2012-0002.

Given that period-over-period comparability of financial results is a cornerstone of credible financial reporting and is part of good corporate governance, OPG submits that a change in a significant financial accounting policy or principle could only result from an extraordinary set of events.[61] As these circumstances have only materialized once since OPG became regulated by the OEB, there is no basis whatsoever for Staff's concerns.

Conversely, changes in accounting estimates result from new information and must be reflected prospectively under US GAAP (as well as Canadian GAAP and IFRS) [62]. In order to present fairly its financial statements, OPG is required to make changes in its estimates when the previous estimate or assumption is superseded by new information. This was the situation that occurred when, effective December 31, 2012, OPG changed the end-of-life dates for the Pickering stations as a result of having achieved high confidence in the extended operations of their fuel channels.

The use of estimates is fundamental to accounting in accordance with US GAAP (as well as Canadian GAAP and IFRS). Given the size and complexity of OPG's operations, a requirement for OPG to track, assess and seek OEB approval of any change in accounting estimates would impact hundreds, if not thousands, of individual routine accounting estimates done throughout the year (e.g., accruals for revenues and labour costs, accrued expenses for materials and

[61] For example, the Financial Accounting Standard Board stated in SFAS No. 154 "Accounting Changes and Error Corrections", "a presumption exists that an accounting principle once adopted shall not be changed in accounting for events and transactions of a similar type." Financial Accounting Series No. 268-A, May 2005, p. 4
[62] See ASC 250, para. 250-10-45-17

services received and charges incurred). This may be the case even with a materiality threshold, if the threshold is applied to multiple transactions on a cumulative basis. As such, OPG submits that a requirement for it to seek approval for all accounting changes in estimates would introduce an unmanageable burden on all parties to the OEB's regulatory process, as well as OPG's internal processes.

Board staff's proposal also appears to be inconsistent with the OEB's treatment of electricity distributors as described in the OEB's July 8, 2010 letter regarding a generic industry depreciation study conducted by Kinectrics Inc. (EB-2010-0178).

That letter sets out the OEB's expectations with respect to the determination of asset service lives for electricity distributors. These expectations do not include a requirement that they seek advance approval from the OEB. Instead, the letter indicates that residual value and useful life for assets are to be assessed annually, and that the distributors are to update the OEB on such changes in future cost of service proceedings. The letter specifically states:

- "Accordingly, effective on transition to IFRS, the Board will no longer prescribe service lives for Property, Plant and Equipment recorded in the accounts of the distributors. So as not to depend on a rate-ruling from the regulator to define the service life (rate rulings have no status under IFRS standards as currently written), distributors are to have identified asset service lives that meet the International Accounting Standards Board (IASB) requirements." (p. 1)

- "When appearing before the Board in future cost of service proceedings after the initial IFRS cost of service proceeding, distributors will be expected to **provide update information** to the Board regarding the useful lives of their assets along with justification for any changes." (*emphasis added*). (p. 2)

- "The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors." (Schedule A to letter, *International Accounting Standard # 16*, para. 51).[63]

[63] IAS 8 provides the IFRS equivalent of US GAAP guidance found in ASC 250.

The approach outlined above for distributors is essentially the approach that OPG currently follows (Ex. L-1.3-1 Staff 006 part c) and L-6.12-1 Staff-149 part b)).

Notwithstanding the broad scope of Staff's proposal, the two examples cited (change in the treatment of gains and losses and the changes in the Pickering depreciation service lives) suggest that Board staff is really focused on "accounting changes" that impact depreciation expense (useful lives, gains and losses on retirement of assets), and its related impact on accumulated depreciation and rate base.

OPG acknowledges that changes in nuclear station end-of-life dates, for depreciation purposes, can have larger impacts on depreciation expense. Because asset retirement costs are a significant component of the overall net book value of the prescribed nuclear assets, this concern is in large part addressed by the EB-2012-0002 Settlement Agreement pursuant to which OPG agreed to seek an accounting order for revenue requirement impacts (greater than $10M annually) of changes in the nuclear liabilities that are not captured by the Nuclear Liability Deferral Account.

To address Staff's concern further, OPG would support the expansion of that requirement to include impacts (subject to the same threshold) of changes in station useful lives on non-asset retirement cost components of nuclear fixed assets reflected in rate base. Such a requirement would capture any future changes similar to the $47M Pickering depreciation example cited by Staff. OPG suggests that this approach would be most pragmatic response to the concerns expressed by Board staff on this matter.

However, if the OEB is inclined to adopt Board staff's proposal, then OPG submits that the proposed $20M materiality threshold should be included. OPG also submits that the threshold should apply on a per-individual transaction basis to keep the impact of the new requirement to a manageable level. Absent a materiality threshold, OPG will be faced with the prospect of making numerous applications to the OEB each year to deal with minor accounting adjustments, resulting in significant effort for OPG and the OEB.

12.0 METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

12.1 ISSUE 11.1

Oral Hearing - Has OPG responded appropriately to Board direction on establishing incentive regulation?

No parties have suggested that OPG has not responded appropriately to the OEB's directions on establishing incentive regulation. Therefore, OPG submits that for all of the reasons set out in its evidence and Argument-in-Chief, the OEB should find affirmatively that OPG has responded appropriately to the OEB's directions on this matter.

Board staff expresses a concern that the start of the planned Working Groups (i.e., Hydroelectric IRM and Nuclear Multi-Year Cost of Service) is being impacted by the fact that the processing of OPG's Application will still be underway in the fourth quarter of 2014 (Board staff argument, p. 131). They see the potential for this delay impacting the timing of OPG's next application, which would reflect the results of the Working Groups' discussions. They have proposed that OPG be directed to publicly file the London Economics International productivity study ("LEI Study") before the end of the year (*Ibid.*)

OPG is also concerned about the impact of delay on its next rate application – an application that would be seeking new payment amounts effective January 1, 2016. While OPG agrees that the Working Groups would not be able to finalize their work until the decision in this case is issued, there is no reason in OPG's submission that the Working Groups cannot at least get started this fall –by mid-November. This early start, coupled with a focused effort by the Working Group, would minimize the potential for delay in the filing of the next application.

The Working Groups could start with a review of the LEI study and discussions regarding a work plan and schedule. These discussions and any related materials would need to remain confidential while the OEB's decision in this Application is still pending to avoid any appearance of interference with the adjudication process. However, once the decision is issued, the materials, including the LEI study, could be posted publicly.

12.2 ISSUE 11.2

Secondary - Is the design of the regulated hydroelectric and nuclear payment amounts appropriate?

No submissions were made on this issue by any party to the proceeding. Accordingly, for the reasons set out in its evidence and summarized in its Argument-in-Chief, OPG submits that the design of the proposed regulated hydroelectric and nuclear payment amounts is appropriate and should be accepted by the OEB.

12.3 ISSUE 11.3

Oral Hearing - To what extent, if any, should OPG implement mitigation of any rate increases determined by the Board? If mitigation should be implemented, what is the appropriate mechanism that should be used?

While acknowledging that the OEB has set a 10% customer bill impact threshold for mitigation, Board staff submits that this threshold is not sufficient for OPG because it is the largest generator in the province that affects all customers and because it is seeking a large increase (Board staff argument, p. 132). In establishing the 10 percent customer bill impact threshold, the OEB has never suggested that it should vary depending on the regulated firm's relative size; perhaps because this fact is irrelevant. If you are served by a large distributor whose newly approved rates represent an eight per cent increase on the total bill, then your bill goes up by 8per cent - the same as it would if you are served by a small distributor. Moreover, among the firms regulated by the OEB there is a largest transmitter, a largest distributor, and a largest gas distribution company, but the OEB has never suggested that these large entities should be subject to a different mitigation standard.

Board staff proposes a phase-in of the new rates for the newly regulated hydroelectric as follows (*Ibid.*, p. 134):

- The payment amount for the period July 1, 2014 to December 31, 2014 should be set at a rate half-way between \$30/MWh (the proxy for market prices for these assets as discussed in the case) and the rate the OEB ultimately approves for these assets.

- For 2015, the full rate approved by the OEB would apply.

Board staff submits that phasing in the increase for these assets is an appropriate mitigation measure for the OEB to consider. It estimates that OPG would “forgo” $52.7M if the OEB was to adopt this phasing in of the new rates (using OPG’s proposed rates). Board staff goes on to say that it has proposed a number of other mitigation measures in its argument which the OEB should also consider (Board staff argument, p. 134).

No intervenor supported Board staff’s proposal. The PWU submitted that it should be rejected for the same reasons that OPG has provided below – namely that it is an impermissible disallowance of otherwise prudently incurred costs (PWU argument, para. 257).

Quite frankly, OPG finds Board staff’s submissions on mitigation astonishing. Nowhere is there any mention of the creation of a deferral account that would capture these mitigated costs for future recovery by OPG, with interest. Board staff must know that without such a deferral account their proposed “mitigation” is really the confiscation of otherwise prudently incurred costs that OPG is legally entitled to recover.

They must also know that such confiscation is contrary to long-standing regulatory principles, the OEB’s own practices and the law.

An explanation of how rate mitigation operates can be found in the expert report on rate mitigation by Navigant Consulting, commissioned by the OEB in December 2010 (EB-2010-0378, Transmission and Distribution Rate Mitigation Measures for Ontario, Navigant Consulting, May 3, 2011, pp. 4, 19). It is also set out in Board staff’s own Discussion Paper on Approaches to Mitigation for Electricity Transmitters & Distributors (EB-2010-0378, November 8, 2011).

At page 43 of its discussion paper, Board staff quotes from a 2007 Edison Electric Institute report entitled Rate Shock Mitigation:

> [t]he basic intent of a deferral or phase-in of a rate increase over a multi-year period is to spread the "pain" associated with the rate increase over a longer period. A rate deferral is simply a deferred recovery of a utility's prudently incurred costs.

Later on that same page, Board staff references the Navigant report and states:

> As noted in the Navigant Report, in order to ensure the utility is kept financially whole, a deferral or phase-in-requires that the deferred amount be recognized as a credible regulatory asset and that the utility be provided the opportunity to earn a reasonable carrying charge. This is consistent with the Board's practice, as noted in section 2.2.2., whereby utilities have generally been permitted to earn interest on a deferred amount, at the Board's prescribed rate.

In addition, the Federal Court of Appeal decision *TransCanada PipeLines Ltd. v. National Energy Board, 2004 FCA,* cited in the OEB's Report of the Board on the Cost of Capital for Ontario's Regulated Utilities at page 19 (EB-2009-0084, December 2009), deals directly with this issue.

The decision of the Federal Court of Appeal makes it clear that any phasing in of rates to address rate shock must be implemented in such a manner that there is no harm to the utility. This is required in order to avoid violating the Fair Return Standard, which the Supreme Court of Canada has recognized as an "absolute obligation" in the rate setting process (*British Columbia Electric Railway Co. Ltd. v. Public Utilities Commission of British Columbia et al*, *[1960] S.C.R. 837*, at p. 848). As the Federal Court of Appeal found:

> It may be that an increase is so significant that it would lead to "rate shock" if implemented all at once and therefore should be phased in over time. It is quite proper for the Board to take such considerations into account, provided that there is, over a reasonable period of time, no economic loss to the utility in the process. In other words, the phased in tolls would have to compensate the utility for deferring the recovery of its cost of capital. (*TransCanada PipeLines Ltd. v. National Energy Board, 2004 FCA149*, at para. 43).

Given its fundamental flaws, OPG submits that Board staff's mitigation proposal should be rejected.

13.0 IMPLEMENTATION

13.1 ISSUE 12.1

Oral Hearing - Are the effective dates for new payment amounts and riders appropriate?

Under this issue parties argue that the effective dates for new payment amounts and riders should be delayed from the dates proposed by OPG of January 1, 2014 in respect of the previously regulated hydroelectric and nuclear facilities, and July 1, 2014 in respect of the newly regulated hydroelectric facilities (Ex. A1-2-2, p. 2).

Board staff argues that payment amounts in respect of all of OPG's prescribed facilities, previously and newly regulated alike, should be July 1, 2014 (Board staff argument, p. 137). Others adopt (even) more extreme positions. SEC (argument, para. 12.1.8) and CCC (argument, p. 21) say that the effective date for the previously regulated facilities should be the beginning of the month immediately following the date on which a payment order is made (it speculates December 2014). CME (argument, paras. 232-235) takes a similar position but includes the newly regulated hydroelectric facilities. LPMA (argument, p. 22) takes the same position.

In OPG's submission, none of these alternative effective dates should be ordered by the OEB. The proposals are blatantly punitive to OPG; have no connection to the reality associated with the preparation of an application such as OPG's; and would, if ordered, result in payment amounts which are unjust and unreasonable.

The naked truth of all parties' arguments in relation to the effective date is that they amount to nothing more than a plea to cut the revenue requirement (and avoid the real cost of electricity for 2014) – the very form of "mitigation" the Federal Court of Appeal has held is unlawful. It is simply impermissible to cut payments amounts based on the magnitude of any increase, which is exactly what parties would like the OEB to do here.

The purported justification given by parties is the observation that given the date on which it filed its application (September 2013), OPG could not reasonably have expected that a decision would be rendered by the OEB until well into 2014. Leveraging off this observation, parties argue that it would not be “fair” to set payment amounts, at least for the previously regulated hydroelectric and nuclear facilities, beginning January 1, 2014.

To the extent this line of thinking is relevant at all, the proper question the OEB should ask is not what is the earliest date on which a decision could be rendered, but rather were parties provided, in advance, with sufficient notice of OPG’s application and the requested change in payment amounts. A fundamental tenet of substantive and procedural fairness in administrative law is the requirement to provide parties with notice. This is reflected in the S*tatutory Powers Procedure Act* as well as the *Ontario Energy Board Act*. To meet its obligation at law to provide notice, the OEB requires applicants to publish a notice following the receipt of an application. In this case, the OEB twice required OPG to post notice. The publication requirement imposed by the OEB was extensive: OPG was directed to publish notice in literally dozens of publications, reaching across all parts of the Province. On both occasions the notice specifically advised readers of the nature of the application and the size of the proposed payment amounts increase. For example, the second notice (December 2013) provided:

> On September 27, 2013, Ontario Power Generation Inc. applied to the Ontario Energy Board to increase the amount it charges for the output of its nuclear generating facilities and most of its hydroelectric generating facilities. If approved, this would have resulted in an increase of about $5.36 each month for the typical residential customer beginning on January 1, 2014. Other customers, including businesses, would be affected as well. On December 6, 2013, Ontario Power Generation revised the application. If approved, the revised application would result in an increase of about $5.94 each month for the typical residential customer beginning on January 1, 2014.

In the result, notice was provided across Ontario by OPG to consumers that it was seeking an increase in the payment amounts to be effective January 1, 2014 in respect of its nuclear generating facilities and most of its hydroelectric generating facilities. OPG further communicated that the impact of the payment amount increase was expected to be approximately $5.94 per month for the average residential customer. Finally, OPG advised where its application could be reviewed and how to participate in the proceeding.

The only reasonable conclusion that can be drawn from the notice is that consumers across the Province have been well aware since the beginning of the year of OPG’s application and the potential consequence of it. In the face of this notice there can be no serious suggestion of unfairness – parties received the notice they are entitled to at law and have had every opportunity to arrange their affairs (to the extent necessary) to respond to OPG's request. There is simply no substance to any complaints otherwise.

It is also important to put the parties' complaints about fairness in context. OPG does not dispute that in percentage terms its requested increase in payment amounts is significant. However, in bill impact terms it is much more modest: the request amounts to less than a 10 per cent impact on the total bill paid by customers.

Parties' arguments also lack any sense of practicality. It will be about 15-16 months from the date of OPG's application to the date the OEB issues its decision and order. If OPG were required to file its application that many months in advance of an effective date of January 1, 2014, it would have to have filed its application in the third quarter of 2012 given that the preparation of the application takes roughly 4-5 months (conservatively). OPG would have had to base the application on information that was available in the spring of 2012; in other words its 2012-2014 business plan which was approved by OPG's Board in November 2011. As a result, this means that OPG would have had to file its application based on information that would be 3-4 years old relative to the test period i.e., practically useless and not reflective of actual costs. Respectfully, this approach does not make any sense to OPG and should be rejected by the OEB.

In its Argument-in-Chief, OPG submitted that having declared a rate payment amounts interim as of January 1, 2014 the OEB is obliged to make the payment amounts it determines to be just and reasonable after review of the application effective from those dates (AIC p. 146). The time taken to process and review OPG's application is legally irrelevant. In response to this submission, Board staff (argument, p. 135) and others point out, correctly, that the OEB in issuing the interim order indicated that its determination was made "without prejudice to the Board's ultimate decision on OPG's application, and should not be construed as predictive, in any way whatsoever, of the Board's final determination with regards to the effective date for OPG's payment amounts arising from this application." Respectfully, OPG disagrees that the

OEB can, in its interim order, reserve the right to set the effective date of the payment amounts to a later date.

Section 78.1 of the *Ontario Energy Board Act* adopts the "just and reasonable" standard for the OEB's determination of the rates to be paid to OPG for the output of the prescribed facilities. This standard is well established. As the Supreme Court of Canada held in *Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] S.C.R. 186 at 192-193, just and reasonable rates are "rates, which, under the circumstance, would be fair to the consumer on the one hand, and which on the other hand, would secure to the company a fair return for the capital invested."

Fair compensation of the utility comprises two legal entitlements: (1) the right to recover all prudently incurred costs; and (2) the right to a fair return on invested capital. Fairness to the consumer is met by ensuring that the utility recovers no more than these two entitlements[64]. Contrary to parties' suggestion otherwise, the OEB is not entitled under the rubric of fairness to deny the utility recovery of its costs.

As the Supreme Court of Canada held in *Bell Canada v. Canada (Canadian Radio and Television and Telecommunications Commission)*, [1989] 1. S.C.R. 1722, the legislature's intention in providing regulators with the ability to set interim rates was to provide regulators with the power to ensure that rates are always just and reasonable. The only question before the OEB is what are just and reasonable rates (as understood and required by law) beginning January 1, 2014. The OEB cannot avoid the requirement to answer this fundamental question under the heading of the effective date; it must address the question of what are just and reasonable rates beginning at that time. This requires consideration of the costs reflected in the application; they cannot be avoided.

