May 29, 2017

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

Re: EB-2016-0152 Ontario Power Generation – 2017 to 2021 Payment Amounts Application
AMPCO Final Submission

Dear Ms. Walli:

In accordance with Procedural Order No. 8, attached please find AMPCO's final submissions in the above noted proceeding.

AMPCO has made every attempt to complete the submission without referring directly to confidential materials, and this filing is suitable for public posting. However, there is one area that requires discussion of confidential materials ("Schedule A"). Schedule A to the AMPCO submission is not included in this public version, but will be submitted under separate cover which will be circulated to only those parties that are eligible to receive it.

Please do not hesitate to contact me if you have any questions or require further information.

Sincerely yours,

Colin Anderson
President
Association of Major Power Consumers in Ontario

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Intervenors

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Ontario Power Generation Inc.

2017-2021 Payment Amounts

EB-2016-0152

Association of Major Power Consumers in Ontario

Final Submission

May 29, 2017

Ontario Power Generation Inc.
2017-2021 Payment Amounts

1. Ontario Power Generation Inc. (OPG) filed an application with the Ontario Energy Board on May 27, 2016, seeking approval to changes in payment amounts for the output of its nuclear generating facilities and the regulated hydroelectric generating facilities for the period January 1, 2017 to December 31, 2021.

2. OPG's pre-filed evidence reflects OPG's 2016 to 2018 Business Plan. OPG's 2017 to 2019 business plan was filed as part of the first Impact Statement on December 20, 2016. Subsequent evidence updates were filed as part of additional Impact Statements on February 22, 2017 and March 8, 2017.

3. AMPCO commends OEB Staff's management of a very involved and complex proceeding. OEB Staff worked with parties to accommodate individual scheduling constraints while maximizing schedule efficiency for the benefit of the Hearing Panel. Our impression is that the progress of the hearing was generally seamless from the perspective of the Hearing Panel, and we believe that was largely the result of OEB Staff's diligence and ongoing communication with all involved. Staff's oversight was certainly of assistance to us.

4. AMPCO also commends OEB Staff's final argument. It was very clear and cogent, well organized and well analyzed. We found Staff's work of tremendous assistance in finalizing AMPCO's own positions, and expect that the Hearing Panel will be equally informed and benefited by that work.

5. AMPCO's submissions are focussed on the Darlington Refurbishment Program, Nuclear Operations OM&A and Capital, Nuclear Benchmarking, Pickering Extended Operations, Nuclear Compensation and Benefits, Nuclear Rate-Setting, Scope of Mid-Term Review and Implementation.

DARLINGTON REFURBISHMENT PROGRAM (DRP)

Issue 2.2: Are the amounts proposed for nuclear rate base for the Darlington Refurbishment Program appropriate?

Issue 4.5: Are the proposed test period in-service additions for the Darlington Refurbishment Program appropriate?

Contingency: Reduce Unit 2 Costs by $116 million.

1. OPG is forecasting a return to service of a refurbished Darlington Unit 2 in 2020, and is proposing to add $4,800.2 billion to rate base for Unit 2 in 2020 and 2021. This amount includes contingency costs calculated at a "P90" confidence level, which amount to $694 million.[1]

2. To determine what contingency costs to include in its forecast of rate base additions for Unit 2, OPG:

   (a) Conducted a comprehensive "monte carlo" simulation of DRP risks, their potential impacts and their potential interrelationships. As explained by Dr. Galloway in her testimony, the simulation runs thousands of risk scenarios, informed by detailed inputs from OPG nuclear experts, and produces a series of potential contingency costs for risk occurrence probability levels between 0 and 100.[2]

   (b) Chose the P90 contingency level costs as the appropriate contingency costs for inclusion in their forecast of Unit 2 rate base additions.[3]

3. The choice of a P90 contingency cost level for inclusion in forecast Unit 2 rate base additions means that, if OPG's proposal is accepted, Unit 2 rate base additions approved in this proceeding are 90% likely to be higher than actual incurred costs. Put another way, if OPG's proposal for contingency costs is accepted, OPG is 90% likely to over-recover in rates, at first instance, in 2020 and 2021.

4. This is only true at first instance given the existence and administration of the Capacity Refurbishment Variance Account (CRVA). As a result of that account and its administration, over collections in 2020 and 2021 through payment amounts approved in this proceeding will be offset by rate riders eventually crediting customers for amounts over collected. In the eventual result, effective rates will not over collect.

5. The choice of contingency level for the purpose of setting payment amounts still matters though, for the following reasons:

[1] Ex. D2/T2/S7, pp. 7-8.
[2] Tr. 5, p.153, lines 4-12.
[3] Tr. 5, p.26, lines 3-16.

(a) The Board is being asked in this proceeding to approve OPG's forecast in-service amounts. While actual in-service amounts will be reported, AMPCO anticipates that OPG expects that only costs in excess of the in-service amounts approved in this application – i.e. CRVA balances - will be subject to prudence review once the Unit 2 actual refurbishment costs are established.

(b) There will be a lag between the in-service date for Unit 2 and the final reconciliation of CRVA balances related to Unit 2 refurbishment for disposition. In the interim, it is 90% likely that customers will be overpaying (though they will be credited back such overpayments later on).

(c) Choosing a contingency level that better reflects a likely, expected cost outcome will provide a proper benchmark and greater transparency for evaluation of OPG's actual performance.

(d) Choosing a contingency level that better reflects a likely, expected and appropriate cost outcome will better incent OPG to manage the refurbishment of Unit 2 as efficiently as possible.

6. For these reasons, the Board should establish a more likely, expected and appropriate contingency level for inclusion in OPG's approved Unit 2 in-service rate base additions.

7. It is perfectly understandable, and even commendable, that for the purposes of commercial planning and project approval OPG applied a P90 level of contingency in developing its $12.8 billion DRP cost forecast. This is the basis upon which the Ontario government has endorsed the DRP project.[4] This approach provides the shareholder with certainty that the project is very unlikely to exceed the P90 cost forecast. As it was put by Dr. Galloway in testimony[5] (emphasis added):

> *You then have to look at, for instance, as I had indicated, a P90 gives you a 90 percent confidence level probability. It's a probabilistic model, a 90 percent probability that you will fall within the estimated cost and schedule.*
>
> *The lessons learned from megaprograms – and I think this has actually been documented now by other megaprogram experts just as recently as even last year, that the lessons learned over the last two decades of megaprograms is that there has not been the extensive upfront planning nor the inclusion of higher probabilities, recognizing that it is difficult to identify all the certainty of those probabilistic risks today when you're looking over a period of several years. And that is why the megaprograms that are taking what I would call a more realistic view of having as much information as they reasonably can based on what is known at the time and modelling that from a probabilistic standpoint, <u>that a financier of the megaprogram, whether that's a private entity, an investment bank, an owner, a commission, gives them a higher confidence of what they know an ultimate cost may be and they can make better informed decisions knowing what that ultimate cost may be</u>.*

[4] Ex. J2.5.
[5] Tr. 5, p.154, line 13 *et seq*.

8. Dr. Galloway continued[6]:

> *And so I think I opined earlier that confidence levels are important not only for the entity building the project, but they are extremely also important to build confidence of some level of certainty or confidence of what costs may be at the end of the program.*

9. Dr. Galloway referred to the London Crossrail project as one of the two projects of which she was aware that used a P90 (or higher) budget estimate.[7] The London Crossrail is a mega transportation project for the city of London, England, which has been undertaken by, and is being funded by, the government. Coming back to this project during cross-examination, Dr. Galloway explained[8] (emphasis added):

> *This – for instance, the example I used on Crossrail, it was extremely important for the government to, before it were to go out on a tax base and trying to obtain funds and to expend funds, to have a good confidence level that that would be the dollars that would be undertaken for that megaprogram.*
>
> *And so it was not just for the entity building it, but also for the government in its confidence level. So when I look at the reasonableness of a confidence level I try to look at it in the context of both, if you call it equations, both sides of the equation, <u>as to whether the entity that has a good confidence that it will come in for those dollars in addition to the entity who's actually building it</u>.*

10. AMPCO endorses the use of P90 DRP costing for the purposes of the Ontario government's decision to accept, and legislate, the determination of need for the DRP.

11. AMPCO also endorses the presentation by OPG of the P90 DRP costing for the purposes of informing the OEB as to the potential scope of DRP costs which the Board will ultimately be asked to consider and approve.

12. It is completely appropriate for a business case, particularly one for this unprecedented project, to take an ultra-conservative approach to approval and commitment.

13. However, such an approach need not, and AMPCO submits should not in these circumstances, be carried through to rate approvals.

14. AMPCO objects to the use of the P90 DRP costing for the purposes of setting nuclear payment amounts in this proceeding. The board should not approve Unit 2 costs for inclusion in the payment amounts to be set in this proceeding which are 90% likely to be higher than what OPG will actually spend.

15. A more appropriate level for contingency costs to be included in the nuclear payment amounts to be set in this proceeding is P50. As Board Staff's expert Mr. Robert's of Schiff Hardin explains[9]:

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[6] Tr. 5, p. 154, lines 24 *et seq*.
[7] Tr. 5, p. 145, lines 6 *et seq.*
[8] Tr. 5, p.161, lines 1, *et seq.*
[9] Ex. M1-4.3 APMCO-009, part b.

> *The P50 is an estimate of the project cost based on a 50% probability that the cost will not be exceeded. Stated another way, the P50 estimate is one with equal chance of project overruns or underruns.*

16. Revising the Unit 2 contingency level from the P90 proposed by OPG to P50 would entail a reduction in the $4.8002 billion Unit 2 in-service amount forecast of $116.1 million (just under 2.5%), leaving $578 million of contingency in the nuclear payment amounts approved for 2020 and 2021.

17. This contingency provision would be in addition to the proposed recovery from ratepayers of $1 billion in planning costs incurred by OPG over a decade of activity to ensure that the DRP is conducted efficiently, safely and cost effectively.[10]

18. From a ratepayer perspective, use of a properly derived P50 contingency cost minimizes both the likelihood and the extent of later rate adjustments.

