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May 29, 2017

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli

**Re: Ontario Power Generation Inc. ("OPG")
2017-2021 Payment Amounts Application
Board File #: EB-2016-0152**

Please find enclosed the Argument of Canadian Manufacturers & Exporters ("CME") submitted in the above-noted proceeding.

Yours very truly

Borden Ladner Gervais LLP

A handwritten signature in black ink, appearing to read 'Scott Pollock', is written over a light blue horizontal line.

Scott Pollock

enclosure

- c. Barbara Reuber and Carlton Mathias(OPG)
- Charles Keizer (Torys)
- EB-2016-0152 Intervenors
- Vince DeRose (Tereposky & DeRose LLP)
- Paul Clipsham and Ian Shaw

OTT01: 8280840: v1

ONTARIO ENERGY BOARD

Ontario Power Generation Inc.

Application for payment amounts for the period
from January 1, 2017 to December 31, 2021

**SUBMISSIONS OF
CANADIAN MANUFACTURERS & EXPORTERS (“CME”)**

May 29, 2017

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1.0 INTRODUCTION

1. These submissions are made on behalf of Canadian Manufacturers & Exporters (“CME”).
2. CME's members, which include over 1,400 Ontario based companies, operate energy intensive businesses. Their continued competitiveness in their respective industries is tied directly to how much energy costs them and, as a result, the dramatically increasing cost of energy in Ontario has made it much more difficult for CME members to be competitive in the market, compared with business from other jurisdictions where energy costs less.
3. The cost consequences of this Application are significant, including a nuclear revenue requirement of \$16.8 Billion between 2017 and 2021, and will drive significant increases in electricity rates for all consumers of electricity in the province.
4. In preparing these submissions, we have benefitted from Board Staff's comprehensive submissions. We have also worked closely with many of the intervenors in this Application, and had the opportunity to review draft of submissions shared by other intervenors. This has assisted CME in making efficient use of resources to the extent possible given the size and complexity of this Application.
5. These submissions focus on the components of OPG's Application which, in CME's submission, require adjustment in order to ensure that the rates which are set in these proceedings are just and reasonable and to protect Ontario's ratepayers with respect to the prices of electricity service.

2.0 CAPITAL STRUCTURE OF OPG

6. OPG has requested that the Board approve 400 basis point increase in their deemed equity thickness from the 45% approved in its most recent payment amounts to 49%, the

effect of which would be to increase the amount of profit which will flow to OPG's shareholder over the five year term.

7. OPG advocates the increase on the basis that the business and financial risks facing the company have changed relative to the risk profile which existed at the time of their previous applications and in this regard relies on the evidence of Concentric Energy Advisors ("**Concentric**").
8. Board Staff also commissioned an expert report from the Brattle Group ("**Brattle**") who suggested that the current deemed capital structure of OPG should be revisited.
9. Both experts list many of the same factors as reasons why an increase in equity thickness is required. These factors include:
 - (a) The change from a portfolio weighted in favour of hydroelectric generation to a portfolio with more nuclear generation;
 - (b) The move from a cost of service model to incentive rate making;
 - (c) The capital expenditure related to the DRP;
 - (d) The capital expenditure related to Pickering Extended Operations;
 - (e) OPG's equity ratio in comparison to each expert's comparator group;
 - (f) Revenue deferred under rate smoothing; and
 - (g) Credit risk.

Concentric also identified a further risk that Brattle disagreed with:

 - (h) The recovery risk associated with pension and OPEB costs.
10. CME submits that these risk factors are exaggerated by Concentric and Brattle, or are ultimately not material to their recommendation, and can be disregarded.
11. We have had the benefit of reading the able submissions of both SEC and VECC on the subject of capital structure. Their position that 45% equity thickness is reasonable, and warrants close attention. Alternatively, CME submits that Board staff's recommendation

of 47% equity thickness should be the upper limit of OPG's equity thickness going forward.

2.1 The Change in Generation Mix

12. As discussed in Board staff's submissions, the Board has previously found that hydroelectric generation is less risky as a business than nuclear generation is, saying:

The Board cannot accept that business risk has not changed since the capital structure was last reviewed in 2010. Since that time, 48 additional hydroelectric facilities have been added to the inventory of prescribed assets, accounting for 12.4 TWh of energy forecast to be produced in 2014 and 12.5 TWh in 2015. These assets, together with the Niagara Tunnel which was brought into service in 2013, increase the proportionate share of rate base related to hydroelectric facilities from about half in 2010 to approximately two-thirds now. The relative business risk of hydroelectric generation versus nuclear has been accepted by the Board as being lower in previous proceedings, even though setting the capital structure on a technology specific basis has not.¹

13. CME agrees that, where the business risks associated with nuclear generation are not otherwise mitigated, the change from a predominantly hydroelectric generating portfolio to one that is heavily weighted towards nuclear generation could increase OPG's risk profile. That is not, however, the current situation.
14. CME notes that several factors attenuate the risk increase as part of the move to nuclear generation including: the proliferation of variance and deferral accounts, the long lived lives of the assets in question, and the generation mix in terms of MWh.

2.1.1 Proliferation of Deferral and Variance Accounts

15. In EB-2013-0321, the Board specifically noted that the creation of deferral and variance accounts lowers risk:

Since the equity component was first set, a new pension variance account has been approved by the Board. This variance account decreases OPG's forecast risk associated with pension and OPEB costs.²

¹ EB-2013-0321 Decision with Reasons, November 20, 2014, p.113.

² EB-2013-0321 Decision with Reasons, November 20, 2014, p.113.

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16. OPG's application contains provisions for three new variance accounts related to the nuclear portion of their business: the rate smoothing deferral account, the Mid-term nuclear production variance account (which CME submits should not be approved as discussed in Section 11.1 below), and the nuclear ROE variance account. It also proposes the establishment of an additional hydroelectric variance account, the hydroelectric capital structure variance account, which is discussed in more detail further in this section.
 17. The Mid-term production review in particular, should the Board approve it, would significantly reduce risks associated with nuclear forecasting. According to OPG's evidence, OPG's underperformance relative to their approved production costs their shareholder, on average, \$154.0 million annually.³
 18. The mid-term production review, if approved, would guarantee OPG's collection of the difference between the production amount approved by the Board in the initial application and the production amount approved by the Board in the mid-term application even if OPG did not produce the corresponding power. In CME's view, this significantly lowers OPG's business risk for nuclear assets.
 19. As discussed in further detail later in our submissions, we submit that this variance account is wholly inappropriate and should not be approved by the Board. If it is approved however, the Board should take note of the moderating impact that it has on nuclear generation risk.
 20. This variance account would close the risk gap between hydroelectric and nuclear riskiness, since hydroelectric generation has had the benefit of the Hydroelectric Water Conditions Variance Account, which has protected production forecasts in previous applications.

³ Exhibit E2, Tab 1, Schedule 1, p.2.

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21. OPG also proposes to create a Nuclear ROE Variance Account, which would track the revenue requirement impact of the difference between the ROE approved by the Board for OPG's nuclear business in 2018 to 2021, and the annually updated ROE specified by the OEB.
22. This account can also moderate the risk of nuclear generation. If the Board's prescribed ROE were to increase, OPG would be able to capture that lost ROE, and recover it from ratepayers when they clear the account.
23. CME submits that as the number of nuclear related variance and deferral accounts increase, and the protections that they offer become more robust relative to the hydroelectric side, the less of a risk profile difference will exist.

2.1.2 Long Lived Asset Lives

24. In EB-2013-0321, the Board concluded that the length of time remaining in the useful lives of regulated assets reduces risk:

As long as there is rate regulation, these assets will produce power and revenue certainty until the end of their useful lives.⁴

25. The DRP is meant to ensure that Darlington operates safely and reliably until approximately 2055, 38 years from now, and approximately 30 years from the completion of the project.
26. CME submits that the DRP will unlock another 30 years of regulated power production that will generate significant guaranteed revenues for OPG. This factor improves OPG's credit metrics according to Brattle:

First, because any capital expenditure program is expected to result in assets that eventually will enter rate base, such programs indicate growth opportunities in the form of higher future income or net cash flow. Thus, the Darlington Refurbishment Program is expected to allow OPG to generate higher cash flows going forward and to maintain its dominant position in the Ontario power market.⁵

⁴ EB 2013-0321 Decision with Reasons, November 20, 2014, p.113.

⁵ Exhibit M3, p.23.

27. This guaranteed regulated revenue over the course of several decades eliminates the large portion of, if not all of the risk from moving to a nuclear based portfolio.
- (i) Mix of Generation in Terms of MWh
28. During SEC's cross examination of Concentric, the latter acknowledged that if the mix of megawatts between hydroelectric and nuclear changes, such a change would affect risk.⁶
29. The evidence shows that the DRP will increase rate base associated with nuclear assets; however, the actual MWh generation produced by the nuclear side of the business is scheduled to decline as the DRP moves through the execution phase. OPG's MWh production will actually become more heavily weighted towards hydroelectric, the less risky form of generation.⁷
30. CME submits that this change in generating mix, and the proliferation of variance accounts for nuclear generation mean that the move from hydroelectric to nuclear does not impact the risk profile of OPG as much as the original move from nuclear to hydroelectric generation did.

2.2 The Move to Incentive Rates Does Not Increase OPG's Risk

31. In EB-2013-0321, the Board did not accept that moving to IR significantly increases risk:
- The Board does not accept that moving to incentive regulation significantly increases risk to the entity such that the capital structure should be reset, and has not done so for any of the other companies that it regulates.⁸***
32. In their report, Concentric suggested that the move to incentive rate making was one of the factors which justified the increase in the equity thickness.⁹
33. CME agrees with the Board and rejects the notion that moving to incentive ratemaking should produce a change in Board approved capital structure.

⁶ Transcript Volume 18, pp.157-159.

⁷ Exhibit K18.4, p.26.

⁸ EB-2013-0321 Decision with Reasons, November 20, 2014, p.114.

⁹ Exhibit C1, Tab 1, Schedule 1, Attachment 1, pp.4-5, 29; Exhibit M3, pp.21, 28.

34. Concentric suggested during cross-examination that the “principal risks” identified were: the Darlington refurbishment, Pickering Extended Operations, and the move to IRM for nuclear and the hydroelectric business.¹⁰

35. However, when Mr. Coyne was pressed on cross-examination, he admitted the following:

Q: *Have you looked at whether other Ontario utilities that were shifted to incentive regulation actually experienced capital flight or increased difficulty in attracting capital?*

A: *No, we have not examined that, nor have we studied it.*¹¹

36. Given that Concentric hasn't seen fit to examine or study whether this is actually a phenomenon that impacts Ontario utilities, CME submits that Concentric has not demonstrated that this is a relevant consideration when determining OPG's future equity thickness.

37. CME also finds it troubling that a move to incentive rate making would end up costing ratepayers through an increase in equity thickness. The point of incentive rate making was to provide ratepayers the benefit of productivity efficiencies achieved by the utilities. If those gains are going to be clawed back through a higher equity thickness, CME submits that this runs contrary to the spirit and purpose of incentive ratemaking.

2.3 Revenue Deferred Under Rate Smoothing

38. Concentric, in their report, states that OPG's rate smoothing program as initially proposed would increase OPG's risk profile.

39. According to Concentric, the risks are twofold:

- (a) First, there is an “inherent uncertainty related to the collection of amounts deferred for a decade into the future”;¹² and

¹⁰ Transcript Volume 18, p.124.

¹¹ Transcript Volume 18, pp.3-4.

¹² Exhibit C1, Tab 1, Schedule 1, Attachment 1, p.28.

- (b) Second, there is a “risk of lower than expected cash flow levels that could impact the Company’s credit metrics, as well as its ability to meet long-term obligations, undertake capital expenditures and otherwise manage cash needs”.¹³

2.3.1 The Uncertainty of Collection of Amounts Deferred Into the Future

40. During cross examination, Concentric admitted that the wording of Ontario Regulation 53/05 would “afford a significant probability that those dollars (deferred) will be recovered.”¹⁴ As a result, Concentric felt that the ‘inherent uncertainty’ was not a material risk to their recommendation that OPG’s equity thickness should increase by 400 basis points to 49%.¹⁵
41. Concentric also suggested that collecting amounts in the future was risky due to the time value money;¹⁶ however, during CME’s cross examination, Concentric confirmed that the rate smoothing deferral account will attract interest, which addressed their concern.¹⁷
42. CME submits that, on the basis of this evidence, the Board should not consider either the uncertainty of future collection or the time value of the money risk factors in determining what the appropriate equity thickness should be.

2.3.2 Cash Flow Impacts

43. Concentric’s concern regarding cash flow problems was based on OPG’s original smoothing proposal. Essentially the concern is that by deferring revenue into the future, OPG’s credit metrics would be further strained, and there would be a risk of credit rating downgrades as a result.
44. OPG updated their smoothing proposal. In the new proposal, OPG would defer approximately \$.4 billion less than the previous proposal.

¹³ Exhibit C1, Tab 1, Schedule 1, Attachment 1, p.28.

¹⁴ Transcript Volume 18, pp.5-6.

¹⁵ Transcript Volume 18, pp.5-6.

¹⁶ Transcript Volume 18, pp.5-6.

¹⁷ Transcript Volume 18, p.87.

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45. On cross examination, Concentric acknowledged that the new smoothing proposal would improve OPG's credit metrics, including FFO interest coverage, and debt to EBITDA.¹⁸
46. By reducing the amount deferred, OPG would improve their credit metrics, and CME submits that, should that approach be adopted, this factor cited by Concentric should not be taken into consideration when determining the appropriate equity thickness.

2.4 OPG's Credit Metrics

47. Concentric and Brattle both pointed to OPG's changing credit metrics as a source of increased risk which warranted a higher equity thickness. Concentric used the metrics developed by OPG, whereas Brattle conducted their own analysis of the underlying data.
48. The usefulness of credit metrics and ratings agencies are encapsulated in the following description given by Brattle:

Credit metrics assessments are used by credit rating agencies to determine solvency and liquidity risks associated with borrowing entities, such as OPG, and provide a strong indication of the financial strain brought about by increased leverage or changes to earning capabilities or cash flow of borrowing entities. ¹⁹

49. Credit rating agencies take into account these metrics to determine the solvency and liquidity risks associated with borrowing entities. In OPG's case, the credit ratings agencies have not altered OPG's credit rating based on these metrics.
50. As others have pointed out, the only such downgrade came as a result of a downgrade in the province of Ontario's credit rating.²⁰
51. It is also worth noting that the credit ratings agencies did not downgrade OPG's credit rating when the Board set the equity thickness to 45% in EB-2013-0321,²¹ nor did they do so after learning of OPG's planned capital expenditures with respect to the DRP.²²

¹⁸ Transcript Volume 18, pp.7-9.

¹⁹ Exhibit M3, p.8.

²⁰ Transcript Volume 18, p.48.

²¹ Transcript Volume 18, p.52.

²² Exhibit K18.4, p.17.

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52. In fact, in April of 2016, despite planned DRP spending, DBRS gave OPG an A(low) rating, with a stable trend.²³ Similarly, Standard and Poors rated OPG as bbb- stand-alone credit rating, including the expenditures on the DRP with a stable outlook.²⁴ They stated

We believe a negative rating action on OPG is highly unlikely in the next 24 months ...

53. DBRS also considers a “Good” equity thickness to be between 45.00% and 49.99%.²⁵ An equity thickness of 47% would adequately meet the rating agency’s threshold for an appropriate equity ratio.
54. If the ratings agencies do not consider OPG’s credit metrics to be problematic enough, or strained enough to change their outlook on the company, then CME submits the Board should not change OPG’s equity thickness either.

2.5 The Darlington Refurbishment Project

55. It is a matter of common ground between CME and OPG that the DRP is a significant capital expenditure. CME agrees with Board staff’s submissions, however; that Concentric has overstated the impact that the DRP has in light of the context of OPG’s application and regulatory framework.

2.5.1 OPG’s Application is Inconsistent

56. CME submits that OPG’s application is inconsistent regarding the DRP.
57. On one hand, they are arguing that the Board should have the utmost confidence that they will responsibly and judiciously manage the DRP project.
58. On the other, they state that their equity thickness should be significantly higher than previous applications due to the risk that the DRP represents, from issues such as schedule and cost slippage.²⁶

²³ Exhibit K18.4, p. 10.

²⁴ Exhibit K18.4, p. 17.

²⁵ Exhibit L, Tab 3.1, Schedule 1, Staff 017, Attachment 1, p.10.

²⁶ Exhibit C1, tab 1, Schedule 1, Attachment 1, pp.20-21.

59. CME finds this troubling and suggests that if OPG is serious regarding the level of planning and thought that went into the DRP, it also necessarily means the risk of schedule and cost slippage should not be considered that great.