In Board staff's submission it attempts to distinguish the Supreme Court's decision in *Bell Canada*. It observes that in that case the determination that the effective date would match the interim order date resulted in a significant refund to customers. With respect this is not a proper

[64] *Enbridge Gas Distribution Inc. v. Ontario Energy Board* (C.A.), *supra* at para. 8; *Advocacy Centre for Tenants-Ontario v. Ontario Energy Board*, [2008] O.J. No. 1970 (Div. Ct) at paras. 19-20; *TransCanada Pipelines Limited v. National Energy Board*, *supra* at paras. 13, 33-36.

basis on which to distinguish the case. There is nothing in the Supreme Court of Canada's decision to support the proposition that the conclusion would have been any different had the situation been reversed. On the contrary, the language used by the Supreme Court of Canada is consistent with the opposite conclusion; that the overriding concern is the justness and reasonableness of the rates, not whether they are higher or lower than amounts determined in relation to a prior period.

Board staff also refers to the Board's decision in EB-2005-0361. Respectfully, this decision cannot be reconciled with the Supreme Court's decision in *Bell*.

As a final matter, CME argues, while admitting that section 6(2)11 of the regulation requires the OEB to fix July 1, 2014 as the effective date for the newly regulated hydroelectric facilities, that the section is invalid and *ultra vires* (CME argument, para. 234). CME makes the trite observation that the regulation cannot override the provisions of the Act. No other party adopts CME's position and it is wrong. There is no conflict between the Act and the regulation for the simple reason that the Act explicitly provides for this result through the combined operation of section 78.1(2) and the regulation.

Appendix A

Geotechnical Baseline Reports for Construction – *Suggested Guidelines*

Geotechnical Baseline Reports for Construction

SUGGESTED GUIDELINES

The Technical Committee on Geotechnical Reports of the Underground Technology Research Council

Randall J. Essex, P.E.

ASCE

Construction Institute

GEOTECHNICAL BASELINE REPORTS FOR CONSTRUCTION

SUGGESTED GUIDELINES

PREPARED BY
Technical Committee on Geotechnical Reports
of the Underground Technology Research Council

SPONSORED BY
The Construction Institute (CI)
of the American Society of Civil Engineers

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COMMITTEE CHAIRMAN
Randall J. Essex, P.E.

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Contents

Dedication to James P. Gould

The second edition of this publication is dedicated to the memory of James P. Gould. Jim is remembered by all who knew and worked with him as a warm, caring man whose good humor was equal to his engineering brilliance. He had an uncanny ability to rapidly filter engineering information, pick out the important issues, identify the problems and suggest a solution. He was a pioneer in promoting alternative means of dispute resolution in underground projects and prepared one of the first Geotechnical Design Interpretive Reports included as part of the contract documents on the Washington, DC Metro subway system.

Born in 1923, Jim grew up in Seattle and graduated with a BSCE from the University of Washington in 1944. This was followed by a hitch in the U.S. Army Corps of Engineers. After World War II, Jim studied at MIT where he received his MSCE in 1946, and at Harvard, where working with Arthur Casagrande, he earned the ScD in 1949. He then spent four years with the U.S. Bureau of Reclamation, where he worked on earth dam projects. In 1953, he jointed Moran, Proctor, Mueser and Rutledge in New York. Jim became a partner in the firm in 1973. This firm became Mueser Rutledge Consulting Engineers in 1985.

Jim's active career included a long list of difficult and noteworthy projects. Among them was geotechnical work on the U.S. Capitol, the U.S. House of Representatives, the National Gallery of Art and the Smithsonian Institution in Washington, D.C., New York's Battery Park City, and numerous port and marine projects. As a result of his work in leading Mueser Rutledge's geotechnical services during 30 years of construction of the Washington D.C. Metro Subway system, he became a valued member of advisory and consulting boards established for other major projects. Jim served on such Boards for highway and rapid transit tunnel projects in Boston, Los Angeles, Dallas and San Juan, Puerto Rico, for the Super Collider in Texas, and the Channel Tunnel between England and France.

He was a former Executive Committee chairman of the Geotechnical Division of ASCE and was active on technical committees on Earth Retaining Structures, Grouting, Tunnel Lining Design, and Groundwater. He delivered ASCE's highly esteemed Terzaghi Lecture in San Francisco in 1990, where he was named an Honorary Member. He was a member of the National Academy of Engineering, National Research Council, Transportation Research Board and the New York Academy of Sciences. He received the prestigious Moles Member Award in 1992, recognizing his outstanding contributions to the field of underground construction.

Jim's Terzaghi Lecture, published in the July 1995 Journal of Geotechnical Engineering was entitled, "Geotechnology in Dispute Resolution." That paper strongly endorsed the use of geotechnical baseline reports for underground construction by describing the need for, and importance of, a workable differing site conditions (DSC) disputes process in underground construction contracts. The paper also described the historical background of the work by the Underground Technology Research Council (UTRC) in developing a series of documents that led to industry-wide acceptance of the use of Geotechnical Baseline Reports, and the publication to which this dedication applies.

The paper emphasizes the importance of carefully planned and reported geotechnical investigations (a life long passion of Jim's) and the need for preparation and review of geotechnical baseline reports by experienced senior personnel. Jim discussed eight case histories involving DSC claims that illustrate many of the difficulties in site characterization and description that can lead to encountering unexpected conditions during construction.

Jim was an influential mentor to many of us, and is remembered fondly by virtually everyone whose life he touched.

Dedication to E. B. Waggoner

The first edition of this publication was dedicated to the memory of Eugene B. Waggoner. Gene is remembered by those who knew him as a caring, warm man, who always had a humorous story relevant to the situation at hand. His ability to enhance a story or joke over time was legendary. As a professional, he was one of the pioneers who developed the classic study of geology into the applied field we recognize today as engineering geology. He understood geologic processes, structural geology, mineralogy, and petrology, and translated that understanding into solutions to difficult engineering and construction problems. Gene was one of the principal movers in the early days of interpretive geotechnical reports for construction. His vision and desire for successful construction projects through improved communication and cooperation has inspired the development of this document.

Born in 1913 in Missouri, Gene's family moved to Los Angeles during his early years. He received his BA and MA in geology from UCLA and set out in 1939 to become a petroleum geologist. He joined the U.S. Bureau of Reclamation in 1942, where he changed his focus to civil engineering projects. He left the government in 1954 and went into private practice, and in 1960, merged his practice with Woodward-Clyde Associates. Gene became president of Woodward-Clyde in 1967, and retired in 1973 to have open-heart surgery. His "retirement" was more active than most professionals' careers during their productive years. He passed away in 1991 after a bout with pneumonia.

Gene was an internationally recognized expert in engineering geology. He worked on hundreds of major projects in more than 50 countries, largely in the fields of dam and underground construction. Those who sought his expertise included the U.S. Department of State, Defense Intelligence Agency, World Bank, United Nations, the U.S. Corps of Engineers, Federal Energy Regulatory Commission, Royal Irrigation Department of Thailand, Greek Ministry of Public Works, Swaziland Electric Board, and many worldwide engineering firms, U.S. earthworks construction contractors, and attorneys practicing in the construction contracts field.

Gene was a member of the National Academy of Engineering, the U.S. National Committee on Tunneling Technology, the Geotechnical Board of the National Research Council, was an honorary Member of the Association of Engineering Geologists, President of the American Consulting Engineers Council, a Fellow of the American Society of Foundation Engineers, and Life Member of the American Society of Civil Engineers.

In the early 1970s he worked on two reports, and in the 1980s led the preparation of a third report for the National Research Council, which served to change the course of underground construction in the U.S. These reports, *Better Contracting for Underground Construction, Better Management of Major Underground Construction Projects,* and *Geotechnical Site Investigations for Underground Projects*, are foundations for many of the concepts discussed in this document.

This dedication should end as it began, by emphasizing Gene's humanity. He had integrity, intelligence, humility, humor, and self-confidence. His greatest asset was that he loved people, and always made the effort to connect with them whether they were laborers with a third grade education or the Royal Family of Thailand. All were treated with respect and dignity. The heavy and underground construction industry will miss Gene's professional insight and dedication to his industry and his country, as well as his good will.

Acknowledgments

This document is the product of many practitioners' contributions over a period of more than 16 years. The first edition evolved from a number of contributors over a period of three years. The second edition was prepared by a working group who offered revisions, updates, and new text to reflect updates and lessons learned. The principal author of this document is Randall J. Essex, Chairman of the Technical Committee for Geotechnical Reports, Underground Technology Research Council.

The following individuals comprised the Technical Committee assembled in 2006 who contributed to this second edition:

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Text for the first edition was adapted from position papers presented during an industry forum held in 1996. The papers were prepared by panels chaired by the following individuals:

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EXECUTIVE SUMMARY

Background

Since the 1970s several forms of interpretive geotechnical reports have been incorporated into the Contract Documents for underground construction projects. Sixteen years ago a number of practitioners felt the need to re-examine the role of this type of report and its benefit in contracting. Poorly written and ambiguous interpretive geotechnical reports, and inconsistencies between the interpretive report and other Contract Documents, were doing more harm than good in the effort to avoid and resolve construction disputes.

The first edition of this document was published in 1997 based on feedback obtained from three industry forums conducted between 1993 and 1996. In 2004, as additional experience was gained using Geotechnical Baseline Reports, and their application expanded into other types of subsurface construction and design-build construction, the need for a second edition became apparent. This second edition is based on feedback obtained during industry forums in 2004 and 2006.

This guideline is intended to serve as a reference for preparers and users of GBRs, and to inform Owners of the importance of the contents of the GBR in the allocation of financial risk. This guideline focuses on subsurface projects involving tunnels and shafts, but also expands the applicability of GBRs to deep foundations, open-cut pipelines, braced and tied-back excavations, and highways.

Though the information contained in this document represents a consensus opinion within the industry on a range of issues, the opinions of practitioners vary on a number of topics. The suggestions provided in this document are therefore intended as guidelines, and should not be interpreted as rules, requirements, or standards of care.

Recommendations

It is recommended that a single interpretive report be included in the Contract Documents and be called a ***Geotechnical Baseline Report (GBR).*** The primary purpose of the GBR is to establish a single source document where contractual statements describe the geotechnical conditions anticipated (or to be assumed) to be encountered during underground and subsurface construction. The contractual statement(s) are referred to as baselines. Risks associated with conditions consistent with or less adverse than the baselines are allocated to the Contractor, and those materially more adverse than the baselines are accepted by the Owner. Other important objectives of the GBR are to discuss the geotechnical and site conditions related to the anticipated means and methods of constructing the underground elements of the project.

The factual information gathered during the project investigations should be summarized in a Geotechnical Data Report (GDR). The GDR should be included as a Contract

Document, however the GBR should be clearly indicated as taking precedence over the GDR within the Contract Documents hierarchy.

Other interpretive reports may be prepared by the design team, addressing a broad range of design issues for the team's internal consideration. Such reports should be referred to as Geotechnical Design Memoranda, and should be clearly differentiated from the GBR. The GBR should be the only interpretive report prepared for use in bidding and constructing the project. Preparation of other interpretive reports in the course of the final design, such as a Geotechnical Interpretive Report (GIR), is superfluous, a potential source of confusion and conflict, and is strongly discouraged.

A Differing Site Conditions (DSC) clause is almost always included as a standard in the general conditions or general provisions of a contract that will involve subsurface construction. Continuation of this practice is strongly recommended. The DSC clause relieves the Contractor of assuming the risk of encountering conditions differing materially from those indicated or ordinarily encountered, and provides a remedy under the construction contract so that the matter can be handled as an item of contract administration. Clear, precise, and quantifiable baselines enhance the benefits and use of the DSC clause.

Baseline statements in the GBR should be interpretations expressed as contractual representations of anticipated subsurface conditions. The baselines should be meaningful, reasonable and realistic, and to the maximum extent possible should be consistent with available factual information contained in the GDR. However, if factual data is not available, or is considered to be misleading and not representative of field conditions, baselines may be based on other information (e.g., previous tunneling experience in similar geology) and engineering judgment, provided the reasoning is clearly explained. If baselines are extreme and unrealistic, the "law of unintended consequences" is likely to prevail, and the practical value of the GBR is otherwise frustrated.

Owners usually retain design consultants (civil and geotechnical engineers, geologists, and hydrogeologists/hydrologists) who are familiar with the local geology, have design and construction experience with similar projects, or both. The Owner should ensure that these individuals are intimately involved, in a collaborative manner, with the preparation and review of the GBR.

Owners should participate in and contribute to the setting of the baselines and should understand the consequences of the levels at which the baselines are set. The Owner may decide to allocate certain risks and costs of potential differing site conditions to the Contractor through the use of more adverse baselines. This will usually result in an increased bid price. Alternatively, the Owner may choose to share the risks and costs through less adverse baselines and utilization of either alternative payment provisions or a change order process, if the more adverse conditions materialize. In this instance, such an Owner may enjoy a lower bid price but in either case, the costs associated with handling the site conditions are the Owner's responsibility. The difference is that in the latter case, the Owner will accrue certain financial benefits if the adverse conditions are not realized.

This is true whether the project utilizes a traditional design-bid-build or design-build procurement approach.

For design-bid-build procurement, GBR preparation should begin only after the design has been advanced to a certain level of completion (usually the 50 or 60 percent level as a minimum). GBR preparation should be a collaborative effort among representatives of the design team, including the project geotechnical consultant and the project Owner.

For design-build procurement, including public-private partnerships, a modified three-step approach to GBR preparation is recommended where the Owner's design team prepares an initial document (Step 1) that provides a common basis for bidders. Each design-build team then supplements the report with their design-based considerations (Step 2). Only upon the Owner's review, clarification, and interaction with a preferred design-build team (Step 3) is the final GBR version vetted and ratified.

The document presented herein contains recommended guidelines for what should and should not be included in the GBR, provides a checklist of items to consider, provides recommendations for the content and wording of baseline statements that will improve their clarity, understanding and usefulness, and presents examples of problematic and improved practice in stating baselines. This document also discusses the importance and benefit of ensuring compatibility between the GBR and other elements of the Contract Documents.

Focus of Second Edition

This second edition provides new perspectives in the following areas:

- applications in addition to tunnel and shaft construction, such as deep foundations, open cut pipelines, braced and tied-back excavations, and highways; and
- application of GBRs to design-build procurement.

Perhaps most importantly, this second edition contains a chapter that summarizes lessons learned from the experiences of Owners, Contractors, designers, consultants, and dispute adjudicators through application of the initial guidelines document between 1997 and 2006. The application of GBRs, along with other contracting practices that have similarly evolved, can be improved upon if the industry captures the experiences of practitioners and presents them in guideline documents such as this one. The industry's challenge is to appreciate those lessons, and take them to heart when scoping, writing, reviewing, and interpreting GBRs on subsequent projects.

1.0 INTRODUCTION

1.1 The Need for Review

The underground construction industry in North America has made significant advances in the development and implementation of methods to avoid and resolve disputes during construction. This evolved in the wake of years of disruptive and antagonistic project disputes, and ensuing time consuming and costly litigation. In the early years, problems developed with the interpretive geotechnical report that was often included as a Contract Document. Some felt the need to re-examine its role and benefit in the contracting process. Others felt that poorly written, overly general, and ambiguous interpretive geotechnical reports, and inconsistencies between interpretive reports and other Contract Documents, were doing more harm than good.

The Technical Committee on Geotechnical Reports of the Underground Technology Research Council (UTRC) obtained feedback from the industry on the subject of interpretive geotechnical reports. The first edition of this publication in 1997 was based on input obtained from more than 150 individuals in the industry in three forums held between 1993 and 1996. The focus of the first edition reflected industry consensus that while interpretive geotechnical reports play a significant role in avoiding and resolving disputes in underground construction, their content, presentation of baselines, and consistency with other contract documents could be improved substantially.

This second edition incorporates additional perspectives and lessons learned from two industry forums held in 2004 and 2006. The final manuscript was reviewed by the UTRC Technical Committee on Geotechnical Reports which is jointly sponsored by the American Society of Civil Engineers (ASCE) and the Society of Mining Engineers, by representatives from the Geotechnical Institute of ASCE, and by the Executive Committees of the UTRC and the Construction Institute of ASCE.

The information contained in this document represents a consensus of opinion among many practitioners who have written, applied, and interpreted GBRs on significant underground construction projects over the last 20 years. Nevertheless, the workshops made clear that different opinions remain on a number of topics. The suggestions in this document should therefore be considered as guidelines and not interpreted as rules, requirements, or as defining a standard of care or code of practice.

1.2 The Geotechnical Baseline Report

For many years geotechnical data gathered during the design phase were made available to bidders, but the Contract Documents typically disclaimed any responsibility for the risk of interpreting the data. The bidders had neither the time nor the guaranteed return on investment to undertake such costly investigations and thus were forced to rely on their own interpretations of the available data. In such circumstances, bidders occasionally failed to recognize a likely problem whose identification required a substantial degree of geotechnical experience. Furthermore, in a highly competitive bidding environment, low bidders would frequently make overly optimistic interpretations of the data, arguing that they were entitled to their interpretation if reasonable/plausible. Significant claims for additional compensation were submitted when actual conditions more adverse than the bidders' interpretations were encountered.

Eventually, many Owners recognized the need to present the designer's interpretations as part of the Contract Documents. Various names were given to this report through the years. For reasons explained in Chapter 5 of this document, it is recommended that this report be called a ***Geotechnical Baseline Report (GBR).***

Projects involving subsurface excavation present many risks, all of which must be assumed by either the Owner or the Contractor. The greatest risks are associated with the materials encountered and their behavior during excavation and installation of support. The main purpose of the GBR is to clearly define and allocate these risks between the contracting parties.

The GBR establishes a contractual understanding (interpretation) of the subsurface site conditions, referred to as baselines. Risks associated with conditions consistent with or less adverse than the baselines are allocated to the Contractor, and those significantly more adverse than the baselines are accepted by the Owner. The latter conclusion derives from the philosophy that the Owner owns the ground, as well as any obstructions in the ground. If conditions are determined to be more adverse than portrayed in the baselines, the Owner pays any additional cost of overcoming those conditions.