19. Mr. Robert's evidence contrasts the choice of a P50 level of contingency with the choice of a P90 level of contingency[11]:

> *The P90 is an estimate of the project cost based on a 90% probability that the cost will not be exceeded. Some project participants prefer to have less exposure to increases in capital budgets and often look for a P90 figure. The P90 contingency means that the contingency allowance on top of the base estimate is sufficient to ensure that there is a 90% chance that the amount will not be exceeded. Budget determinations and the confidence level for projects/programs vary by the contracting strategy, schedule and other project/program factors.*

20. Approving forecast costs and setting a forecast of rate base additions for a megaprogram of the scale and scope of the DRP on the basis that there is a 90% chance that the amount included in rates will not be exceeded would be inappropriate.

21. Approving forecast costs and setting a forecast of rate base additions for the DRP on the basis that there is an equal chance of project overruns and underruns would;

    (a) better protect rate payers, both from later rate increases and from overcollection;

    (b) ensure a greater degree of transparency by more appropriately setting the approved Unit 2 refurbishment budget at the level which OPG actually expects to spend; and

    (c) better incent cost efficiency in execution of the DRP project.

22. In respect of the latter point – efficiency incentive – AMPCO is concerned that in respect of the largest single electricity infrastructure project ever undertaken in Ontario,

[10] Ex. D2/T2/S4.
[11] Ex. M1-4.3 APMCO-009, part b.

OPG's "destiny project", OPG has not set any efficiency stretch or expectations for itself.

23. Express and transparent efficiency expectations are a central tenet of the Board's regulatory policy, and are typically employed within a Custom IR Application such as the one OPG has filed. Setting payment amounts for OPG which are <u>expected</u> to be higher than necessary would be completely contrary to this policy.

24. The Hearing Panel should also consider that regardless of the "P level" adopted for the purposes of setting rates and cost approval benchmarks for the refurbishment of Unit 2, OPG has proposed to allocate 40% of the total DRP contingency to the first unit. This was a judgement call by OPG management in order to ensure an appropriate amount of the total contingency is allocated to the first unit opened.[12] This gives OPG a significant cushion in order to manage any surprises arising in respect of the work to be undertaken between now and the end of the test period for which payment amounts are being determined in this proceeding.

25. Of course, a determination to set the Unit 2 contingency level at P50 for the purposes of the nuclear payment amount approval in this application will not in any way cap OPG's ultimate Unit 2 refurbishment recovery. All variances from approved payment amounts will be captured in the CRVA, and prudent variances, including those for risks foreseen and unforeseen which crystallize, will be eligible for cost recovery if OPG can demonstrate prudent response.

26. The budget which OPG presented to the government for DRP approval was the full DRP program budget ($12.8 billion), not a disaggregated Unit 2 budget. In approving the DRP as a whole, with the knowledge that this Board would ultimately review and approve DRP costs for inclusion in payment amounts, the government did not approve a Unit 2 specific budget. That has been left for this Hearing Panel.

27. AMPCO has considered OEB Staff's proposal that the Board adopt a P37 contingency cost level for Unit 2 refurbishment. Staff has determined that revising the Unit 2 contingency level from the P90 proposed by OPG to P37 would entail a reduction in the $4.800.2 billion Unit 2 in-service amount forecast of $144 million (just under 3%), leaving more than half a billion dollars ($550 million) of contingency in the nuclear payment amounts approved for 2020 and 2021.

28. Staff's proposal is based on OPG's "working schedule", which equates to a P37 contingency level in OPG's risk analysis. OPG's witnesses characterized a P37 working schedule as "ambitious", though it is nonetheless their working schedule, i.e. the schedule that they are aiming to meet.

29. It is noteworthy that OPG's internal performance metrics "stretch target" is also set at P37.[13] It could be argued that the same "stretch target" would be advisable for the external benchmark for eventual evaluation of the appropriateness and prudence of

[12] Tr. 5, p.26, lines 3-16.
[13] Ex. J3.1, as discussed at Tr.5, p.31, lines 10 *et seq*.

Unit 2 refurbishment spending. Again, using P37 instead of a higher contingency budget will not limit OPG's ability to recover prudently incurred costs as actually incurred, through the CRVA.

30. AMPCO recognizes, and accepts, the logic in Staff's position on contingency, and would certainly not object to adopting such an approach if the Board concludes that it would be appropriate to include an express efficiency "stretch factor" in determining Unit 2 refurbishment costs to approve at this time.

31. Otherwise, a P50 level of contingency - presenting an equal chance of a positive or negative variance in the CRVA – is intuitively appropriate.

32. In response to suggestions that a lower "P level" contingency would be more appropriate, OPG's witnesses contended in examination that Dr. Galloway of Pegasus Global Holdings Inc. Kenneth Roberts of Schiff Hardin endorsed OPG's choice of a P90 confidence level. AMPCO's counsel asked both OPG Panels 1A and 1B to provide references to the external expert opinions on the record in this proceeding on which they rely in asserting that approval of a P90 contingency estimate by this Hearing Panel in setting nuclear payment amounts is appropriate.

33. The statements relied on by OPG are collected in Undertaking J2.4. They are all from Dr. Galloway's prefiled report, save for one from Mr. Roberts' report. None of these statements suggest that this Hearing Panel set nuclear payment amounts based on P90 contingency cost estimate. All of these statements speak to approaches to commercial project planning, commercial project approvals and commercial project management, not regulatory approvals.

34. That is completely appropriate, in light of the basis upon which these experts were qualified and the basis upon which they approached their testimony in this proceeding.

35. Dr. Galloway was qualified by OPG's counsel as *"an expert in megaprojects and megaprograms, including execution, planning, risk management, prudence in project controls, which is the nature of which her testimony will be given"*[14] (emphasis added).

36. When OPG counsel was asked by the Chair whether he was asking to have Dr. Galloway qualified with respect to prudence as the Board uses it in doing its review, counsel responded; *"No"*[15], and went on to say (emphasis added):

> *I think that ultimately, it's more in terms of an objective – it's my understanding, and Dr. Galloway maybe can correct me if I'm wrong, that the prudence reviews she would do would be an objective view as to the aspects that were taken out – taken on during the steps undertaken by the regulated entity, let's say, and those steps at the time, from a megaproject/megaprogram management perspective, that they were prudent and reasonable.*

[14] Tr. 5, p. 126, lines 8-11.
[15] Tr. 5, p.136, line 12.

> *I think ultimately the aspect of – the final arbiter of what is prudent or not prudent obviously is yours.*

37. In a follow-up exchange with AMPCO's counsel[16] Dr. Galloway agreed that when she discusses "prudence" what she means is:

> *... that you examine the reasonableness of the decisions made in project execution from a commercial perspective as opposed to making a regulatory or legal determination for inclusion of costs in rates.*

38. In cross-examination it was established that Dr. Galloway's considerations of "prudence" related to *"a decision from the undertaker* [of a particular project] *to proceed with that project or not"*[17], and that she did purport any expertise on regulated rate making or rate regulation[18].

39. This was further confirmed in the following statements by Dr. Galloway during testimony elaborating on the basis upon which her evidence was provided (emphasis added):

> *Based on the review that Pegasus Global undertook of OPG's organization, its structure, its policies, its procedures, its project controls, its risk management and assessment, and based on the interviews of OPG personnel, I found that OPG had reasonably and prudently prepared itself <u>for the execution of the Darlington refurbishment project</u>.*
>
> *Secondly, I found that OPG, in its approach to this megaprogram, is that as is typically found in the planning of other megaprograms in which I am familiar. <u>The extensive preplanning that was conducted for the Darlington refurbishment program favourably positions OPG to successfully execute the DRP.</u>* (Tr. 5, p.138)
>
> *And its preparation of a detailed estimate and schedule that was based on a thorough and robust probabilistic model, OPG established a P90 confidence level and an approach contingency. That basically means that there would be a 90 percent probability that the Darlington project will come in within the estimated cost and schedule, and I found that <u>process</u> in that P90 and the allocation to be reasonable.* (Tr. 5, p.139)
>
> *We have both* [in reference to Mr. Roberts] *concluded that the risk management <u>process</u> used by OPG is in accordance with industry best practices and utility industry practices and that it is a – was found to be a reasonable <u>process</u>.* (Tr. 5, p.142, lines 17-20)
>
> *I have not been asked to opine on setting rates.* (Tr. 5, p.159)

40. AMPCO invites the Hearing Panel to read the entirety of the discussion between Dr. Galloway and AMPCO's counsel, of which the foregoing excerpts are representative of

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[16] Tr. 5, p.137, lines 17-22.
[17] Tr. 5, p. 127, lines 12-13.
[18] Tr. 5, p. 150, lines 6-11.

the nature of Dr. Galloway's evidence regarding the use of a P90 level of contingency costs. This discussion is recorded at Volume 5, commencing at page 146.

41. Considered fairly and in its entirety, there is nothing in Dr. Galloway's testimony, written or oral, that opines on the appropriateness of use of a P90 contingency cost level for the purposes of setting OPG payment amounts in this proceeding.

42. Earlier in this section of the Argument AMPCO referred to Dr. Galloway's reference to the London Crossrail project. The only other project that Dr. Galloway, having reviewed the matter prior to testifying, is aware of that used a P90 level of contingency cost for approval purposes[19] was the Bellfonte nuclear plant.[20] In that instance, Pegasus advised the Tennessee Valley Authority's (a utility) Board of Directors regarding a choice between completing 2 already started nuclear units or to instead build two new units using a new technology.[21] Dr. Galloway described that situation as one of considering[22]:

> *.... given the risks and complexities of both completing a plant that had been sitting for many, many, many years and to looking at a new design on a new nuclear plant, and that's why the P90 confidence level.*

43. In its Argument in Chief (AIC) OPG asserts that Mr. Roberts of Schiff Hardin confirmed in testimony that the use of a P90 estimate is well within industry standards.[23]

44. What Mr. Roberts said, in full, and in the context of being asked about whether the DRP is likely to come in under budget, was:

> *Mr. Yauch: ..... Now you've done a lot of work on megaprojects. How confident are you that nine times out of ten, a project like this will actually hit that budget?*
>
> *Mr. Roberts: I'm not in a position to give you testimony on that. They used the P90 and <u>my testimony is limited to the planning stage and what they did</u>, and using a P90 as well within industry standards.*

None of this exchange is about how the Board should set rates.