2.5.2 Favourable Regulatory Framework

60. As discussed by Board staff in their submissions, even if the DRP started to slip in terms of cost or schedule, OPG has the benefit of a very strong regulatory framework from the province in the form of Ontario Regulation 53/05.
61. Ontario Regulation 53/05 section 6(1)4 establishes that “the Board shall ensure” that OPG recovers prudently incurred capital and non-capital costs, as well as prudently made firm financial commitments that relate to the DRP.²⁷
62. The regulation also establishes the need for the DRP:

[T]he Board shall accept the need for the Darlington Refurbishment Project in light of the Plan of the Ministry of Energy known as the 2013 Long-Term Energy Plan and the related policy of the Minister endorsing the need for nuclear refurbishment. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2; O. Reg. 312/13, s. 4; O. Reg. 353/15, s. 3; O. Reg. 57/17, s. 2.²⁸

63. CME further submits that there is no evidence on record to suggest that there will be a change in this legislation at any point during the application term. As a result, CME submits that the risks of the DRP to OPG’s ability to attract capital has been greatly overstated by Concentric.

2.6 Pickering Extended Operations

64. CME submits that, to the extent that OPG proceeds with its plan to extend Pickering Operations, the extension of operation would not represent a materially different risk relative to the risk which were considered by the Board in EB-2013-0321.
65. In their report, Concentric suggests that there are a number of concerns related to Pickering Extended Operations, including the potential for a future determination that

²⁷ O.Reg. 53/05, section 6(1)4.

²⁸ O.Reg. 53/05, section 12(v).

extended operation is not feasible, the risk of recovery of expenditures incurred; and foregone production;²⁹ however, capital investments at Pickering, whether they are undertaken in the context of extended operation or otherwise are also afforded the protection of the Capacity and Refurbishment Variance Account.

66. During the cross-examination performed by SEC, Concentric acknowledged that those risks are the same as the risks that existed in EB-2013-0321, save for reliability concerns that come from the plant being three years older:

Q: *But in terms of the Pickering risk itself, the risk is -- the only change in risk is that the plant is older, right? That's the only change?*

A: *Which increases reliability concerns, yes, as we stated in that paragraph.³⁰*

67. Once you strip away the concerns that are identical to those that existed in EB-2013-0321 all that is left is the fact that the plant is 3 years older. CME acknowledges and agrees that the risk a nuclear plant faces will increase over time, but given the longevity of nuclear generating facilities' useful lives, CME submits that the fact that the Pickering facility is three years older is not a substantial enough risk to impact the determination of what the appropriate debt to equity ratio should be for OPG.
68. CME submits that Pickering Extended Operations is not a significant factor in determining whether OPG should be granted higher equity in their capital structure. The risks have not increased enough since EB-2013-0321 to make it a contributing factor in increasing OPG's risk profile.
69. Should the Board find otherwise, CME submits that this should be one more economic cost that should be considered when determining whether, and to what degree ratepayers bear the burden of Pickering's extension.

²⁹ Exhibit C1, Tab 1, Schedule 1, Attachment 1, p.22.

³⁰ Transcript Volume 18, p.140.

2.7 Pension and OPEB Costs

70. CME notes that the Board has recently published a report entitled: Regulatory Treatment of Pension and Other Post-employment Benefits (“**OPEBs**”) Costs.³¹
71. In that report, the Board finds that it will use the accrual accounting in rate setting for pension and OPEB amounts, unless it would result in an unjust result.³²
72. This result was not known to Concentric at the time of writing the report, or giving evidence in the oral hearing. CME submits that since accrual accounting has been determined to be the accounting method of choice from the Board that this risk is no longer present, or is greatly diminished and should not be considered when determining the appropriate equity thickness for OPG.

2.8 The Comparison between OPG and the Comparator Group

73. As the second prong of their analysis, both Concentric and Brattle compare OPG to a group of roughly similar companies, in order to determine whether or not OPG is of lower risk, a similar risk, or higher risk than the group.
74. This comparison is never an exact science. Finding two companies that are even closely alike in terms of: regulatory framework, generation and distribution mix, type of generation mix, and capital expenditures is a difficult, if not impossible task. That is why adjustments are made when looking at the subject utility as part of the analysis.
75. For example, when Concentric compares OPG to the group, they find that OPG has more generation, rather than distribution than the group, because generation is considered more risky, Concentric opines that that factor weighs in favour of OPG being more risky than the comparator group.³³

³¹ Ontario Energy Board, May 18, 2017 (“Pensions and OPEBs Report”).

³² Pensions and OPEBs Report, p.8.

³³ Exhibit C1, Tab 1, Schedule 1, Attachment 1, pp.35-36, 41.

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76. Similarly, Brattle opines that OPG's has a higher nuclear generation risk than Brattle's refined comparable sample.³⁴
77. This is ultimately the comparative exercise, identify differences between the subject utility and the comparator group, and use the differences as directional markers to determine whether that factor makes them more or less risky.
78. Concentric and Brattle did not however, acknowledge two factors which make OPG less risky than the comparator entities: it's Canadian, and it is fully owned by the government.
79. Canadian utilities tend to have lower equity thicknesses compared to their American counterparts. Fortis and Emera were both considered as part of Concentric's analysis, and with a respective 43.31% and 40.27% equity,³⁵ they are the lowest in Concentric's sample group.
80. This phenomena has been observed by Concentric both in Gas and electricity distributors. During cross-examination, Concentric acknowledged that Canadian distributors will have approximately 10% less equity than their American counterparts.³⁶
81. However, on cross-examination, Concentric admitted that they "did not make an adjustment for the difference between Canada and the U.S.A".³⁷
82. The reason for this, according to Concentric, was that:
- [T]his Board has found in the past that it finds the use of U.S. proxy groups to be useful when it comes to purposes of setting cost of capital, and because the risk differences between OPG and this proxy group are so substantial we did not feel as though any such adjustment would be necessary or appropriate.***³⁸
83. With respect to the statement that the Board has found U.S. comparators useful: we submit that finding information useful, or valuable, is not the same as saying that there should be no adjustment to the information to account for the differences inherent in U.S. and Canadian utilities.

³⁴ Exhibit M3, p.44.

³⁵ Exhibit C1, Tab 1, Schedule 1, Attachment 1, p.39.

³⁶ Transcript Volume 18, p.170.

³⁷ Transcript Volume 18, p.175.

³⁸ Transcript Volume 18, p.175.

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84. For example, one might find it useful to determine how long a hockey rink is by understanding how far away center ice is from one end of the arena. That does not mean that center ice is the end of the rink. It is a point of reference, not the end of the discussion.
85. The simple fact is that the universe of utilities in North America is small. The universe is smaller still when looking just at Canadian utilities. The integrity and explanatory power of a comparison depends upon a critical mass of comparators, so it is only natural that the Board should find the use of American utilities useful.
86. This does not mean that when comparing US and Canadian utilities that no account should be taken of the differences. Regulators across Canada have set lower equity thicknesses for Canadian companies for reasons that are unique to Canada and the utilities which operate here. To take U.S. data without accounting for the differences is akin to holding Canadian utilities to American standards without reason or justification.
87. CME submits that this is the wrong approach. Although we agree that a 10% difference should not be applied mechanically, the experts weighing the capital structure should make *some* adjustment when using primarily U.S. data.
88. The second reason given by Concentric is that the difference in risk between OPG and the proxy group were so substantial that an adjustment would be inappropriate. Respectfully, Concentric's own evidence contradicts that assertion.
89. In their report, Concentric finds that the mean equity of the comparator group to be 49.06% and the median to be 49.95%.³⁹ On this basis, Concentric recommends a floor of 49% equity.⁴⁰
90. In setting a floor, CME submits that Concentric would feel the fair return standard satisfied by a 49% equity ratio, and indeed that is what OPG submits is appropriate.

³⁹ Exhibit C1, Tab 1, Schedule 1, p.40.

⁴⁰ Exhibit C1, Tab 1, Schedule 1, p.5.

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91. Setting the return on equity at the median of the proxy group is inconsistent with Concentric's notion that the risk difference between OPG and the proxy group are so substantial that an adjustment isn't necessary.
92. As discussed before, the difference for Canadian and American distributors is 10%. In contrast, the substantial difference in risk that OPG represents can be satisfied by an equity thickness that is at the mean of the proxy group.
93. In CME's submission an adjustment that uses 10% as a guidepost is more than significant enough to come into play in a circumstance where the risk differences are such that setting the equity thickness at the mean for the proxy group is sufficient. Concentric's contention to the contrary is, in our opinion, incredible and should be rejected by the Board.

2.9 The Board Should Not Approve the Establishment of a Hydroelectric Capital Structure Variance Account

94. OPG proposes the establishment of a deferral and variance account to capture the impact of the difference between the capital structure approved by the OEB in this proceeding and the capital structure approved by the OEB in EB-2013-0321 that underpins the hydroelectric payment amounts in this proceeding for 2017 to 2021.
95. While CME supports the proposition that, consistent with the Board's holdings in previous decisions, capital structure should be set on a company wide basis, CME disagrees that OPG should be entitled earn additional revenue on the basis of a capital structure which is different than the capital structure which forms part of the "going in" rates for the IR term for the purposes of determining OPG's hydroelectric payment amounts.
96. On cross examination, OPG was asked to confirm that the proposed "going in" rates, being the hydroelectric payment amounts approved in EB-2013-0321, would include an

approved ROE of 9.33 percent, being an average of the approved ROE for 2014 and 2015, notwithstanding that 2017 approved ROE is lower at 8.78 percent.

97. OPG confirmed that the “going in rate” includes an ROE of 9.33% stating:

MR. FRALICK: This is the basic compact of going into an IRM framework, in that the base rate were established in 2014 and 2015, and the fact we're not rebasing at this point in time means the ROE at the time of the rebasing would form the basis for ROE for the term of the IRM ... and that changes in the ROE through time are captured in the annual update of the inflation factor.

98. OPG also confirmed in an undertaking that the impact on the hydroelectric revenue requirement if ROE is update from 9.33% to 8.78% is approximately \$25 M per year over the IR period.⁴¹ In other words, OPG is receiving a benefit of approximately \$125 M over the IR period because it the “going in” rate allows it take advantage of the higher approved ROE which was in place during 2014 and 2015. While CME accepts that this is part of the “basic compact of going into an IRM” and further acknowledges that the issue of the appropriate going in rate is a settled issue as between the parties, CME states that it would be unfair to allow OPG benefit from the higher ROE implicit in the going in rate and also receive the benefit of a new capital structure, to the extent that one is approved by the Board.
99. CME therefore submits that the Board should refuse to establish the requested deferral and variance account.

3.0 NUCLEAR RATE BASE ADDITIONS

100. In their application, OPG is requesting that the Board approve forecast rate base in-service additions of \$389, \$315.2, \$239, 300.4 and \$215.6 million in the respective years of the plan's term.⁴²

⁴¹ Undertaking J20.2.

⁴² Exhibit D2, Tab 1, Schedule 2, p. 2.

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101. These amounts reflect the addition to rate base of a number of projects including the Darlington Auxiliary Heating System (“**AHS**”) project and the Darlington Operations Support Building Refurbishment (“**OSB**”) project.
102. CME agrees with Board staff that the evidence in these proceedings has demonstrated that both the AHS and OSB projects have been mismanaged by OPG, and that this proceeding is the appropriate venue for the Board to consider arguments on whether the incremental costs were prudently incurred, since these projects are either completed or quite close to completion.
103. For the reasons set out in more detail below, CME submits that the Board should decline to include in rate base the entire incremental cost of completing the AHS and the OSB projects, measured as the variance between the first execution business case cost estimate and the final cost of these projects, less removal and decommissioning costs.

3.1 OPG's Mismanagement of the Projects

104. There is a significant amount of evidence demonstrating that OPG's management of the AHS and OSB projects fell short of what ratepayers should reasonably expect.
105. The AHS project, according to its first execution business case, had a total cost of \$45.6 million.⁴³ The updated cost that has been approved by OPG for the project is \$107.1 million,⁴⁴ an overage of \$61.5 million. The total approved spend therefore is approximately 235% of the original execution business case budget.
106. The forecast in-service amount is slightly below that at \$98.7 million, which still represents a 116% increase over the original execution business case amount.
107. Similarly, the OSB project had a first execution business case which estimated the total cost for the project at \$47.8 million.⁴⁵ The total cost of the project ended up being \$62.7

⁴³ Undertaking JT2.16.

⁴⁴ Undertaking JT2.16.

⁴⁵ Undertaking JT2.16.

million,⁴⁶ an overage of \$14.9 million dollars. The total approved spend is approximately 131% of the original execution business case budget.

108. The in-service amount is slightly lower at \$60.6 million.⁴⁷ This represents 26% increase over the original execution business case amount.

109. The 2nd Quarter 2014 Report to the Nuclear Oversight Committee of OPG's Board of Directors contains critical analysis on why these projects are substantially over budget:

Our findings show that the predominant cause of these overruns was P&M's original strategy to use a project "oversight" management model for the EPC contracting strategy utilized by OPG that was inappropriate in application and lead to a series of cascading management failures and contractor performance issues. The oversight management model employed a disengaged, "hands-off" approach by the P&M organization which caused the fledgling P&M organization to: (1) wrongly assume that the contractors understood the scope on the basis of performance specifications that outlined scope initial requirements; (2) utilize inexperienced project managers; (3) allow Operations & Maintenance and other OPG stakeholders to initiate scope changes to these projects long after the conceptual design period ended; (4) to accept the poor schedules and cost estimates by the contractors without appropriate vetting and challenge, and which were not updated to incorporate the impact of scope changes on a timely basis; and (5) to inaccurately or untimely report the projects' progress, risks and cost and schedule overruns to the DR Team and senior management.⁴⁸

110. Of particular concern is the evidence that OPG's project management organization:

- (a) Employed a "hands off approach" which was inappropriate and led to cascading management failures;
- (b) failed to challenge the cost estimates given by contractors, and failed to update the impact of the scope changes on a timely basis; and,
- (c) reported the risks and cost overruns to senior management late or inaccurately.

111. Ratepayers should not be required to bear the burden of cost increases flowing from this degree of mismanagement.

⁴⁶ Undertaking JT2.16.

⁴⁷ Undertaking JT2.16.

⁴⁸ Report to Nuclear Oversight Committee- 2Q 2014 Darlington Nuclear Refurbishment Project. Exhibit L, Tab 4.3, Schedule 1, Staff-072, Attachment 4, p.6.

3.2 Amounts to be Included in Rate Base

112. CME submits that the entire amount of the difference between the first execution release and the final amount should be permanently disallowed from entering rate base, less whatever costs are necessary for removal and decommissioning the AHS and OSB projects.
113. OPG has argued that it should be entitled to recover in rates the actual cost of completing the AHS and OSB projects because, had more detailed engineering and cost estimating work been undertaken at the outset, the execution release estimate would have been close to the actual cost to complete the projects.⁴⁹ As articulated by OPG's auditor:

*Moreover, many of the cost variances appear to be scope based, i.e. OPG is getting more value albeit for a higher cost.*⁵⁰

114. CME urges the Board to reject this reasoning.
115. The baseline budget for a project is determined with reference to how much the organization believes it will cost, having regard to the engineering, design and execution challenges that are involved.
116. The evidence in this proceeding demonstrates unequivocally that the completion of engineering at the appropriate time gives management the ability to evaluate and exercise cost saving options which are not available later in the execution of a project.
117. During the oral hearing, SEC had the following exchange with an OPG witness regarding the importance of the gated process:

MR. LAWRIE: Some projects didn't have all the documentation they should have had.

MR. RUBENSTEIN: And if we look at the impact, the impact of when this occurs is potential for cost increases and schedule delays due to insufficient independent oversight and control of project activities and objectives.

⁴⁹ OPG Argument-in-Chief, p.28.

⁵⁰ Supplemental Report to Nuclear Oversight Committee – 2Q 2014 Darlington Nuclear Refurbishment Report, Undertaking J15.3, Attachment 1, p.3.

MR. LAWRIE: *There is risk without having a solid base line, yes.*

MR. RUBENSTEIN: *So how do we know that the table you showed me before, with the superseding business cases, projects going in-service or have already gone in-service, this isn't the reason why there's the cost increases, that OPG just didn't implement the process that its own documents said it should have.*

MR. LAWRIE: *As I mentioned earlier, these wouldn't directly contribute to increased cost of a particular pump installation, or the cost increase to a particular design. What it would do is give us a late indication that the project is performing off plan, not having a solid base line to compare current performance to.*

MR. RUBENSTEIN: *I would assume earlier indication allows you to minimize cost issues, correct?*

MR. LAWRIE: *It has an opportunity to minimize impact.*

MR. RUBENSTEIN: *And because you didn't do that, the costs may have been higher than they otherwise would have been.*

MR. LAWRIE: *It's possible.*⁵¹

118. Burns & McDonnell and Modus Strategic Solutions Canada (BMcD/Modus), the auditors which OPG retained to review their execution of the project have also confirmed a robust execution release estimate can give management additional options during critical periods in the projects' lifecycle that are irreplaceable.
119. BMcD/Modus observes that during the AHS project, the project management team characterized the cost estimate of AHS as a class 3 estimate, and the cost was estimated to be \$45.6 million (the amount later approved by the Board for this project). All of this was done at a time when the engineering hadn't even begun.⁵²
120. As a result of this cost estimate, "the option of building a new AHS was preferred over seven alternatives", based primarily on the projected cost.⁵³ Based on the foregoing, it appears that at least some of the seven alternatives contemplated not constructing a new auxiliary heating system at all.