The manner in which a GBR is developed and presented will be different for projects procured under traditional Design-Bid-Build and Design-Build (DB) procurement. Under traditional project procurement, the GBR is used by:

- the entity preparing the technical specifications in cases when means and methods of construction are specified;

- the design team, as a basis for preparing a construction cost estimate, including contingencies, for the Owner's budgeting purposes;

- the bidders, for contractual statements of anticipated subsurface conditions and geotechnical risks allocated to the Contractor;

- the Contractor for the selection of construction means, methods and equipment;

- the Contractor and the Owner during construction, for comparing encountered subsurface conditions with the contractual baseline interpretation as the basis for identifying differing site conditions; and

- dispute adjudicators for resolution of disputes related to encountered conditions that are asserted to be more adverse than those indicated in the GBR.

With DB project procurement, GBR development may be modified as discussed in Chapter 8. However, the resulting GBR is used in the same manner as indicated above.

1.3 Purpose of the GBR

The principal purpose of the GBR is to set clear realistic baselines for conditions anticipated to be encountered during subsurface construction, and thereby provide all bidders with a single contractual interpretation that can be relied upon in preparing their bids. Other key objectives of the GBR include:

- presentation of the geotechnical and construction considerations that formed the basis of design for the subsurface components and for specific requirements that may be included in the specifications;

- enhancement of the Contractor's understanding of the key project constraints, and important requirements in the contract plans and specifications that need to be identified and addressed during bid preparation and construction;

- assistance to the Contractor or DB team in evaluating the requirements for excavating and supporting the ground; and

- guidance to the Owner in administering the contract and monitoring performance during construction.

The GBR is more than a collection of baselines. This report is the primary contractual interpretation of subsurface conditions and the report should discuss these conditions in enough detail to accurately communicate these conditions to the bidders. As noted in subsequent chapters herein, the discussions should explain the rationale for the baselines.

The GBR allocates risks depending upon how the baselines are defined. It is also a risk management tool, because it can address the resolution of circumstances beyond the baselines.

1.4 Purpose and Scope of This Document

This document is intended to serve as a guide for preparers and users of GBRs, and to inform Owners of the importance of the contents of the GBR in the allocation of financial risk. Benefits of implementing these guidelines should result in:

- Owners selecting consultants to prepare and review GBRs on the basis of demonstrated qualifications and experience in the preparation and review of such documents;

- Designers preparing more precise, clear, and quantifiable baselines;
- GBRs becoming more standard and consistent with respect to content;
- Owners having a better understanding of how the financial risks for subsurface conditions have been allocated and how they can manage their risk in a proactive manner;
- bidders having a better basis for assessing their risks and pricing the work;
- fewer disagreements among the Contractor, Owner, and Designer regarding the anticipated surface and subsurface conditions; and
- clearly defined bases for Dispute Adjudicators to determine if an asserted differing site condition has, in fact, been encountered.

Guidelines provided in this document address:

- types of information to be included in a GBR;
- types of information that should not be included in a GBR, but are more appropriately addressed elsewhere in the Contract Documents or in design-phase memoranda;
- how the GBR should be coordinated with other Contract Documents;
- wording suggestions in preparing baseline statements;
- how GBRs can be applied to a range of projects involving subsurface excavation;
- how GBRs can be developed and implemented for DB procurement; and
- key roles and responsibilities in the preparation and application of GBRs.

This Second Edition includes three new chapters:

- Chapter 7 on the application of GBRs to projects other than tunnel and shaft construction, such as deep foundations, pipelines, braced or tied-back excavations, and highway earthworks;
- Chapter 8 on the application of GBRs to DB procurement; and
- Chapter 11 that discusses lessons learned through application of the initial guidelines document between 1997 and 2006.

2.0 BACKGROUND

2.1 Improved Contracting Practices

In 1972, the Washington Metropolitan Area Transit Authority recognized the importance of describing the subsurface conditions that bidders should anticipate when preparing their bids for tunnel contracts on the Washington, D.C. Metro. It was decided to address these conditions in a separate report made a part of the Contract Documents.

During this same period, important reference documents were being developed within the construction industry to address the rising costs of underground construction, and ways to reverse the trends. The first of these reports was published in 1974 by the U. S. National Committee on Tunneling Technology (USNCTT), within the National Research Council. The report, entitled *Better Contracting for Underground Construction,* had a profound, positive influence on the tunneling industry. This document identified the fundamental need to improve the overall approach to contracting for underground construction projects, with statements such as the following:

> "...if all bidders can base their estimates on a well defined set of site conditions with assurance that equitable reimbursement will be made when changed conditions are encountered, the Owner will receive the lowest reasonable bids with a minimum of contingency for unknowns."

In the 1970s and 1980s, the old way of resolving claims in court continued to flourish, and more tunneling practitioners began to recognize the need to change their ways. In 1984, the USNCTT published a two-volume report entitled *Geotechnical Site Investigations for Underground Projects.* The report, which based its conclusions and recommendations on the partial review of 200 heavy construction projects, and a thorough review of 87 of those projects, made two fundamental contributions to the industry. First, the report demonstrated that the greater the investment in exploring, clearly communicating, and disclosing the subsurface conditions, the lower the final cost of the project. Second, the report presented a recommended outline for interpretive geotechnical reports and a checklist of items to be addressed.

In 1989, the UTRC's Technical Committee on Better Contracting Practices published a booklet entitled *Avoiding and Resolving Disputes in Underground Construction.* An updated edition was published in 1991, entitled *Avoiding and Resolving Disputes During Construction.* Both editions contained a section that discussed the objectives and contents of interpretive geotechnical reports.

2.2 Contractual Geotechnical Reports

The approach to the preparation of contractual geotechnical reports for underground construction evolved over the past 30 years. Historically, some practitioners prepared only one report, essentially a Geotechnical Data Report (GDR), which presented only factual information such as boring logs and the findings from field and laboratory tests. Interpretations and predictions as to the behavior of the indicated subsurface materials during construction were left to the bidders. Other practitioners included their interpretations in the Contract Documents, either in a report separate from the GDR, or combined with the data in a single document.

Interpretations are needed for design and for construction. At the earliest stages of the design process, geotechnical information must be reviewed to identify subsurface conditions warranting special design considerations, and to evaluate construction methods most suitable to the anticipated conditions. Because some of the options considered might be discarded later during the design, it is necessary to distinguish between interpretations addressed by the design team during the design process, and interpretations that relate specifically to the design and construction methods addressed in the Contract Documents.

A further source of variability relates to the manner and degree in which these various geotechnical reports are presented in the Contract Documents. Contract Documents are intended to define and control the construction of the work. Documents provided for information only are subsidiary to the Contract Documents, but are intended to serve as background information relevant to the project. Generally the provision of documents "for information only" has been driven by the need to make a full disclosure of all related geotechnical information, and to avoid the appearance of withholding this information from prospective bidders.

The purpose of including an interpretive geotechnical report in the Contract Documents has changed somewhat through the years. Initially, the objective was to assist Contractors in developing their own interpretations of the factual information, rather than only providing them the "facts". In providing this interpretation, it was considered appropriate to frame these interpretations within the context of the design and the designer's intent. The term *Geotechnical Design Summary Report*, as described in previous guideline documents, was intended to set forth the designer's interpretations of the anticipated subsurface conditions, and their impact on design and construction. Occasionally, when explaining the basis for design, practitioners described the uncertainties involved, and used generalized terms in their discussion that may have been geologically correct, but were ambiguous when considered as a "baseline". This ambiguity in turn led to disputes.

The critical issue is how the Contractor addresses the anticipated conditions. The GBR should have <u>construction</u> issues as its main focus; the basis for design, which may be addressed, should be secondary. This establishes a clear focus for why the report is prepared, how it is to be used, and how it should be written.

In the 1990s, it was suggested that the interpretive geotechnical report to be included in the Contract Documents be called a Geotechnical Baseline Report. In 1997, as follow-on to the 1991 publication, the UTRC's Technical Committee on Geotechnical Reports published the booklet entitled *Geotechnical Baseline Reports for Underground Construction,* setting out guidelines and practices for the preparation of such reports.

2.3 Shortcomings of Previous Practice

Contractual geotechnical interpretive reports that were used before the advent of GBRs had a number of shortcomings. Some of these shortcomings persist today:

- baselines, if provided, have not adequately described the conditions to be expected;
- descriptions of anticipated conditions have often been overly broad, ambiguous or qualitative, resulting in disputes over what is indicated in the Contract;
- descriptions of assumed conditions and behaviors have been much more adverse than indicated by the data, or have appeared arbitrary and unrealistic, without adequate explanation or justification for such conservatism;
- discussions have been either unnecessarily repeated or in direct conflict with information contained on the drawings, in the specifications, or other provisions of the Contract; and
- the effects of means and methods of construction excavation and support on ground behavior have not been well described.

This publication provides guidelines intended to improve the clarity of content within the GBR, and to improve the consistency between the baseline document and the other Contract Documents.

Other shortcomings had to do with two fundamental considerations on the part of some Owners who were concerned by the number and dollar value of claims by Contractors for differing site conditions, despite the existence of baseline statements in the Contract. First, these Owners often feel that the authors of the GBR should have "gotten it right at the beginning so that we are not stuck with this nasty surprise", i.e., they misunderstand the relationship of the level of risk they are, or are not, taking and the level of conservatism reflected in the baseline statements. Second, they may not understand that the level of reliability and accuracy of baseline statements is closely related to the thoroughness of the geotechnical investigations, which in turn is dependent on the time and cost the Owner is willing to invest. These sentiments led to the conclusion that additional effort is required to educate Owners about the role of baseline statements in identifying and allocating risk between the parties.

The Owner must recognize that the contractual baselines represent one interpretation of the subsurface conditions, as developed from the available information. More than one interpretation of subsurface conditions may be reasonable based on the information available during preparation of the Contract Documents. Additional investigations, involving additional time and money during the design phase, may be required to improve the level of certainty of the baseline interpretations.

3.0 GEOTECHNICAL REPORTS

3.1 Geotechnical Data Report (GDR)

The GDR is a document developed by the Designer and/or the Designer's geotechnical engineer, which contains the factual information that has been gathered during the exploration and design phases of the Project.

The GDR should contain the following information:

- a description of the geologic setting;
- a description/discussion of the site exploration program;
- the logs of all borings, trenches, and other site investigations;
- a description/discussion of all field and laboratory test programs; and
- the results of all field and laboratory testing.

The GDR must be included as a Contract Document. The GBR, in the event of conflict or ambiguity, must be given precedence over the GDR within the Contract Document hierarchy.

In the event that the GBR is silent on a particular circumstance, the GDR should be reviewed to see if there is any data/information relevant to the issue in question. This is discussed further in Chapter 11.

3.2 Geotechnical Memoranda for Design

The project design may be carried out by a multi-firm team. An interpretation of the available geologic data is often needed within the design team well in advance of the preparation of a GBR.

Following completion of site exploration activities and preparation of a draft GDR, the geotechnical firm (or designer, if the same firm) may prepare a draft memorandum for design that addresses a broad range of issues for the project team's internal consideration. The interpretive report for design may be used to:

- comment on and discuss the data;
- present one or more initial interpretations of the data;
- evaluate the limitations of the data and discuss additional data needs;
- present an evaluation of how the subsurface conditions would affect alternative approaches to project design and construction;
- evaluate project risks as a function of alternative construction approaches;

- assess any construction impacts on adjacent facilities; and
- provide geotechnical design criteria for both permanent and temporary subsurface structures.

The discussions may appropriately address broad ranges of anticipated conditions to indicate the level of certainty (or uncertainty) in these judgments. Such discussions are not appropriate as baselines. The report may discuss design and construction alternatives that are subsequently judged of unacceptably high risk to the Owner (or third parties), and are thus eliminated from further consideration and not addressed in the GBR. Because of the differences between this preliminary interpretive report and the GBR, it is recommended that a title be given to the report (or reports) that clearly portrays its intent and timing within the design process, e.g., "Draft Geotechnical Memorandum", or "Draft Geotechnical Memorandum for Design". Although the document must be disclosed to bidders as available information, it should not be a part of the Contract Documents. The report should include specific introductory statements that it is a preliminary document not to be used for construction purposes and that interpretations and discussions presented therein will be superseded by subsequent interpretations and baselines in the GBR.

Depending on the design approach and the number of design iterations that occur during the design process, multiple geotechnical memoranda, or amended or revised versions of the memoranda, may be produced. However, the GBR should be the only interpretive report that is included in the Contract Documents. Preparation of another interpretive report by the geotechnical consultant or design team in the course of the final design, such as a Geotechnical Interpretive Report (GIR), is superfluous, a potential source of confusion and conflict, and is strongly discouraged.

3.3 Geotechnical Baseline Report

The GBR should be the sole geotechnical interpretive document upon which the Contractor may rely. The GBR should be limited to interpretive discussion and baseline statements, and should make reference to, rather than repeat or paraphrase, information contained in the GDR, drawings, or specifications. Chapters 5 and 6 contain further discussion of the suggested content and format of GBRs.

4.0 DIFFERING SITE CONDITIONS CLAUSE

4.1 Historical Development

A primary purpose for the baseline statements in the GBR is to assist in the administration of the Differing Site Conditions (DSC) clause. In order to appreciate the role that the GBR serves in this regard, it is helpful to review the history of the clause. The first standardized "changed conditions" clause was developed by an Interdepartmental Board of Contracts and Adjustments on November 22, 1921 by the U.S. Bureau of the Budget. The purpose of this clause was to provide a contractual basis for relief to the Contractor for encountered site conditions that were more adverse than those indicated in the construction contract. This clause was included in a standard form of general conditions for construction contracts that was issued on August 20, 1926, and was subsequently approved by the President of the United States for use by the federal government (Mathews, 1985). To this day, Federal Regulations mandate its use in U.S. Government contracts.

The federal clause (reproduced in Section 4.2 below), or a similar provision, has been incorporated into the standard contract documents sponsored by a number of professional and public organizations, including:

- the American Institute of Architects;
- the Engineers Joint Contract Documents Committee (American Consulting Engineers Council, American Society of Civil Engineers, National Society of Professional Engineers);
- the American Society of Civil Engineers, in collaboration with the Associated General Contractors of America;
- the American Association of State Highway and Transportation Officials; and
- numerous state and local governments.

Over its 80-year history, the wording of the clause has undergone minor refinement, but the underlying principle has remained. In 1968, for example, the term "Changed Conditions" was changed to "Differing Site Conditions".

The DSC clause was developed to take at least some of the gamble on subsurface conditions out of the bidding process, and thereby reduce the bid prices. Without relief under the DSC clause, the Owner would assign all risk to the Contractor, and would thus pay all of the Contractor's contingency costs for adverse conditions, whether the adverse conditions were encountered or not. The DSC clause was developed to avoid these unnecessary costs and remove part of the risk from the Contractor.

Despite the early institution of the DSC clause, arguments continued to develop as to the conditions indicated in the Contract. Contracts typically included disclaimers that bidders should not rely on boring logs and other information obtained during the design, and encouraged Contractors to make their own subsurface investigations during the bidding phase of the project. The favorite expression among Owners and engineers was: "You bid it - you build it." Contractors responded by pursuing, and often winning, construction claims, despite the existence of the disclaimers and exculpatory clauses. Judges and juries believed that if geotechnical information were made available to bidders, they had the right to rely on this information, even when the information was disclaimed and not included in the Contract Documents. Driven by increasingly frequent litigation and escalating costs for construction, the heavy construction industry was motivated to change its approach to disputes resolution, and to provide tools to supplement the DSC clause.

4.2 Standard Clause

A DSC clause is nearly always included as a standard clause in the general conditions or general provisions of a contract that will involve subsurface construction. The Federal clause is typical. Articles (a) and (b) of the Federal clause are presented below:

DIFFERING SITE CONDITIONS (APRIL 1984)

> *(a) The Contractor shall promptly, and before such conditions are disturbed, give a written notice to the Contracting Officer of (1) subsurface or latent physical conditions at the site which differ materially from those indicated in this contract, or (2) unknown physical conditions at the site, of an unusual nature, which differ materially from those ordinarily encountered and generally recognized as inhering in work of the character provided for in the contract.*
>
> *(b)The Contracting Officer shall investigate the site conditions promptly after receiving the notice. If the conditions do materially so differ and cause an increase or decrease in the Contractor's cost of, or time required for, performing any part of the work under this contract, whether or not changed as a result of the conditions, an equitable adjustment shall be made under this clause and the contract modified in writing accordingly.*

The function of the DSC clause is twofold. First, it relieves the Contractor of assuming the risk of encountering conditions differing materially (i.e., in a significant, meaningful way) from those indicated or ordinarily encountered. Second, it provides a remedy under the construction contract, to handle the matter as an item of contract administration.

The ease of administering the DSC clause during construction depends on how well the anticipated conditions are defined. There can be more than one plausible interpretation of the subsurface data collected from the investigations. The GBR presents one such set of interpretations as the anticipated conditions under the Contract. The more clearly defined those anticipated conditions, the more easily the encountered conditions can be evaluated as being materially different or not. Clear, precise baselines enhance the benefits and use of the DSC clause, because they provide a more straightforward basis for its administration.

4.3 Modifications to the Standard Clause

Over the years, an impressive body of case law has emerged with respect to the application and interpretation of the Federal DSC clause. The Federal Clause has been modified in some jurisdictions. The authors of the GBR should understand the contractual significance of such modifications, and adjust the wording in the GBR accordingly.

Some Owners and engineers have expressed that the Owner should be entitled to a credit from the Contractor if the subsurface conditions encountered are less adverse that indicated by baselines. As the Federal DSC clause is written, only the Contractor can initiate a claim under the clause. However, once the Contractor brings forward a claim under the DSC clause, the Owner could possibly find a basis for a lowering of the Contract Price. Some believe that the standard clause should be modified to permit the Owner to initiate a claim for a credit under the clause. For the following reasons, this is not recommended.