45. The additional references on this point provided by OPG at page 56 of its AIC relate to planning process and procedure, and in the case of the reference to Concentric's evidence to the wisdom of a utility seeking cost approval at a high probability level since *"[i]t will have to show amounts above that estimate as being prudent before it would be able to file for inclusion in rates in the future"*.[24]

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[19] Tr. 5, p.147.
[20] Tr. 5, pp. 145-146.
[21] Tr. 5, p.148.
[22] Tr. 5, p.146.
[23] AIC, p.56, lines 25-26.
[24] AIC, p.57, lines 20-21.

46. In summary, none of the evidence relied on by OPG provides any support for the view that it would be appropriate for the OEB to set Unit 2 rate base additions to be included in nuclear payment amounts in 2020 and 2021 to include contingency costs at a P90 level of certainty. There is simply no evidence, opinion or otherwise, on the record which supports this outcome, other than evidence of OPG's witnesses reflecting OPG's desire.

47. As stated above, AMPCO takes no issue, and indeed endorses, use of a P90 level of cost and schedule contingency for the purposes of project planning and project approval. Not, however, for the purposes of setting rates, and in particular considering that:

(a) OPG has the protection of variance account treatment for prudent over-expenditures; and

(b) ratepayers are already expected to pay more than $1 billion on account of the costs of a decade of planning intended to make sure that the DRP proceeds effectively and efficiently.[25]

[25] Ex. D2/T2/S4.

NUCLEAR OPERATIONS CAPITAL & IN-SERVICE ADDITIONS (Excluding DRP)

Issue 2.1: Are the amounts proposed for nuclear rate base (excluding those of the Darlington Refurbishment Program) appropriate?

Issue 4.2: Are the proposed nuclear capital expenditures and/or financial commitments (excluding those for the Darlington Refurbishment Program) reasonable?

A. Summary of AMPCO Recommendations:

48. AMPCO submits OPG's 2016 nuclear in-service amount should be adjusted to reflect 2016 actuals of $292 million and $8.9 million for Support Services Capital, reflecting a total reduction of $206.6 million in 2016 ISA.

49. Over the 2010 to 2016 period, OPG has placed 12.5% less capital in-service compared to planned amounts. Of the projects with in-service dates in 2014 to 2016, the total cost variance is approximately 11.72% based on the variance between the total cost approved in the first execution business case and the actual or forecast in-service amount. Of the Tier 1 projects with in-service dates over the test period, the current total cost variance is approximately 25%. Under both scenarios, the average project delay is 17 months. Taking into consideration OPG's project performance, AMPCO submits that OPG's ISA for the years 2017 to 2019 should be reduced by 15% annually.

50. AMPCO submits the Board should not accept OPG's proposal to capitalize 50% of the Darlington New Fuel and accordingly, 2019 ISA should be reduced by $15.3 million.

51. AMPCO recommends that OPG undertake an audit of its P&M project controls in time for the mid-term review and provide a status report at that time.

52. On the Auxiliary Heating System Project, AMPCO submits the Board should disallow 75% of the incremental cost from the First Execution BCS to the amount requested (i.e. 75% of $53.9 million = $40.4 million).

53. On the Darlington Operations Support Building Project, AMPCO submits ratepayers should not have to pay for the incremental cost from the First Execution BCS to the amount requested (i.e. $14.9 million).

54. The sections set out below will provide the context and justification for the recommendations shown above.

B. Nuclear Operations Capital and In-Service Additions - General

55. OPG's Nuclear capital budget[26] consists of Operations Capital and DRP capital. AMPCO's submissions on DRP Capital and in-service additions are covered under Issues 2.2 and 4.5.

56.

Capital Expenditures Summary - Nuclear ($M)

Line No.	Category	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Operations Capital**	201.2	292.7	314.8	353.0	279.0	258.0	282.4	278.5	199.3
2	**Darlington Refurbishment Capital**	430.3	694.3	705.8	1,230.9	1,094.6	1,121.4	979.2	858.3	1,194.8
3	**Total Nuclear Capital**	631.5	986.9	1,020.6	1,583.9	1,373.6	1,379.4	1,261.7	1,136.7	1,394.1

Test Period - 2017 to 2021

57. Over the 2017 to 2021 test period, OPG proposes to spend $1,297.2 million on Nuclear Operations capital. This represents a 20% increase in annual average capital spend compared to the 2010 to 2015 period. OPG seeks approval of $1,495.5 million in in-service additions over the test period.

58. Average annual in-service additions (ISA) are proposed to increase by $117 million over the test period to $292 million compared to $175 million historically. OPG's ISA as a percentage of capital increases from an average of 81% over the 2010 to 2015 period to a forecast of 112.5% over the 2017 to 2021 period.

Nuclear Operations Capital & ISA 2017 to 2021

$ M	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	Total	Average	Reference
CAPEX	279.0	258.0	282.4	278.5	199.3	1,297.2	259.4	D2-1-2 T2
ISA	389.0	315.2	239.3	300.4	215.6	1,459.5	291.9	D2-1-3 T4
% Capital	139.4%	122.2%	84.7%	107.9%	108.2%	112.5%	112.5%	

59. As discussed below, based on historical performance, AMPCO does not believe OPG will achieve the proposed increase in ISA over the test period. Also, AMPCO wishes to point out that an increase in ISA does not automatically mean more project work is being accomplished. The increase in cost growth of projects within OPG's Project Portfolio is a significant contributor to an increase in ISA.

[26] D2-2-1

Nuclear Operations - Capital & ISA 2010 to 2016										
	2010	2011	2012	2013	2014	2015	Total	Average	2016	2016
$ M	Actual	Actual	Actual	Actual	Actual	Actual			Budget	Actual
CAPEX	176.2	148.1	161.4	201.2	292.7	314.8	1294.4	215.7	353.0	
ISA	249.0	103.2	131.9	212.6	148.6	204.1	1049.4	174.9	497.0	292.0
% Capital	141.3%	69.7%	81.7%	105.7%	50.8%	64.8%	81.1%	81.1%	140.8%	
Capital: EB-2013-0321 Decision P 52; D2-1-2 T2										

C. Nuclear Operations Capital

60. Nuclear Operations capital consists of Portfolio Projects, Darlington New Fuel and Minor Fixed Assets. [27]

Capital Expenditures Summary - Nuclear Operations ($M)

Line No.	Category	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Portfolio Projects (Allocated)									
1	Darlington NGS	76.4	164.2	194.4	212.7	176.6	140.9	88.6	37.4	30.2
2	Pickering NGS	90.6	96.1	93.4	89.7	23.0	2.4	0.0	0.0	0.0
3	Nuclear Support Divisions	24.0	9.5	4.6	14.2	4.6	0.2	0.0	0.0	0.0
4	Subtotal Portfolio Projects (Allocated)	191.0	269.8	292.5	316.5	204.2	143.4	88.6	37.4	30.2
5	Portfolio Projects (Unallocated)	0.0	0.0	0.0	5.5	48.8	94.6	159.4	221.6	149.8
6	Subtotal Project Capital (Portfolio)	191.0	269.8	292.5	322.0	253.0	238.0	248.0	259.0	180.0
7	Darlington New Fuel	0.0	0.0	0.0	0.0	0.0	0.0	15.3	0.0	0.0
8	Minor Fixed Assets	10.2	22.9	22.3	31.0	26.0	20.0	19.1	19.5	19.3
9	Total Nuclear Operations Capital	201.2	292.7	314.8	353.0	279.0	258.0	282.4	278.5	199.3

C.1 Darlington New Fuel Capital

In 2019, OPG proposes to capitalize $15.3 million for Darlington new fuel with the return to service of refurbished Unit 2, and expense $15.3 million in 2020. OPG confirms that it does not have a past practice to capitalize new fuel.[28] AMPCO submits OPG's evidence to support this capitalization proposal is weak. AMPCO submits this amount should be expensed. Accordingly, AMPCO submits the in-service amount in 2019 should be reduced by $15.3 million.

C.2 Portfolio Projects Capital

[27] D2-1-2 Table 2
[28] L-6.3-1-Staff-111

61. OPG's total annual Project Portfolio spend over the test period 2017 to 2021 is $323.8 million which represents an increase over OPG's historical spend of $250 to $300 million per year.[29] Part of the increase is due to five projects from DRP that OPG reclassified to Nuclear Operations in 2015 totalling $327 million.[30]

Nuclear Operations Project Portfolio Expenditures

Line No.	Category	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Project Portfolio - Capital	190.9	269.8	292.5	322.0	253.0	238.0	248.0	259.0	180.0
2	Project Portfolio- OM&A	87.4	80.8	100.7	78.2	98.9	90.4	81.7	83.0	86.8
3	Total Nuclear Portfolio	278.3	350.6	393.2	400.2	351.9	328.4	329.7	342.0	266.8

Portfolio Project Level Performance

62. For each project, OPG prepares a Business Case Summary (BCS). Upon approval of a BCS, funding releases are approved and the project moves forward to the project execution phase.

63. If a project experiences an over-variance in cost or schedule, OPG requires additional approval through a Project Over-Variance Approval form. If the over-variance is over 20% of cost or schedule or both, OPG requires approval of a Superceding BCS. If cost and/or schedule increases continue, approval of additional Project Over-Variance or Superceding BCS forms are required. Project cost increases beyond $40 million require OPG Board approval.

64. OPG indicates the number of projects with a Superceding BCS and release of funds has increased over the past 5 years,[31] although OPG does not specifically track this. OPG expects that its project management initiatives will reduce the number of projects with a superceding release and the magnitude of the additional budget required to complete the project. AMPCO's proposal to apply the Stretch Factor to OPG's Project Portfolio costs (OM&A & Capital) will drive further improvements to project performance. AMPCO submits OPG should track and monitor the number of Superceding BCS over time as a metric to inform project performance.

65. At the time of the pre-filed evidence, seven out of 38 Tier 1 projects had Superceding BCS[32] [33] totalling over $110 million. As part of the interrogatory process, OPG filed seven more Superceding BCS for Tier 1 projects.[34] Since November, there have been

[29] Line 1 Project Portfolio – Capital = Line 6 in Table X
[30] The 2015 ISA for DRP F&IP was reduced by $66.0 million, the amount for the AHS and OSB projects that are now in the Nuclear Operations Portfolio.
[31] L-4.2-2-AMPCO-026
[32] D2-1-3 Table 1 + AHS Project #34000
[33] Project #25619, 33977, 36001, 41023/49247, 25609
[34] L-4.2-2-AMPCO-017

three additional updates to the Tier 1 BCS.[35] The number of Tier 1 projects with cost or schedule variances >20% is significant. OPG's project performance does not appear to be improving.