⁵¹ Transcript Volume 14, pp.111-112.

⁵² Report to Nuclear Oversight Committee- 2Q 2014 Darlington Nuclear Refurbishment Project. Exhibit L, Tab 4.3, Schedule 1, Staff-072, Attachment 4, p.9.

⁵³ Report to Nuclear Oversight Committee- 2Q 2014 Darlington Nuclear Refurbishment Project. Exhibit L, Tab 4.3, Schedule 1, Staff-072, Attachment 4, p.9.

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121. CME submits that OPG's failure to undertake appropriate engineering at the outset deprived ratepayers of possible alternatives which may have been capable of being accomplished at a cost significantly less than the \$107.1 million which represents the actual cost of the AHS project.
122. The lack of reporting by OPG's project managers' would have compounded the effect of insufficient engineering. According to BMcD/Modus, despite expending \$20 million, more than half of the approved budget (without contingency) the DR Project's and Campus Plan reports never varied from the BCS amount.⁵⁴
123. This lack of reporting:
- [D]eprived senior management and the Board the option of revisiting the original BCS analysis in order to determine if building a new AHS facility continues to be the preferred option – and if not, change course.***⁵⁵
124. This is especially troubling considering that, as of November of 2012, there were three competing options to building the AHS facility that were priced at less than \$50 million.⁵⁶
125. The opportunity to choose a different alternative, or to stop the project and go with a different alternative are time sensitive.
126. In light of the above, CME submits that OPG's argument that ratepayers are receiving value for the scope of work which was ultimately involved in completing the AHS project fails to take into account the lost opportunity to pursue alternative and less costly options for achieving the same outcome.
127. OPG's management of the OSB project was not any better according to the evidence. In the "Project Over-Variance Approval" form, OPG explained that the majority of what was then a \$14.4 million overage was due to: revisions to the design packages due to

⁵⁴ Report to Nuclear Oversight Committee- 2Q 2014 Darlington Nuclear Refurbishment Project. Exhibit L, Tab 4.3, Schedule 1, Staff-072, Attachment 4, p.9.

⁵⁵ Report to Nuclear Oversight Committee- 2Q 2014 Darlington Nuclear Refurbishment Project. Exhibit L, Tab 4.3, Schedule 1, Staff-072, Attachment 4, p.9.

⁵⁶ Report to Nuclear Oversight Committee- 2Q 2014 Darlington Nuclear Refurbishment Project. Exhibit L, Tab 4.3, Schedule 1, Staff-072, Attachment 4, p.9.

incomplete original documentation and increased work and delays needed to complete the revisions.⁵⁷

128. An OPG senior manager writes that "This is poor performance".⁵⁸
129. On that basis, CME submits that the entire incremental cost of both the AHS and OSB projects, less the decommissioning and removal costs, should disallowed.
130. Besides the fact that the disallowances recommended by CME are entirely justified by the evidence in this proceeding, the effect of the disallowance will be to emphasize the importance of effective project management as OPG embarks the Darlington Refurbishment Project (DRP).
131. OPG's has adopted a multi-prime contracting strategy for the DRP, meaning that OPG remains responsible for coordinating multiple contractors and retains the risk with respect to project integration. Schiff-Hardin testified that in order to be successful using this approach:

[T]he owner must employ a strong, capable, and experienced project management team that is able to coordinate and track the work of such a complex project/program. Otherwise, the multi-prime approach is at risk to miss schedule and cost objectives, thereby preventing the owner from securing the benefits of a multi-prime contracting strategy as discussed later in this testimony.⁵⁹

132. It is critical that OPG's project management excels during the DRP, too much money is at stake for OPG to continue the management practices it was using during the AHS and OSB projects.
133. BMcD/Modus highlight some of OPG's previous project management failure in the following passage:

Based on our observations, it appears that all P&M's identification of risks is a "check-the-box" activity due the fact that having a list of risks is a prerequisite to obtaining a funding release. P&M does not actively manage its on-going risks as a part of an effective risk management program. As an example, the risk sections of the D20 and AHS BCSs consist of lists of potential risks and some

⁵⁷ Exhibit D2, Tab 1, Schedule 3, Attachment 1, Tab 1, p.1.

⁵⁸ Exhibit D2, Tab 1, Schedule 3, Attachment 1, Tab 1, p.5.

⁵⁹ Exhibit M1, p.25.

evaluation of their nature, but it is not apparent that these risks in any way influenced the calculation of these projects' contingency, nor are there any regular reviews or updates of these risks until required to do so in order to pass a gate and obtain a funding release. Once a project obtains full funding for execution, very little, if any, attention is paid to day-to-day risk management, including the ongoing identification of new risks and opportunities as well as the formalized implementation of risk mitigation strategies. Additionally, there is no structured or defined risk program management oversight (such as the NR Risk Oversight Committee).⁶⁰

134. These problems are not unique to the AHS and OSB projects. Recent audit reports have continued to identify these same issues in other projects.

135. In a more recent audit report dated March 9, 2016:

It was noted that of the six projects sampled in the execution phase, all six projects did not have an Estimate at Completion ("EAC") for the project established at either a Class 3 or Class 2 level and they were still performing detail engineering work while in their execution phase.⁶¹

136. According to OPG's internal audit group, the above finding warranted a "High" risk rating, signifying that it presents a risk that could potentially have severe/major impact on the project, including from a financial sustainability perspective.

137. The 2016 audit demonstrates that project management issues first identified in the execution of the AHS and OSB projects appear to be persisting in projects being executed today. These issues must be addressed by OPG immediately.

138. The overages on the OSB and AHS projects, if they were replicated on the DRP's scale would be staggering. If the DRP went over by 31%, as the OSB project did, it would cost ratepayers nearly \$4 Billion more than estimated. If the DRP went 135% over budget, as the AHS project did, it would end up costing rate payers approximately \$17 Billion more than estimated.

139. Ratepayers cannot afford to have OPG manage the DRP the way it managed the AHS and OSB projects.

⁶⁰ Report to Nuclear Oversight Committee- 2Q 2014 Darlington Nuclear Refurbishment Project. Exhibit L, Tab 4.3, Schedule 1, Staff-072, Attachment 4, p.8.

⁶¹ Ontario Power Generation, Internal audits on Project Controls Audit – Project & Modifications Group, March 9, 2016, Undertaking J7.3, Attachment 2, p.1.

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140. CME submits that the Board should disallow the entire incremental cost, less removal and decommissioning costs to send a clear signal to OPG that it cannot afford to manage the DRP the way it managed the AHS and OSB projects.

4.0 DARLINGTON REFURBISHMENT PROJECT

141. OPG is seeking approval of in-service additions to rate base in the amount of approximately \$4.8 Billion associated with the refurbishment of Unit 2. This includes contingency, interest and escalation.
142. Additionally, OPG is seeking \$377 million for the Campus Plan projects which are also slated to go into service during the bridge year and test period.
143. The contingency amount associated with Unit 2 of the DRP is \$694 million. Contingency has been estimated at a P90 confidence level. This confidence level is the product of statistical modelling of risks identified by OPG and signifies that there is a 90% likelihood that the estimated contingency amount will be sufficient to cover the risks which may materialize during the refurbishment of Unit 2.
144. As described in further detail below, CME urges the Board to disallow certain of OPG's costs in this application, and insist upon a prudence review of all of the costs incurred during the DRP, not just of costs incurred over and above the amount budgeted by OPG in their P90 confidence estimate.
145. This review should be aided by a granular reporting by OPG regarding the contingency amounts allocated to each component of the program, and the OPG should provide the Board with the reporting that is elucidated by Schiff Hardin in undertaking J7.1.

4.1 A Full Prudence Review of ALL DRP Costs Incurred is Necessary

4.1.1 Ontario Regulation 53/05 Precludes approval of Forecast Costs

146. OPG takes the position that to the extent that it is able to complete the refurbishment of Unit 2 without exceeding their \$4.8 billion estimate, inclusive of contingency as

discussed above, none of the costs associated with the refurbishment of Unit 2 would be subject to a prudence review as demonstrated by the following exchange that occurred on cross-examination by CCC:

Q: *Now, the way the application is framed suggests that there wouldn't actually be a prudence review. The assumption would be that 4.6 billion came in under cost, even though the original -- even though it's eaten into the contingency amount, it's come in under the \$4.8 billion total estimate, and, therefore, there is no need for a prudence review, and it's close to rate base, and there'd be a negative amount collecting in the CRVA which would eventually be refunded to ratepayers. That's what you anticipate happening in that scenario; is that right?*

A: *That's correct.* ⁶²

147. CME has had the benefit of reading draft submissions shared by GEC, and believes that their view regarding the proper interpretation of Ontario Regulation 53/05 warrants consideration by the Board.

148. In particular, CME agrees that use of the past tense in reference to costs and financial commitments **"incurred"** explicitly precludes any prospective conclusion about the prudence of forecast costs and financial commitments. Specifically, Subsection 6(2)4 of O.Reg 53/05 states:

The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs and firm financial commitments incurred in respect of the Darlington Refurbishment Project

...

ii. if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made. [Emphasis added.]

149. Ontario Regulation 53/05 does not provide a carve-out for well planned projects, and doesn't require the Board to determine that costs or financial commitments are prudent before they are incurred.

⁶² Transcript Volume 1, p.128.

150. Instead, the regulation insists that the prudence analysis should occur with respect to costs which “were prudently incurred” and financial commitments which “were prudently made” based on all of the information in existence at the time that the expenditure or commitment was made.

4.1.2 The CRVA Does Not Obviate the Need for Full Prudence Review

151. OPG takes that position that the preapproval of contingency amounts, and the prospective determination that the refurbishment of Unit 2 has been executed prudently to the extent that it is delivered at a total cost of \$4.8M or less will not prejudice ratepayers because, to the extent that the refurbishment of Unit 2 can be accomplished below the \$4.8 Billion 90% confidence level estimate reflected in this Application, the variance between the forecast amount and the actual cost of the project will be refunded to ratepayers through the CRVA.⁶³
152. CME disagrees that the CRVA affords sufficient protection to ratepayers against the inclusion of imprudently incurred amounts in rate base.
153. CME accepts that, particularly in a project as large as Darlington, some risks that have been identified will materialize, and some will not.
154. For example, consider a scenario where the Retube Feeder Replacement portion of the program is completed below the amount budgeted for that project, and fewer of the risks identified with respect to this component of the Unit 2 refurbishment are triggered. Because this component of the project makes up 38% of the total budget for Unit 2,⁶⁴ savings with respect to this component would translate into a large percentage of the total budget in savings.
155. If, in the same scenario, OPG mismanages the Turbine Generator component of the program, even with significant imprudent spending, because the Turbine Generator component is only 5% of the budget, it is possible that the net effect of fewer risks

⁶³ Transcript Volume 5, p.36.

⁶⁴ Exhibit D2, Tab 2, Schedule 1, p.5.

materializing in the Retube Feeder Replacement component and the mismanagement of the Turbine Generator is that the total program comes in under budget.⁶⁵

156. If OPG's proposal is accepted, the CRVA would refund the cost differential between what the Board approved and what was actually spent, but there would be no accountability for the money that OPG spent imprudently.
157. During cross-examination, OPG did not deny that there could be prudent and imprudent causes of cost escalation, and the only way the Board and ratepayers could ensure that the company acted prudently would be to do a review *ex post facto*.⁶⁶
158. CME submits the only way to ensure that ratepayers are not required to fund costs which are imprudently incurred in the delivery of a megaproject such as the DRP is for the Board to engage in a full prudence review of all costs incurred by OPG in the context of the DRP, regardless of whether the project comes in under budget, at budget or over budget.

4.2 Reporting Requirements

4.2.1 OPG Should Report Individual Component Contingency Amounts

159. OPG has structured their contingency amounts such that there are amounts which are earmarked for specific tasks,⁶⁷ for specific program elements,⁶⁸ as well as a general reserve of contingency. The evidence given by OPG's witnesses was that when a certain task does not use all of the contingency which it is allocated, the excess unused contingency funds are flowed back out to the general reserve category of contingency.⁶⁹
160. The general contingency funds may then be used for other project components which will require contingency at a later date.⁷⁰

⁶⁵ Transcript Volume 1, pp.128-129.

⁶⁶ Transcript Volume 1, pp.128-129.

⁶⁷ Transcript Volume 4, pp.54-55.

⁶⁸ Exhibit D2, Tab 2, Schedule 7, p.8, Chart 2.

⁶⁹ Transcript Volume 4, p.53.

⁷⁰ Transcript Volume 4, pp.53-56.

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161. CME submits that the Board should be provided with the individual contingency levels actually spent with respect each component of the project in order to provide visibility into which tasks have required an over expenditure of contingency and which have required less contingency spending than budgeted as well as to provide further detail as to contingency expenditures flowing from general contingency funds.
162. The provision of the above information is well within OPG's capabilities. As part of their application, OPG has already broken out how much of the \$694.1 million of contingency is allocated to each project required to complete the refurbishment of Unit 2.⁷¹ It would not be difficult for them to track how much of that contingency is used on each individual program element.
163. CME agrees with the approach advocated by Board staff in its submissions with respect to the degree of granularity which will be required to support an adequate review of spending associated with the DRP, including as set out in Tables 13 and 14.⁷²
164. This information will provide transparency to the Board and ratepayers regarding what areas or projects are running into difficulties, and it will be of assistance in undertaking the prudence review which CME submits is required as discussed above.

4.2.2 Additional Reporting Requirements

165. CME submits that it is appropriate that OPG report to the Board in the manner specified by Mr. Roberts of Schiff Hardin in undertaking J7.1. We agree that it is critical for the Board to be provided reports which are appropriately tailored for it to be kept apprised of:
- (a) What is going on at the Darlington site including known and potential risks to budget and schedule;
 - (b) The technical, commercial, schedule, safety, quality or other risk management challenges facing the DRP; and

⁷¹ Exhibit D2, Tab 2, Schedule 7, p.8, Chart 2.

⁷² Board Staff Submissions at pp 58-59.

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- (c) The actions OPG is taking to mitigate risk, respond to issues as they arise, and make project management decisions.⁷³
166. CME also endorses the attachments to the report suggested by Schiff Hardin, including:
- (a) Cost Report(s) Covering the Reporting Period;
 - (b) Earned value Metrics by discipline and area;
 - (c) Level 1 Schedule Planned and Current comparison;
 - (d) Level 2 Schedule Planned and Current comparison;
 - (e) Supplemental exhibits, as appropriate;
 - (f) Audit reports for all audits performed during the Reporting Period; and
 - (g) Third-part oversight reports submitted to OPG during the Reporting Period.⁷⁴
167. The above information will provide greater clarity with respect to issues arising during the DRP including what information was known to OPG when they encountered the issue and what actions, if any, they took to mitigate or ameliorate risks.
168. This in turn will inform the *ex post facto* prudence review of DRP spending which CME submits is required.

4.3 Disallowances of Costs

4.3.1 The Use of P90's Estimates and the Forecast Approvals

169. CME supports the use of P90 estimates as a project management tool.
170. A consistent theme in the hearing is that megaprojects and mega-programs are almost universally liable to run over budget and over schedule. The use of a P90 estimate helps ratepayers, governments, and the public understand, with more accuracy, what the true cost of a project is going to be, so that they can make an informed choice about whether the cost of the project is worth the benefits it provides.
171. Notwithstanding the foregoing, we submit that the use of a P90 estimate as the basis for rate recovery, in conjunction with Board approval of in-service rate base additions on a

⁷³ These are the requirements for reporting set out by Schiff Hardin at Undertaking J7.1, p.1.

⁷⁴ Undertaking J7.1 p.6.

forecast basis is inappropriate, lacking in transparency, and creates a project spending relationship that is fundamentally contrary to the public interest.

172. Included in the \$4.8 Billion associated with Unit 2 which is scheduled to come into service during the application period, there is \$694.1 million dollars allocated for contingency at a P90 level. According to OPG's response to CCC interrogatory #18, that contingency amount would drop by \$116 million if the project were managed at a P50 confidence level.⁷⁵
173. The relationship between P confidence estimates and budgeted contingency becomes an issue to the extent that there is no prudence review of costs that come in under the budget as recommended by OPG. In this scenario, because an increased P confidence level requires increasing the time and money budgeted, then increasing the P confidence level means both that there is a lower chance that there will be a prudence review, and that a larger amount of costs will be exempt from a prudence review.
174. The benefits of approving budgets at a lower P confidence level were described by OPG's own witnesses during cross examination. When questioned about why OPG doesn't allow contractors to budget to a P90 budget, Mr. Reiner answered:

[I]t could create a situation where there isn't sufficient attention paid to the performance of the project and to resolution of the issues...So the place that we opted to land with the contracts is to create that transparency, create that tension that recognizes there is a 50 percent likelihood this could go over budget so we always have visibility and focus on the issues that are being managed.⁷⁶

175. Our submission is that the ratepayers of Ontario deserve similar transparency into how OPG is managing their projects and should benefit from the same tension described by Mr. Reiner.