As discussed throughout this document, the concept of a GBR is to establish baselines for contractual purposes during the performance of the construction contract. The bidders are not mandated to base their bids on the baselines stated. To the contrary, bidders may bid consistent with the baselines or less adverse than the baselines in an effort to win the work. If Contractors believe that the actual conditions will be more favorable than stated in the baselines and wish to be as competitive as possible, they may choose to accept the risk of being mistaken and bid below the stated baselines. The economic benefit of a Contractor's decision to bid below the baselines is conveyed to the Owner in a lower bid, thereby already reflecting the economic consequences of better conditions in their bid.

If the Contract Documents included a DSC clause that entitled the Owner to a downward adjustment in the contract price for encountered conditions less adverse than indicated by the baselines, bidding Contractors would have no incentive to bid below the baseline. To do so would expose them to the risk of a downward adjustment when they have already reflected such an adjustment in their bid. The lack of incentive for Contractors to bid as competitively as possible would tend to increase the bid prices, and at the very least, lead to debates as to what the Contractor did or did not assume in his bid. The use of a deductive DSC clause is not recommended.

5.0 THE CONCEPT OF A BASELINE

5.1 Baselines

The planning, design, and construction of underground projects must cope with uncertain subsurface conditions. "Mother Nature" did not create subsurface conditions in accordance with a materials properties handbook, nor do geologists or geotechnical engineers (or any other participants in the process) have magical predictive powers. The design and construction process must account for the variability of subsurface conditions, and for potential project costs associated with that variability. To establish realistic contractual baselines (not necessarily based on the most optimistic of reasonable interpretations), and have provisions to address conditions more adverse than those baseline conditions, is a reasonable and effective approach to risk allocation and acceptance.

The cost of constructing the project along a predetermined, linear path or within a limited area represents the greatest single risk associated with underground projects. The path may be optimized to a degree, but it will more often be constrained by functional, right-of-way, environmental, and constructability considerations. The geotechnical challenges presented to the design team are two-fold. One challenge is to understand the range of possible ground and groundwater conditions at the site, so that the design and the contract provisions account for those conditions. The other challenge is to realistically describe the anticipated conditions so that the financial risks of coping with them are clearly allocated between the Owner and the Contractor.

The first challenge has room for uncertainty and generality. So long as the facility can be constructed and operated under the most adverse range of conditions anticipated, it will fulfill its intended long-term function. In many cases, the variability of the subsurface conditions may have little to do with the feasibility of constructing the facility (e.g., the strength of rock formations to be bored by a tunnel boring machine), but usually will influence the cost and schedule. However, the second challenge has no room for uncertainty or generality. The less clearly the anticipated geotechnical conditions are described in the form of baseline statements, the more likely the potential for misunderstandings during construction, for disputes, and for increases in cost.

The goal of baselines is to translate the results of geotechnical investigations and previous experience into clear descriptions of anticipated subsurface conditions upon which bidders may rely. The baselines also provide the Owner with the opportunity to allocate risks associated with these conditions. Items to be addressed in baselines include:

- the estimated amounts and distribution of different materials on the project;
- description, strength, permeability, grain size, and mineralogy of the various intact materials;
- description, strength, and permeability of the ground mass as a whole;

- quality of rock mass and characteristics of discontinuities, including roughness, infilling materials and alteration;
- groundwater levels and groundwater conditions anticipated, including items such as inflows, estimated pumping volumes and rates, and anticipated groundwater chemistry;
- the anticipated behavior of the ground, and the impact of groundwater, with regard to applicable methods of excavation and installation of ground support;
- construction impacts on adjacent facilities;
- potential or known faults, shears, fault zones, and shear zones; and
- other geotechnical and known man-made sources of potential difficulty or hazard that could impact the construction process, such as boulders, abandoned piles, buried utilities, buried debris and other obstructions, high or low top of bedrock, mixed face conditions, geologic contacts, gas, and contaminated ground and groundwater.

To the maximum extent possible, baseline statements are best described using quantitative terms that can be measured and verified during construction. The importance of this point cannot be overstated. Qualitative descriptions, if required, should be clearly defined using generally accepted industry definitions such as those published by the American Society for Testing and Materials (ASTM), International Society for Rock Mechanics (ISRM), American Society of Civil Engineers (ASCE), and other recognized standards.

However, some baseline issues may be qualitative, and not definable in quantitative, measurable terms. For example, an appropriate baseline statement might be:

> "Even though the P2 sand has high SPT *N* values, when exposed in an open face below the groundwater table, it will tend to exhibit unstable, flowing ground behavior unless positive measures are taken to prevent the flowing behavior from developing."

In other instances, baselines may be appropriately stated in qualitative terms, but may not be reliably measured during construction. For example, the occurrence of boulders might be described in terms of the number of boulders in different size ranges, as a percentage of the excavated volume, or as a certain number of boulders of an assumed excavation dimension. Shaft excavation might facilitate the detection and counting of encountered boulders. But in a TBM-mined tunnel, some boulders might be broken up during the mining process, and not actually measurable during construction. In such cases the Contractor and Owner may need to jointly agree on a procedure for monitoring boulders encountered.

By establishing clear baselines as a part of the Contract Documents, the parties are more likely to agree on the conditions indicated in the Contract, without time consuming and costly arguments (or litigation) that become counter-productive to a successful project.

The DSC clause provides a mechanism for the Contractor to seek additional compensation due to conditions materially different from those indicated in the Contract. In the question: "Different from what?" the baseline statements define the "what". The more definitive and verifiable the baselines, the easier it should be for the contracting parties to determine the existence of a differing site condition.

As discussed in Chapter 4, Contractors may base their bids on performing the work at a level of difficulty equal to or less adverse than indicated by the baselines. If a Contractor bids below (less adverse than) a baseline for whatever reason, it carries the additional risk associated with that decision. The Contractor has no legitimate basis for a claim if those less adverse conditions are not actually experienced, regardless of whether its assumptions are documented in their bid.

5.2 Contractual Assumptions

Baseline statements in the GBR are assumptions expressed as contractual representations of anticipated geotechnical conditions. A well-written baseline resolves, at least contractually, the uncertainty that may exist in the data or may even extrapolate beyond the range of the data. While the baseline should be realistic and have a rational basis, a reasonable baseline does not have to be based solely upon specific project subsurface information.

The following examples illustrate this point:

- The number of boulders to be encountered may have little to do with how many boulders were identified during the drilling, because the drilling of small diameter holes is not an effective means to detect the presence of boulders. If the designer and Owner consider the risk of encountering boulders to be high, to the extent that it could impact the type of equipment to be used or the manner in which that equipment is outfitted or utilized, the baseline may indicate a greater number of boulders to be encountered than suggested by the borings.

- The potential for slaking behavior of a weak rock may not be based on laboratory test results, but on experiences of nearby projects previously mined within similar geologic formations, and using similar excavation equipment.

- There might be wide scatter in the results of certain rock strength tests; this variability may be related to the quality of the rock samples tested, the manner in which the rock samples were tested; and the availability of a sufficient number of representative rock samples tested. In any case, if it is suspected that the suite of test results might not be representative of the conditions to be encountered, the description of that material's strength in the baseline will probably differ from what could be derived from the data alone.

It is important to provide clear baseline statements. It is also important to describe or present the possible range of property values or material behaviors, for general understanding. The recommended approach is to indicate the expected range of conditions and uncertainty, but then state a specific baseline (upon which bidders may rely) that has been established for contractual purposes. The baseline may be expressed as a maximum value, a minimum value, an average value, a histogram distribution of values, or combinations thereof. The following example illustrates these concepts.

Assume that a tunnel project is to be constructed with a tunnel boring machine through two types of rock; one rock type is stronger and more difficult to bore than the other. The relative percentages of the two rock types along the tunnel alignment are unclear. Given the available information, a reasonable interpretation of the stronger rock to be encountered could range between 30% and 60% of the total tunnel length.

It is almost a certainty that the design team would not correctly predict the actual percentage of stronger rock to be encountered along the tunnel alignment. The recommended approach would be to state the possible range of percentage of stronger rock to be encountered (i.e., 30% to 60%), and then state a realistic percentage to be assumed as the baseline. In this example, that baseline might be set at 45% of the tunnel length. By establishing a clear baseline, the Contractor and Owner both understand the risks to be borne by each; the baseline percentage establishes the amount of stronger rock up to which the Contractor is financially responsible, and beyond which the Owner is financially responsible. The range provides bidders with an informed opinion, so that they may appreciate the level of risk they will take if they base their bid on a set of assumptions less adverse than the baseline (i.e., less than 45% of the tunnel being stronger rock).

If the baseline quantity of stronger rock to be encountered is established at 45%, and the Contractor encounters 50%, and the additional 5% has a quantifiable impact to the extent additional costs were incurred, the Contractor is entitled to additional compensation for the additional 5% strong rock encountered, even though the 50% encountered falls within the range indicated by the data. However, if the baseline is established at 45%, the Contractor bases his bid on 35%, and actually encounters 40% strong rock, there is no basis for a claim. This example underscores the need for a careful mapping and testing of the rock encountered in the tunnel. Effective use of the GBR baseline concept clearly depends on careful documentation of actual conditions encountered in the field during construction.

5.3 Where to Set the Baseline

The baseline can be set, for a given project and set of geotechnical data, at different levels of perceived adversity or difficulty. Where the baseline is set determines the respective levels of risk allocated to the Owner and Contractor. Consider a soft ground tunnel project where it is expected that 100 to 300 boulders could be encountered. An adverse baseline could be set at 300 boulders. The Contractor is obligated to handle 300 boulders and the risk of a differing site condition related to unforeseen boulders is reduced if not eliminated entirely. However, the Owner may pay for the expectation of encountering 300 boulders, whether 300 boulders are encountered or not.

Alternatively, a somewhat less adverse baseline could be set at only 100 boulders. Boulders encountered in excess of the first 100 would be subject to additional payment to the Contractor, through either a pre-determined bid item or a negotiated change order. In this instance, more risk is allocated to the Owner, because additional amounts will be paid if more than 100 boulders are encountered. However, the Owner will probably receive a lower bid, and will only pay an additional sum to the extent that the 100 boulder baseline is exceeded.

Thus, the Owner has an opportunity to exchange higher initial bid prices for a lower number of contract modifications during the work. Regardless of the selected approach, the cost of site conditions remains with the Owner. Risks associated with this issue are discussed further in Chapter 9.

5.4 Baseline Not a "Warranty" of Conditions to be Encountered

The baseline is a representation of what is assumed will be encountered for the purpose of defining "the indications of the Contract". Thus, the provision of a baseline in the Contract is not a warranty that the baseline conditions will, in fact, be encountered. It is therefore not appropriate for the Owner or Contractor to conclude that baseline statements are warranties. However, the baseline statements in a Contract can be considered a contractual commitment by the Owner that those baseline conditions will be applied in the administration of the DSC clause.

This understanding should be addressed in the Contract Documents.

5.5 Link with the Other Contract Documents

Baseline statements in the GBR should be consistent with the design, anticipated construction methods, and measurement and payment provisions in the drawings and specifications. Various means of establishing this consistency are discussed in Chapter 6.

All possible conditions and circumstances that may be encountered cannot and do not need to be included in baseline statements and addressed by measurement and payment provisions. For some conditions, it may be impossible to establish methods of measuring quantities against which payment provisions may be applied. Also, it may prove constructive to require the Contractor to be equipped to accommodate certain potential occurrences, but to treat the payment for such occurrences as DSCs when and if encountered. Examples include the control of groundwater inflows greater than a stated baseline quantity, the encountering, handling and disposal of unknown quantities of contaminated ground and groundwater, or the need for extraordinarily different or additional temporary support of the excavation.

In addition to the need for a close link to other Contract Documents, the GBR offers the opportunity to provide an overview of the project, so that what is contained in the other documents is easier to understand. The drawings and specifications will typically indicate the "what, where, how and when," with little or no justification or explanation. The GBR provides a platform to explain the "why"; i.e., the rationale and bases for items detailed elsewhere. By considering the GBR, all participants to the construction project are provided with an understanding of the key project issues and constraints that have shaped the design and construction requirements. With this background, they are better prepared to understand the rationale behind the requirements of the drawings and specifications, and better prepared to offer innovative ideas for improvements in the form of value engineering change proposals. In some cases, an accepted value engineering change proposal could warrant a modification to the baseline(s) in the GBR.

A careful balance must be sought between providing a document that can be readily absorbed by a bidder without the benefit of having reviewed the other Contract Documents, and paraphrasing the other Contract Documents to the degree of creating ambiguity or contradiction. The GBR should make reference to, rather than repeat or paraphrase, information contained in the GDR, drawings, or specifications.

6.0 PREPARATION OF A GEOTECHNICAL BASELINE REPORT

6.1 Organization and Content

A checklist of items to be considered when preparing a GBR is presented in Table 1. The checklist contains items that permit the GBR to be read as a stand-alone report, without the reader having to refer to discussions or descriptions contained in other Contract Documents. While the checklist in Table 1 is provided within a suggested organizational sequence, other formats may work equally well. The goal is to be clear and concise.

Table 1 covers a broad range and some of the topics will not be applicable to every project. Additionally, the sequence and grouping of topics may be altered to accommodate project requirements or personal preference. For example, a project that has particularly variable conditions across the site and a number of different project components may require the organization and presentation of the anticipated conditions, characterizations, and design and construction considerations separately for each project component. In this manner, the continuity of explaining the key geologic, design, and construction issues for each of the project components may be more effectively maintained.

One important objective in writing a GBR is to produce a concise document that can be read and understood in 2 to 3 hours. For a deep foundation or pipeline project, the GBR will only need to address a few key subsurface and construction issues, and may be as short as 5 to 10 pages in length. A maximum length of 30 pages of text is recommended for straightforward tunneling projects, and no more than 40 to 50 pages for more complicated projects. These page length recommendations can be met while still addressing the items included in Table 1. As explained in Chapter 11, experience in the use of GBRs is that too much is being included in these documents, causing the documents to be so long as to make it difficult to ferret out the baselines. Writers of GBRs are strongly cautioned to avoid overly long or complex descriptions of physical conditions or behaviors. Emphasis should be directed to those physical conditions or behaviors that will most influence the cost of construction or critical equipment to be utilized. Extended geologic descriptions and details should be limited to the Geotechnical Data Report. The writers of GBRs must meet this challenge.

6.2 Writing the GBR – Who, When, and How

The GBR must be prepared by knowledgeable personnel with considerable geotechnical, design, and construction experience relevant to the anticipated project. Owners should retain consultants or consultant teams that include individuals with experience in the local geotechnical conditions, the design and construction of similar projects, and the use of GBRs in the administration of previous construction contracts. Owners should confirm that these individuals will be intimately involved with the preparation and review of the GBR document.

Table 1 - GBR Checklist

Introduction
- project name
- project Owner
- design team (and Design Review Board, if any)
- purpose of report; organization of report
- contractual precedence relative to the GDR and other Contract Documents (refer to the General Conditions)
- project constraints and latitudes

Project Description
- project location
- project type and purpose
- summary of key project features (dimensions, lengths, cross sections, shapes, orientations, support types, lining types, required construction sequences)
- reference to specific specification sections and Drawings to avoid repeating information from other Contract Documents in GBR

Sources of Geologic and Geotechnical Information
- reference to GDR
- designated other available geologic and geotechnical reports
- include the historical precedence for earlier sources of information

Project Geologic Setting
- brief overview of geologic and groundwater setting, origin of deposits, with cross-reference to GDR text, maps, and figures
- brief overview of site exploration and testing programs - avoid unnecessary repetition of GDR text
- surface development and topographic and environmental conditions affecting project layout
- typical surficial exposures and outcrops
- geologic profile along tunnel alignment(s) showing generalized stratigraphy and rock/soil units, and with stick logs to indicate drill hole locations, depths, and orientations

Previous Construction Experience (key points only in GBR if detailed in GDR)
- nearby relevant projects
- relevant features of past projects, with focus on excavation methods, ground behavior, groundwater conditions, and ground support methods
- summary of problems during construction and how they were overcome (with qualifiers as appropriate)
- conditions and circumstances in nearby projects that may be misleading and why

Table 1 - GBR Checklist (Continued)

Ground Characterization

- physical characteristics and occurrences of each distinguishable rock or soil unit, including fill, natural soils, and bedrock; describe degree of weathering / alteration; include near-surface units for foundations/pipelines.
- groundwater conditions; depth to water table; perched water; confined aquifers and hydrostatic pressures; pH; and other key groundwater chemistry details
- soil/rock and groundwater contamination and disposal requirements
- laboratory and field test results presented in histogram (or some other suitable) format, grouped according to each pertinent distinguishable rock or soil unit; reference to tabular summaries contained in the GDR
- ranges and values for baseline purposes; explanations for why the histogram distributions (or other presentations) should be considered representative of the range of properties to be encountered, and if not, why not; rationale for selecting the baseline values and ranges
- blow count data, including correlation factors used to adjust blow counts to Standard Penetration Test (SPT) values, if applicable
- presence of boulders and other obstructions; baselines for number, frequency (i.e., random or concentrated along geologic contacts), size and strength
- bulking/swell factors and soil compaction factors
- baseline descriptions of the depths/thicknesses or various lengths or percentages of each pertinent distinguishable ground type or stratum to be encountered during excavation; properties of each ground type; cross-references to information contained in the drawings or specifications
- values of ground mass permeability, including direct and indirect measurements of permeability values, with reference to tabular summaries contained in the GDR; basis for any potential occurrence of large localized inflows not indicated by ground mass permeability values
- for TBM projects, interpretations of rock mass properties that will be relevant to boreability and cutter wear estimates for each of the distinguishable rock types, including test results that might affect their performance (avoid explicit penetration rate estimates or advance rate estimates)

Design Considerations – Tunnels and Shafts

- description of ground classification system(s) utilized for design purposes, including ground behavior nomenclature
- criteria and methodologies used for the design of ground support and ground stabilization systems, including ground loadings (or reference the drawings/specifications)
- criteria and bases for design of final linings (or reference to drawings/specifications)
- environmental performance considerations such as limitations on settlement and lowering of groundwater levels (or in specifications)

Table 1 – GBR Checklist
(Continued)

- the manner in which different support requirements have been developed for different ground types, and, if required, the protocol to be followed in the field for determination of ground support types for payment; reference to specifications for detailed descriptions ground support methods/sequences
- the rationale for ground performance instrumentation included in the drawings and specifications

Design Considerations - Other Excavations and Foundations

- criteria and methodologies used for the design of excavation support systems, including lateral earth pressure diagrams (or in drawings/specifications) and need to control deflections/deformations
- feasible excavation support systems
- minimum pile tip elevations for deep foundations
- refusal criteria for driven piles
- allowable skin friction for tiebacks
- environmental considerations such as limitations on settlement and lowering of groundwater levels (or in specifications)
- rationale for instrumentation/monitoring shown in the drawings and specifications

Construction Considerations – Tunnels and Shafts

- anticipated ground behavior in response to construction operations within each soil and rock unit
- required sequences of construction (or in drawings/specifications)
- specific anticipated construction difficulties
- rationale for requirements contained in the specifications that either constrain means and methods considered by the Contractor or prescribe specific means and methods (e.g., the required use of an EPB or slurry shield)
- the rationale for baseline estimates of groundwater inflows to be encountered during construction, with baselines for sustained inflows at the heading, flush inflows at the heading, and cumulative sustained groundwater inflows to be pumped at the portal or shaft
- the rationale behind ground improvement techniques and groundwater control methods included in the Contract
- potential sources of delay, such as groundwater inflows, shears and faults, boulders, logs, tiebacks, buried utilities, other manmade obstructions, gases, contaminated soils and groundwater, hot water, and hot rock, etc.