66. AMPCO has significant concerns regarding OPG's execution of its capital plan and the resulting number of Superceding Business Cases to increase the release of funds and/or extend the in-service dates. As discussed below, OPG's historical performance shows OPG is consistently over-budget and behind schedule on most of its capital work, and performance continues to decline. Current project performance shows that for projects greater than $20 million, the majority are over budget and behind schedule.

Portfolio Level Performance - SPI & CPI Metrics

67. At a Project Portfolio level, OPG has two key project management performance metrics to track Project Schedule and Project Cost across the portfolio of nuclear projects: Schedule Performance Index (SPI) and Cost Performance Index (CPI).

Over the past five years, the SPI shows a declining trend. The CPI has remained constant and since 2014 is trending slightly above target.[36]

Project & Modifications SPI, CPI 2012-2016

	Target	2012	2013	2014	2015	2016
Cost Performance Index (CPI)	1.00	1.05	1.02	0.99	1.01	1.03
Schedule Performance Index (SPI)	1.00	0.95	0.87	0.85	0.81	0.85

68. The negative SPI trend can be explained by key projects taking longer to execute.37 A CPI close to or above 1.0 with a negative trending SPI means that these delayed key projects are also costing much more to execute.

Work Management Metrics: Scope Stability & Schedule Adherence

69. Based on two new industry benchmarking metrics related to Work Management: Scope Stability and Schedule Adherence38, OPG's results show that for both Darlington and Pickering, OPG is below the top quartile for Scope Stability of 92% and Schedule Adherence of 95%.39

Historical Project Performance

70. OPG's historical performance demonstrates that OPG has a history of being over-budget and behind schedule on most of its capital plan.

[35] J15.5
[36] J15.8
[37] L-4.2-2-AMPCO-026
[38] F2-1-1 Attachment #3 P12
[39] L-6.2-1-Staff-106

71. Many of the projects identified in the last application (EB-2013-0321) that were scheduled to go in service in 2014 and 2015 did not. Out of 25 projects ($5 million and greater) with in service dates in 2014 and 2015, 21 projects were late, 3 were early and 1 was on time. 14 projects (56%) were not placed in service in 2014 or 2015 as specified in EB-20130-0321. Of these, 9 were still not in-service by the end of 2016.[40] .

72. The total variance of projects with in-service dates in 2014 to 2016 totals 424 months or an average of 17 months per project. 41 The total cost variance for all projects is approximately 11.7% based on the variance between the total cost approved in the first execution business case and the actual or forecast in-service amount. For the five Tier 1 projects, greater than $20 million, costs are 41.8% higher than the First Execution BCS.[42]

73. Project cost increases are due to:

Additional scope
Additional OPG Project Management for additional OPG oversight
Additional OPG Engineering
Additional OPG Procured Materials
Additional Design and Construction costs
Additional vendor costs to support extended schedule
Additional engineering field support
Standby Costs – where contractors are asked to stand down
New consultant costs
Rework
Interest charges
Currency escalation
Contingency increases especially if new risks identified

74. In 2015, $533 million in OM&A and $327 million in capital was reclassified from DRP to Nuclear Operations.[43]

	2015 LTD	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
OM&A	12	32	62	48	44	54	63	73	70	49	27	0	533
Capital	200	20	31	15	12	14	35	-	-	-	-	-	327

75. The cost details are as follows:

[40] D2-1-3 Table 7
[41] Transcript Volume 14
[42] L-4.4-15-SEC-46
[43] L-4.5-2-AMPCO-105

OM&A and Capital Costs Details Underlying AMPCO 105 ($M)	Total
Unit Maintenance / Operations (Online / Outage)	398
Contracted Maintenance Programs (T/G, BOP)	81
Engineering Systems Surveillance Activities	28
Operator Training Program	25
Total OM&A	**533**
Darlington Operations Support Building Refurbishment	63
Darlington Auxiliary Heating System	99
Emergency Service Water Pipe and Component Replacement	7
Primary Heat Transport Pump Motor Replacements & Overhaul	130
Highway 401 & Holt Road Interchange	29
Total Capital	**327**

76. As a result of moving these five projects from DRP to Nuclear Operations, they are no longer eligible for CRVA treatment that includes a true-up and formal prudence review. AMPCO submissions regarding reductions to OPG's proposed in-service additions related to the Operations Support Building (OSB) and the Auxiliary Heating System (AHS) are set out later in this submission.

2016 Project Performance

77. OPG's 2016 actual ISA are $292 million; $205 million lower than the 2016 test year budget of $497 million[44]. Thus, OPG achieved only 60% of its ISA forecast for 2016.

78. OPG explains that the lower actual nuclear in-service capital amounts compared to the 2016 budget reflects project delays and deferrals that moved some or all the planned in-service declarations for each applicable project beyond 2016.

79. AMPCO submits OPG's 2016 in-service amount for Project Portfolio capital should be adjusted to reflect 2016 actuals of $292 million given that this final amount is now known. It would be inappropriate for ratepayers to pay the revenue requirement impact of the forecast amount.

80. OPG's 2016 actual amount for Support Services capital was $8.9 million, $1.6 million less than the $10.5 million forecast. AMPCO submits OPG's 2016 in-service amount for Support Services capital should be adjusted to reflect 2016 actuals of $8.9 million. Thus, AMPCO proposes a total reduction in nuclear in-service capital additions of $206.6 million (excluding DRP).

81. Historically OPG has been challenged to meet its ISA forecast as shown in the table below.

[44] J14.1

Nuclear ISA $M	2010	2011	2012	2013	2014	2015	2016	Total
Plan	191.5	175.5	187.6	180.8	158.3	141.7	497.0	1532.4
Actual	249.0	103.2	131.9	212.6	148.6	204.1	292.0	1341.4
$ Variance	57.5	-72.3	-55.7	31.8	-9.7	62.4	-205.0	-191.0
% Variance	30.0%	-41.2%	-29.7%	17.6%	-6.1%	44.0%	-41.2%	-12.5%
Capital: EB-2013-0321 Decision P 52								
D2-1-3 T4								

82. Over the 2010 to 2016 period, OPG has placed 12.5% less capital in-service compared to planned amounts.

Current Project Performance

83. OPG's 2017 to 2021 capital program consists of[45]:

38 Tier 1 projects (>$20 M each);
74 Tier 2 projects ($5 M to $20 M each);
71 Tier 3 projects (<$5 M)
Total = 183 projects

84. The number of portfolio projects has increased from 78 in EB-2007-0905 to 183 in EB-2016-0152, an increase of over 230%.

85. 16 of the Tier 1 projects are ongoing from EB-2013-0321. Half of these projects were classified as Tier 2 projects in EB-2013-0321 but due to cost increases are classified as Tier 1 projects now (>$20 million). 15 of the Tier 1 projects are >$40 million. Since 2005, the Niagara Tunnel Project is the only capital project at OPG's regulated facilities with a cost greater than $250 million.[46] [47] Of the 2 completed projects since EB-2013-0321, one project has a Superceding Business Case for $11.7 million.[48]

[45] D2-1-3 Pages 1-2
[46] L-4.3-15-SEC-021
[47] NTP- Capital cost variance is $479 million; Schedule variance is 2 years and 9 months.
[48] Sustaining Project #49285 (+$11.7 M)

# of Portfolio Projects							
			Tier 1	Tier 2	Tier 3		
Case #	**> $20 M**	**$5M to $20M**	**>$10 M**	**$5M to $10M**	**<$5 M**	**Sub-Total**	**Reference**
EB-2007-0905			28	15	35	**78**	D2-1-2 P1-2
EB-2010-0008			41	15	34	**90**	D2-1-2 P1-2
EB-2013-0321	16	61			81	**158**	D2-1-3 P1-2
EB-2016-0152	38	74			71	**183**	D2-1-3 P1-2

86. AMPCO's analysis of the cost and schedule performance of the 38 Tier 1 projects (>$20 million)[49] in this application as of November 2016 shows that the total cost overruns of the Execution Phase BCS projects is $246 million or 25% and the schedule overrun is on average 17 months per project[50], consistent with the average schedule overrun per project discussed above for projects scheduled to be in service in 2014 to 2016.

87. Based on these project performance results and OPG's history of placing 12.5% less capital in-service compared to planned amounts over the 2010 to 2016 period, and P&M's ongoing project control issues discussed below, resulting in cost overruns and schedule delays, AMPCO submits OPG's capital ISA for the years 2017 to 2021 should be reduced by 15%.

<u>Project Management Performance: Projects and Modifications</u>

88. Projects and Modifications (P&M) is responsible for most of the nuclear project work carried out at the generating stations and associated sites.

89. P&M was chosen to manage the DRP pre-requisite projects (F&IP and SIO) as the DRP execution team at that time was in early stages of being organized. The inclusion of the DRP Campus Plan Projects caused P&M's portfolio to increase by four to five times, and the scale and technical complexity of this work was unprecedented for P&M.

90. The management deficiencies within P&M were highlighted by Burns & McDonnell/Modus in their ongoing oversight reviews of P&M's performance on the DRP Pre-requisite projects.[51]

Burns & McDonnell/Modus concluded P&M created the conditions for a perfect storm of cost and schedule overrun.[52]

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[49] L-4.2-2-AMPCO-017
[50] K15.1 P34 Deferred/Cancelled Projects & Definition Phase projects removed
[51] L-4.3-1-Staff-072-Attachments#3-9
[52] Staff #72 P7

91. In 2012, OPG implemented a new contracting strategy using an Engineering Procure and Construct (EPC) model to improve its project management function by increasing its ability to execute additional project work with a single point of accountability for the complete delivery of a project. Two vendors - ES Fox Ltd. and Black & McDonnell Ltd. - entered into Extended Services Master Service Agreements (ESMSA) agreements for EPC services. In 2014, OPG selected SNC/AECON JV as a third ESMSA contractor.