⁷⁵ Exhibit L, Tab 4.3, Schedule 5, CCC-018, p.1.

⁷⁶ Transcript Volume 3, pp.46-47.

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176. CME has had the benefit of reading Board staff's submissions on this subject. We agree that reducing the in-service amount requested by OPG by \$144 million is appropriate under these circumstances.
177. The \$144 million reduction corresponds to a reduction in contingency to a P37 confidence level. This is the confidence level of OPG's working schedule.
178. CME acknowledges that according to OPG's Monte Carlo simulation, the final costs of the DRP are more likely than not to be above the P37 estimate; however, due to the CRVA, OPG is not in jeopardy of non-recovery of these funds.
179. As long as the costs are prudently incurred, there is no limit to the amount of money OPG can recover through the CRVA, whether it be commensurate with a P50, P90 or P99 confidence level. Approving amounts commensurate with the P37 level as a part of this application ensures that OPG will remain focused on managing risks as they arise, and provide visibility to the Board and rate payers regarding how they reacted to those risks.

4.3.2 OPG Should Be Held to a P37 Confidence Level on Individual Components

180. During cross-examination, OPG resisted the notion of being reviewed below the project level. During cross-examination, OPG stated:

So I'm not sure I understand your question, but I think we believe what we've done in terms of building a detailed cost, a detailed schedule, a detailed risk register, and the foundation we put this on demonstrates that the company has taken every reasonable action to deliver the project for 4.8, and that if we deliver it at 4.8, that should be a primary measure of prudence.

If you get below that in a project of this nature and start parsing, because we've acknowledged that risks don't materialize in small pieces; they materialize in large pieces, and one project here if the risks materialize may be higher than the number that's on the sheet. Another project may be lower than the number that's on the sheet. And these offset, and we manage it under the 4.8. Conceivably, you could continue to raise that bar until you lowered this test to the

task level, but the farther down you go, the more you're moving toward perfection as a standard.⁷⁷

181. We disagree with OPG's assessment. The standard would not change. The standard has been and would continue to be whether the costs and financial commitments were prudently made. Risks sometimes materialize in greater quantities or to a greater extent than anticipated. As OPG has pointed out on several occasions simply going over the allotted contingency amount for any given task is not *sine qua non* with imprudence.
182. Holding OPG to a P37 across individual components of the project would ensure that the ratepayers of Ontario would have the transparency required to determine which costs were imprudently incurred across the full range of project tasks.

4.3.3 DRP Rate Base Additions – Third Emergency Power Generator Project

183. CME agrees with Board staff's submissions regarding the breadth of the required prudence review of the Third Emergency Power Generator Project. Simply reviewing the difference between the requested in-service amount and the actual in-service amount misses a critical portion of cost escalation, the difference between the initial full release and the proposed in-service amount.
184. There is evidence on the record identifying factors which contributed to the approximately \$62 million cost increase associated with the Third Emergency Power Generator Project⁷⁸:

I'll give you one characterization, and I'll let Deitmar finish up with that. You know, I talked about a gated process and that you can't lock in an estimate until the engineering is sufficiently advanced enough to be able to lock in that estimate. So some of the early estimates that were in our systems were based on some -- when I talk about the third emergency power generators, as an example, was based on preliminary estimates done prior to the completion of engineering.

185. The evidence shows that OPG has systemically failed to use the gated process properly.

⁷⁷ Transcript Volume 2, pp.99-100.

⁷⁸ This is based on an initial release of \$77.2 found at Exhibit D2, Tab 2, Schedule 10, Table 2 and the updated forecast/actual in-service amount found at Undertaking J2.6 Attachment 1, p.1.

186. A gated project management process requires an estimate that is sufficiently detailed in order to be moved past certain gates or stopping points in the project management process. By allowing projects to move through the gated process without the appropriate level of estimates, based on completed engineering, OPG has frustrated the entire purpose of the gated process.

187. During cross examination, OPG's witness described the value of completing detailed engineering in advance going ahead with a project:

*If you understand all the aspects of a design and have that information available to you, then you can do a risk review of saying this particular design has all these aspects that are required during installation. And then you can decide, from a risk management perspective, how you're going to manage them. You may do things in the planning phase that will mitigate or eliminate the risk.*⁷⁹

188. OPG failed to develop the detailed engineering required to have the information described above. OPG went ahead with projects without it. As a result, schedule and cost estimates kept increasing.

189. For the reasons described in more detail in sections 3.1 above, submits that the partial disallowance recommended by staff is insufficient and that the entire variance between the initial execution release and the actual cost of the Third Emergency Generator Project should be disallowed in this instance and in any other scenario OPG has not completed detailed engineering and has failed to properly apply the gated project management process.

4.4 DRP Project Management and Oversight Costs

190. CME agrees with and adopts the submissions of Board staff with respect labour costs for the Project Management and Oversight functions for the DRP during the test period. It is inappropriate for OPG to consistently overestimate their staffing complement, and ask ratepayers to pay extra for employees that OPG is not employing.

⁷⁹ Transcript Volume 14, p.100.

191. CME acknowledges that some of the employee gap is offset through the use of contract labour, which is why the percentage of spending that OPG has not incurred is the appropriate measure for the reduction.
192. CME notes that when OPG answered questions on the topic of understaffing during cross examination, they were not concerned about the level of work that they could complete at their current staffing and contractor level:

Q: *I understood from that conversation that, although you were currently understaffed compared to plan, you're not concerned about having enough people do the work. Is that a fair characterization of what you were saying yesterday?*

A: *Yes. Because even though our staffing numbers are not precisely at the forecast that we had originally developed, we do have access to resources through other means to help us manage the work. So, at this point -- and we have significantly moved up that curve in the last couple of months in terms of getting to the numbers we believe we should be at. But, at this stage, I'm not concerned that we have a shortage of critical resources that would put us at risk.*⁸⁰

193. Given that OPG has consistently over-estimated their employee complement, and they have no concerns that keeping their current amount of employees and contractors will cause any risk to the project, CME submits that Board staff's reduction of 13% to the total requested in-service amounts associated with labour costs for the Project Management and Oversight functions for the DRP during the test period is appropriate.

4.5 Schiff Hardin's Evidence

194. The Board retained Schiff Hardin to provide an independent and objective assessment of the DRP, which included an analysis of, *inter alia*, DRP risks and risk management.⁸¹
195. CME submits that while the work of Schiff Hardin did provide some assistance in developing a detailed list of reporting requirements as described by Board staff, the scope of work undertaken by Schiff Hardin represents a missed opportunity for the

⁸⁰ Transcript Volume 4, pp.65-66.

⁸¹ Exhibit M1, p.5.

Board and ratepayers to receive an independent third party review of the challenges that OPG is currently facing with respect to its execution of the DRP.

196. As described in his report, Schiff Hardin's review was limited to OPG's actions documented in the written material. They did not perform a compliance audit to determine whether OPG has adhered to their internal policies, and did not include any assessments of the DRP's likelihood of success at staying on budget or on schedule.⁸²
197. One of the report's central contentions is that OPG's risks, risk assessment, and project control systems are consistent with industry standard practice.⁸³ Schiff Hardin never actually investigates to see if OPG is following any of these controls or practices, since they never ask OPG employees any questions, nor conduct any sort of compliance audit. We submit that it is impossible to come to a reliable conclusion about OPG's risks, or risk management, without verifying whether OPG has the capacity to implement the procedures and practices that are consistent with industry standards.
198. This is especially troubling in light of the findings of BMcD/Modus that:

Some groups have embraced risk analysis, but others pockets within the team have produced contingency input merely to meet the RQE deadline; despite effective Risk Management tools, infrastructure and a support organization.⁸⁴

199. Schiff Hardin also did not investigate the issues associated with the execution of some of the Facilities and Infrastructure Projects and Safety Improvement Opportunities. In their report, Schiff Hardin noted that the budget for the Heavy Water Facility was originally \$110 million and that this amount had to be increased to \$381.1, which is a variance of 247%.⁸⁵
200. Schiff Hardin goes on to state that OPG's evidence does not contain enough information to determine whether OPG followed the prudent management decision-making

⁸² Exhibit M1, pp.5-6.

⁸³ Exhibit M1, p.7.

⁸⁴ Exhibit K3.2, p.22.

⁸⁵ Exhibit M1, p.15.

framework.⁸⁶ When pressed on cross examination on whether they followed up for more information after discovering the issue, Schiff Hardin was unable to say if they made any specific request of that nature.⁸⁷

201. According to Schiff Hardin's own report:

The true test will be whether OPG actually executes those plans and whether OPG continually and reliably follows the prudent management decision-making framework described above to make reasonable management decisions.⁸⁸

202. Despite this finding, Schiff did not review what previous issues OPG has had with project execution, such as on the heavy water facility project to see whether there might be any common causes which might impact the DRP.

203. The limited scope of the Schiff Hardin evidence deprived the ratepayers of a well-grounded second opinion with respect to OPG's ability to execute on its plans.

5.0 CORPORATE COSTS

204. In response to the Board's decision in EB-2013-0321, OPG commissioned and filed a benchmarking report completed by The Hackett Group regarding four categories of costs: IT costs, HR costs, Finance costs, and Executive and Corporate Services (ECS) costs.

205. After engaging in the Business Transformation initiative, OPG has made gains relative to the peer group. CME is concerned however, that OPG's application does not contain the appropriate initiatives and programs to build on their success and continue to drive down corporate costs.

206. CME submits therefore that it would be appropriate for the Board to set a cost structure which will drive further cost decreases.

⁸⁶ Exhibit M1, p.15.

⁸⁷ Transcript Volume 7, p.33.

⁸⁸ Exhibit M1, p.14.

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207. CME proposes that the Board should allow OPG to recover the amount that it would cost ratepayers if they had achieved the second quartile for finance, and the third quartile for ECS costs in the benchmark completed by The Hackett Group.

5.1 Corporate Cost Reductions

5.1.1 Finance Costs

208. OPG is currently benchmarking in the third quartile for these costs, despite the gains achieved by the Business Transformation Initiative. As far as CME can tell, the only explanation for this result was due to the fact that OPG operates in a unionized environment.⁸⁹ On cross-examination; OPG acknowledged that the peer group of 19 companies included 11 that were unionized.⁹⁰
209. CME suggests that the Board reduce OPG's revenue requirement by the amount require to bring OPG's finance costs in line with the median.
210. According to OPG, this would be a reduction of \$19 million over the course of the IR period.⁹¹

5.1.2 ECS Costs

211. OPG contends that there are a number of drivers of poor results in terms of ECS costs. While CME accepts that there are some particularities of OPG's operations which merit consideration when assessing ECS costs, CME believes that the effect of some of these factors may be overstated or may be factors which similarly impact other members of the peer group identified in the benchmarking study.
212. In particular, OPG states that one of the factors driving higher costs was the unique safety, environmental and regulatory concerns involved with nuclear generation.⁹² CME notes that five members of the peer group are also nuclear operators.⁹³

⁸⁹ Exhibit F3, Tab 1, Schedule 1, p.16.

⁹⁰ Transcript Volume 20, p.29.

⁹¹ Undertaking J20.3, Chart 1, p.1.

⁹² Exhibit F3, Tab 1, Schedule 1, p.15.

⁹³ Transcript Volume 20, pp.29-30.

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213. OPG also relies upon the fact that they work in a unionized environment to justify their poor performance in this category. As discussed above, CME notes that eleven of nineteen of the members of the peer group operate in a unionized environment.⁹⁴
214. CME submits that incenting OPG to bring their ECS to the level of the third quartile is the appropriate amount given the difficulties OPG has encountered in raising its performance on this measure.
215. CME acknowledges that measuring the third quartile with the information available would not be possible with perfect accuracy.
216. We submit that a reasonable approximation of the third quartile could be determined by taking half of the revenue requirement impact of moving OPG's performance to the second quartile, then making an adjustment to account for the inflation of the peer group's third quartile standard.
217. OPG identified a revenue requirement impact associated with moving to the second quartile for ECS costs is \$307 million.⁹⁵ Half of this number therefore would be \$153.5 million.

5.1.3 Static Median Comparison

218. During the oral hearing, CME requested that OPG provide the revenue requirement impact of median performance on finance and ECS costs. OPG provided that for all four of the cost groupings in Undertaking J20.3.
219. When this undertaking was requested, OPG raised a concern that using a static median would not be an appropriate measure. This is outlined in their undertaking response:

Moreover, it is reasonable to expect the peer median value to change over a period of up to 7 years, from 2014 to 2021. In OPG's view, using a static median does not represent a valid comparison. It is likely that inflationary cost pressures would increase the median value over this period. This is consistent with Hackett's

⁹⁴ Transcript Volume 20, p.29.

⁹⁵ Undertaking J20.3, Chart 1, p.1.

approach of escalating peer performance by 2% per year, from 2010 to 2014, in their study (Ex. F3-1-1, Att. 1, p. 6).⁹⁶

220. CME acknowledges that the peer group would likely be impacted by inflationary pressures, so we submit that the Board reduce OPG's revenue requirement by \$100 million rather than \$153.5 million, to account for the inflation in the peer group over the course of the term.
221. CME notes that while it is not ideal to use 2014 benchmarking results, this is the most up to date information that OPG has provided us with on the topic.

5.2 Over-Forecasting

222. SEC has identified that OPG has historically not spent what it says it requires. They propose a reduction in test period costs by 2.5% a year, which matches the variance between approved and actual amounts for the common support costs. CME supports this conclusion as well.

6.0 PICKERING EXTENDED OPERATIONS

6.1 Introduction

223. CME has, on a number of occasions, including in OPG's previous rates applications, expressed its support for nuclear power generation, including investments, such as the DRP, which will increase or extend the operating capacity of nuclear generation assets; however, this support has always been subject to the important caveat that continued operation of and investments in nuclear facilities must be **economically feasible**.
224. During the course of the hearing, it became apparent that there is a reasonable basis to conclude that OPG's plan to extend operations at Pickering is not economically feasible and, far from producing savings for ratepayers, may increase the price of electricity service in Ontario.

⁹⁶ Undertaking J20.3, p.2.

225. While CME appreciates that the Board is not the System Planner, CME submits that the issue of whether to approve costs associated with OPG's plan to extend operations at Pickering is squarely within the Board's jurisdiction established in the *Ontario Energy Board Act* SO 1998, c. 15, Sch. B which provides:

Board objectives, electricity

1 (1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service ...

2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry. (emphasis added)

226. The above objectives are intended to inform the exercise of the Board's jurisdiction, including in determining the just and reasonable payment amounts for prescribed generators.
227. OPG is seeking approval in this hearing of significant funding associated with the operation of its nuclear facility at Pickering beyond 2020 as is currently contemplated in the province's 2013 Long Term Energy Plan.⁹⁷
228. OPG's plan for Pickering Extended Operations would see all six units at Pickering continue to operate until 2022 at which point two units would be shut down and the remaining four would operate until 2024.
229. As indicated in the summary chart included at Table 7.3 of OPG's Argument in Chief,⁹⁸ costs associated with Pickering Extended Operations totalling \$1,952 Billion can be broken down into three categories:

⁹⁷ Ontario Long Term Energy Plan, 2013 at pages 5 and 47.

⁹⁸ OPG AIC at page 92, chart 7.4.

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- (a) Enabling Costs (\$307 M) which include reviews, inspections, maintenance programs and potential modifications required to demonstrate fitness for service beyond 2020 and maintain safety and reliability;
- (b) Restoration of Normal Operating Costs (\$250 M) which are costs required to reverse a planned decline in normal operating and maintenance programs associated with a shutdown of the facility in 2020;
- (c) 2021 Operating Costs (\$1,395 B) comprised of fully allocated OM&A and capital costs necessary to fund Pickering operations in 2021.
230. OPG is proposing to recover the above costs notwithstanding the persistently abysmal performance of Pickering by any objective measure, including Total Generating Cost, Unit Capability Factor and WANO NPI, as illustrated by the Summary of Nuclear Benchmarking Reports prepared by Board Staff.⁹⁹
231. In addition there appears to be no reasonable expectation of improvement with respect to Pickering performance today or at any time throughout the proposed extended operations term. According to OPG's Vice President, Project Assurance and Contract management, Nuclear Projects:
- ... Pickering, though we do know that it compared to benchmark, maybe fourth quartile, in most of these metrics, the reason is it's just technically not possible for Pickering to have anything higher than [fourth quartile] in total generating costs due to the size of its units. So basically, it generates half the amount of each Darlington station unit. So it's technically not feasible for it to reduce its cost.¹⁰⁰*
232. In this context, CME submits that it is reasonable for ratepayers to expect a detailed, current and reasoned explanation of why continuing to operate an inefficient, costly and unreliable facility beyond its planned end of service date will not negatively affect electricity rates, particularly at a time when rising electricity prices in the province are causing increasing hardship for ratepayers.