Construction Considerations – Other Excavations and Foundations

- anticipated ground behavior in response to required construction operations within each soil and rock unit

Table 1 – GBR Checklist (Concluded)

- rippability of rock, till, caliche, or other hard materials, and other excavation considerations including blasting requirements/limitations
- need for groundwater control and feasible groundwater control methods
- casing requirements for drilled shafts
- specific anticipated construction difficulties
- rationale for requirements contained in the specifications that either constrain means and methods considered by the Contractor or prescribe specific means and methods
- the rationale for baseline estimates of groundwater inflows to be encountered during construction, with baselines for sustained inflows to be pumped from the excavation
- the rationale behind ground improvement techniques and groundwater control methods included in the Contract
- potential sources of delay, such as groundwater inflows, shears and faults, boulders, buried utilities, manmade obstructions, gases, or contaminated soils or groundwater

For smaller projects, where experience with GBRs may not be as well established within the design and construction community, it is particularly important that someone experienced with the preparation of GBRs be retained to either guide its preparation, provide detailed review throughout its development, or both. Some have suggested a form of prequalification to ensure that owners retain professionals with suitable experience in the preparation of GBRs. For example, while having geotechnical engineers involved in GBR preparation is critical, a properly written GBR is substantially different from a more traditional geotechnical or foundations report. Writing an effective GBR represents a challenge for all subsurface projects. Experience suggests that this concern is magnified for smaller projects. Chapter 7 discusses the application of GBRs to other types of subsurface excavations such as deep foundations, open-cut pipelines, or braced or tied-back excavations. It is clear that the success of extending the GBR concept to these types of projects will hinge on the ability to have suitably qualified professionals involved in the process.

An annotated outline of the document should initially be prepared by the geotechnical and design personnel from the design team. This will help focus the report format and content to suit the key project components and construction issues. Sections of the initial draft should then be prepared by the geotechnical consultant, to ensure that interpretations of the exploration results and geotechnical conditions developed earlier in the design process are properly transferred to the GBR. Other sections should be prepared by the design team member who developed the design and prepared the plans and specifications. Close collaboration should be maintained between the geotechnical and design personnel throughout this effort.

All subsequent drafts of the GBR should be advanced jointly by the design team (designer and geotechnical) so that GBR statements are consistent with the developing design, drawings, specifications and payment items. This will facilitate consistency between what is set forth in the GBR, what is contained in the drawings and specifications, and how the Contractor is to be compensated. Advancing drafts should be jointly reviewed by the design team, the Owner, and independent reviewers.

6.3 Link with Risk Registers

Whether under traditional Design-Bid-Build or DB procurement, it is recommended that the GBR be written after most of the design or reference design has been completed. During the site exploration and design phase, Risk Registers should be utilized at earlier stages of project planning, site exploration, and design to help identify key issues. As site exploration, project planning, and detailed design are advanced, certain risks will be identified that are associated with geotechnical and other subsurface conditions. It is precisely those conditions associated with the greatest perceived risks that should be addressed specifically in the GBR. However, as discussed in Chapter 11 there is no need to include the Risk Register in the GBR.

6.4 Wording Suggestions

Baselines are difficult to write without ambiguity. No one can accurately predict the nature and distribution of materials underground and how they will react to excavation. This creates a tendency to use ambiguous words to describe ranges of physical properties and behavior of the materials. The use of words such as "may," "can," "might," "up to," "could," "should," "some", "few", "ranges from ...to...," and "would" are imprecise, and must not be used in baseline statements. Better words include "is," "will," and "are". The use of such definitive terms clearly establishes the intended baselines . As discussed in Section 5.4, the use of these definitive terms must not be taken by the Owner as a warranty by the designer that the underground materials or behaviors are precisely defined. This is the goal of a well-written GBR - to avoid contractual ambiguity.

Whenever possible, baseline statements should be in terms of measurable properties or parameters that can be objectively observed and recorded during construction. The use of adverbs should be avoided. The use of adjectives such as "large," "significant," "local", "many", and "minor" should either be quantified or avoided. If qualitative terms are used, they should be standardized and defined in a summary table or a glossary. As a simple test when writing a baseline statement, ask the question: "If I encountered a site condition pertaining to this baseline would I know if it differed from the indicated conditions?" If a reasonably straightforward affirmative answer is not given, the baseline statement is not sufficiently clear.

Baseline statements regarding anticipated ground behavior should be presented in context with the use of defined means and methods of construction. The baseline statements should make it clear that the ground can (or cannot) be expected to behave differently with the use of alternative tools, methods, sequences, and equipment. In some cases, the Owner may mandate the means and methods and the baselines need to reflect this.

The presentation of baselines regarding groundwater inflows or other phenomena to be measured during performance needs to consider the methods, timing, and responsibilities for measurement in the field. These aspects must be clearly defined and expressed in the Contract Documents.

6.5 Baseline Examples

Examples of problematic and improved baseline statements are presented in Table 2 (the problematic and improved wording are underlined for ease of understanding; baseline words would not normally be underlined in the GBR).

6.6 Consistency and Compatibility

A fundamental shortcoming expressed during the industry forums, is the incompatibility between statements in the GBR and other Contract Document elements and provisions. The GBR should be consistent with and complement the other documents. The following guidelines are useful in achieving these objectives:

- The GBR may present the rationale behind the specification requirements, but should avoid stating the requirements themselves. Detailed requirements should be stated in the specifications only.

- As each baseline statement is prepared and finalized, the technical specifications and payment provisions related to that baseline statement should be reviewed for consistency and reasonableness. For example, if rates of groundwater inflow at the heading are stated as a baseline, the specifications need to define the term "heading", and where and how groundwater inflow measurements are to be taken in the field. If a TBM is involved, these descriptions must consider the physical limitations that will control where a weir or other system for measuring flows may be implemented. Payment provisions included in the Contract for handling and disposing of water must be consistent with the statements in the GBR and specifications.

- The other Contract Documents should be referenced, rather than repeated or paraphrased. If something is stated twice, even only slightly differently, an element of ambiguity is created. As with specifications, the basic rule is "Say it once, and say it well."

- The GBR should explain how the baselines relate to the data contained in the GDR. For example, if the GDR indicates that the maximum unconfined compressive strength (UCS) tested was 19,157 psi, but after discussion with the Owner, the decision was made to require the Contractor to provide for excavating 25,000 psi rock because the strongest rock is seldom found during exploration, an explanation similar

Table 2 - Examples of Baseline Statements

Example	Problematic	Improved
1. Background: A tunnel that is constructed through weak rock that is anticipated to deteriorate when exposed in the tunnel.	*The formation is a weak, clay-rich moisture sensitive, soil-like, rock subject to deterioration upon drying.*	*The formation is a weak, clay-rich, moisture sensitive, soil-like rock that will deteriorate upon drying.*
2. Background: Unstable soils and significant groundwater pressures are expected below the base of a deep shaft excavation.	*If groundwater pressures are not adequately controlled, the materials in the bottom of the shaft may pipe, heave, or boil, which could lead to instability of the shaft excavation.*	*Unless groundwater pressures are maintained below the bottom of the shaft, the materials in and below the bottom of the shaft will pipe, heave, boil, and lead to instability of the shaft excavation.*
3. Background: A hard rock tunnel is expected to include three shear zones, each between two and ten feet wide. An open TBM is to be used.	*Gripping for TBM thrust reaction may be somewhat affected by these conditions, but the effect is not expected to be severe.*	*Gripping for TBM thrust reaction will be inadequate in these conditions and supplementary thrust reaction must be provided.*
4. Background: In a four-mile long tunnel, two short lengths of bouldery alluvium are expected. Materials less than one foot in diameter are identified as cobbles and are incidental to the excavation. All tunnel excavation and support is bid as a lump sum.	*It should be anticipated that up to 10 boulders, as large as three feet, could be encountered in the tunnel.*	*For baseline purposes, ten boulders, between one foot and three feet in maximum dimension, are expected to be encountered within soil unit "X" in the tunnel.*
5. Background: Ten shear zones are anticipated to be encountered in a three-mile long tunnel. The definition of "shear zone" is provided in a glossary in the GBR.	*Some shear zones may yield up to 250-gpm initial inflow near the heading, but the flows should dissipate with time.*	*Ten shear zones are expected to be encountered in the tunnel. Three of the shear zones are expected to each yield 250-gpm initial inflow to the heading, as measured at the station of the TBM grippers. Regardless of the initial inflow, each of these shear zones is expected to yield no more than 60 gpm after one month.*
6. Background: A hard rock tunnel is to be excavated using a TBM through massive rock.	*The tunnel will encounter granite and granodiorite rocks. The unconfined compressive strength (UCS) of the intact granite may range from 6,000 to 25,000 psi; the UCS of the granodiorite may range from 8,000 to 35,000 psi.*	*Granite will be encountered over 40 percent of the length of the tunnel; the unconfined compressive strength (UCS) of the intact granite will range from 6,000 psi to 25,000 psi, with an average of 20,000 psi. Granodiorite will be encountered over the remaining 60 percent of the length of the tunnel; the UCS of the intact granodiorite will range from 8,000 psi to 35,000 psi, with an average of 28,000 psi and a range of values as indicated in the histogram in Figure "X".*

to the following should be provided: "Although the highest UCS tested was 19,157 psi, bidders can anticipate that rock with a UCS of 25,000 psi will be encountered, and that 25% of the total quantity of rock to be excavated will range between 20,000 and 25,000 psi UCS". Stating the baseline in this manner ensures that the project will be equipped to excavate the strongest rock thought likely to be encountered, and establishes as a baseline the quantity of such rock to be encountered. In situations like this, the specifications should also indicate how the strength of such rock is to be evaluated or determined during construction.

- Quantitative baselines should be presented only once. While it is preferable to limit baseline presentations to the GBR, this may not be possible in all instances. For example, if there is a need to indicate the anticipated lengths of different ground types to be encountered in the tunnel, it may be more expedient to show this information on the drawings, with their respective ground stabilization or ground support requirements presented either on the Drawings or in the Specifications. In this instance, the appropriate Drawing(s) or Specification sections should be specifically referenced in the GBR.

- The order of precedence of the different Contract Documents must be clearly indicated in the General Conditions or Special Provisions, to resolve conflicts that may be perceived to exist within the documents. The GBR should take precedence over any other geotechnical report or statement.

While the above may seem axiomatic and reasonably easy to achieve, past performance suggests that the potential for redundancy, ambiguity, and contradiction between the GBR and other Contract Documents is high. Once the drawings and specifications have been finalized, the GBR should be revisited for consistency and to ensure that specification language is not duplicated in the GBR. It is not unusual to revise the GBR four or five times as the drawings and specifications are being finalized. Owners or design managers should not view this iterative process as a negative, but as a critical step toward getting the documents "in sync."

Engaging the "fresh eyes" of independent reviewers in a page-turning process that incorporates the general conditions, technical specifications, drawings, and GBR is the ultimate check on internal compatibility. Because statements in the GBR will be subject to intense scrutiny, interpretation, and possible misinterpretation in the evaluation of potential DSC claims, this independent review of the documents is an essential step in developing an integrated GBR, and is strongly recommended. It is easy to say "make the GBR compatible with the other Contract Documents" but it takes vigilance in practice to achieve it.

6.7 Time and Budget for Preparation

The desired high-quality GBR will not be achieved unless the proper time and budget are allocated to facilitate its development. Preparation of an integrated GBR is as important as the preparation of a set of drawings that is consistent with the specifications. The time and effort involved in making the GBR document internally compatible can rival the efforts expended in preparing the preliminary drafts. An attempt to save money in the preparation of the GBR, either through a truncated or accelerated review process, or the bypassing of a "fresh eyes" review of the Contract Documents, is a false economy - a claim costing the Owner millions of dollars may occur that could otherwise have been avoided.

6.8 Owner Involvement

During preparation of the GBR, meetings should be conducted with the Owner to discuss the topic of baselines. The Owner should be advised of the consequences of an adverse presentation of the anticipated subsurface conditions, versus those of a less adverse presentation, and the need to stay within reasonable limits. The relative implications for how the bid items (or other payment formats) are developed, the initial contract price, potential change orders, and final cost of the work should be carefully reviewed with the Owner, who must be an informed, active participant in the setting of the baselines. The interpretations and baseline statements contained in the GBR should reflect the risk allocation attitudes and preferences of the Owner. The rationale and potential consequences of establishing conservative baselines (i.e. baselines set higher than the data would suggest) should be clearly explained.

7.0 APPLICATIONS FOR OTHER EXCAVATIONS AND FOUNDATIONS

As the application of GBRs has grown in acceptance within the tunneling industry, many Owners have used GBRs for projects or project components involving construction operations other than tunneling. The risks and potential impacts of unforeseen subsurface conditions are just as important for other projects involving subsurface construction. Where construction will involve excavation of the ground that is not visible pre-bid, a set of baseline conditions can reduce uncertainty in the pricing of the work and can serve to assist Contractors and sub-contractors in evaluating the work. Examples of other excavations that would benefit from a GBR include deep building and bridge foundations, open-cut pipelines, braced and tied-back excavations, and highway and other types of earthworks.

As for tunnels, these types of projects are especially prone to adverse schedule and cost impacts as a result of unanticipated subsurface conditions because successful prosecution of the work is focused at one location. Perhaps one of the more ubiquitous applications within public contracting is open-cut pipelines, where disputes, cost over-runs, and construction delays associated with a linear impact zone could be reduced if a GBR were incorporated into the Contract Documents.

7.1 Amplification of Impacts

For the projects addressed here, subsurface risks are often passed-down from the prime Contractor to one or more specialty subcontractors. However, delays to the work can impact the overall project well beyond the specific cost or schedule associated with the subcontract work. Schedule delays, additional overhead, rescheduling, and inefficiencies to the prime Contractor and other subcontractors can result from insufficient information or an inaccurate interpretation of subsurface conditions.

These projects can benefit from the use of a GBR; one that communicates geotechnical risks to the prime Contractor in a manner that can be readily communicated to his applicable subcontractors. The more concise the presentation of the information, the more likely the subcontractors will obtain the information in advance of submitting a bid.

7.2 Baselines for Small Projects

The benefits of the baseline concept are not limited to large projects. Uncertainty regarding subsurface conditions can have a substantial cost and schedule impact on the overall success of smaller projects as well. A delay on an open cut pipeline project can have just as much impact to the public (and the Owner's political circumstances) as a similar delay on a tunnel project.

For projects where the work scope is limited to only a few technical operations, baselines may only need to address one or two key parameters that might affect the equipment requirements, pricing and scheduling of the work. The scope of the GBR should be consistent with the project's size, complexity, and risks. A GBR need not be lengthy in order to be effective.

7.3 Identification of Risk Factors

The key to developing appropriate baselines is to first recognize those aspects of the project that are most dependent on a proper and realistic assessment of the subsurface conditions. As the consequences of geotechnical variations increase, the importance of clear descriptions of key properties and behaviors in the Contract also increases. Critical factors are those that relate to:

- potential construction methods;
- techniques to improve or control the ground or groundwater conditions;
- measurement and payment provisions;
- schedule-related issues;
- environmental and public impacts; and
- design and performance parameters.

The baselines should focus on specific material properties and behavioral characteristics, and should avoid relying on ranges or ambiguous definitions.

Baselines should be relevant to the anticipated construction methods, and readily quantifiable and verifiable using methods that are clear to both the Contractor and the Owner. For example, a recent project described ground conditions as follows:

> "The clay in stratum 2 ranges from stiff to hard..."

An improved means of conveying the same information would be:

> "As a baseline, the clay in stratum 2 is expected to range in unconfined compressive strength from 2 tsf to 5 tsf, with 25 percent of the clay's strength between 4 tsf and 5 tsf as sampled by ...measured by..."

In the first example the Contractor is left to address several open-ended questions, such as: Is there an upper-bound limit to "hard"? Which published definitions of "stiff" and "hard" should be assumed? How will the ground be sampled and how will strength be measured? In this case, the first example is not a baseline at all, and the Contractor is forced and, arguably, entitled to refer to the data report if included in the contract documents, to develop its own interpretations on soil consistency. In the second example, although the variability of the stratum material is acknowledged, specific strength bounds are established, a baseline that defines the percentage of material within an upper range of strength is clearly portrayed and the method of sampling and measurement is defined. Both the Owner and Contractor can then agree on the details of a field method to assess the soil's unconfined compressive strength throughout the project.

Identification of the appropriate parameters to baseline will be more involved if multiple construction methods are addressed in the project specifications. In this case, the GBR should address each of the anticipated suitable construction methods, and provide baselines (if different) for the various parameters that may affect associated construction under each method, such as the following:

- Stratigraphy
- Material description and classification
- Physical properties (strength, density, moisture content, grain size, plasticity, consolidation, etc.)
- Groundwater elevations and pressures (including perched or artesian)
- Bedrock, till, caliche and other rock-like geologic materials
- Depth of weathering profile and definition of weathering categories
- Buried utilities
- Occurrence of obstructions, both natural and man-made

The list is not comprehensive, and should be evaluated by the design team for each project.