92. P&M piloted the EPC contracting approach and early implementation of the EPC model was on large and complex projects. The D2O and AHS projects were the pilots for the new EPC contracting model.[53]

93. AMPCO submits the findings of Burns & McDonnell/Modus on the pre-requisite DRP projects managed by P&M are relevant to the cost and schedule overruns on the Nuclear Operations Portfolio Projects, also managed by P&M. Burns & McDonnell/Modus indicated that it is likely that each of the P&M non-Refurbishment projects at Darlington and Pickering will require a full, bottom-up rebaseline of costs and schedules as Burns & McDonnell/Modus cannot ascribe any confidence to any project estimate that was developed by P&M's former regime. Burns & McDonnell/Modus indicated P&M needs to perform this reforecast on an urgent basis.[54]

Key findings of Burns & McDonnell/Modus

94. Campus Plan Projects' variances were caused by initial poor cost and schedule estimates; P&M's management model was flawed.[55]

95. The P&M Team for the Campus Plan Projects struggled with the initial application of a hands-off oversight model paired with largely cost reimbursable target price contracts with vendors.

96. The "hands-off" approach by the P&M organization 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

[53] Staff #72 May 13, 2014 P1
[54] Board Staff #72
[55] Report to the Nuclear Oversight Committee Q2 2014 P5

(5) to inaccurately or untimely report the projects' progress, risks and cost and schedule overruns to the DR Team and senior management.[56]

97. There is evidence of P&M mismanagement of EPC contract terms with ESMSA; P&M organization made several mistakes with respect to determining the projects' budgets.

98. In the management of the work, P&M mischaracterized the nature of these estimates by assuming anything provided by a contractor was at a very high level of maturity (Class 3/2) when such estimates were based on conceptual (at best) engineering, meaning these estimates could not have been better than Class 5 (-50% to +100%) in nature.

99. P&M failed to establish accountability standards for the contractors.

100. P&M failed to identify or mitigate known risks.

101. P&M did not effectively react to problems when they materialized and accurately and timely report the extent of cost overruns, schedule delays and scope increases to senior management.

102. The P&M Team did not seek to lock down the scope at start of this work and allowed the "customer" – Operations and Maintenance – to make significant changes to the design that were not properly understood, quantified or captured in subsequent reports to senior management.

103. The ESMSA contractors contributed to the problem by not transparently reporting or timely identifying how these projects were evolving and failing to provide any reliable metrics—cost, schedule or otherwise – that informed OPG of these brewing problems.[57]

104. This estimate classification drove P&M to vastly underestimate the amount of contingency associated with each package.

105. P&M staff includes inexperienced personnel who need guidance.

106. Risk management was not taken seriously in the P&M organization, thus many of the problems that have emerged were hidden below the surface.[58]

107. There is no evidence that P&M engaged in the type of vetting of the estimates that one would expect on projects of this size and importance.

108. P&M needs to break down the silos—All of the Campus Plan Projects are being performed by two contractors. However, all of the Campus Plan work has been managed as 26 separate projects. All of the project management functions—i.e.

[56] Staff #72
[57] Staff#72 P5
[58] Satt#72 P13

schedule, cost and risk need to be managed through an integrated approach so that resources and management focus can be applied appropriately. We recommend that P&M look at its organizational structure to optimize the ability of its project managers to have more direct accountability. This may require more and different resources.

109. P&M's project management procedures were not developed to manage multi-year projects of the size and scope of some of the Campus Plan Projects. Over the last several months, P&M has begun to manage the Campus Plan projects in accordance with the project management procedures developed for the DR Project in an attempt to implement industry-standard risk, cost and schedule controls.

110. Performance of the Campus Plan projects were the direct result of the fact that the P&M organization had not adopted many of the procedures developed by the DRP Team for the Refurbishment Project, the legacy issues that caused the schedule and cost variances for two key projects—D2O Storage and AHS.

111. In the current application, OPG has identified new initiatives in P&M to improve project outcomes that include a Centre of Excellence (CoE) for project management, and improving project cost and schedule predictability through collaborative front end planning. In March 2017, Nuclear Operations launched the Centre of Excellence with a target to have it fully operational by July 1, 2017.[59]

112. OPG indicates the PM CoE will leverage experience from the DRP's F&IP and SIO projects, including implementing the lessons learned and corrective actions from the execution of the projects cited on pages 18-21 of the Second Quarter 2014 Supplemental Report to the Nuclear Oversight Committee by Burns & McDonnell/Modus.[60]

113. The corrective actions on pages 18-21 referenced above include recovery responses from P&M as follows:

-P&M is following the Refurbishment gate process.
- P&M is adopting the Refurbishment gate process and will not submit projects for full release until a reliable estimate is prepared.
- P&M is instilling rigor into the schedule process and requiring the vendors to develop Level 3 schedules that depict their plans for the work.

114. P&M has abandoned previous practices and is now working collaboratively to review engineering and develop reasonable cost estimates. OPG Engineering is fully engaged in developing, vetting and approving design work.

115. P&M is revamping its entire suite of metrics to align with the requirements of Refurbishment.

[59] J15.3
[60] J15.3 Attachment #1

116. The lessons learned and corrective actions to implement a gated process and instill extra rigour were identified in the June 26, 2014 report yet OPG is only now proposing initiatives to implement the corrective actions in P&M, more than two years later. Notwithstanding, that OPG's project management processes have referenced a gated approval process dating back to EB-2007-0905, and OPG has not applied the appropriate amount of rigour in adhering to its own project management processes, AMPCO submits it is not prudent project management for OPG to delay implementation of the lessons learned and corrective actions from the early DRP projects to P&M's management of the Nuclear Project Portfolio.

117. In EB-2013-0321, OPG provided an update61 dated June 26, 2014 on OPG management's response to the key observations of Burns & McDonnell/Modus report provided to the Nuclear Oversight Committee in May 2014.62 In response to insufficient front end planning, OPG indicated that Management has implemented a collaborative front end planning process to ensure ambiguities in design requirements are resolved, scopes of work are clearly defined methodologies for the delivery of the work are agreed to by both parties, and reliable schedules and cost estimates are developed. With respect to the finding that schedules for ES-MSA executed projects were inadequate, OPG indicated that P&M's project management procedures were not developed to manage multi-year projects of the size and scope of some of the refurbishment projects. P&M has now adopted the procedures that were developed by the DRP for implementation of large multi-year projects, including the Gating and Scheduling processes. OPG's response also states "The DRP and P&M organizations operate under a common Management System. However, a combination of previous leadership, utilization of metrics and controls that were developed for much smaller and shorter term project work, and a less rigorous implementation of key elements in the Management System, have resulted in less corrective action and continuous improvement capability in the P&M organization. This is being corrected through process improvements and organizational changes being implemented across the Nuclear Projects organization. Considering the early implementation of the EPC model with the ES-MSA contractors was on large and complex projects, and through Management's understanding of the underlying issues and implementation of process changes and corrective actions, Management believes that the cost growth is limited to the early pre-requisite projects." [63]

118. As can be seen from the cost growth in projects expected to go in service in 2014 to 2016 of 11.7%, and the current cost growth of Tier 1 projects in this application of 25%, cost growth was not limited to the early pre-requisite projects.

119. OPG's evidence in this proceeding is that the Nuclear Operations process is now being supplemented by the implementation of a gated process[64] [65] and Collaborative Front

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[61] EB-2013-0321 JT3.7 P1-2
[62] L-4.3-1-Staff-072 Attachment#4
[63] EB-2013-0321 JT7.3 Appendix B P4-5
[64] L-4.4-15-SEC-045
[65] Gated process is a formal review of project readiness in terms of having completed sufficient project development to provide confidence in the project cost and schedule estimates for the next project phase of work

End Planning initiative, two initiatives identified back in 2014 to improve project outcomes. To date four Tier 1 Business Case Summaries in this application have gone through the revised gated process66 and it will apply to all nuclear projects going forward.

120. AMPCO submits P&M's delay in implementing lessons learned and corrective actions previously identified demonstrates P&M has not acted prudently.

Gated Process & Class 3 Estimate at Execution Phase Not New

121. Looking back at OPG's description of its project management processes in previous applications, AMPCO submits that the gated process is not new. OPG has historically had in place a management process to govern progression between the project phases.

122. In EB-2007-0905, OPG says its management process ensures that a periodic, systematic review is conducted and that approvals are obtained in each phase before proceeding with further investment.

123. In 2006, the Asset Investment Steering Committee (AISC) was created. OPG described the AISC in EB-2007-0905 as playing a key role in challenging value at each decision point.[67]

In EB-2010-0008 OPG states "Based on industry best practices, rigorous planning and project evaluation processes have been implemented. These processes, at the front end of the project life cycle, focus on value engineering, project scoping and scheduling, and a disciplined approach to cost estimating and management of project risk. Industry best practices include Project Management Institute (PMI), the Association for the Advancement of Cost Engineering (AACE), the U.S. Department of Defence and the Construction Industry Institute (CII).[68]

124. The Associating for Advancement of Cost Engineering (ACCE), established in 1953, developed a cost estimate classification system standard that requires that the cost estimate be developed to at least a Class 3 estimate prior to execution. AACE uses five estimate classes with Class 5 being the least accurate and Class 1 being the most accurate. The classification system is linked to the five standard phases in a project life-cycle: Identification, Initiation, Definition, Execution and Closeout. OPG indicates its BSC template includes instructions for Cost Estimates that follows the AACE cost estimate classification system.

125. In EB-2010-0008, OPG states "During the project execution phase, design engineering is completed, a detailed project execution plan is prepared, and requests for proposal of bids from prospective contractors are reviewed for contract award (as applicable). A level 3 schedule (task level detail) and an updated cost estimate for the entire project

[66] J15.7 Project #31710, (31508, 49158, 49299), (41027,32202), (73566, 80144)
[67] EB-2007-0905 D2-1-1 P2
[68] EB-2010-0008 D2-1-1 P12

with an accuracy of +15 per cent/-10 per cent (consistent with Project Management Institute standards) are also prepared."

In EB-2007-0905 the project execution phase is also described as requiring a level 3 schedule (task level detail) and an updated cost estimate with an accuracy of +15 % to -10%.

126. In OPG's last application EB-2013-0321, OPG further described its project management process as follows:

"A project's movement through the five project phases is monitored by the AISC which ensures that periodic and systematic reviews are conducted, and that approvals (in accordance with OPG's project management process) are obtained before proceeding to the next phase.[69]

As part of its project management process, OPG uses cost estimate ranges that are consistent with industry best practices as reflected in the Association for the Advancement of Cost Engineering (AACE) guidance for the stages of the project life cycle. For example, a project released as a "definition" phase release would have an accuracy range of -20 per cent and +30 per cent where as projects at the "execution" phase might have an accuracy range of -15 per cent and +20 per cent.