⁹⁹ Board Staff Submissions at p.83.

¹⁰⁰ Transcript Vol 13, p. 13, lines 5-12.

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233. In support of its plan to extend Pickering's operations, OPG points to an economic analysis undertaken by the IESO in 2015 and a number of statements made by the Ontario Minister of Energy and takes the position that "the evidence demonstrates that Pickering can operate cost-effectively over the IR term and will provide value to customers."¹⁰¹
234. CME disagrees with this proposition as discussed in more detail in the following submissions.
235. CME acknowledges the considerable efforts of Environmental Defence in bringing to light the significant potential for negative impacts on the price of electricity service associated with OPG's plan for Pickering Extended Operations and the absence of sufficient economic analysis supporting OPG's planned expenditures taking into account accurate and current production forecasts, fully allocated costs and prices associated with comparable alternative sources of generating capacity.

6.2 IESO's Economic Analysis

236. OPG relies on an economic analysis undertaken by the IESO in March of 2015 and updated in October of 2015 which estimated the net present value of the change in electricity system costs of extended operations relative to the closure of Pickering in 2020, as contemplated in the current LTEP by comparing the cost of extended operations against the cost of operating a single-cycle gas generator.¹⁰²
237. Based on the information available to it at the time, the IESO concluded that Pickering Extended Operations "offers moderate probabilities for savings".¹⁰³ However, at no point in its economic analysis does the IESO recommend OPG's plan for continued operations

¹⁰¹ OPG AIC, p. 5, line 1-2.

¹⁰² Exhibit F2 Tab 2, Schedule 3, Attachment 1, p. 18.

¹⁰³ Exhibit F2 Tab 2, Schedule 3, Attachment 1, p. 18.

at Pickering. It simply states that “on balance, Pickering extension to 2022/2024 is an option worth continuing to explore.”¹⁰⁴

238. There are three main variables which influenced the IESO’s economic analysis namely: Pickering production, Pickering operating costs and natural gas prices. Evidence elicited by Environmental Defence and other intervenors has demonstrated that if these assumptions were updated with current information, it is likely that the same analysis would now demonstrate that Pickering Extended Operations has become uneconomic.

6.2.1 Pickering Production

239. The IESO notes that “as production from Pickering decreases, the likelihood of savings also decreases.”¹⁰⁵
240. The IESO’s original analysis considered 3 potential production scenarios for Pickering: +73 TWh, +65 TWh and +62 TWh (the updated analysis eliminated the +73 TWh scenario).
241. OPG has confirmed the production forecasts for Pickering underpinning its Application are premised on an expectation that Pickering Extended Operations will produce just 62 TWh, being the worst case scenario contemplated by the IESO in their analysis from a production standpoint.
242. In addition, OPG consistently over-estimates its production forecasts for its nuclear operation¹⁰⁶ such that there is genuine concern that even the 62 TWh production scenario is unrealistic.

6.2.2 Operating Costs

243. The IESO also notes that “if OPG’s actual capital and operating costs exceed estimates, then the cost savings resulting from Pickering’s life extension could be reduced or eliminated.”¹⁰⁷

¹⁰⁴ Exhibit F2 Tab 2 Schedule 3, Attachment 1, p.9.

¹⁰⁵ Exhibit F2 Tab 2, Schedule 3, Attachment 1, p.18.

¹⁰⁶ Exhibit E2, Tab 1, Schedule 1, Chart 2.

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244. In light of the impact of Pickering capital and operating costs on the value proposition of extended operations, IESO recommends “exploring options for cost control”;¹⁰⁸ however, as indicated by OPG’s Vice President of Project Assurance and Contract management, Nuclear Projects, it is “technically not feasible for [Pickering] to reduce its costs.”¹⁰⁹
245. It is not clear exactly to what extent the forecast operating and capital costs for Pickering included in OPG’s Application exceeds the cost estimates provided to the IESO for the purposes of their economic analysis in 2015. However, it is clear that they are higher (ED has calculated that they are as much as 22% higher) and that there is a reasonable likelihood that they are such that the cost savings resulting from Pickering’s life extension could be eliminated.

6.2.3 Gas Costs

246. According to the IESO Analysis, “the benefits of extended Pickering operations are also sensitive to natural gas prices.” In this regard, the IESO concluded that, in the scenario where Pickering Extended Operations only produce 62 TWh, Pickering Extended Operations become economic at natural gas prices greater than \$4.7/MMBtu.¹¹⁰
247. In interrogatories and cross examinations conducted by Environmental Defence, the IESO confirmed that the financial markets for gas futures predict prices that are substantially lower than those contained in the IESO’s economic analysis, with gas futures prices averaging 3.07/MMBtu between 2017 and 2024¹¹¹, as opposed to the \$6.07/MMBtu assumption used in the analysis.
248. While CME acknowledges that there are other factors which may add complexity to this portion of the analysis, including costs associated with compliance with cap and trade regulations, CME states that the difference between the gas price assumed by the IESO

¹⁰⁷ Exhibit F2 Tab 2, Schedule 3, Attachment 1, p.18.

¹⁰⁸ Exhibit F2 Tab 2, Schedule 3, Attachment 1, p.5.

¹⁰⁹ Transcript Vol 13, p. 13, lines 5-12.

¹¹⁰ Exhibit F2 Tab 2, Schedule 3, Attachment 1, p.17.

¹¹¹ Undertaking Response J8.5

in its study and prices today is so significant that, at a minimum, it creates further material concerns that Pickering Extended Operations will not be economic.

6.3 The Province's "Approval" of OPG's Plan to Extend Pickering Operations

249. OPG states that the Minister has "approved" Pickering extended operations and refers to a press release issued by the Minister which states:

The Province has also approved OPG's plan to pursue continued operation of the Pickering Generating Station beyond 2020 up to 2024, which would protect 4,500 jobs across the Durham region, avoid 8 million tonnes of greenhouse gas emissions, and save Ontario electricity consumers up to \$600 million. OPG will engage with the Canadian Nuclear Safety Commission and the Ontario Energy Board to seek approvals required for the continued operation of Pickering Generating Station ¹¹²

250. OPG also cites a very similar statement from the Minister contained in the 2016 Provincial Budget which contains the same reference to "[saving] Ontario electricity consumers up to \$600 million" as well as to the protection of jobs in Durham and the avoidance of greenhouse gas emissions.
251. CME notes that the \$600 Million figure cited by the Minister is the same net benefit identified by the IESO in the earlier version of its economic analysis in connection with a cumulative increase in Pickering production by 73 TWh, a scenario which the IESO removed from its updated analysis in October of 2015 and which OPG admits is not achievable.
252. A reasonable interpretation of the statements from the Minister cited by OPG is that the approval to "pursue" Pickering Extended Operations was predicated on the assumptions that savings "up to \$600 Million" were feasible.
253. CME submits that, in any event, the statements from the Minister relied on by OPG do not constrain the Board's authority to set just and reasonable rates, particularly given that:

¹¹² OPG AIC, p.89.

- (a) OPG's plan to Extend Pickering Operations is not consistent with the 2013 Long Term Energy Plan, being the plan in place as of the date of these submissions; and,
- (b) The province elected not to amend O.Reg 53/05 to mandate the need for Pickering Extended Operations when it amended the regulation in this regard in respect of the DRP.

6.4 CME's Submissions with Respect to Pickering Extended Operations

254. When asked whether it would continue with Pickering Extended Operations if it was demonstrated that continuing with Pickering Extended Operations is uneconomic, OPG responded that it would proceed regardless citing other benefits, such as preserving jobs and the reduction of greenhouse gas emissions over the addition 4 years of operations.¹¹³
255. While CME does not dispute the value of these other benefits, CME submits that in the context of establishing just and reasonable rates, such considerations are at best secondary.
256. OPG's assertion that it would proceed with its plan to extend operations at Pickering even if it was uneconomic to do so is of significant concern to CME and we submit should also be of concern to the Board.
257. During cross examination, OPG stated that they had not yet reached a 'point of no return' for the Pickering Extended Operations investment.¹¹⁴
258. OPG also stated that Pickering Extended Operations was an extension of OPG's existing work programs, and additions to the existing outage programs, rather than being a single project.¹¹⁵ As a result, that there will be no large, single, capital expenditure

¹¹³ Transcript Volume 13, pp. 55, lines 5-14.

¹¹⁴ Transcript Volume 14, pp.151-152.

¹¹⁵ Transcript Volume 14, pp.152-153.

which would mark the point at which a full commitment to Pickering for all five years needs to be made.

259. CME submits that the Board should not approve any costs associated with extending Pickering operations beyond 2017 until a new economic analysis has been run and clear direction has been received from both the System Planner and the IESO that the Pickering Extended Operations will provide a real economic benefit to ratepayers. In the absence of the foregoing, the costs associated with Pickering extended operations should not constitute "just and reasonable rates" which should be passed on to ratepayers.

7.0 COMPENSATION

7.1 Introduction

260. OPG's compensation costs during the test period average approximately \$1,605 Billion per year representing one of the largest components of OPG's revenue requirement.
261. Given the significant percentage of OPG's operating costs that are human resources related, managing these expenditures to a level which is reasonably consistent with the levels achieved by OPG's peers, is a cornerstone of the value proposition that ratepayers expect from OPG.
262. An inability to reduce compensation costs, pensions and OPEBs to a reasonable level has plagued OPG since its first payment amount application up to the present day. In each of OPG's three previous rate cases the Board has concluded that it would be unreasonable for OPG to pass all of these costs on to ratepayers and has made significant disallowances in an effort to incent OPG to exercise better cost control.
263. While CME acknowledges that OPG appears to have achieved some efficiencies, CME submits that there remains significant room for improvement and agrees with Board

staff, SEC and many other intervenors in these proceedings that significant disallowances with respect to compensation, pensions and OPEBs are again warranted.

7.2 Compensation Benchmarking

264. Benchmarking provides critical insight into OPG's compensation costs and is intended to assist the Board with the assessment of the reasonableness of such costs.

265. The usefulness of a compensation benchmarking study, however, depends on the extent to which it provides a complete and accurate picture of how a company's total compensation costs compare to those of its peers.

266. CME shares the concerns expressed by SEC with respect to the Willis Towers Watson ("WTW") study which was commissioned by OPG in response to direction from the Board in EB-2013-0321. Specifically, CME submits that the following factors obscure OPG's actual performance relative to its peers:

- (a) The TWT benchmarking study does not consider employees who are considered "non-regular staff" which includes any employee hired with the understanding that their employment will not continue once Pickering ceases to operate;
- (b) A number of material components of compensation are excluded from the TWT study including:
 - i) Overtime costs (averaging \$107 M annually for the nuclear business);
 - ii) Compensation provided in the form of lump sums or share grants to OPG employees under their collective agreements; and,
 - iii) Incentive compensation to the extent that OPG employees receive such compensation more than estimated by WTW;
- (c) WTW does not make an adjustment to account for the fact that many of OPG's employees work 35 hours a week compared to 40 hours per week in many of the comparator companies;

- (d) Only 78% of OPG's employees are included in the WTW benchmarking study; and,
 - (e) Benchmarking of pension and OPEBs was conducted as a separate analysis, using a separate group of comparators.
267. While the WTW study finds the OPG's total direct compensation is only 5% above the target market, the study also identifies segments of the employee population which are being compensated significantly above market rates, including 1341 benchmarked employees in the "General Industry" group which are being compensated at 27% above the target market.¹¹⁶
268. CME also notes the comparison chart prepared by SEC illustrating an increase in the number of OPG's employees whose earnings are above \$200,000 and \$300,000 and agrees that it appears that compensation levels at OPG are now moving in the wrong direction after a brief improvement following the release of the 2013 Auditor General's report on OPG's Human Resources.

7.3 Pensions and OPEBs

269. OPG acknowledges that its pension and benefit costs "remain above those in the broader labour market."¹¹⁷
270. The extent to which these costs continue to exceed market is identified in benchmarking studies submitted by OPG in these proceedings, including in the WTW study and materials which were filed on a confidential basis. These studies demonstrate that OPG is significantly above market respecting its pensions, OPEBs and benefits.
271. An important factor driving OPG's pension and benefit costs is the extent to which OPG's contribution to the pension plan exceed those made by OPG's employees.

¹¹⁶ Exhibit F4-3-1, Attachment 2, page 11 (TWT Study)

¹¹⁷ F4-3-1 pg. 2.

272. According to the 2013 Auditor General's report, Ontario's public service has a "50-50 split between employer and employees for making pension contributions and funding pension shortfalls" including a 1:1 ratio for contributions to pension plans.¹¹⁸
273. Board Staff has calculated a contribution ratio of approximately 3.8:1¹¹⁹ for 2017 and 2018.

7.4 Recommended Disallowances

274. SEC undertook a detailed analysis in order to establish that OPG's direct compensation costs would have to be reduced by \$46.7M per year in order to bring OPG's total direct compensation costs down to the median.
275. CME agrees with SEC that an annual disallowance of \$46.7M over the custom IR term is the minimum disallowance that the Board should consider.
276. Particularly in light of OPG's poor performance in efficiency metrics, Board Staff have recommended a rounded annual disallowance of \$50M, which is also intended to recognize the potential for cost savings if OPG's pension and benefit costs, including employee contribution ratios, were at market instead of significantly above it.
277. OPG was unable to provide information which would assist the Board to quantify the amount of savings which would be realized if its pension and benefit costs were closer to market; however, the mere fact that there appears to be no means of attaching a precise number to these excessive costs does not justifying passing them on wholesale to ratepayers.
278. Similarly, the fact that significant costs such as overtime costs and employee incentives are not addressed through the compensation benchmarking submitted by OPG in support of its Application, does not make these costs reasonable.
279. CME recognizes that, in light of improvements identified in the WTW study, it may not be appropriate to continue the annual disallowance of \$100 M ordered by the Board in EB-

¹¹⁸ 2013 Annual Report of the Office of the Auditor General, Chapter 3, VFM Section 30.5 at page 166.

¹¹⁹ Board Staff Submissions at pg.111.

2013-0321; however, in light of the above, CME submits that annual disallowances up to \$80 M should be considered.

8.0 NUCLEAR LIABILITIES

280. OPG is required to provide for the continued management and disposal of the nuclear waste which is created during the operation of its nuclear facilities, as well as the future decommissioning costs of those facilities.
281. OPG's costs are notionally split into: short-term costs, which OPG funds internally through operating cash flow,¹²⁰ and long-term costs, which are funded through the segregated Funds.
282. The Ontario Government and OPG entered into the Ontario Nuclear Funds Agreement which outlines the amount that OPG is liable for, in present dollar values, for the disposal of nuclear waste and the decommissioning of their nuclear facilities.
283. ONFA also sets up the segregated Funds, which OPG is obligated to pay into, which holds the money for the long term disposal of nuclear waste and decommissioning of nuclear generating facilities. Payments into these funds are the long-term nuclear liabilities mentioned above.
284. As it stands, OPG uses an accrual method of accounting that matches the liability generated during the term to the benefit flowing from the asset during the same period. The liabilities generated as a result of the accrual accounting method do not necessarily bear any resemblance to OPG's cash expenditures regarding nuclear liabilities during the period.
285. OPG proposes to recover \$1.808 billion over the IR term for nuclear liabilities, as set out in their First Impact Statement filed in December of 2016.¹²¹

¹²⁰ Transcript Volume 20, pp.105-106.

¹²¹ OPG Argument in Chief, p. 131.

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286. OPG proposes to credit ratepayers with approximately \$295 million through the Nuclear Liability Deferral Account and Bruce Lease Net Revenues Variance Account as the result of the contribution schedule that was approved by the province in February of 2017.¹²²
287. CME agrees with Board staff that the main issues with OPG's application regarding nuclear liabilities are:
- (a) OPG's failure to update their test period nuclear payment amounts to accord with the province's updated contribution schedule as set out in impact statement at Exhibit C2-1-2;
 - (b) OPG's continued use of accrual accounting principles to calculate nuclear liabilities when the segregated fund is in an overfunded position and requires no contributions for the next five years; and
 - (c) The use of a discount rate that is inconsistent with that set out in ONFA, leading to an ARO that is \$2.2 billion higher than it would be had OPG used the rate set out by the Government of Ontario.

8.1 Fully Updated Test Period Nuclear Payment Amounts

288. CME agrees with Board staff's submissions that ratepayers should not be asked to pay amounts for nuclear liability costs when the estimates are known to be inaccurate.
289. While CME appreciates the complexity of the application and the rapidly evolving changes that provincial information has had on OPG's calculation of its nuclear liabilities, CME suggests that every effort should be made in future applications to provide relief to ratepayers based on the best available information.
290. It is CME's understanding of the evidence given by OPG during the oral hearing that OPG would not oppose the incorporation of the updated contribution schedule into test period nuclear payment amounts. OPG's witness stated:

¹²² Transcript Volume 20, p. 43.