7.4 Baseline Parameters for Consideration

The issues that will impact cost and schedule will vary according to different construction methods. In some cases items to be baselined may deal with construction conditions, obstructions, or hazards. In other instances, the baselines may be represented in terms of design or construction parameters. Table 3 contains a suggested list of items to be considered when developing baseline descriptions for a range of construction methods. The recommendations presented in Table 1 (Chapter 6) apply to all projects, including smaller non-tunneling-related excavations. The purpose of Table 3 is to encourage Owners and designers to consider the application of GBRs for open cut and foundation engineering projects.

Table 3 – Items to Consider When Developing Baselines

Method	Element of Work	Baseline Item
Open Cut Pipelines	Excavation means and methods	• Soil contact elevations • Top of rock or hard material (till, caliche), thickness and characteristics of weathered rock • Rippability of rock with specific methods • Blasting of rock with specific methods and constraints • Use of hoe mounted rock breakers or boom mounted impact hammers • Stand up time
	Groundwater management	• Static water elevation • Location of perched or confined water • Anticipated water inflow rates and volumes • Susceptibility of soils to piping • Water inflow volumes from the backfill around adjacent utilities • Stability of ground below the water table • Need or limits for groundwater control (including feasible groundwater control methods)
	Earth support methods	• Feasible excavation support systems • Limitations – such as limits on driving sheet piles • Lateral earth pressures for the design of excavation support systems; short and long-term
	Excavation methods	• Obstructions and frequency
	Spoil disposal	• Spoil disposal criteria • Amount of material to be disposed by special methods • Influence of Contractor-selected trench width
Excavation and earthwork	Material balance	• Soil stratigraphy, and quantification of material volumes where segregation is required for reuse and/or disposal • Bulking/Swell factors
	Compaction	• In situ soil moisture content • Optimum moisture content • Need for moisture conditioning • Swell/shrink factors
	Rock excavation	• Rippability of rock, till, caliche, etc. • Need for blasting • Bulking/swell factors
	Contaminant disposal	• Extent of contamination and disposal requirements for water and soil
Driven Piles	Installation time Load capacity Equipment selection	• Blow count profiles for use in pile driving analyses • Correlations to be used to convert different sampling methods • Refusal criteria, depth to refusal • Obstructions, including nature, frequency, and distribution

Table 3 – Items to Consider When Developing Baselines (Concluded)

Method	Element of Work	Baseline Item
Drilled Shafts	Casing requirements	• Ground strength • Stand-up time • Water conditions and occurrence of permeable strata • Need for casing or drilling mud
	Groundwater management	• Inflow elevation and pressure • Hydraulic conductivity of specific strata • Inflow volume • Anticipated water or drilling fluid loss rates, disposal issues
	Drilling tool selection	• Material strength and hardness • Presence and number of obstructions • Definition and characteristics of rock, weathered rock, and intermediate degrees of weathering
	Concrete volumes	• Anticipated overbreak
	Soil disposal	• Disposal of muck with contamination
Slurry Walls	Site preparation Obstruction delays	• Obstructions and abandoned utilities – occurrence and frequency • Occurrence and frequency of boulders
	Slurry stability	• Natural pH of the ground, and its effect on slurry
	Desanding systems	• Soil gradation, in particular fines content
	Excavation means and methods Rock excavation rate	• Top of rock, thickness and characteristics of weathered rock • Strength of rock with depth, bedding, or discontinuity orientations • Presence of clay seams, sand pockets, or voids
Ground Freezing	Site preparation drilling of freeze holes	• Obstructions and abandoned utilities – occurrence and frequency • Occurrence and frequency of boulders
	Groundwater hydrology	• Ground mass hydraulic conductivity • Groundwater flow velocity
Tiebacks and Anchors	Material quantities	• Allowable skin friction (w/caution) • Grout take and overbreak (w/caution) • Corrosion protection requirements
	Casing requirements Seal and gasket requirements	• Stand-up time • Water inflow volume and frequency

8.0 DESIGN-BUILD PROCUREMENT

GBRs initially evolved within a traditional Design-Bid-Build procurement framework, where the design was completed by the Owner's consultant prior to a competitive bid process. Under DB procurement, or variations of DB such as public-private partnerships or concessionaire schemes, adjustments to the GBR development process are warranted, but the fundamental concept remains - the Owner owns the ground. The role of a GBR as a risk-sharing tool is equally critical to construction projects under DB procurement as it is under the traditional method.

A significant issue for DB procurement is the means by which the Owner and DB team reach agreement about the geotechnical conditions to be expected during the work. Once that agreed definition of expected conditions is reached, the issue of Differing Site Conditions during construction is handled in the same way as for traditional Design-Bid-Build procurement. This chapter addresses suggested means for reaching that agreement.

8.1 Site Exploration

In traditional contracting, the Owner and his design engineer will address the full scope of geotechnical investigation and design, including exploration of subsurface conditions along the project alignment. Under the DB method, the Owner may seek to transfer the responsibility for portions of this effort to the DB team, whether to achieve schedule efficiencies, transfer subsurface risk, or other reasons.

It is recommended that the same level of exploration be carried out in advance of DB procurement as would be accomplished under the traditional method.
To "economize" on the amount of subsurface information provided in advance of DB proposals increases the risk that the designer will have insufficient information upon which to base a reliable design.

8.2 Geotechnical Data Report

The philosophy with regard to geotechnical data reports is substantially the same for DB procurement as for traditional procurement. It is incumbent upon the Owner to assemble all data and information that has been obtained in the course of the site characterization effort, and to disclose this information in an organized fashion. The information should be organized and presented in a meaningful format in a Geotechnical Data Report (GDR) in much the same manner as for traditional procurement methods. It is imperative that all such factual information be incorporated into the Contract Documents, so that the DB team has an appropriate database upon which to rely in the development of their design and in selecting their means, methods, and excavation approaches.

Bidders in a DB procurement process should be afforded the opportunity to obtain additional information at locations critical to their planning and design. Providing a background understanding of exploration gaps and constraints will help guide bidders in understanding what might be accomplished through supplementary exploration requests.

The results of any exploration and testing carried out by the Owner during the bid process should be included in the GDR, and made available to all the DB teams.

8.3 Geotechnical Baseline Report

Under DB, although the Owner supervises the gathering of the subsurface information, design-specific interpretations and decision-making lie with the DB team. The content of GBRs for DB projects should be substantially the same as described in Chapter 6; however a modified process that allows the DB team to participate in the development of the GBR is required.

Several projects have incorporated a GBR into a DB contract, as discussed in Section 8.4. Drawing on these and other experiences, the following three-step approach is suggested:

Step 1 – GBR-B. On the basis of the site exploration program and preliminary design, the Owner (through its geotechnical and design team) prepares a Geotechnical Baseline Report for Bidding (GBR-B). The focus of this document is the *physical* nature of the subsurface conditions likely to be encountered, consistent with the layouts and geometries represented in the preliminary design. In this manner, all Design-Build teams are provided with the same set of physical baseline conditions to be used in their design and construction planning. The document should:

- describe the bases for the preliminary designs provided by the Owner's design team;

- provide key baselines of anticipated physical conditions consistent with the exploration program and other relevant construction; and

- to the extent desired by the Owner or required by third-party constraints, mandate or preclude the use of certain equipment, means, and methods.

The degree to which the GBR-B provides *behavioral* baselines will be a function of the level of specificity in the preliminary design. It would be inappropriate for the Owner's design team to address behavioral issues in detail because such issues will be closely linked to the equipment, means and methods selected by each DB team. Different construction approaches may warrant different geotechnical considerations, and therefore warrant different behavioral baselines. Some examples are provided for illustration.

In a hard rock tunnel, viable alternatives might include drill and blast methods, or the use of a roadheader or tunnel boring machine (TBM). Different rock mass characteristics will influence the efficiency of the three different excavation methods, as well as the behavior of the resulting excavated openings and required ground support. Certain rock defects, such as bedding planes, joints, or shears, may have a relatively minor impact on the advance rates achieved by drill and blast methods but will have a more significant impact on overbreak, the need for initial support, and the cost of providing a final lining. In contrast, those same rock mass defects, depending on their orientations, may have more influence on the advance rate (penetration rate) of a roadheader or TBM, but have less influence on overbreak during excavation or the extent of initial support required. Thus, a discussion of rock mass parameters and behavioral characteristics must be described within the context of the various anticipated methods of tunnel excavation.

In a soft ground tunnel, the effectiveness of a cutter wheel machine might depend on different ground characteristics than those that would influence the effectiveness of an open-face digger shield. Boulders might represent a problem for the cutter wheel machine but not for the open face shield. Zones or pockets of unstable ground might influence each excavation method to a differing degree. If the use of a pressurized face machine is mandated, soil types, grain size distribution, permeability, and groundwater conditions will most likely have a different impact on an earth pressure balance machine as compared to a slurry pressure machine. Again, the specific soil characteristics and behaviors important to project success will vary with the specific means and methods.

In order to facilitate the comparison of documents from multiple teams, a common format is achieved by having the GBR-B prepared with discrete sections of the report left blank. The blanks contain annotations prompting bidders to address these specific issues and behavioral aspects consistent with their chosen equipment, means and methods.

The Owner should update the GBR-B during the bid process to reflect the results of any additional exploration and testing carried out by the Owner during that time.

Step 2 – GBR-C. As a part of their detailed design and construction planning process, each DB team will interpret the various baselines expressed in the GBR-B, consider those baselines in the development of their design and construction approaches, and fill in the gaps and blanks in the GBR-B accordingly. Consideration could be given to distributing the GBR-B in electronic form, so that any modifications or clarifications suggested by each DB team are captured in the track-change mode of most computerized word processing software programs. In its completed form, the

GBR for Construction (GBR-C) will reflect the physical baselines established by the Owner and its design team (as augmented by any supplemental exploration) and as clarified or modified by the DB team, and the behavioral baselines described by the DB team consistent with it's design approach, equipment, means, and methods.

Step 3 - Owner Review and Negotiation. As a part of the negotiation process, the Owner should have the opportunity to review each DB team's GBR-C for concurrence and reasonableness. If, in the Owner's (or its design team's) opinion, the baseline assumptions prepared by a particular team are judged to be optimistic, vague, or otherwise incompatible with statements in the GBR-B, the Owner should seek clarifications through discussion with that team. If those clarifications have an influence on the cost of the work, the DB team should be given the opportunity to revise their pricing, adjust the payment terms or provisions, or a combination thereof. The Owner may also choose to carry out such negotiations with more than one DB team. After the Owner and the successful DB team agree on such changes, the modified GBR-C supersedes the GBR-B and is incorporated into the DB contract. From that point forward, its use and function is similar to that for a GBR within the traditional contractual framework.

8.4 Recent Applications

A number of DB projects have been implemented in recent years with some variation of the above-described approach. **The Tren Urbano Subway** in San Juan, Puerto Rico provided a database of geotechnical information, and required each bidder to propose supplemental investigations to be carried out by the Owner during the bid period. No interpretations were submitted within the context of baseline statements or descriptions. Supplemental information gathered by the Owner during the bidding process was shared with all bidders prior to the submittal of final bids. Each bidder was required to prepare a Geotechnical Design Summary Report (GDSR) and to submit their GDSR with their bid. The Owner utilized this information during the bid review to gain an understanding of each team's perceptions of the risks on the project. Portions of the winning team's proposal were excerpted and included in the DB contract. Their GDSR was retained as a part of their Bid Escrow Documentation. The Contract included a Differing Site Conditions clause and a Dispute Review Board.

For the **Deep Tunnel Sewerage Scheme** in Singapore, a different approach was taken. The Owner's engineering consultant provided a Geotechnical Data Report only, with only modest interpretations of the anticipated subsurface conditions for each of a number of different construction contracts. As a part of the tender process, each DB team was required to prepare a Geotechnical Interpretive Report (GIR), which was required to address specific issues, estimated behaviors, and anticipated parameters influencing tunnel heading advance rate. The Owner and their consultant critically reviewed the interpretive reports during the evaluation of tenders. The contract included a form of a Differing Site Conditions clause, and the selected team's

GIR was incorporated into the DB contract. The number of borings drilled in advance of the tenders was less than suggested by industry standards, and each team was required to price a certain number of supplementary borings at specific locations. Unfortunately, because timetables for the selection of means and methods preceded the completion of the supplementary borings, certain equipment and design decisions were made without the benefit of the additional information.

Seattle's Sound Transit Program pursued yet another approach to ground characterization for a DB project that was bid but never awarded. The Owner's approach built upon experience gained during the Tren Urbano project, and engaged the tunneling community in seeking new ideas. The north corridor portion of the project, which was to include about 5 miles of twin-bore tunnel, was to have been constructed following a DB format. A phased exploration program was completed during the feasibility and preliminary design phases of the project. Borings were spaced an average of 330 feet apart along the tunnel alignment. In addition, six to nine borings were drilled at each of four transit station sites. All exploration and laboratory data, as well as a discussion of local tunnel case histories were presented in a GDR and interpreted in a Geotechnical Characterization Report (GCR).

Three DB teams were pre-qualified, but one withdrew during the proposal phase. An additional four borings were drilled at the suggestion of the two remaining teams. After the selection of the preferred team, an additional 15 borings were completed based on discussions with that team. All additional exploration information was presented in an appendix to the GDR. The Owner's geotechnical engineer prepared a Tender Geotechnical Baseline Report (TGBR) that established baseline conditions for relevant physical conditions such as boulder quantities, the nature of the soil units to be encountered, and baseline behavior of the soils referenced to an unsupported face condition. All three reports were to be included in the DB contract (Robinson, et al., 2001). The teams were requested to factor the contents of the TGBR into their bids, and to write a companion document to the Owner's TGBR that documented their selected means, methods, and associated ground behavior assessments. The intent of the process, had it been fully completed, was for the Owner and preferred DB team to reach a consensus understanding of a joint GBR, which would have been incorporated into the DB contract. The process did not advance to the final stages of negotiation due to funding issues.

The Niagara Tunnel Project in Ontario is a DB project that closely followed the three-step process described above. A tender document entitled a GBR-A was prepared by the Owner and submitted as a tender document to prequalified DB teams. The GBR-A contained gaps in the form of comment boxes that solicited input from each team. The document included with each team's proposal was referred to as their GBR-B. Though the construction approaches and designs were different among the different teams, the Owner was able to compare the different GBR-B assumptions and assess compatibility with different design and construction approaches. The selected team's GBR-B was discussed, modified, and agreed upon by the parties prior to incorporating it into the Construction Contract as the GBR-C. The Niagara Tunnel Project, which is currently under construction, includes a Disputes Review Board and a form of a Differing Site Conditions clause.

The San Diego County Water Authority utilized a DB approach for the **Lake Hodges to Olivenhain Pipeline - Tunnel and Shaft**. This project involves the construction of a 5,800 foot-long tunnel and 200 to 800 foot-deep drop shafts. A GBR-B was prepared by the Owner's engineer and issued with the bid documents. After Notice to Proceed, as part of their design development, the Contractor was required to prepare a GBR-C incorporating interpretations of any new geotechnical data obtained and providing assessments of ground behavior and ground response for the selected means and methods. The project is currently under construction and this approach to the development of the GBR appears to have been effective.

The **Sea to Sky Highway Improvement Project** is a DB roadway project that utilized a baseline approach on one portion of the project alignment. The Public-Private Partnership undertaking involves the widening and upgrading of 39 miles of two, three, and four-lane highway between Vancouver and Whistler, British Columbia. No tunnel construction is involved. The work involves drilling and blasting of cut slopes, the construction of downslope retaining walls and viaduct-like structures, and multiple bridge crossings. The Owner provided all pre-bid subsurface information to the bidders in a data room. For the majority of the project, the DB team is responsible for all geotechnical and subsurface conditions.

However, for a particularly challenging 7-mile portion of the alignment, the DB team developed and presented a set of design assumptions relating to the presence of rock, and the presence and depth of rock fill. These assumptions were recognized by the Owner and DB team as contractual baselines. During the execution of the work, if the subsurface conditions are found to be more onerous than baselined, the DB team and Owner have a means of negotiating design changes to mitigate additional construction costs. The residual impacts are shared equally between the Owner and DB team. The DB team retains the financial benefit of more favorable conditions.

A more collaborative GBR development process can be realized under DB procurement. It is considered that the more collaborative the process, the more effective the resulting product will be in helping to avoid and resolve disputes. The key is for both parties to fully understand and agree what the baselines mean, and how changes will be addressed if different conditions are encountered during the work.

9.0 OWNER PERSPECTIVES

9.1 Realities in the Public Sector

The Owner of an underground project must deal with certain issues that the Contractor and designer may not readily appreciate. One common issue is that funds are generally limited. A public project must compete with others, many times in a political venue, for the available capital funds. When the competition and demand for funds is high, the "budget" for a given project may be redefined as the project moves through preliminary design, final design, and construction bidding. When the design of the project is being developed, the "budget" is the sum of the designer's estimate and contingencies. However, once the project bids, the "budget" often becomes the amount of the awarded contract; previously included contingency funds may be reassigned to other public works projects.

Some Owners may be able to maintain a percentage of the contract award amount as contingency funds. As high as 10 to 50 percent of the contract amount, depending on the design and geotechnical risks anticipated, may be set aside. Many Owners, however, are not that fortunate.

Requests for additional funds often present a degree of political risk for the Owner's project manager or project manager's supervisor, to the extent that there is resistance to seek additional funds during construction. In certain organizations, the performance of the Owner's project manager may be judged on his ability to avoid "cost overruns." Thus, the Owner may prefer to have a baseline that attempts to minimize project change orders even at the cost of higher initial contract prices. Alternatively, the Owner may elect to include specified allowances or provisional funds in the initial bid price to be utilized, if required, for contract adjustment.

The Owner may also prefer to specify less risky but more costly designs and construction procedures to avoid politically undesirable events, such as the risk of excessive settlements of public streets or adjacent buildings. In this event, the rationale for these requirements should be clearly explained so that the bidders will be able to understand the reason for the "conservative" approach.