Given the amount of assessment and engineering completed at each state of a project life cycle, OPG works to ensure that project scope is appropriately defined prior to the next stage in the process.

Except in unique circumstances, a project is generally not approved for execution until project engineering, scope definition and planning execution is sufficiently complete. The scoping process, combined with the ongoing AISC review and approval processes, enhances OPG's ability to bring projects to completion within budget and on schedule."[70]

In EB-2013-0321, OPG refers to a "unique circumstance" to explain a project variance of $20.9 million (>10%) for project #49270 where a tight timeline resulted in the project being approved at the Project Definition phase prior to the completion of engineering design. OPG characterizes this as a "deviation from OPG's project management process where a project is generally not approved to proceed until sufficient project engineering, scope, definition and planning is completed to provide a more reliable cost estimate."[71]

127. On November 28, 2012 OPG issued a "Gated Process Manual" approved by Project Planning and Control, Nuclear Projects entitled "Nuclear Projects - Gated Process N-

[69] Ex K 15.2 EB-2013-0321 D2-1-1 P1-2
[70] Ex K 15.2 EB-2013-0321 D2-1-1 P3
[71] D2-1-3 P4

MAN-00120-10001." This document is referenced extensively in other governance documents72 (including DRP specific documents).

128. OPG says its objective over the test period is to move forward with a Class 3 estimate into execution.73 AMPCO submits OPG's requirement for a Class 3 estimate into execution is not new. Further, AMPCO submits OPG's failure to adhere to its own project management guidelines and apply the appropriate level of rigour has resulted in significant cost and schedule overruns.

129. KPMG's review of the DRP identified a number of gaps and risks and concluded that Process Integration was needed.[74] The response to this finding states "Now that the Gated Process has been rolled out to all Nuclear projects, a follow up audit will be done in all PP&C processes and governance to ensure:[75]

Alignment and Integration to the Gated Process
Alignment and Integration to PM Standard 0028
Alignment and Integration among all processes

130. Based on 2016 audit results, it is clear P&M did not achieve a roll out of the Gated Process to all Nuclear Projects as intended and that is why further initiatives are being proposed in this application.

<u>Internal Audit –Project Controls within P&M</u>

131. An audit of OPG's internal project controls within P&M in early 2016, through an evaluation of 13 projects from P&M's AISC portfolio up to the end of 2015, concluded the following:[76]

132. Project estimates are not at a sufficient level of accuracy prior to the execution phase.

133. Cost and Schedule Control Baselines (CSCB) are not keeping pace with approved project changes.

134. A Gating Process for AISC projects has not been formally implemented. The AISC acted as a de facto Gate Review Board for AISC projects.

135. Governance and Procedures specific to AISC projects require improvement.

136. The Project Controls Audit has a final report rating of "Requires Improvement" which means that control and risk management practices require significant improvements in

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[72] Project Management N-PROG-AS-0007; Project Management Standard N-STD-AS-0028; Nuclear Projects Cost Estimating N-MAN-00120-10001 July 25, 2012; Project Controls N-MAN-00120-10001 January 1, 2013
[73] Transcript Volume 14
[74] Ex L-T4.3-S1-Staff-068-Attachment #1 P5
[75] L-4.3-1-Staff-068 Attachment #1P4
[76] Project Controls – Project & Modifications Group" dated March 9, 2016

high risk and/or core areas to provide reasonable assurance that business process objectives will be achieved.[77]

137. Specifically, the gating process outlined in the Nuclear Projects governance (N-STD-AS-0028) and Project Management Manual (N-MAN-00120-10001-GRB) has not been fully implemented for AISC projects.

138. AMPCO submits based on historical and current project performance discussed above, P&M's project management controls are not sufficiently effective to support the timely completion of the current portfolio of AISC projects in a manner that achieves project goals.

139. The audit recommended that the Nuclear Projects group work with the AISC Chair in the implementation of a gating process for AISC projects, clearly defining the requirements for each gate. In addition the audit recommended that the P&M Group ensure, through implementation of its new gating process, that an AACE Class 3 or better estimate for the project is developed, approved and established as a baseline prior to the start of execution phases.

Nuclear Oversight Audit of P&M

140. A performance based audit conducted by Nuclear Oversight of the Project Management program implemented by P&M over the period January 26 to February 12, 2015, 78 revealed the following:

-Deficiencies in the Execution of Project Management Oversight;
-Deficiencies in Projects & Modifications Staff Qualifications and Requirements
-Deficiencies in Project Management Program Governance and Supporting Documents

141. The objective of the audit was to determine whether the project management requirements defined in governance have been met. The audit concluded OPG's Project Management Program is not fully effective and the above deficiencies are among the contributors to project delays, cost over-runs, quality issues, and some safety concerns.

Conclusions Associated with P&M

142. AMPCO concludes that P&M's Nuclear Portfolio Projects suffer from the same flaws as seen in the early DRP pre-requisite projects managed by P&M resulting in cost and schedule overruns.

143. It seems to AMPCO that OPG has known it needs to improve its P&M project management controls since early lessons learned from the DRP pre-requisite projects but has been challenged to do so. Notwithstanding AMPCO's criticisms that OPG has

[77]J7.3 Attachment #1 Page 16
[78] JT1.8 Attachment#2

not implemented known corrections in a timely fashion, AMPCO supports OPG's project improvement initiatives in this application on the basis OPG needs to get these issues fixed. However, AMPCO questions whether OPG has the capability to do it now. AMPCO recommends that OPG undertake an audit of its P&M project controls in time for the mid-term review and provide a status report at that time.

144. The issues with the P&M Organization support AMPCO's recommended adjustments, set out at the beginning of the Nuclear Capital and In-Service Amounts section. It is hoped that such adjustments will provide added incentive for OPG to improve its performance.

D. Project Specific Disallowances

D.1. Auxiliary Heating System (AHS) Project

145. The AHS project provides a source of reliable back-up steam to the Darlington main heating steam header to support irregular operating conditions. This project replaces the existing original Construction Boiler House with a new facility. The contractor for this project is ES Fox Ltd.[79]

146. Based on OPG's pre-filed evidence, OPG is seeking in-service additions of $94.2 million in 2016.80 AMPCO notes that OPG's evidence incorrectly shows the project had an Initial Release of $99.5 million with no Superseding BCS, when in fact the project has had more than one superseding fund releases.

147. In EB-2013-0321, the BCS reflected a cost of $45.6 million and an in-service date of April 1, 201581.

148. As part of the DRP update in EB-2013-0321, OPG updated the forecasted total project cost to $85.1M with a new in-service date of March 2015 and an in-service amount of $75.3 million.82 Burns & McDonnell/Modus indicates this cost increase is largely attributable to two causes: (1) remediation of contaminated soil that as of the time of bid was known by both OPG and the contractor to be of poor quality; and, (2) prescriptive design requirements that served to make a stock steam boiler design follow nuclear Engineering Change Control ("ECC") processes, which caused an increase in the size, complexity and nature of the work.[83]

149. In 2014, Burns & McDonnell/Modus raised concerns regarding the execution of the AHS project due to the cost and schedule variances. Burns & McDonnell/Modus concluded that the predominant cause for the AHS project being forecasted to be completed significantly beyond approved budgets and schedules was P&M's incorrect application of the "oversight" project management approach for its EPC contracting

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[79] June 26, 2014 P17
[80] D2-1-3 Table 1 Line 11
[81] EB-2013-0321 D2-2-1 Attachment 8-5
[82] D2 Tab 2 Schedule 2 Page 6
[83] May 13, 2014 P8

strategy which led to a series of management lapses and contractor issues related to scope, cost estimates and risk management.[84]

150. The AHS project was one of three projects reviewed as part of OPG's Project Management Audit85 (March 13, 2015), with a focus on project oversight including contract management and field engineering. The audit noted that scope of the AHS was expected to be complete in April 2015 per the PMP NK38-PLAN-73110-0495234 at a cost of $28.5M; however, the new projected completion date at the time of the audit was October 2015 with an estimated completion cost of $85M.

151. Deficiencies in the execution of project management oversight was a finding of the audit. Specifically, the audit concluded the P&M organization is not effectively executing key project management oversight activities. Unclear guidance and deficiencies in project management training are some of the causes of these deficiencies. Further, these deficiencies are among the contributors to project delays, cost over-runs, quality issues, and some safety concerns.

152. The 2015 audit noted the main reason for the delay in the AHS project is the scope was not fully understood at inception (August 2007) causing the design requirements to be revised 4 times with the latest revision at that time in July 2014. Further, there have been about 170 SCR's on this project thus far and about 40% relates to the Design Engineering performance. All of the SCR's were D-4. The team did not clearly understand this new role as oversight while EPC manages the work.[86]

153. Further design changes on the AHS project occurred and the forecast project increased again by $14.4M to $99.5M and the in-service date changed to October 2016.[87] As part of the interrogatory process, a Project-Over-Variance was issued for the project resulting in a further $7.6 million increase to $107.1 million, however, OPG is not seeking to recover this increase. Over $3 million of the increase is for additional OPG Project Management and Design and Engineering due to further design changes and extended duration of construction.[88] The in-service date has changed from October 2016 to October 2017.[89]

154. More concerning than the cost and schedule overruns is that a priority project goal set for the AHS project was not met. The project had an expected objective to be available for service prior to the next station Vacuum Building Outage (VBO) in April 2015 to provide steam for TRF processes and heating to the station. This objective was stated in the Project Charter.90 At one point when there was a possibility that the AHS would miss its completion milestone, the DRP Team was readying mitigation plans including utilizing the existing construction boilers and/or procuring temporary

[84] EB-2013-0321 D2 Tab 2 Schedule 2 Page 10
[85] JT1.8
[86] JT1.8 P21
[87] D2-1-3 Attachment 1, Tab 11
[88] L-4.4-15-SEC-046
[89] JT2.16
[90] EB-2013-0321 D2-2-1 Attachment 8-5

back-up steam capacity if needed.91 OPG's inability to meet the targeted in-service date represents imprudence on OPG's part and the operations and cost consequences of not meeting the in-service date prior to the 2015 VBO are not known.