*In the end, if the Board so ordered to take these into account in the revenue requirement and not flow them through the variance accounts, it was really done to try to make this a simpler process for discussion. Dealing with this as part of a rate order, if it so chooses to flow through the revenue requirement, we would not have a problem, we just didn't want to go through the process of the multiple updating that would have to happen, especially since we're doing this during the hearing.*¹²³

291. On this basis CME submits that the Board reduce the test period nuclear payment amounts by \$294.6 million, as laid out in Exhibit C2-1-2 of OPG's application.¹²⁴ That would leave the nuclear liability amount as \$1.503 billion.

8.2 Accrual Accounting Principles and the Fully Funded Segregated Funds

292. CME has had the benefit of reading SEC and CCC's submission on this topic, and we agree that the point of regulated rate recovery to pay for nuclear liability costs is in tension with the purpose of accrual accounting, and sometimes produces incongruous results.
293. Of critical importance in this Application is that OPG, for the first time, does not have to contribute to either the "Approved Used Fuel Fund" or the "Approved Decommissioning Fund" over the test period.¹²⁵
294. Despite the fact that the segregated Funds are fully funded, OPG proposes to collect from ratepayers the full costs of nuclear liabilities during the period, totaling \$1.503 billion.¹²⁶
295. At the same time, OPG only expects to spend \$1.1859 billion to actually fund its nuclear liabilities.¹²⁷ As a result, OPG proposes to collect approximately \$314 million dollars more than it needs.
296. CME submits that the incongruity between regulated ratemaking, and accrual accounting are, in this context, too great to ignore.

¹²³ Transcript Volume 20, pp.42-43.

¹²⁴ To see the required calculations, see Board staff submissions, p. 129, footnote 403.

¹²⁵ Exhibit C2, Tab 1, Schedule 2, Attachment 1-2, p.29-30.

¹²⁶ Exhibit C2, Tab 1, Schedule 2, p.2.

¹²⁷ Undertaking J20.7, Chart 3. This is the additional of lines 10 and 20.

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297. CME submits that a just and reasonable rate for recovery of nuclear liability costs should not include amounts that aren't required to fund present nuclear liabilities, and not necessarily going to be needed to fund future nuclear liabilities.
298. As a result, CME submits that the Board should move to the cash accounting calculation method, and only allow OPG to recover \$1.0801 billion. This is the amount that OPG would pay on a forecast basis over the test period, given that the segregated Funds are fully funded for the first time since OPG was subject to regulation by the Board.

8.2.1 Additional Tax

299. Not only will ratepayers be forced to pay for liabilities that OPG may never need to cover, but they will in fact be paying more in rates now than if the segregated Funds were not fully funded for the same liabilities due to the way that the tax treatment around segregated Funds works.
300. When OPG contributes to the segregated Funds for the prescribed facilities, the revenue that they generate is taxed, and their contributions to the segregated funds are tax deductible. OPG is then taxed when they take money out of the segregated Funds.
301. Since OPG is not contributing to the segregated Funds, and as a result they are not getting the tax deduction associated with paying into the segregated Funds, they have to gross up the amount required to ensure that the after tax amount is consistent with their accrual accounting figures. This gross up means that rate payers are paying more for the same liability coverage due to OPG's use of accrual accounting.
302. CME submits that a just and reasonable rate would not make ratepayers bear an increased taxation burden simply to satisfy OPG's accounting methods.

8.2.2 Board Staff's Proposed Solution

303. Board staff, in their submissions, propose a new method of calculating OPG's long and short-term nuclear liabilities. They suggest that short-term liabilities, which are directly paid by OPG from their operating cash flow, be paid for in accordance with accrual

accounting principles, while the long-term payments OPG makes into the segregated Funds be recovered with regard to what OPG actually pays into it.

304. Board staff does not go so far as to advocate a particular methodological approach, and suggest that there should be a “more comprehensive review of the current recovery methods” in order to determine whether they should be continued.¹²⁸
305. As CME understands Board staff’s submission, there would be a comprehensive study in its next cost-based nuclear payment amounts application. Prior to that, there would be no determination or relief for ratepayers.

8.2.3 CME’s Proposed Solution

306. CME respectfully disagrees with Board staff that this can or should wait the expected five years until OPG’s next payment application.
307. According to the ONFA contribution plan, OPG does not need to contribute during any of the five years of this application. That will be five years that ratepayers will be paying OPG for nuclear liabilities that they do not need to fund now, and may not ever need to fund. Similarly, ratepayers will be burdened for the next five years with extra payments to OPG due to the tax differential between segregated Fund contributions and OPG keeping the money.
308. CME therefore submits that the Board use the cash accounting calculation methodology to determine just and reasonable rates to combat the incongruity caused by the fully funded status of the segregated Funds. This would reduce the revenue requirement from \$1.503 billion to \$1.0801, which was what OPG is required to receive to be kept whole.
309. In the alternative, should the Board agree with staff’s suggestion that a comprehensive review is required to study the issue, we suggest that the Board only allow OPG to recover its cash requirements for nuclear liabilities, and set up a new deferral account to record the differential between the accrual and cash valuations for nuclear liabilities

¹²⁸ OEB Staff Submission, Ontario Power Generation Inc. 2017-2021 Payment Amounts (EB-2016-0152), p.131.

expenses, much like they did while they determined the best way to account for pension and OPEB costs.

310. This will provide immediate relief to ratepayers while ensuring that OPG could be compensated if accrual accounting was deemed to be the appropriate method going forward.

8.3 The Discount Rate

311. As discussed during the oral hearing as well as in Board staff's submissions, OPG's recorded Asset Retirement Obligation ("**ARO**") exceeds the ONFA funding liability by \$3.1 billion.¹²⁹ According to OPG, this discrepancy is on account of two factors:

- (a) OPG's ARO includes the internally funded costs that are ineligible for reimbursement from the segregated Funds; and
- (b) OPG used a different discount rate.

312. According to OPG, \$2.2 billion of the difference can be attributed to the use of an alternate discount rate.¹³⁰

313. The Ontario government, through ONFA has stipulated that the liabilities should be calculated using a 5.15% rate when discounting the estimated future cost of liabilities to their present day value. OPG, using accounting principles and the Ontario long-term bond yield rate, determined that the discount rate should be 4.95%.¹³¹

314. This .2% difference in discount rate is the cause of the \$2.2 billion dollar discrepancy.

315. OPG, in recovering Funds related to ARO, amortize the amount of the liability over time. This amortization is included in rates.

316. In practice, this means that ratepayers will have to be paying increased rates for an amount that is the accounting discrepancy between the Ontario Government's prescribed rates and OPG's accounting rate.

¹²⁹ Transcript Volume 20, p.79.

¹³⁰ Undertaking J21.3, p. 2.

¹³¹ Undertaking J21.3, p. 2.

8.3.1 Board Staff's Proposed Solution

317. Board staff acknowledge that this is a significant in terms of what ratepayers are being asked to pay, but suggested that resolution of this issue too should wait for a later date as part of the comprehensive study on recovery methodologies.

8.3.2 Recommended Approach

318. CME disagrees with this approach on the same basis that it disagreed with Board staff about their methodologies submission: it is unjust to ask ratepayers to pay for this amount while the Board is preparing to study the issue.
319. CME submits that it would be inappropriate to ask ratepayers to fund, for the next 5 years, the amortization of an amount that OPG has put on their books as the result of their accounting method, over and above what the Government of Ontario has stipulated is the proper liability calculation.
320. CME submits that the Board should reduce OPG's ARO discount rate to match the ONFA prescribed amount.
321. The difference between the ARO and ONFA funding liability attributed to OPG's internal funding responsibilities should be kept.
322. In the alternative, CME submits that the Board should not allow OPG to collect for this amount, but set up a deferral account to track the amount that OPG would have gained in rates for the amortization of this liability. That way if the Board should find it appropriate for OPG to use a different discount rate from the Government of Ontario, there will be a mechanism to effect that.

8.4 Transition Issues from Switching to a Cash Accounting Method

323. We agree with CCC's submission that there will not be any transition issues for OPG by switching to cash accounting, and that there may in fact have been an over-recovery on OPG's part through the use of the previous accrual method.

324. OPG's evidence is clear that a total of \$106.6 million in under-recovery is attributable to the difference between their approved and actual nuclear production.¹³²

325. CME agrees that that OPG should be responsible for their under-production and would reiterate what the Board stated regarding OPG's nuclear production risk:

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.¹³³ (emphasis added)

326. CME submits that the Board has confirmed that OPG should be at risk if their output falls short of forecast. The under-recovery of nuclear liabilities is one of the outcomes that OPG is at risk for. To move to a cash accounting system and not allowing OPG to collect that revenue is consistent with the Board's previous holding.

327. CME also agrees that there likely isn't even an under-recovery of amounts, given the evidence OPG gave in undertaking J20.7.

328. In oral evidence, OPG seemed to suggest that the tax would be relatively neutral:

MR. BUONAGURO: I think you're telling me that you could include the taxes, but it would be the same under both scenarios? Taxes are a pass-through, so you only charge in the revenue requirement taxes if you also pay those taxes? Or is that not the case? If you were to include the taxes on top of the amounts say -- for example, on top of line 5 for the prescribed facilities, did the company actually pay those taxes and therefore it also would be included again as an amount that the company paid in the same year?

MR. KOGAN: Yes, that would be the principle upon which that would operate the way you described for the prescribed facilities. And similarly, yes.¹³⁴

329. In their undertaking however, OPG confirmed that from April 1, 2008 to December 31, 2016, amounts recovered by OPG are higher than the amount expended by OPG by approximately \$108 million.¹³⁵

330. This seems to suggest that the taxes make a material difference to whether OPG under or over recovered during that period.

¹³² Exhibit C2, Tab 1, Schedule 2, p. 25, Chart 3, line 2.

¹³³ EB-2007-0905, Decision with Reasons, November 3, 2008, p.174.

¹³⁴ Transcript Volume 20, p. 100.

¹³⁵ Undertaking J20.7, p. 1.

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331. Given that OPG has over-recovered during the regulated period, CME submits that there are no negative transition issues that OPG will have to face as the result of moving to a cash accounting system.
332. CME also agrees that the appropriate period to examine for transition issues, should such a period exist at all, is the period of regulation of OPG from April 1, 2008 until the present. The period between April 1, 2005, when the province set rates, and April 1, 2008 when OPG began to be regulated by the Board is irrelevant. Furthermore, as CCC suggests, it is based on the assumption that the Province of Ontario used the methodology later advocated by the Board in EB-2007-0905.
333. CME submits that the Board should not concern itself with trying to correct rate shortfalls from over a decade ago which arose due to the province's rate-making.

9.0 HYDROELECTRIC PAYMENT AMOUNT SETTING

9.1 Introduction

334. This Application marks the first time that OPG has filed a proposal for an incentive rate-setting mechanism plan for the hydroelectric side of its business.
335. CME is generally in support of the form of IRM plan proposed by OPG, being a price cap plan which provides for the annual adjustment of hydroelectric payments by an inflation factor less expected productivity improvements.
336. CME submits, however, that a number of the elements of the plan as proposed by OPG would deprive ratepayers of the benefit of efficiency gains which they are reasonably entitled to expect over the 5 year IRM term.
337. CME's submissions in this regard focus on the development of the industry productivity or "base X-factor", the formulation of the inflation factor (the input price index or IPI) and proposed off ramps.

9.2 Base X-Factor

338. OPG proposes a zero-percent productivity factor for their prescribed hydroelectric facilities. The basis for this productivity factor is the total factor productivity study of the North American hydroelectric generation industry prepared by Ms. Frayer of London Economics International LLC ("**LEI**"), which found that productivity in the industry is -1%, or declining by 1% annually. OPG then adjusted the productivity factor to zero recognizing the Board's previous decisions on negative productivity factors.
339. CME submits that the study conducted by LEI has a number of methodological flaws which skew the industry productivity findings. As a result, the study conducted by Pacific Economics Group ("**PEG**"), which found that industry productivity was increasing by .29% annually should be preferred.
340. Additionally, due to the fact that the productivity study results are impacted by the existence of the Capacity and Refurbishment Variance Account ("**CRVA**"), the X factor should be adjusted to make an apples-to-apples comparison of OPG to its peer group, which would entail removing 35% of the peer group's capital expenditure from the study. This would increase the productivity rate for the industry to .75%, which is the appropriate industry productivity rate.

9.2.1 Methodology

(a) The Use of MWh as the Output Variable

341. As discussed by PEG, one of the most significant issues associated with LEI's study is the use of MWh as the productivity output.
342. In hydroelectric generation, MWh produced are necessarily the result both of the hydroelectric facility, as well as hydrological conditions. Areas and time periods with heavy rainfall or meltwater will provide more hydroelectric generation than they would under normal conditions, and conversely, areas that are suffering from drought

conditions, or have less water than normal will experience reduced hydroelectric generation than normal.

343. This makes LEI's study susceptible to showing climate and rainfall trends as industry productivity trends. For example, hydroelectric facilities in areas with less rainfall wouldn't necessarily be producing less due to declining productivity, but simply as a result of reduced generation from hydrology.
344. Evidence on the record in this application clearly indicates that several of the peers in LEI's study did suffer from significant and prolonged drought, which would have impacted the results of LEI's study. Indeed Ms. Frayer admitted on cross examination that California suffered through years of "severe drought".¹³⁶
345. The results of LEI's study are even more vulnerable to changes in hydrology because of the implicit weighting given to companies based on their size.¹³⁷ California is the home to two utilities studied by LEI in their peer group: Pacific Gas and Electric and Southern California Edison. Pacific Gas and Electric alone constitutes 11% of the 2014 MW Capacity of the peer group, and 16% of the O&M dollars in 2014.¹³⁸ The drought in California would clearly have a dramatic impact on the California utility's productivity over many years of the period, and therefore have a dramatic impact on the study as a whole.
346. This flaw in LEI's methodology is exacerbated by two other complementary methodological flaws: a small sample size, and a short time frame. For their sample, LEI used data from the years 2002-2014.¹³⁹ Contrastingly, PEG used data using both the 1975-2014 as well as 1996-2014 timeframes.¹⁴⁰ Even the shorter study which produced PEG's "featured results" included an additional 6 years of data, making the time frame half-again as long as LEI's results.

¹³⁶ Transcript Volume 9, p.58.

¹³⁷ Exhibit M2, p.38; see also Exhibit L, Tab 11.1, Schedule 1, Staff-242, p.1.

¹³⁸ Exhibit A1, Tab 3, Schedule 2, Attachment 1, p.30.

¹³⁹ Exhibit A1, Tab 3, Schedule 2, Attachment 1, p.44, Figure 27.

¹⁴⁰ Exhibit M2, p.46.

347. The time frame is of particular importance when comparing these two studies, because LEI's shorter time frame magnifies the effect of drought related data points caused by the California utilities. PEG's use of a longer time period helps to offset this by including more years where the California utilities experienced normal or above average hydrological conditions.
348. Similarly, LEI's small peer group also heightens the effect of the hydrological variance on the study. LEI's sample included sixteen firms, including OPG.¹⁴¹ In contrast, PEG's sample has twenty utilities, and does not include OPG.¹⁴² The increase the number of utilities also helps to offset the effect of variance, since it includes more data points from areas that are not impacted by adverse hydrological conditions in any given year.
349. Critically, skewing the results is both: not representative of what OPG has experienced over those years, since Ontario has not been in drought conditions; and not what OPG is projecting their hydrological situation to be over the course of the IR term.¹⁴³ We submit that it would be inappropriate to base the IR "X" factor on a study skewed by conditions which are not indicative of what OPG has faced previously, or is expected to face going forward.

9.2.2 The Inclusion of OPG in the Peer Group

350. PEG is also critical of LEI's decision to include OPG in the peer group analysis. As PEG points out in their report, OPG's performance incentives are weakened if its results were included in future X factor calibrations.¹⁴⁴
351. The justification provided by LEI as to why OPG is included is not persuasive. LEI states that they include the regulated company as part of the study because:

The ultimate purpose of the TFP study and the resulting X factor is to simulate the competitive pressures that the regulated company would face if it were to be operating in a competitive environment, free of regulation. As such, since the regulated company would be

¹⁴¹ Exhibit A1, Tab 3, Schedule 2, Attachment 1, p.8.

¹⁴² Exhibit M2, p.46.

¹⁴³ Transcript Volume 9, pp. 61-62.

¹⁴⁴ Exhibit M2, p.27.

*part of the industry, its experiences should be included in the industry trends.*¹⁴⁵

352. While we agree that the purpose of the TFP study and the resulting X factor is to simulate competitive pressures the inclusion of a relatively inefficient regulated entity into the study has the effect of decreasing the measured competitive pressures that that same regulated entity would face in the results of the study.
353. The reduction in measured industry productivity then lowers the efficiency required of OPG going forward and deprives ratepayers of the benefit of properly calibrated productivity targets.