9.2 Setting the Baseline

Chapter 5 describes the concept of the baseline, and explains that different baselines can be developed considering the same geotechnical data. Where the baseline is set determines risk allocation and has a great influence on risk acceptance, bid prices, quantity of change orders, and the final cost of the project.

Owners should participate in and contribute to the setting of the baselines and should understand the consequences of the levels at which the baselines are set. The design team should explain the possible baseline range (with a discussion of the associated risks) and offer a "most reasonable" interpretation for the Owner's consideration.

A baseline that portrays a relatively adverse site condition will tend to:

- increase the bid price by allocating more risk to the Contractor;
- allocate less risk to the Owner and reduce the potential for change orders; and
- cost the Owner more, due to paying for the contingency of encountering the adverse condition, whether or not the condition is actually encountered.

A baseline that portrays a less adverse site condition will tend to:

- decrease the bid price by allocating less risk to the Contractor;
- allocate more risk to the Owner and increase the potential for change orders;
- cost the Owner more than the bid price if the adverse site condition(s) is encountered; but
- cost the Owner less if the adverse site condition is not encountered.

If the condition actually encountered requires a significant modification of the means and methods, the associated cost and schedule impacts will likely be greater than establishing a more adverse baseline in the first place.

In cases, a) a relatively adverse baseline, and b) a less adverse baseline, the cost of dealing with subsurface conditions ultimately rests with the Owner. Varying the baseline does not shed that responsibility. The difference between the two cases is whether the Owner a) pays a premium at the beginning of the Contract with higher bid prices (irrespective of whether the adverse condition is actually encountered); or b) pays only if and when it is actually encountered during construction, either by change order or some other provision under the Contract.

The attempt to eliminate claims through an overly adverse baseline may have the opposite effect if the baseline is unrealistic. Bidders will recognize an unrealistic baseline, and in order to be competitive, will be inclined to base their bid upon a more realistic condition, in effect, below the baseline. Then, if the more adverse condition is actually encountered during construction, a claim may still be filed with the argument that the "baseline" was unrealistic. As discussed further in Chapter 11 the risks associated with bidding below the baseline lie with the Contractor, however the Owner may suffer through an expensive adjudication process to prove the point. The possible benefits of arbitrarily adjusting the baseline for selective allocation of risk must be given careful consideration. Usually the best approach is to set a realistic baseline and incorporate contingencies for adverse conditions. Deviation from this principle will often lead to problems of "unintended consequences".

Baselines that strictly reflect the data and interpretations developed during site exploration and design may not be the best choice from the Owner's perspective if other information suggests that the database is incomplete or non-representative. The design team should convey to the Owner the potential consequences of setting the baseline at different levels of adversity, as they relate to:

- the effect on the bid price;
- the potential for change orders relating to differing site conditions; and
- the likely overall cost of construction.

The Owner needs to appreciate the inter-relationships between the above factors, the limitations involved with the characterization of ground conditions and ground behavior, and participate in the discussions and considerations that precede the setting of the baselines. Only then will baselines, and the resulting allocations of risk, reflect the Owner's desires relative to management of change orders, requests for additional budgets, and management of overall construction costs.

When considering the Owner in the process of setting baselines, it is imperative to differentiate and anticipate who the "Owner" is during the design phase as opposed to the construction phase. During the design process, when baseline decisions are made, the Owner's interests may be represented by individuals from the design or engineering branch. However, when the consequences of the baseline decisions are revealed during construction, the Owner's interests may be represented by more senior officials, board members, or the legal division who have little or no relevant construction or engineering experience, or construction managers who had no involvement during the design. The Owner's interests will be best served if these representatives either participate in setting the baselines, or are informed of earlier baseline decisions before the contract goes out for bid.

9.3 Managing the Owner's Risk

The Owner is understandably concerned about managing the financial risk throughout the construction process. Four realities that the Owner must understand and appreciate at the outset, through careful advising by the design team, are:

- Accurately anticipating every ground condition is rarely possible. Variations and unexpected conditions will occur.

- Construction risk should be allocated fairly; Owners must deal with the risk of unanticipated subsurface conditions. This risk cannot be eliminated.
- A baseline is no guarantee against differing site condition claims, or against the need to adjust pay quantities for unit price work during contract performance.
- Exceeding the baseline, in and of itself, does not represent a defective design.

Owners should understand what they can do to reduce their risk. One measure is to provide adequate schedule and budget to explore the subsurface conditions, not only for the designers' purposes, but also for bid preparation and construction purposes. There is no substitute for carrying out a comprehensive site exploration program. The more that is known about the ground conditions, the more accurate the anticipated cost of the project will be. If there is an area of identified risk that can be better managed or understood by seeking additional information in a supplementary exploration program, Owners should be willing to invest the time and money to carry out such additional investigations. This is money well spent.

A second measure is to retain suitably qualified and experienced geotechnical and design consultants with prior local geotechnical and construction experience to investigate the subsurface conditions, to evaluate the potential risks, and to prepare internally consistent drawings, specifications, and GBR.

A third measure is to allocate sufficient budget and time to permit proper preparation and review of all of the contract documents, including the drawings, specifications, and GBR. If an independent review board is utilized, it is beneficial to give the board the opportunity to review and provide comments on at least two drafts of the GBR together with the drawings and specifications. This will better ensure that the documents are internally consistent. When the exploration and design process are accelerated to meet predetermined deadlines, the result may be a sub-standard GBR, which could increase the final cost and schedule of the project. An additional month or two at the end of a multi-year design schedule will mean little to the overall schedule but may have a profound impact on the quality of the final Contract Documents. If a separate Construction Manager (CM) is to be used for the project, the Owner should engage the CM during the design process, not only to provide constructability review of the design, plans, and specifications, but also to participate in review of the GBR.

A fourth measure is to develop unit price payment provisions that can accommodate the full range of anticipated conditions and reasonable variations in ground conditions. By including these items in the bid schedule, competitive prices for these items are obtained during the bid process. Bid items for different degrees or quantities of items, such as groundwater inflows, ground support, grouting, etc., provide an effective means of dealing with those conditions if and when they are encountered, and minimize or eliminate DSC claims. A bid item for delay time, with a fair preset price or high enough quantity to preclude unbalancing, provides a means to deal with completely unanticipated conditions.

A fifth measure is to minimize misunderstandings as to what is indicated by the GBR, by discussing the baselines and encouraging candid discussion of the GBR contents with the bidders at the prebid meeting. This may be more easily achieved with private Owners than in the public domain. However, the ability to eliminate uncertainties among the potential bidders prior to the submission of bids will resolve many questions that might otherwise lead to unanticipated change orders and disputes.

The Owner can manage exposure to additional construction costs by maintaining a contingency fund apart from the construction contract. This fund should be maintained until all the potential design and geotechnical risks have been adequately addressed. An appropriate contingency fund should reflect the complexity of the anticipated conditions and the Owner's perceived risk. This is usually much higher for tunnel projects than for other types of construction.

10.0 ROLES AND RESPONSIBILITIES

Though the various roles and responsibilities of the parties have been discussed previously, it is useful to summarize them here.

The Owner should:

- provide adequate funding and schedule for geotechnical exploration and for preparation and review of the GBR;
- participate in the process of setting baselines, both to understand the risks and risk allocation and to fully understand and approve the baseline statements;
- thoroughly review and understand the various iterations during GBR development, including the review of DB GBR-C submittals;
- understand the vagaries of subsurface construction, and maintain an adequate reserve fund until all potential risks have been adequately addressed;
- provide sufficient budget during construction for adequate documentation of the actual conditions, so that the parties can agree on the conditions that were encountered, and the circumstances under which they were encountered; and
- promptly compensate the Contractor for valid DSC claims.

Under Design-Bid-Build procurement, the design team (geotechnical engineer or engineering geologist, and design engineer) must:

- provide geotechnical engineers and engineering geologists experienced in site investigations, data collection, and report preparation for the type of construction project being undertaken;
- prepare interpretations of the data that address design and construction concerns for geotechnically feasible design options;
- provide geotechnical and design engineers experienced in the appropriate type of design and construction to prepare and review the plans, specifications, and GBR;
- inform and educate the Owner as to the purpose and use of baselines;
- write clear, concise, definitive, and realistic baselines that are compatible with the drawings and specifications;

- explain baselines that are different than indicated by the data;
- explain the baseline statements and their consequences to the Owner and Contractor;
- write baselines that can be objectively evaluated; and
- indicate how baseline conditions will be measured and evaluated in the field.

Under DB procurement, the Owner's design team must also:

- provide a thorough review of the various GBR-C documents from the DB teams;
- explain to the Owner any differences that may exist between the different proposals; and
- assist the Owner in negotiating agreeable wording in what will become the standing GBR to the DB contract.

The Contractor must:

- seek clarification of unclear contractual provisions before bid;
- bid the work with a clear understanding of the GBR information, the contractual baselines, and his interpretation of the anticipated geotechnical conditions;
- bid the work with full consideration of the available geologic data in the GDR information if the bid is based on innovative or unusual equipment, means or methods, or if the bid is below the baseline(s);
- share the GBR and GDR information and interpretation of ground conditions with its major equipment suppliers, subcontractors, design consultants, and materials suppliers;
- understand and accept the level of risk associated with his bid assumptions that are less adverse than the baselines;
- accept the responsibility for selection of means and methods of construction and their impact on ground performance;
- provide means, methods, and equipment consistent with the baseline conditions and other indications in the Contract; and

- promptly make required adjustments if the initially selected means and methods are inappropriate.

Under DB procurement, the Contractor must also:

- retain its own design team to assist with preparation of the GBR-C and if required, help negotiate and finalize the standing GBR.

The Construction Manager should:

- be given the opportunity to participate in the review of the GBR during its preparation;

- fully document the actual conditions encountered (particularly those described in the baselines) and the impacts of such conditions on the construction;

- carefully and thoroughly evaluate DSC claims submitted by the Contractor;

- acknowledge the existence of, and encourage the Owner to promptly compensate the Contractor for, valid DSCs; and

- when appropriate, firmly and convincingly explain to the Contractor why a particular DSC claim is not valid.

Finally, if called upon, the Dispute Adjudicators must:

- make interpretations using the Contract as a whole, and in the event of conflict respect the contractual hierarchy of the Contract Documents;

- apply the baselines as stated in the GBR, e.g., refrain from invoking judgments that conflict with stated baselines;

- take into account the influence of the Contractor's means and methods, workmanship, and efficiency on ground behavior and overall performance/progress;

- recommend entitlement for conditions more adverse than the baselines only if they have resulted in material additional costs to the Contractor; and

- deny the merit of claims if encountered conditions are shown to be consistent with or less adverse than the conditions described in the GBR.

11.0 LESSONS LEARNED

The first edition of this document was published in early 1997. In the following ten years, many projects have been planned, designed and constructed. Likewise, many disputes have been argued and reconciled, and a multitude of lessons have hopefully been learned. One way to improve the business practice is to capture these lessons learned and share them among practitioners.

This chapter discusses feedback obtained during two industry workshops that were specifically directed at capturing lessons learned. The first workshop, held in association with a national tunneling conference in 2004, consisted of an all-day program dedicated to the review and discussion of items regarding GBRs that a six-person panel considered the most controversial. The second workshop, held in association with a national tunneling conference in 2006, involved industry review and commentary on a draft manuscript of this publication.

11.1 GBR Preparation

The general observation from both workshops is that the GBR concept is working well and that properly expressed baselines and GBR documents will go a long way to enhancing the effectiveness of GBRs. Authors need to do a better job of anticipating construction conditions, and then explaining those conditions in clear, concise, and unambiguous terms. It has also become increasingly evident that a poorly written GBR, or a GBR that is poorly integrated into the other Contract Documents, can become a lightening rod for claims and disputes.

As a tool for avoidance and minimization of disputes related to subsurface conditions, the GBR is the single most important document in the Contract. It is typically one of the first documents a bidder will review, and likely the first that an adjudicator will assess when presented with a dispute.

The importance of GBRs being prepared by suitably qualified professionals, and for the GBR and other Contract Documents to be reviewed by the "fresh eyes" of professionals experienced in the types of construction under consideration cannot be over emphasized. It is not unusual to have the GBR go through eight to ten reviews throughout the design and development of the Contract Documents. This is not an indication of having it wrong – it is a requisite for getting it right.

11.2 April 2004 Workshop

The Workshop held in Atlanta in 2004 consisted of discussions among a panel of representatives including Contractors, Owners, engineering consultants and attorneys, along with feedback and commentary by the audience. Each panelist addressed what they considered to be their three top issues and concerns regarding the preparation and interpretation of GBRs within a construction contract. The program Chairman led the panelists through a point-counterpoint discussion of each issue. The audience participants were encouraged to voice their views regarding the panelists' issues, as well as to raise any additional observations or concerns.

A broad array of issues was addressed, many focusing on "nitty-gritty" topics that have arisen in the course of dispute resolution on multiple projects. The more significant issues discussed at the workshop are summarized below.

Are baselines only enforceable if based solely on the available data?

In most instances the available exploration database is not sufficiently complete to fully characterize the anticipated subsurface conditions. In this instance, the GBR must go beyond the available data to provide a reasonable baseline of anticipated conditions. Examples include: boulders in the baseline when no boulders are actually detected in the soil boring program but generally known to exist; complex depositional environments not sufficiently documented in the borings, but known to exist based on the geology and/or experience from previous construction contracts in the area; the existence of vertical shears or faults that may have been missed in the boring program for a variety of statistical and geometric reasons; and adverse rock mass or groundwater conditions known or thought to occur at formation contacts, but not well documented in the boring logs.

The consensus is that such interpretations and extrapolations from the available geotechnical data should be reasonable, and should be explained if the resulting baselines deviate from the available data. Such modifications should be thoroughly vetted and resolved during the pre-bid and pre-award period, and not left to form the basis of potential disputes during actual prosecution of the work.

Baselines are contractually binding, regardless of the presence or absence of specific substantiating geotechnical data. The "baseline" is the "baseline".

Should dispute adjudicators respect the baselines when hearing disputes?

The majority of contracts that include GBRs also include a Disputes Resolution Board (DRB) as part of the disputes resolution process. As stated above, the baselines are binding on both parties and must be respected by the DRB.

Early DRB guidelines used the terms "fair" and "equitable" in reference to resolution of disputes. Some DRB members may have misunderstood these terms to mean that the DRB had the authority, if not the responsibility, to correct seemingly "unfair" or "inequitable" conditions contained in the Contract Documents. However, by bidding the work, the terms of the Contract, including the baselines, were acceptable to all bidders.

Recent DRB guidelines do not contain the terms "fair" and "equitable". Rather, the guidelines state that disputes brought to the Board are to be resolved "on the basis of the facts in the case, the terms of the contract and prevailing law" and, further, that the DRB does not have the authority to alter the terms of the Contract.

The lessons learned here are that: (1) GBRs should be written by knowledgeable professionals with clear and precise baselines that minimize the potential for misinterpretation; (2) Contractors should price the work with full consideration of the risks allocated by the baselines; (3) DRBs and other dispute adjudicators should interpret the GBR as a singular document, not as multiple sections with different priority levels; and (4) DRBs and other dispute adjudicators should apply the baselines in the GBR in accordance with the Contract Documents.

Should baselines be precise values, or can/should they be ranges?

If the variability of a material property or characteristic is legitimately reflected in the range of data, it is considered appropriate to state: "The available information indicates that item Q will range between X and Z; and for baseline purposes assume that the average Q = Y". This satisfies the desire and appropriateness of communicating the uncertainty, while providing a clear contractual baseline. As addressed in Chapter 6, a histogram presentation of the available data helps to clarify the anticipated variation in material property or characteristic from the baseline average.

"Soft" baselines (stated as a range of material properties or characteristics, rather than an average) run counter to the general proposition that baselines seek to enhance clarity and reduce ambiguity. A baseline "range" serves neither of the above objectives. Before the development of baselines, only numerical geotechnical data were provided, and usually in the form of ranges. The concept of stating baselines as a range is a step backward, not forward. Proponents of baseline ranges defend it by maintaining that the range represents an "uncertainty zone." While that might be true, the job of the GBR is to wring the geotechnical ambiguity out of the bidding process, not add to it. Excessively wide range-expressions are inconsistent with the overall goal of minimizing disputes. In reality, the use of ranges in a GBR results in the creation of an unnecessarily wide "battle zone".

Some Owners and GBR authors have expressed a concern about being "wrong" if an average property or characteristic is presented as a baseline. If an Owner or Owner's representative is concerned that presenting an average condition as a baseline will lead to a number of minor claims, they have the latitude to adjust the baseline to represent a more adverse condition, recognizing that in exchange for the more conservative baseline, they should anticipate higher bids. Adjusting the baseline to a more conservative value is viewed as a better solution than presenting the baseline as a wide numerical range.

This said, Owners and Engineers are strongly advised to present reasonable, realistic baselines. Building in excessive conservatism not only frustrates the purpose and role of the GBR but will inevitably cause confusion and in the end, may cause the very claims and lawsuits they were trying to prevent.

Can a bidder interpret the Contract payment quantities as a baseline?

Quantities in a bid schedule are frequently interpreted as indications of anticipated geotechnical conditions.

From a legal perspective, under the Federal Differing Site Conditions clause discussed in Section 4.2, a claim for relief due to adverse unexpected site conditions depends on the claimant being able to show that the conditions differ materially from those "indicated in this contract." U. S. construction case law generally supports the interpretation that planned contract payment quantities in the bid schedule are valid "indications" of physical conditions to be expected during construction.

Therefore, while payment quantities are similar to baselines in that they are "indications" of conditions of the Contract, they are not the same. Payment quantities represent the amount of work to be performed by the Contractor and baselines are a description of the physical conditions involved with the work. Nevertheless, payment quantity provisions that are related to certain physical conditions should be compatible with baseline statements made in the GBR. This is precisely the clarity and consistency that is sought in the proper preparation of a GBR. Compatibility with payment provision statements and quantities will serve to eliminate ambiguity, confusion, and disagreement.