155. Burns & McDonnell/Modus' oversight review stated that P&M's early management of the D2O and AHS project exposed some critical project management gaps.[92] These two projects were the pilot projects for the new EPC contracting model.[93] The management failures observed by Black were most evident and acute with the D2O Storage and AHS projects. AHS suffered from scope confusion and untimely decisions.[94]

156. Burns & McDonnell/Modus further noted "The fact this project had so substantially changed from the original BCS was not accurately or timely reported to management. The failure of the gate process was that the Gate Review Board members did not provide adequate oversight in ensuring that the AHS project team had a reliable estimate, schedule, and well-defined scope prior to approving the gate and recommending a funding release. This lack of accurate reporting has deprived 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. This is particularly true in light of the fact that as of November 2012, three of the competing options to building AHS were priced at less than $50 M."[95]

157. In considering the above project management deficiencies and the fact that the priority project goal was not in-service as intended before the 2015 VBO, AMPCO submits the Board should disallow 75% of the incremental cost from the First Execution BCS to the amount requested (i.e. 75% of $53.9 million = $40.4 million[96]). OPG has not demonstrated prudence in managing this project and the management deficiencies go well beyond an initial poor cost estimate. Ratepayers should not pay for the imprudent costs related to this project.

D.2. Darlington Operations Support Building (OSB)

158. The OSB houses technical services essential to the business operations of DNGS, including Local Area Network (LAN) servers, telephone network hubs and security systems. It also houses 375 employees who provide daily support to station and control room staff. The purpose of this project is to extend the life of OSB to support the continued operations of the Darlington station.[97] The EPC contractor for the OSB project is Black and McDonald.[98]

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[91] June 26, 2014 P17
[92] June 26, 2014 P2
[93] May 13, 2014 P1
[94] May 13, 2016 P6
[95]
[96] $99.5-$45.6=$53.9 million
[97]
[98] L-4.4-15-SEC-048

159. In EB-2013-0321, OPG updated the project cost to $47.7 million reflecting the First Execution BCS changing the in-service amount in 2015 to $45.1 million from $29.7 million.[99]

160. The forecast cost of the OSB project was updated to $62.7 million, an increase of $12.8 million from the First Execution Business case amount of $47.7 million.[100] [101] OPG met the in-service date of October 2015 at a final cost of $60. 6 million. OPG recorded on the August 2015 Project-Over-Variance Approval form for the additional release of funds to $62.7 million "This is poor performance".[102]

161. This increase is due in part to increased EPC contract costs due to under-estimation of the effort to complete contract scope, and other scope changes and delays in the execution schedule requiring extra labour to complete.103 The estimate at the time of the full release approval was inadequate. The full release for the project was approved prior to the completion of detailed engineering, which was not

162. in accordance with established practices. Engineering assumptions were not validated.[104] The procured equipment and construction work has now increased significantly. [105] In addition, a contingency of $1.5 million was added for further estimate inaccuracy and possible realization of unknowns. OPG placed an over reliance on the vendor proposal. This resulted in additional costs. The design subcontractor was required to complete revisions to the design packages due to incomplete details.[106]

163. AMPCO submits the reasons for the cost overruns on this project align with Burns & McDonnell/Modus findings related to the P&M organization and mistakes made by Management. AMPCO submits ratepayers should not have to pay for the incremental cost from the First Execution BCS to the amount requested; i.e. $14.9 million.

E. Schedule A - Confidential

164. AMPCO's confidential submissions (Schedule A) related to nuclear capital and ISA are submitted under separate cover.

F.1. Other Considerations – Business Transformation

[99] EB-2013-0321 D2-2-2 P6
[100] D2-1-3 Attachment #1 Tab 1
[101] JT2.16
[102] D2-1-3 Attachment#1 P5
[103] D2-1-3 Page 14
[104] L-4.2-1-Staff-025
[105] D2-1-3 Attachment #1, Tab #1 P1
[106] D2-1-3 Attachment #1, Tab #1

165. Prior to Business Transformation, P&M and Nuclear Refurbishment (Execution & Engineering) were under one roof along with Nuclear Commercial Development within the Nuclear Projects Business Unit, led by the SVP Nuclear Projects.

166. As a result of Business Transformation, OPG's organizational structure moved from two Nuclear Business Units (Nuclear Projects and Nuclear)[107] to one Business Unit ("Nuclear") led by the President and Chief Nuclear Office (CNO).[108] Based on the pre-filed evidence, Nuclear Projects is now in the same Business Unit as all of the other Nuclear functions. The current Nuclear Projects Division, led by the SVP, Nuclear Projects is responsible for managing the planning and development of all projects in Nuclear. This includes major refurbishment projects at Darlington.[109]

167. Business Transformation created a centre-led matrix organization design with centre-led functions supporting the Nuclear business unit to allow best practices to be better shared and integrated across the company.[110] OPG created one nuclear group with a centre-led Engineering management structure and accountability.[111] Nuclear Oversight moved to Assurance, with Internal Audit, to form a centre-led Assurance function.

168. OPG has undergone an organizational change (J7.2 - Organization effective March 10, 2017) and instead of one Nuclear Business Unit, OPG again has two Nuclear Business Units (Nuclear & Projects and Nuclear[112] moving away from OPG's Business Transformation objectives and outcomes. The most noteworthy change from this reorganization is that P&M, responsible for the Nuclear Project Portfolio and Darlington Refurbishment are no longer under one roof and the centre-led engineering function is no longer; the DRP engineering function has moved to the Nuclear & Projects Business Unit. In addition, the Nuclear Oversight function has been moved to the

[107] EB-2013-0321 A1-5-1
[108] A1-5-1
[109] D2-2-1
[110] EB-2013-0321 A4-1-1 P2
[111] EB-2013-0321 Attachment #2 P6
[112] J7.2

Nuclear Business Unit thereby undoing the Business Transformation centre-led Assurance function. Internal Audit is no longer shown on the organizational chart.

169. AMPCO submits OPG's organizational structure is important because with Projects & Modifications and Nuclear Refurbishment together under Nuclear Projects, and a centre-led engineering function, the fact that common project management processes were adhered to differently and with varying degrees of rigour demonstrates a shortcoming on the part of Management.

170. AMPCO submits that OPG's recent organizational change will make it a challenge to achieve a better integration of common project management processes and lessons learned. It appears as though many of the drivers associated with Business Transformation changes that informed OPG's decisions in the past have been largely abandoned.

F.2. Other Considerations – Post Implementation Review

171. The Post Implementation Review (PIR) process is used by OPG to verify project benefits and capture lessons learned. All projects must have a PIR completed, ideally within 12 months of the project being completed.

172. In EB-2007-0905, OPG noted that it has not reached full compliance with respect to post – implementation reviews and a back log of reviews exists.[113]

173. OPG provided a list of the 15 PIRs completed over the last 12 months. All of the projects have actual costs less than budgeted amounts and only one of the projects has a value greater than $20 million. Ten of the 11 projects are less than $5 million each.[114]

174. OPG selects a number of complex or high value projects to undergo a comprehensive PIR within each business planning period. This review provides detailed feedback on how the project was developed, planned and executed to obtain lessons for future investments. The back-log issue appears to persist today as OPG completed the PIR of its largest capital project to date, the Niagara Tunnel project, almost 4 years after the tunnel was placed in-service.

175. AMPCO submits that by failing to complete comprehensive PIRs in a timely fashion, opportunities for continuous improvement and maximum future economic benefit to OPG through the dissemination of "lessons learned" is not being realized. AMPCO submits by applying the Custom IR stretch factor to nuclear capital, OPG will be further incented to seek continuous improvement through "lessons learned". It is not clear to AMPCO that lessons learned are being cascaded through the organization.

F.3. Other Considerations – D2O Project

[113] EB-2007-0905 D2-1-1 P8
[114] JT3.22

176. Due to uncertainty regarding the D2O project, OPG is excluding the capital in-service amounts for the D2O project and revised the revenue requirement accordingly. The actual revenue requirement will be recorded in the CRVA once the project is in-service. The impact is a decrease in revenue requirement of $40.4 M in 2017, $36.9M in 2018, $36.4M in 2019, $40.9 M in 2020 and $40.1 M in 2021.[115]

177. The prudence review of the D2O project is expected to occur at the mid-term review in the first half of 2019. A concerning aspect of the D2O project beyond the significant increase in cost and schedule is that the original project goals have not been met. The heavy water storage and processing facility for the removal of heavy water from the Darlington units during refurbishment was to be in place before breaker open and the start of Unit 2 refurbishment. Burns & McDonnell/Modus' review indicated the D2O Storage Facility project is needed to accept water from Unit 2 so that there is confidence Unit 2 Refurbishment can proceed.[116]

NUCLEAR BENCHMARKING

Issue 6.2: Is the nuclear benchmarking methodology reasonable? Are the benchmarking results and targets flowing from OPG's nuclear benchmarking reasonable?

178. OPG retains ScottMadden to benchmark its annual performance of Darlington and Pickering based on 20 metrics under four categories: Safety, Reliability, Value for Money and Human Performance. These categories are consistent with OPG's Nuclear focus areas/objectives.

179. ScottMadden identifies three of those metrics as key: Total Generating Cost ($/MWh), Nuclear Performance Index (NPI) which is a weighted composite of 10 safety and performance indicators, and Unit Capability Factor (UCF), which measures a plant's actual output as a percentage of its potential output over a period of time.

180. Starting in 2016, OPG is adopting Total Generating Cost (TGC) ($/MWh) as an enterprise-wide measure of operational cost effectiveness, in addition to TGC per MWh metrics for each of Nuclear and Hydroelectric operations. TGC is defined as the total of OM&A expenses from ongoing operations, fuel and hydroelectric GRC expenses for OPG-operated stations, and capital expenditures for sustaining projects. AMPCO notes operational excellence and project excellence are critical to ensure OPG's enterprise wide TGC is trending positively over time. This means OPG must continuously improve on optimizing staffing levels and resource plans (OM&A) and delivering projects safely, on time, on budget and with high quality (Sustaining Capital).