9.2.3 The "Physical" Measurement of the Capital Quantity Trends

354. PEG's industry productivity conclusion should also be preferred over LEI's because of the latter's use of the physical measurement method of calculating the capital quantity trend as an input component, rather than a monetary method such as the one used by PEG.
355. One reason to prefer the monetary method over the physical method is that it better fits the price-cap indexes in the IRM proposed by OPG. The cost of service approach to capital cost involves valuations of plant and the application of depreciation. Hydroelectric generation is a very capital intensive industry, so it is appropriate that the design of the price-cap index for OPG reflect depreciation.¹⁴⁶
356. OPG argues that the physical method of calculation is preferable because it does not require assumptions or conversions from financial data into capital quantities. The only assumption that OPG takes issue with however, is the depreciation profile chosen by PEG. LEI and OPG's argument as to why hydroelectric generating facilities do not fit a

¹⁴⁵ Exhibit M2, p.38; see also Exhibit L, Tab 11.1, Schedule 1, Staff-241, p.2.

¹⁴⁶ Exhibit M2, Attachment 1, p.3.

- geometric decay model is that they are long lived assets that produce a consistent flow of services over the course of their lives.¹⁴⁷
357. What this analysis neglects to include is the consistently rising OM&A required to produce that constant flow of services,¹⁴⁸ a fact that LEI acknowledges.¹⁴⁹ PEG found that the average annual growth rate of O&M productivity was .10% from 1975 to 1995 and -1.30% from 196 to 2014.¹⁵⁰ Additionally, OPG has had to continue to pour refurbishment capital into their hydroelectric facilities.¹⁵¹
358. This is not the profile of a business that produces a constant flow of services, such as a lightbulb, but rather a business that requires constant maintenance increases and refurbishments to producing at a steady state, a state of affairs which is more closely aligned to gradual geometric decay rather than the more static physical model.
359. The monetary approach has another advantage over the physical approach used by LEI, and that is the ability to model the service of multiple assets in a cohort. As described by Dr. Lowry, OPG has a number of hydroelectric assets, and each of those hydroelectric assets is made up of innumerable parts.¹⁵²
360. Even if each individual component or facility were to have a constant flow of services until it suddenly was no longer usable, all of OPG's assets across the province are not going to give constant services up until the same point in time and then all stop working simultaneously. Even if their individual assets will provide constant services until the moment they stop working entirely, OPG's assets as a class, or in total, will have varied service lives which are better modeled by the geometric decay method.
361. Additionally, the Board has previous held that the physical method was inappropriate, holding that:

¹⁴⁷ Exhibit A1, Tab 3, Schedule 2, Attachment 6, p.7.

¹⁴⁸ Exhibit M2, Attachment 1, pp.4-5.

¹⁴⁹ Exhibit A1, Tab 3, Schedule 2, Attachment 6, p.9.

¹⁵⁰ Exhibit M2, Attachment 1, pp.4-5.

¹⁵¹ Exhibit M2, Attachment 1, p.5.

¹⁵² Transcript Volume 11, pp.11-12.

*Of greatest concern with Ms. Frayer's approach is the measurement of capital, which is inconsistent with the prior Ontario TFP studies and does not appear to have been adopted in any jurisdiction other than New Zealand. While the Board recognizes Ms. Frayer's efforts to construct an Ontario specific TFP trend, the Board does not believe that the methodology advocated by Ms. Frayer is appropriate.*¹⁵³

362. Given all of the above, we submit that it would be appropriate for the Board to prefer the methodology recommended by PEG. Not only does it apply less variable statistical techniques, but it is more in keeping with the conditions that OPG has faced and will face during the term, cleaves more closely to the purpose of incentive rate making, and has been accepted previously by this Board. As a result, we submit the appropriate productivity starting point is .29% as identified by PEG.

9.2.4 Hydroelectric Productivity's Interaction with the CRVA

363. As discussed above, the purpose of the productivity study and the resulting X factor is to simulate the competitive pressures that the regulated company would face if it were to be operating in a competitive environment, free of regulation.
364. There are however certain regulatory mechanisms the existence of which should be taken into account when considering the results of the productivity study. In this case, this is particularly true of the Capacity Refurbishment Variance Account.
365. If OPG were free of regulation, and in the competitive market, there would be downward pressure on costs across the entire gamut of OPG's costs, whether they be capital costs, O&M costs, or otherwise.
366. This is the central proposition embedded in the total productivity factor reports. The peer group is getting more productive by a certain percentage every year, in this case .29% according to PEG, across the spectrum of their costs, in an effort to be more efficient and productive in the market.

¹⁵³ EB-2007-0673, "Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors", September 17, 2008, p.12.

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367. In actuality, OPG is not unregulated. The existence of the CRVA means that some of OPG's capital costs are flowed through that account, and are guaranteed to be recovered. According to the evidence, around 35% of OPG's capital costs are flowed through the CRVA.¹⁵⁴
368. Since OPG's peers do not have the benefit of the CRVA, their productivity measures include the full downward pressure on productivity of capital expenditures. When a peer group firm decides to spend capital on refurbishment or capacity, the increased expenditure hurts that firm's productivity results.
369. Since OPG is able to flow 35% of their capital expenditures through the CRVA, they do not have to deal with the downward pressure on those costs, and are free to enjoy unfettered productivity increases despite spending that capital on refurbishment or capacity.
370. Dr. Lowry identified this issue, and stated that in PEG's research experience, productivity growth is substantially higher when a share of plant additions is removed from the calculations.¹⁵⁵
371. While Dr. Lowry advocates that the CRVA should be abolished, CME is cognizant that this may not be an option in light of the provision of O.Reg. 53/05. We submit therefore that the Board should adopt Dr. Lowry's other proposal, and make an apples-to-apples comparison of OPG to its peer group.
372. According to Dr. Lowry, if 35% of the peer group's capital expenditures were removed from the study, to accord with the 35% of capital expenditures that OPG is allowed to flow through the CRVA, the productivity of the peer group moves from .29% to .75%.¹⁵⁶
373. This, in our submission is the appropriate industry productivity factor which should be applied to OPG. Not only is this figure based on a more methodologically sound study,

¹⁵⁴ Transcript Volume 11, p.26.

¹⁵⁵ Exhibit M2, pp.64-65.

¹⁵⁶ Transcript Volume 11, pp.133-134.

but it is a better true comparison of OPG to its peers, which more fully accounts for the pressures that OPG would be under from their competitors if OPG were placed in a competitive and unregulated market. This aligns it more closely with the purpose of the productivity study and X factor as elucidated by LEI.

9.3 Inflation Factor

374. In addition to the X factor, the incentive rate formula also includes an inflation amount, or "I" factor that attempts to model the impact of inflation on a firm's efficiency through the term. This is achieved by applying inflation related sub-indices to categories of OPG spending.
375. In their application, OPG proposes to apply the Gross Domestic Product Implicit Price Index – Final Domestic Demand ("**GDP-IPi FDD**") to capital and non-labour O&M costs. The only other subcategory that OPG proposes is for labour costs, where OPG proposes to use the Average Weekly Earnings for Ontario – Industrial Aggregate ("**Ontario AWE**").
376. OPG has not broken out any other category of costs in its treatment of the "I" factor, including the Gross Revenue Charge ("**GRC**"), which are fees paid by hydroelectric generators for property taxes and water rental charges. We submit that it is inappropriate not to give separate treatment to the GRC, on the basis that it is a fully passed through cost, and as a result, OPG has no exposure to inflation on that amount. It artificially increases OPG's inflation quantum, leading to higher rates for ratepayers, who will also have to pay the passed through cost.
377. According to evidence given at the hearing, the GRC amounts to \$350 million a year.¹⁵⁷ This amount is a pass through cost that is charged to ratepayers¹⁵⁸ and does not impose any inflationary pressure on OPG.

¹⁵⁷ Transcript Volume 10, p.59.

¹⁵⁸ Transcript Volume 10, p.79.

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378. In a presentation from 2014, LEI stated that indices should be selected, in part, based on the relevance to the utility's costs.¹⁵⁹ In the inflation study by LEI, they applied that approach when they proposed a separate inflation index for labour, which is more relevant to the actual costs OPG will incur for their labour. Interestingly, LEI did not apply the same approach to the GRC, despite the fact that the GRC makes up roughly one quarter of OPG's revenue requirement.
379. LEI applied the same GDP IPI FDD sub-index to the GRC as it did to OPG's capital spending and all of the other non-labour O&M. We submit that this is an inappropriate inclusion into the inflation quantum for OPG.
380. In our submission, this is essentially asking for ratepayers to pay for elements of the GRC twice. First, ratepayers will have to pay the full extent of the GRC as it is passed through OPG. Second, despite having already paid the full amount, OPG is asking ratepayers to provide it with increased rates on the basis that they have to deal with inflationary pressures on those costs, when in actuality; they have no exposure to upwards pressures on those costs because the ratepayers have already covered the full cost.
381. Board staff have suggested that half of the GRC should have a 0% inflation weighting attached to it, on the basis the GDP-IPI FDD necessarily includes some costs which do not attract inflation.
382. CME disagrees with this conclusion. Board staff acknowledge that OPG's situation is significantly different from most firms and business sectors.
383. Applying a 0% inflation to 50% of the GRC is not supported anywhere in the evidence, and CME submits that the GDP-IPI FDD, insofar as it is a composite of many industries and firms, does not adequately account for 12.5% of a company's costs being free from inflation.

¹⁵⁹ Exhibit K10.4, p.20.

384. We suggest that this is fundamentally unfair to ratepayers, and the Board should set the inflation rate on the full GRC amount to zero, which will more accurately represent OPG's inflation pressures, and protect ratepayers from paying \$80-100 million dollars over and above the full cost of the GRC during the incentive rate term.¹⁶⁰

9.4 Off-Ramps and Materiality

385. In the application, OPG has requested a Z-factor with a materiality threshold of \$10 million.¹⁶¹ This threshold is unchanged since the Board's first decision with respect to OPG's payment amounts in EB-2007-0905.

386. CME submits that it is inappropriate for the materiality threshold to remain static, considering that it has not been adjusted in the previous 10 years. This is especially true considering how much was added to the hydroelectric rate base with the Niagara Tunnel Project entering service, and the addition of previously unregulated hydroelectric assets.

387. According to the interrogatory response given by OPG, distributors' materiality thresholds are calculated using a formula that blends the rate base and revenue requirement.¹⁶²

388. CME agrees with the methodology advanced by LPMA, which arrived at an average threshold of \$12.7 million. A 50/50 weighting of .25% of the hydroelectric rate base and .50% of the regulated hydroelectric revenue requirement is an appropriate way to calculate the materiality threshold for the purposes of the Z factor which will account for exogenous events that may require accommodation for recovery under the proposed IRM plan.

¹⁶⁰ Transcript Volume 10, pp.94-95.

¹⁶¹ Exhibit A1, Tab 3, Schedule 2, p.22.

¹⁶² Exhibit L, tab 11.1, Schedule 5, CCC-047, pp.1-2.

10.0 NUCLEAR PAYMENT AMOUNT SETTING

10.1 The Proposed Stretch Factor

389. OPG argues that the most appropriate stretch factor for their Nuclear Custom Incentive Rate-setting ("**Custom IR**") plan is .3%.¹⁶³ Respectfully, we disagree.
390. CME submits that a stretch factor of up to 0.6% would be appropriate in light of OPG's current benchmarking results and the need to drive efficiencies throughout the Custom IR term.

10.1.1 Benchmarking Results Support a Higher Stretch Factor

391. OPG derived the .3% stretch factor by taking the TGC per MWh of the Darlington and Pickering facilities found in the 2015 Nuclear Benchmarking Report, assigning the quartile performance of the facility a stretch factor, weighting them by the Board approved production amounts for each facility, and then averaging the weighted amounts to produce a combined stretch factor.¹⁶⁴
392. This methodology inappropriately weights the results of the Nuclear Benchmarking Report in OPG's favour. OPG states that the 2015 Nuclear Benchmarking Report is a more accurate reflection of its performance than the 2016 Nuclear Benchmarking Report due to the fact that, in their view, it shows the performance of Darlington in a "comparatively steady-state".¹⁶⁵
393. OPG performed worse on the 2016 Nuclear Benchmarking report, with the Darlington Facility falling from the first to second quartile. The reasons OPG gave for this drop in ranking included: that there was a vacuum building outage, a ramp up in capital spending, and an increase in the station's forced loss rate.
394. CME submits that occurrences similar to those cited by OPG as a basis for discounting the 2016 benchmarking results (e.g. unanticipated outages, significant capital programs,

¹⁶³ Exhibit A1, Tab 3, Schedule 2, p.32.

¹⁶⁴ Exhibit A1, Tab 3, Schedule 2, p.32.

¹⁶⁵ Ontario Power Generation, "EB-2016-0152, OEB Application for Payment Amounts for OPG's Prescribed Facilities: Argument in Chief", p.168.

and increased forced loss rates) are likely to have been experienced by the others in the peer group at some point during the life of their nuclear assets which case OPG would have been the beneficiary in previous years of these types of efficiency issues appearing in other plants, a fact that they admitted on cross-examination.¹⁶⁶

395. We submit that benchmarking OPG, while it is at an efficient point in the life cycle of their facilities, against other nuclear operators who are subject to the normal vicissitudes of owning nuclear facilities, including: vacuum outages, increased capital spending, and increased forced loss rates, subverts the entire point of benchmarking, which is an apples-to-apples comparison of the efficiency of the nuclear operators, and artificially inflates OPG's performance relative to their peers.
396. According to OPG's evidence on cross-examination, if their methodology were run using the results of the 2016 Nuclear Benchmarking Report instead of the 2015 Nuclear Benchmarking Report, the result would be a .43% stretch factor.¹⁶⁷
397. In the Three-Year Total Generating Cost per MWh Rankings, OPG was benchmarked twelfth out of thirteen nuclear operators.¹⁶⁸ OPG furthermore has been ranked between 10th and 12th for every year except 2013.¹⁶⁹ We submit that OPG's 12th place ranking in 2015, which takes into account the vacuum outage, increased capital spend and increased FLR shows that this is not an aberration in the results, but part of a consistent ranking cluster for OPG in the total generating cost category.
398. We submit that a stretch factor of .3% would be appropriate for a nuclear operator who was benchmarking in the middle of their peers. In contrast, OPG is benchmarking below the median according to their own calculations using the most up to date data, and benchmarking perilously close to dead last in terms of their total cost generation company wide.

¹⁶⁶ Transcript Volume 6, pp.126-127.

¹⁶⁷ Transcript Volume 6, p.129.

¹⁶⁸ Exhibit K6.3, p.10.

¹⁶⁹ Exhibit K6.3, p.10.

10.1.2 A More Aggressive Stretch Factor Will Align with Better with OPG's
Prospective Performance

399. In addition to better reflecting OPG's present performance, a more aggressive stretch factor will also align more closely with OPG's expected performance during the IR term.
400. According to OPG, while Darlington's steady state performance shows it as being a top quartile performer, they are targeting third quartile performance for most of the IR term.¹⁷⁰ OPG argues that a .3% stretch factor is still appropriate in the circumstances for three reasons: they are targeting the top quartile for the Darlington facility for 2021, it is more appropriate to target a steady state for Darlington and the cost per unit on Darlington is still quite low.¹⁷¹ We submit that none of these arguments are persuasive in the circumstances.
401. The first reason given by OPG as to why .3% is still appropriate is that they are targeting top quartile performance in 2021 is not persuasive because it only addresses the last year of the term, and only on a target basis. Even if OPG were to successfully reach their target in all years of the application, that would still leave 2017, 2018, 2019 and 2020 with the Darlington facility operating at a third quartile level, and the Pickering Facility operating at a fourth quartile level, all while having a stretch factor appropriate for a second quartile operator applied to it.
402. Additionally, this is just OPG's target for 2021. As OPG itself pointed out, setting targets five years in advance requires assumptions that may not happen as expected.¹⁷² There is a very real possibility that OPG does not rehabilitate the Darlington facility's performance to a first quarter level in 2021, and therefore none of the years of the term would have the appropriate stretch factor to their benchmarking results.

¹⁷⁰ Transcript Volume 14, pp.142-143.

¹⁷¹ Transcript Volume 14, pp.29-30.

¹⁷² Transcript Volume 13, pp.19-20.