Are unreasonably onerous or conservative baselines binding, or should DRBs and other adjudicators ignore them?

As discussed above, the baselines are a part of the Contract, they are binding, and they are not to be ignored or otherwise set aside.

How large a variance is required from the baseline to justify additional compensation?

The answer to this question depends on the particular circumstances - how the baselines are stated, the nature of the encountered conditions, whether the conditions can be deemed a "material difference", and whether an adverse financial impact can be clearly demonstrated.

The concept of what constitutes a "material difference" in the contract definition of a differing site condition, whether physical or behavioral, is central to the dispute resolution process. If there is no demonstration of material difference, there can be no compensation in either time or money.

Should the GBR be presented as a series of discrete statements?

This perspective is offered by those who are concerned that GBRs are becoming too long, and that as the length of a GBR increases, the clarity of what is really important is diminished. However, to reduce the GBR to a list of short, concise statements is equally ineffective. Doing so would exacerbate other expressed shortcomings in GBRs. For example, as discussed earlier in this chapter, it is important to provide the context of a numerical baseline; it helps bidders understand the risks they are accepting if they bid below the baseline. Also, it is important to recognize that the GBR is the sole interpretive geotechnical report provided to the Contractor that has contractual significance. In this context it is fundamental that the GBR help the Contractor understand the project, its challenges, and critical issues, in particular where the geologic conditions are involved. A brief description of limitations of the site characterization effort, clarified with specific baselines can be very effective in communicating the project realities to the Contractor. Removing this background information serves to undercut a full contextual understanding of the conditions and impairs the bidders' ability to assess the level of risk they are being asked to accept, and it is recommended that this not be done.

In summary, the longer and more complicated a GBR, the more likely it is that its message will be diluted and the greater the chances for internal inconsistency. For this reason, authors of GBRs are advised to keep the GBR concise and to the point.

11.3 June 2006 Workshop

A draft of this document was circulated to interested parties, and was discussed in an open forum during a workshop held in conjunction with a national tunneling conference in Chicago in 2006. The five-hour workshop was audio recorded, and a transcript was prepared to capture individuals' comments.

Discussions during this workshop reinforced a number of items raised during the April 2004 Workshop. Positive feedback on two projects ratified the three-step GBR process for DB applications as described in Chapter 8, specifically the Lake Hodges project discussed in Chapter 8, and the New York Avenue Extension of the Washington Metropolitan Area Transit Authority in Washington, DC.

A number of suggestions raised during the workshop were subsequently incorporated into the text of this document. Comments regarding additional topics are provided below.

The Use of Risk Registers

The use of Risk Registers as a formalized risk assessment tool has become more common in recent years. A question was raised about possible incorporation of discussion of Risk Register evaluations into the GBR.

By its nature, the Risk Register process addresses a much broader range of risks than those addressed in a GBR, and discusses specific mitigation strategies. For an underground project, the outgrowth of such mitigation strategies may have already been incorporated in the design, project alignment, selection of construction methods, etc. Thus, the goals of the Risk Register process may have already been achieved. Nevertheless, there is a logical connection between the identification of geotechnically-related aspects that could present risks to a project, and the need to address such items in a GBR. The Risk Register and GBR are complementary. The Risk Register process identifies, among other items, key geotechnical, construction, and third party risks. The GBR has the opportunity to provide a contractual platform for describing how certain risks have been addressed in the planning and design, and how other risks are to be allocated and managed during construction.

While the use of Risk Registers is strongly encouraged during the design of underground construction projects, the presentation and discussion of the details of a Risk Register evaluation process are best contained in other documents, perhaps Geotechnical Memoranda for Design such as discussed in Section 3.2.

Baselines by Tunnel Reach

When the tunnel passes through two or more distinct geologic regimes, it may be practical to define expected conditions in terms of separate baselines, and that is commonly done. It would follow that ground conditions and physical properties, as well as tunnel support measures, should be baselined within the context of these different regimes or reaches.

However, many tunnels cross geologic settings in which different ground conditions are completely intermixed in an unknown manner. For these instances, there is no rational basis for subdividing the tunnel into reaches with individual baselines. As an example, for most rock tunnel projects, a baseline would be given for expected maximum groundwater inflow for the entire tunnel in the absence of grouting for water cutoff. Whether or not this baseline was exceeded would not be known until the last day of excavation.

As another example, a tunnel might be expected to encounter only one geologic formation. The manner in which the various geotechnical parameters are distributed throughout the formation are not known, and cannot be reasonably predicted within the context of reach-by-reach baselines. For these instances, baselines defined for the entire tunnel drive are considered the more appropriate approach.

The Need for Qualified Preparers and Reviewers of GBRs

A number of comments have been made with regard to the importance of having suitably qualified geotechnical, design, and construction professionals involved in the preparation and review of GBRs. Experience has demonstrated that the ability to prepare a foundations report or a geotechnical report for design is insufficient background to prepare a GBR. Others have suggested that for projects large and small, Owners would be well served to institute a prequalification process at the preparer level, at the reviewer level, or both.

Another concern that has been raised is that given the recommended practice of developing the GBR at the later stages of design, insufficient review of the final GBR could result. It was considered that a minimum of two rounds of independent review of an advanced version of the GBR will improve clarity of content. Also, the value of a thorough page-by-page review of the GBR together with the other Contract Documents was underscored as a critical step to ensuring consistency and compatibility among the Contract Documents.

Use of GBRs on Small Projects

The extension of the GBR concept to areas of construction other than tunnels and shafts has received healthy debate, with the majority of the workshop participants acknowledging that more and more projects were utilizing this approach, and that the suggestions provided in Chapter 7 were both helpful and timely. Table 3 is offered knowing that improvements will be realized as the concept is implemented and further lessons are learned. It is hoped that foundation engineering practitioners and Contractors will advance a new guidelines publication more closely directed to this growing area of GBR application.

Baseline Measurement and Verification

This document stresses the importance of presenting GBR baselines in clear quantifiable and measurable terms. One comment raised by several workshop participants was that underground construction contracts should address the measurement and verification of baselines during construction as a matter of course. Guidance could be provided in the context of either specific activities to be accomplished from the inception of construction, or in the event that a dispute arose. Such guidance could be provided in the GBR or in the specifications.

It is considered that the measurement of certain aspects, e.g. groundwater inflows at the portal, shaft, or heading, can and should be provided for within the specifications. The documentation of boulders encountered during a soft ground tunneling project might also be accomplished with relative ease. However, a number of owners have resisted more extensive programs such as mandatory sampling and testing of rock conditions during the project to measure parameters such as compressive strength or abrasivity, due to the anticipated delay and costs of such programs. They offer that if the Contractor believes at some point in time that a DSC exists, the Owner will, upon proper notice, expend the necessary investigative costs at that time.

Certainly establishing a suitable process that assures that both parties will agree as to what the encountered conditions are is an important step toward avoiding and resolving disputes. For the parties to agree on how and when certain measurements are to be accomplished, based on guidance provided in the Contract Documents, bears consideration. However, such agreements might also be reached in the instance of an actual dispute, following the wisdom that "if it ain't broke, don't fix it." For example, in one recent rock TBM project, the Owner and Contractor agreed to have a mutually acceptable independent consultant carry out geologic mapping during the excavation. It was agreed that neither party would dispute the mapping results, and that the mapping costs would be shared. These agreements were made post-contract award.

While these types of agreements can and should be sought, they need to be implemented on a project-by-project, case-by-case basis. Inclusion of limited guidance provided in the Contract Documents should be helpful.

List of Abbreviations

DSC	Differing site condition
DRB	Disputes Resolution Board
DRBF	Disputes Resolution Board Foundation
EPB	Earth pressure balance
GBR	Geotechnical Baseline Report
GDR	Geotechnical Data Report
GIR	Geotechnical Interpretive Report
TBM	Tunnel boring machine
USNCTT	U.S. National Committee on Tunneling Technology
UTRC	Underground Technology Research Council

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Appendix B

Affidavit of Roger Ilsely

ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board Act, 1998;

AND IN THE MATTER OF an Application by Ontario Power Generation Inc. for an order or orders, approving payment amounts for prescribed generating facilities commencing January 1, 2014.

AFFIDAVIT OF ROGER ILSLEY

I, Roger Ilsley, of Topanga, California in the United States of America, **MAKE OATH AND AFFIRM**:

1. I am the Principal of R I Geotechnical Incorporated. I was retained to provide an independent review and assessment of the geological and geotechnical investigations and related reports, project drawings and specifications in relation to the Niagara Tunnel Project, as well as to review and assess OPG's conduct in a dispute with Strabag Inc. over differing subsurface conditions. In connection with these matters, I prepared a report entitled "Niagara Diversion Tunnel Report" dated September 9, 2013 (the "Report") and provided sworn oral testimony at the Ontario Energy Board (OEB) on June 12 and 13, 2014 in connection with matter EB-2013-0321.

2. In the course of my oral testimony, I was asked about the standards that I used in preparing the Report. Among the documents that I mentioned were the guidelines produced by the American Society of Civil Engineers. The full citation for the document that I referenced is: Geotechnical Baseline Reports for Construction – Suggested Guidelines, 2nd Ed., 2007 (the "GBR Guidelines").

3. As noted on page ix of the GBR Guidelines, I was a member of the Technical Committee that contributed to the first edition of these guidelines and two of the members of the Dispute Review Board ("DRB") for the Niagara Tunnel, Peter Douglass and P.E. "Joe" Sperry, were on the Technical Committee that contributed to the second edition of the GBR Guideline.

4. OPG has provided me with the arguments submitted by SEC and AMPCO and asked me to respond to the arguments made by these parties about the content, use and interpretation of the

GBR Guidelines. None of the arguments regarding these issues were put to me during my cross-examination. My responses are provided in the questions and answers that follow.

5. **Q:** How are the GBR Guidelines used in Tunneling Projects?

A: The GBR Guidelines provide checklists and general guidance on the matters to consider when preparing Geotechnical Baseline Reports ("GBRs"). They are not rules or minimum requirements that must be followed. As the GBR Guidelines note on the first page:

> Though the information contained in this document represents a consensus opinion within the industry on a range of issues, the opinions of practitioners vary on a number of topics. The suggestions provided in this document are therefore intended as guidelines, and should not be interpreted as rules, requirements, or standards of care.

6. **Q:** SEC argues that "The terminology used by the Geotechnical Baseline Report (GBR-C) did not follow proper guidelines, as the language used was imprecise and too broad to describe critical issues." Do you agree?

A: No. In my view, the language used by the GBR-C was not imprecise or too broad or contrary to the guidelines; to the contrary, the language used by the GBR-C avoids imprecision where appropriate and the stated baselines, where quantitative, are clearly expressed. For example, GBR-C, Section 8.1.2 Construction Methodology lists six paragraphs which describe the various types of ground behavior (which paragraphs include the terms "a potential for", "generally" and "can"), which the Contractor must consider in the design and installation of the initial tunnel support.

The Suggested Guidelines for Geotechnical Baselines for Construction has the following statement on page 17, "However, some baseline issues may be qualitative, and not definable in quantitative, measureable terms." An example is then given which is related to ground behavior; note that the following modifying phrase is used: "it will tend to exhibit".

Clearly, when describing ground behavior (which is a characteristic that can be only described qualitatively and cannot be quantified), it is appropriate to use such modifying language. Such modifying language was in fact used in the GBR in the instances referenced by SEC.

7. **Q:** Are the examples from GBR-C quoted at paragraph 103 of AMPCO's Argument imprecise or too broad?

A: No. The examples quoted, which are from Section 4 of the GBR-C, Geologic Setting, are modifiers that are appropriate in their context. For example, in sections 4.4.1.1 Bedrock Characteristics, Bedding Planes, the term "generally" is used and in 4.4.1.3 the word "may" is used; in section 4.4.2.4 Faulting and Discontinuities the word "generally" is used twice.

As the title of the section indicates, these descriptions of the general geologic conditions for an alignment that is 10.4 km in length, necessarily use the language of geology which is for the most part descriptive and therefore qualitative in nature. In doing so, modifiers such as those used and shown above, were appropriate.

8. **Q:** Are there any other sections of the Suggested Guidelines that you believe would be helpful to the OEB in considering the argument related to ambiguous terms?

A: Yes. While it is preferable to be as precise as possible, it is important to recognize that a GBR establishes baseline conditions expected over the alignment of the entire tunneling project based on sampling from exploratory borings. Section 6.4 of the GBR Guidelines, which SEC quotes from, begins with the statement that: "Baselines are difficult to write without ambiguity. No one can accurately predict the nature and distribution of materials underground and how they will react to excavation."

For example, if the sampling indicates that, for example, the rock "is generally massive," which refers to the frequency, and orientation of the discontinuities present, then the GBR should reflect those observations and say "generally massive" rather than to just say "massive". In most instances, as was the case here, general descriptors are followed by text intended to more precisely delineate the anticipated rock conditions and related design and construction considerations. An example of this, from GBR-C, is as follows:

> The Queenston Formation is generally massive. However, construction of the tunnel in the Queenston Formation will have to allow for high in situ stresses and variations in rock mass strength. In addition, the presence of major sheared bedding planes at specific elevations must be accounted for. The weathered zone below the contact with the Whirlpool Formation and below the St. David's Gorge

> represents a weaker zone. Sheared bedding planes have developed within the Queenston Formation along Type IV (reddish-brown silty mudstone) and Type V (mudstone) rocks. These sheared planes are of low strength, are planar on a large scale and observed to be continuous throughout the test adit. There is potential for these sheared bedding planes to be continuous throughout the tunnel alignment. The performance of the trial enlargement has shown that significant slabbing can occur in the crown, in areas where sheared bedding planes exist some 2 m or less above the crown elevation, and on the sidewalls, particularly in areas immediately below such planes. These planes will be intersected by the tunnel at a low angle for a substantial portion of the tunnel length. (GBR-C, page 35).

9. **Q:** Is it your view that the single page from the GBR Guidelines attached to SEC's argument includes all the information that is useful for the OEB's evaluation of the Niagara Tunnel Project?

A: No, I believe that there are several other sections that are directly related to the OEB's review of the Niagara Tunnel Project and that the OEB's understanding of the guidelines would be informed by reviewing the entire document rather than a single page. For example, the GBR Guidelines contain a whole chapter (Chapter 8) on the use of GBRs in connection with Design-Build procurement. In Section 8.3, the GBR Guidelines (pages 39-41) set out a three-step process for how to develop GBRs in the Design-Build context. In section 8.4, the GBR Guidelines discuss how several projects incorporated GBRs into Design-Build contracts. One of the projects discussed in the GBR Guidelines (page 41-42) is the Niagara Tunnel Project, as follows:

> The Niagara Tunnel Project in Ontario is a DB project that closely followed the three-step process described above. A tender document entitled a GBR-A was prepared by the Owner and submitted as a tender document to prequalified DB teams. The GBR-A contained gaps in the form of comment boxes that solicited input from each team. The document included with each team's proposal was referred to as their GBR-B. Though the construction approaches and designs were different among the different teams, the Owner was able to compare the different GBR-B assumptions and assess compatibility with different design and construction approaches. The selected team's GBR-B was discussed, modified, and agreed upon by the parties prior to incorporating it into the Construction Contract as the GBR-C. The Niagara Tunnel Project, which is currently under construction, includes a Disputes Review Board and a form of a Differing Site Conditions clause.

In my view, this description is noteworthy because the Technical Team that worked on the second edition of the GBR Guidelines included two members who were serving on the Niagara Tunnel DRB at the same time that the GBR Guidelines were being written.

10. **Q:** Are there any other sections that you believe would be helpful to the OEB in considering the GBR for the Niagara Tunnel?

A: Yes. One other notable section is Section 5.1 (pages 16-18), which is entitled "Baselines". This section begins by noting: "The planning, design, and construction of underground projects must cope with uncertain subsurface conditions. 'Mother Nature' did not create subsurface conditions in accordance with a materials properties handbook, nor do geologists or geotechnical engineers (or any other participants in the process) have magical predictive powers." It goes on to discuss how some baselines cannot be stated quantitatively or reliably measured during construction.

Also of note is Section 6.4, which is entitled "Wording Suggestions". This section states: "Baseline statements regarding anticipated ground behavior should be presented in context with the use of defined means and methods of construction." As pointed out in paragraph 6, above, that is what was done here.

11. **Q:** In response to AMPCO's assertion in paragraph 102 of its Argument, that the test from the GBR Guidelines for determining whether the baseline statement is sufficiently clear was not applied, is it your view that the description of the anticipated rock condition was sufficiently clear that the DRB could find differing subsurface conditions with respect to the overbreak encountered?

A: Yes. The DRB Report on page 18 finds that, putting aside the issues with the GBR wording, there is a DSC associated with excessive overbreak. As I previously testified, the actual rock behavior was different than anticipated as evidenced by the excessive overbreak that was experienced and thus the basis for acknowledging a DSC. The nature and extent of the overbreak was readily apparent. This would have also been readily apparent to the members of the DRB through their frequent site visits.

Under the terms of the Design Build Agreement, the DRB was required to meet at the project site, at least quarterly, to review the project progress, discuss any issues with Strabag and OPG and tour the project. The DRB Report (page 5) indicates that the first of these meeting occurred on February 7, 2006. By the time the DRB heard the dispute in June 2008, it would have had multiple opportunities to see the nature and extent of the overbreak being experienced and the methods that Strabag was required to use to advance the tunnel safely in the conditions being encountered.

12. **Q:** In response to AMPCO's assertion at paragraph 105 of its Argument, that an independent review should have been carried out where the GBR is jointly developed by the parties, do the parties in your experience typically obtain an independent review?

A: No. As I noted previously, the GBR Guidelines (pages 38-40) contain a three-step process for developing GBRs in the context of design-build agreements. This three-step process does not include an independent assessment because it envisions that the GBR incorporated into the contract will be jointly developed by the parties using their combined expertise and detailed understanding of the project. That is what was done for the Niagara Tunnel Project.

SWORN BEFORE ME at Torrance, CA)
this 5 day of Sept, 2014,)
)
A Notary Public)   Roger Ilsley

ERIC NELSON
Commission # 1965593
Notary Public - California
Los Angeles County
My Comm. Expires Jan 6, 2016