403. The second reason OPG gave as to why .3% is still appropriate is that the benchmarking should be done when Darlington is at a steady state. As discussed above, benchmarking a steadily efficient Darlington facility against a peer group that contains all the periodic inefficiencies required in the operation of a nuclear plant runs contrary to the purpose of benchmarking and artificially inflates OPG's efficiency performance against the rest of the field.
404. The final reason OPG gave as to why .3% is still appropriate is that the per-unit cost of Darlington is one of the lowest cost performing plants in North America. The cost per unit measurement proposed by OPG is, at best, a poor indicator of cost efficiency. The cost per unit measurement tallies the total cost, and divides it by the number of units in the facility.
405. On cross-examination,¹⁷³ and in their submissions, OPG recognizes that MWh is central to the calculation of value for money:

TGC/MWh is particularly well-suited to determining a stretch factor since it is measured relative to the units of production (MWh) that customers ultimately pay for. Since MWh are the ultimate output for which OPG is paid, improvement on this measure reflects a benefit to customers.¹⁷⁴

406. The fact that TGC per unit metric does not use MWh as part of the calculation means that critical efficiency issues are not captured, such as extensive outage programs.¹⁷⁵ Since one of the ways that OPG can become more efficient, and pass on that efficiency through a stretch factor is by managing outages more effectively, it would be unfair to allow a measurement that doesn't capture those possible efficiencies to buttress an unsuitable stretch factor. In effect, using the TGC per unit metric would ignore an area that OPG could gain efficiencies, and using that to justify why OPG can't gain more efficiencies.

¹⁷³ Transcript Volume 6, p.123.

¹⁷⁴ Ontario Power Generation, "EB-2016-0152, OEB Application for Payment Amounts for OPG's Prescribed Facilities: Argument in Chief", p.168.

¹⁷⁵ Exhibit F2, Tab 1, Schedule 1, p.10.

407. Evidence of how questionable the TGC per unit as a value for money metric is can be found in OPG's own results for the measurement. In OPG's chart, the Pickering facility, which is one of the least cost effective nuclear plants in the world according to the ScottMadden methodology, is not only ranked in the top quartile under TGC per unit, but it is ranked as significantly lower cost, and significantly better value for money than the Darlington facility, one of the top performers historically on ScottMadden's methodology.¹⁷⁶ OPG chose not to ask ScottMadden whether, in their professional opinion, the TGC per unit metric was an appropriate addition to OPG's value for money metrics.¹⁷⁷

408. We submit that the use of a .3% stretch factor is out of line with OPG's results, both currently and prospectively. The .3% stretch factor should be used for a nuclear operator that benchmarks near the median. OPG ranks twelfth of thirteen as a whole, in the second quartile for the Darlington facility and the fourth quartile for the Pickering facility in their 2016 Nuclear Benchmarking Report, and is targeting the third and fourth quartiles respectively for their facilities during the Custom IR term.

409. As a result, we submit that a .6% stretch factor is more appropriate.

10.2 Application of the Stretch Factor

410. OPG argues that the stretch factor should apply to their base OM&A costs and Corporate Support OM&A, which comprise 75% of the company's nuclear OM&A, but not to Project OM&A and Outage OM&A. OPG states that this is because "Project OM&A and Outage OM&A cover unique endeavours that do not present opportunities for recurring efficiency gains."¹⁷⁸

¹⁷⁶ Exhibit F2, Tab 1, Schedule 1, p.10, Chart 2.

¹⁷⁷ Exhibit L, Tab 6.2, Schedule 1, Staff-102, p.1.

¹⁷⁸ Ontario Power Generation, "EB-2016-0152, OEB Application for Payment Amounts for OPG's Prescribed Facilities: Argument in Chief", p.170.

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411. The amount of money that OPG proposes to exclude from the application of the stretch factor ranges from \$395.3 million in 2021, to \$515.4 million in 2019.¹⁷⁹
412. Such exclusions are unjustified and are contrary to the Renewed Regulatory Framework for Electricity ("RRFE") and previous decisions of the Board.¹⁸⁰
413. CME submits that the stretch factor should apply to the entirety of the company's nuclear OM&A costs during the application term.

10.2.1 Efficiency Gains with Respect to Outage and Project OM&A Work are Possible

414. OPG's position regarding the nature of Project and Outage OM&A as being unique endeavors, which do not lend themselves to recurring efficiency gains does not hold up under scrutiny. For instance, Project OM&A (Portfolio) is made up of an "Infrastructure" component, which includes:

Funding for staff that do not support specific projects but provide management oversight and direction, administration and coordination of project portfolio activities, and ensure compliance with OPG governance and standards.¹⁸¹

415. These positions are not involved with supporting specific projects, but provide a more general management and oversight. We submit that these types of costs, embedded within the Project OM&A portfolio, are not in themselves unique endeavors, but rather repeated work that would be amenable to recurring efficiency gains.
416. Similarly, while some aspects of outage work may be unique, that does not preclude more generalized efficiencies from being pursued with respect to work common to all outages.
417. In OPG's evidence on Outage Improvement Initiatives, they list a number of areas which would be common to many if not all outages that the company is seeking improvement on, such as:

¹⁷⁹ Exhibit L, Tab 11.3, Schedule 20, VECC-049, p.2, Chart 1.

¹⁸⁰ Transcript Volume 6, pp.138-139.

¹⁸¹ Exhibit F2, Tab 3, Schedule 1, p.2.

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- (a) improved outage scheduling;
 - (b) improved resource planning;
 - (c) execution improvements within Inspection and Maintenance services;
 - (d) implementing an outage model template; and,
 - (e) developing and implementing a long term purchased services and vendor quality strategy.¹⁸²

418. These areas of improvement, especially the creation of templates and long term strategies are initiatives which will should generate efficiencies across all outages, demonstrating that there are generalized efficiency gains which OPG has found and can continue to find in managing Outage OM&A.

419. In addition, some of the outage work itself will benefit from the application of a "lessons learned" process.

420. For instance, OPG originally budgeted 28 days for the replacement of PHG pump motors, but has found efficiencies to reduce that to 20 days.¹⁸³ Although there may not be further efficiencies on that particular project, it is our submission that project work on a go-forward basis will likely continue to have efficiency opportunities such as that that OPG can take advantage of, and ratepayers should be able to realize some of that efficiency gain as relief from rates.

10.2.2 A Partially Applied Stretch Factor Runs Contrary to IR, the RRFE and
Previous Board's Decisions

421. Allowing OPG to apply the stretch factor to only a portion of their OM&A costs is contrary to the spirit of the RRFE, as well as previous decisions from the Board.

¹⁸² Exhibit F2, Tab 4, Schedule 1, p.8.

¹⁸³ Transcript Volume 14, p.19.

422. During cross-examinations, OPG's witness admitted that there was no reference in the RRFE to excluding either Outage or Project OM&A from the application of the stretch factor.¹⁸⁴

423. The Board has previously held that stretch factors should apply to total costs, even in custom applications. For instance, in EB-2014-0116, the Board held:

The OEB has consistently applied stretch factors to total costs in order to incent productivity in both the areas of capital expenditure and OM&A. The OEB finds no compelling reason to depart from this approach. While the Application put forward by Toronto Hydro may be a custom application, one of the key aspects of the OEB's RRFE is the requirement to continue to make productivity improvements.

424. We submit that it would therefore be inappropriate for OPG to exclude Project and Outage OM&A from the application of the stretch factor, as it would undermine the goals of incentive regulation, namely incenting productivity in all areas of the applicant's business.

10.3 The Use of Total Generating Cost

425. There are inconsistencies in OPG's use of measurements for the stretch factor. As discussed above, OPG has stated in the evidence that it believes that TGC per MWh is the appropriate measure for the nuclear stretch factor. TGC however, contains capital costs as well. This creates a comparison problem for OPG's stretch factor because their proposal does not apply the stretch factor to capital OM&A.

426. As a result of this mismatch, the true efficiency of the costs that have the stretch factor applied in OPG's application, base OM&A and Corporate Support OM&A, may be obfuscated by the use of an 'all in' cost efficiency metric, and the true performance of OPG in those cost categories may require a different stretch factor based on their performance in that individual sub-category of costs.

¹⁸⁴ Transcript Volume 6, pp.138-139.

11.0 MID-TERM REVIEW

427. In their application, OPG proposes a mid-term review for their nuclear production forecast, and proposes a complementary capacity and variance account.
428. The variance account would specifically track the impact of the production variance between the nuclear production forecast approved in the present application, and the production forecast approved in the mid-term review application.
429. The purpose of these tools will be to allow OPG to alter the production forecast two and a half years into the term, while keeping the revenue requirement the same.
430. CME agrees that there should be a mid-term review; however, we submit that an update of the nuclear production forecast and a corresponding variance account are inappropriate, and the mid-term review should instead deal with the progress of the Darlington Nuclear Facility and the Pickering extended operations.

11.1 The Mid-Term Nuclear Production Review

431. In EB-2007-0905 Decision with Reasons, the Board found that OPG should bear the risk of their production forecasts. Specifically, the Board said:

*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. This is the same position OPG would be in if the nuclear facilities were not regulated and were compensated through the hourly spot market or bilateral contracts.*¹⁸⁵

432. The mid-term production review clearly runs contrary to this finding in two ways. First, the mid-term review, coupled with the proposed variance account limits OPG's risk if output falls short of forecast during the second half of the term. This risk should remain with OPG and benefits ratepayers by incenting OPG to manage the operation of their nuclear facilities, including outages, in as efficient a manner as possible.
433. Second, we submit that the proposal as given by OPG does not incent OPG to produce as accurate a forecast as possible. Instead, it incentivizes OPG to over-estimate their

¹⁸⁵ EB-2007-0905, Decision with Reasons, November 3, 2008, p.174.

production during the initial application, and then lower their production forecast in the mid-term review application.

434. OPG states in their application, “if production is lower than forecast (in the present application) OPG may not recover its revenue requirement and a debit balance in the account would be required.”¹⁸⁶ The contrasting circumstances, when the mid-term review production forecast is higher than the initial application forecast, would see OPG crediting the variance account.
435. OPG has also taken the position that while the Board can update the production forecast, it cannot alter the revenue requirement as approved in the initial application, unless of course the revenue requirement is fuel cost, in which case, they can.¹⁸⁷
436. OPG’s application also states that the account would protect both customers and OPG symmetrically. While we acknowledge that, in the abstract, there are complementary protections, the fact that OPG has overestimated their production in every single year since 2008 suggests that in practice, an account that protects OPG in the event of overestimation is asymmetrically beneficial to OPG.
437. We submit that there is evidence on the record to show that OPG is over-estimating their production forecast for the first half of the term. This includes the following:
- (a) OPG is using aggressive FLR targets that are much lower than their achieved results for the previous 5 years.¹⁸⁸ According to OPG’s application, the following is the Darlington Forced Loss Rate for the previous 5 available years:

	2010	2011	2012	2013	2014	2015	Avg
FLR (%)	3.2	0.6	2.3	4.8	1.5	4.9	2.9

¹⁸⁶ Exhibit H1, Tab 1, Schedule 1, p.31.

¹⁸⁷ Transcript Volume 6, pp.154-157.

¹⁸⁸ Board Staff Interrogatory #81, Issue 5.1.

Despite these results, OPG is forecasting a FLR of 1% for 2016, 2017, 2018 and 2019 for Darlington, an amount that would require an almost two-thirds decrease in the FLR level from the previous average.

Similarly, the Pickering's forced loss rate for the last five years are as follows:

	2010	2011	2012	2013	2014	2015	Avg
FLR (%)	9.3	11.6	7.0	9.7	10.7	2.9	8.5

OPG forecasts however a 5% steady forced loss rate for Pickering through the entire term, which would require approximately forty percent reduction in FLR rates from the previous five year average.

- (b) OPG has not, since 2008 correctly estimated their production. The overestimation of their own production averages out to a 3.2TWh per year;¹⁸⁹
- (c) OPG has said that Darlington and Pickering, given their stage of life and planned capital expenditures are in a less steady state than they have been in previous years.¹⁹⁰
- (d) One of the main drivers of underproduction (Forced Extensions to Planned Outage "FEPO" Days) are still not directly factored into outage forecasts.¹⁹¹

438. For the foregoing reasons, CME submits that the Board should not permit OPG to review their production forecasts during the term.

12.0 RATE SMOOTHING

439. OPG has advanced a revised rate smoothing proposal which would produce an annual increase in OPG's nuclear "weighted average payment amounts" of 2.5% per year and would result in an average year over year increase of approximately \$0.65 on the typical residential customer's bill.

¹⁸⁹ EB-2016-0152, Exhibit E2, Tab 1, Schedule 1, Chart 2.

¹⁹⁰ Transcript Volume 14, p. 30; Transcript Volume 6, pp.150-151.

¹⁹¹ Exhibit L, Tab 5.1, Schedule 1, Staff-084, p.1.

440. The smoothing proposal results in the deferral of approximately \$1B over the 2017-2021 period which amount attracts interest at approved rates.
441. Both OPG and Board staff are recommending that the determination respecting rate smoothing be deferred until the Board makes a determination on payment amounts. CME submits that this is a reasonable approach given that the amount of the revenue requirement should govern the extent to which it is reasonable to incur interest costs to smooth rates.

13.0 IMPLEMENTATION

442. OPG requests that the Board grant an order approving payment amounts effective January 1, 2017 through December 31, 2021.¹⁹²
443. OPG's request for retroactive application would burden ratepayers with significant costs associated with 2017 payment amounts not currently included in rates.
444. CME submits that retroactive amounts should not be recovered from ratepayers and that this is inconsistent with the Board's practice as articulated in OPG's last payment amounts application:

The Board has determined that the effective date for the payment amounts for the nuclear and previously regulated hydroelectric facilities will be November 1, 2014. The Board is not prepared to accept the January 1, 2014 effective date proposed by OPG as it is contrary to the Board's long-standing practice of setting rates on a forecast (i.e. forward test year) basis.

The Board's general practice with respect to the effective date of its orders is that the final rate becomes effective at the conclusion of the proceeding. This practice is predicated on a forecast test year which establishes rates going forward, not retrospectively. Going forward, the utility knows how much money it has available to spend and the ratepayer knows how much it is going to cost to use electricity in order to make consumption decisions. The forecast test year enables both the utility and the Ontario Energy Board EB-2013-0321 Ontario Power Generation Inc. Decision with Reasons November 20, 2014 135 ratepayer to make informed decisions based on approved rates. The forecast test year is a pillar in rate setting and the Board's practice must be respected.

¹⁹² Exhibit A1, Tab 2, Schedule 1, p.1.

The Board must control its regulatory process. The Board hears a large number of cases throughout the year and must plan its resources accordingly to ensure cases are completed and decisions are rendered. In cases where utilities have not filed their applications in time to have rates in place prior to the effective date, the Board's practice has typically been to not allow the utility to retrospectively recover the amounts from the period where the interim order was in effect.¹⁹³

445. As observed by the Board, the principle that the Board sets rates prospectively and not retroactively is a pillar of the rate setting process. It allows the utility to know, going forward, how much money it has available to spend, and, more importantly from CME's perspective, it allows ratepayers to know "how much it is going to cost to use electricity in order to make consumption decisions."
446. Board staff, in their submission, contend that a retroactive effective date is reasonable in this case because OPG filed shortly after the 2015 audited results were filed because OPG met the deadlines established by the OEB in Procedural Order No. 1 issued on August 12, 2016.
447. CME submits that these reasons are unpersuasive.
448. The selection of a filing date for a new payment amounts order is a matter which was entirely within OPG's control, irrespective of when audited financial results became available.
449. OPG understood that this particular application would be inherently complex, presented a number of issues not previously addressed in the context of an OPG proceeding and would require the presentation of a large volume of information.¹⁹⁴
450. Knowing this, it filed this Application on May 27, 2016, just less than six months before January 1, 2017, being the date to which it now requests that the payment order be retroactive. In light of how long OPG's previous applications have taken to complete the regulatory process as calculated by SEC, we submit that there is no reasonable basis

¹⁹³ EB-2013-0321, Decision with Reasons, pp.134-135.

¹⁹⁴ OPG AIC at p.1

upon which OPG could have expected a new payment order to issue prior to January 1, 2017.

451. CME submits that had the Board set an order which condensed the necessary timeframe such that a ruling could be ready by January 1, 2017, there would be significant risks to procedural fairness, completeness of the hearing, and the ability to set just and reasonable rates.

452. CME submits OPG's adherence to Procedural Order No. 1 does not justify a departure from the long standing and important principle that rates are to be set on a prospective basis, with all of the attendant cost consequences of ratepayers that this would entail.

13.1 Recovery of these Amounts through Other Means

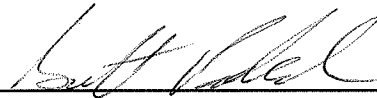
453. We agree with SEC and Board staff that the recovery of the retroactive rates using tools such as the RSDA is inappropriate and would subvert a principled finding that rates should be determined on a prospective basis.

454. CME therefore submits that the Board should expressly provide in its decision that revenues forgone on account of the effective date should not be recorded in the RSDA.

14.0 COSTS

455. CME requests that it be awarded 100% of its reasonably incurred costs in connection with this matter.

ALL OF WHICH IS RESPECTFULLY SUBMITTED this 29th day of May, 2017.



Emma Blanchard
Scott Pollock
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Counsel for CME