181. OPG's benchmarking results for 2008 to 2013 and the targets for 2014 and 2015 were reviewed by the Board in OPG's last application, EB-2013-0321. In its Decision, the Board stated "there is no dispute that OPG's performance in the three key metrics is not top quartile, nor does it demonstrate continuous improvement. In fact, for many of the measures OPG remains in the third or fourth quartile. It is also reasonable to

[115] N2-1-1 P1
[116] D2-2-9 Attachment #2 Page 23

conclude that OPG will not reach the aspirational 2014 targets set by ScottMadden and OPG in 2009 in order to close the gap. This is not the type of performance that ratepayers would expect. OPG is not satisfied with its performance either: "... clearly we would like to see better performance from our plants."[117]

Benchmarking Results

182. AMPCO supports Board Staff's analysis and summary of OPG's Nuclear Benchmarking Reports.[118]

183. Specifically,AMPCO agrees[119]:

- Pickering is a poor performer; 4th Quartile on 3 key metrics since 2013;
- Pickering has had 4th Quartile TGC since 2008; 4th Quartile WANO NPI since 2010 & UCF has declined to 4th Quartile in 2013 to 2015 from 3rd Quartile in 2012

184. Darlington's performance in 2015 slipped:

-TGC - 2nd Quartile from 1st Quartile in 2014
-WANO NPI – 3rd Quartile from 2nd Quartile in 2014
-UCF – 4th Quartile from 2nd Quartile in 2014

185. Two of the Three 2014 Quartile Targets set in Scott/Madden Phase 2 Report for Darlington were not met:

-WANO NPI achieved 2nd Quartile compared to Top Quartile Target
-UCF achieved 2nd Quartile compared to Top Quartile Target
-TGC achieved Top Quartile Target

186. Two of the Three 2014 Quartile Targets set in Scott/Madden Phase 2 Report for Pickering were not met:

- WANO NPI achieved 4th Quartile compared to 2nd Quartile Target
- UCF achieved 4th Quartile compared to 3rd Quartile Target
- TGC achieved 4th Quartile Target

187. Darlington's 2015 performance is the worst since benchmarking began in 2008. OPG attributes its 2015 poor performance at Darlington to a Vacuum Building Outage in 2015 and forced losses caused by problems with primary heat transport pump motors.

188. AMPCO notes that in its first Impact Statement in EB-2013-0321[120] in 2013, OPG identified the following key risks with significant impact to the Nuclear Business,

[117] EB-2013-0321 Decision with Reasons Page 24-25
[118] Board Staff Submission dated May 19, 2017 P82-87
[119] Based on Rolling Actual Results
[120] EB-2013-0321 Ex. N1-1-1 Attachment 5 P6

specifically to Operational Performance:

- Top Risk: Darlington Primary Heat Transport (PHT) Pump Motor Failures
- Emerging Risk: Failure to Achieve a Successful Darlington Vacuum Building Outage
- Emerging Risk: Failure of Darlington PHT Pump Seals

189. Although OPG was aware of these risks in 2013, it seems that poor performance in effectively managing these risks has impacted OPG's operational performance resulting in a marked decline in Darlington's performance in 2015.

190. Overall, OPG's performance enterprise wide with respect to the three-key metrics has declined over the period 2008 to 2015.[121]

As filed with Applications

OPG Nuclear	2008	2011	2014	2015
WANO NPI (Index)	17th out of 20	24th out of 27	22nd out of 24	23rd out of 24
2-Year Unit Capability Factor (%)	18th out of 20	25th out of 28	21st out of 24	23rd out of 24
3-Year Total Generating Costs ($/MWh)	16th out of 16	12th out of 14	10th out of 13	12th out of 13

191. Specifically, for the TGC/MWH metric, OPG is in second last place. Sustaining capital expenditures is an input to Total Generation Cost. In AMPCO's submissions on Nuclear Operations Capital, AMPCO concludes that OPG's performance with respect to delivering sustaining projects on time, on budget and with high quality has deteriorated in recent years. OPG has control over its project performance and the Board needs to take these project results into consideration in assessing OPG's poor overall benchmarking results.

<u>Forecast Operational Targets</u>

192. OPG provided 2016 to 2018 targets in its 2016 to 2018 Business Plan and 2016 to 2019 targets in its 2017 to 2019 Business Plan as shown in the two tables below.

193. OPG's 2016 to 2018 Business Plan: Operational Targets for the Nuclear Business Unit are as follows:

[121] K12.4 Page 18

Metric	NPI Max	Industry Best Quartile	Pickering 2015 Actual	Pickering 2016 Annual Target	Pickering 2017 Annual Target	Pickering 2018 Annual Target	Darlington 2015 Actual	Darlington 2016[1] Annual Target	Darlington 2017[1] Annual Target	Darlington 2018[1] Annual Target
All Injury Rate (#/200k hrs worked)	N/A	0.66	0.44	0.24	0.24	0.24	0.22	0.24	0.24	0.24
Collective Radiation Exposure (person-rem/unit)	80.00	42.25	100.90	111.50	126.90	137.30	73.72	65.00	87.80	72.10
Unit Capability Factor (%)	92.0	89.4	79.4	77.6	71.5	72.0	76.9	91.1	85.1	86.0
Forced Loss Rate (%)	1.00	1.03	2.89	5.00	5.00	5.00	4.86	1.00	1.00	1.00
On-line Corrective Maintenance Backlog (work orders/unit)	N/A	11	125	55	28	28	24	20	15	10
WANO NPI (Index)	N/A	92.9	68.5	72.3	71.1	71.1	83.7	87.3	84.3	93.0
Human Performance Error Rate	N/A	0.0020	0.0055	0.0030	0.0030	0.0030	0.0031	0.0030	0.0020	0.0020
Total Generating Cost per MWh[2]	N/A	$38.71	$64.00	$71.09	$76.48	$75.32	$52.40	$47.35	$47.85	$48.68

[1] Darlington targets reflect the impact of the Unit 2 Refurbishment starting in October of 2016, where applicable.

[2] Metrics exclude centrally-held Pension and OPEB costs and asset service fees. Targets may change subject to allocations and assumptions being finalized. Darlington metrics have been normalized after 2016 for generation forgone during the Unit 2 refurbishment. The non-normalized Darlington target for 2017 is $63.76/MWh and 2018 is $63.50/MWh.

Green = Max NPI Points Achieved (if applicable) or Best Quartile Performance
White = 2nd Quartile Performance
Yellow = 3rd Quartile Performance
Red = 4th Quartile Performance

194. OPG's 2017 to 2019 Business Plan: Operational Targets for the Nuclear Business Unit are as follows:

			Pickering					Darlington[1]				
Metric	NPI Max	Industry Best Quartile	2016 Target	2016 Forecast	2017 Target	2018 Target	2019 Target	2016 Target	2016 Forecast	2017 Target	2018 Target	2019 Target
All Injury Rate[2] (#/200k hrs worked)	N/A	0.69	0.24	0.49	0.24	0.24	0.24	0.24	0.23	0.24	0.24	0.24
Collective Radiation Exposure (person-rem/unit)	80.00	38.17	111.50	104.50	126.90	137.30	153.30	65.00	80.90	111.90	82.70	78.40
Unit Capability Factor (%)	92.0	91.3	77.6	75.3	71.5	72.0	72.6	91.1	90.0	85.1	86.0	87.8
Forced Loss Rate (%)	1.00	0.38	5.00	4.37	5.00	5.00	5.00	1.00	1.93	1.00	1.00	1.00
On-line Corrective Maintenance Backlog (work orders/unit)	N/A	7	55	80	28	28	28	20	20	15	10	7
WANO NPI (Index)	N/A	93.5	72.3	75.6	69.7	67.2	65.9	87.3	85.5	83.1	90.7	91.0
Human Performance Error Rate	N/A	0.0010	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0053	0.0020	0.0020	0.0020
Total Generating Cost per MWh[3]	N/A	$38.93	$71.09	$72.46	$78.83	$80.09	$81.49	$47.35	$46.46	$49.75	$49.54	$52.33

[1] Darlington targets reflect the impact of the Unit 2 Refurbishment starting in October of 2016, where applicable.

[2] Also applies to Darlington Refurbishment Project and Contractors.

[3] Metrics exclude centrally-held Pension and OPEB costs and asset service fees. Targets may change subject to allocations and assumptions being finalized. Darlington metrics have been normalized after 2016 for generation forgone during the Unit 2 refurbishment.

195. AMPCO notes the 2017 and 2018 targets for TGC/MWh have increased in the latest Business Plan. AMPCO submits OPG's TGC/MWh targets are not designed to drive continuous performance improvement. In fact, quite the opposite is true.

Darlington: Total Generating Cost	**2017 TGC ($/MWh)**	**2018 TGC ($/MWh)**
2016 to 2018 Business Plan	47.85	48.68
2017 to 2019 Business Plan	49.75	49.54

Pickering: Total Generating Cost	**2017 TGC ($/MWh)**	**2018 TGC ($/MWh)**
2016 to 2018 Business Plan	76.48	75.32
2017 to 2019 Business Plan	78.83	80.09

Collective Radiation Exposure Metric

196. AMPCO notes the 2016 forecast for this metric (80.90) exceeds the 2016 target of 65.00 and the forecast target for 2017 has been increased in OPG's 2017 to 2019 Business Plan to 111.90 from 87.80 in OPG's 2016 to 2018 Business Plan, which was already 4th Quartile. The NPI max is 80.00 for this metric and the Industry Best Quartile is 38.17.

197. It is unclear to AMPCO how the latest results and the increase in the target impacts operational performance, but it is clear directionally, things are getting worse, not better.

Summary

198. In considering the above benchmarking analysis that points to OPG's declining performance over time, as best determined by OPG's enterprise wide measure of operational cost effectiveness, TGC ($/MWh), AMPCO submits that OPG has not demonstrated continuous cost effectiveness improvement. Further, OPG's forecast target for TGC does not drive continuous improvement over the test period. AMPCO submits OPG's benchmarking results support AMPCO's recommended disallowances in Nuclear Operations OM&A, Capital and Compensation, and a nuclear stretch factor of 0.6% instead of 0.30% as proposed by OPG.

NUCLEAR OPERATING COSTS

Issue 6.1: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities (excluding for the Darlington Refurbishment Program) appropriate?

Nuclear OM&A

199. OPG's Nuclear Operations OM&A (line 4) and Total OM&A (line 11) for the years 2013 to 2015 and forecast for the years 2016 to 2021 are summarized in the following table.[122] Nuclear Operations OM&A is equal to the sum of Nuclear Base, Project and Outage OM&A.

[122] F2-1-1 Table 1

Ontario Power Generation Inc.
2017-2021 Payment Amounts

Operating Costs Summary - Nuclear ($M)

Line No.	Cost Item	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	OM&A:									
	Nuclear Operations OM&A									
1	**Base OM&A**	1,127.7	1,127.1	1,159.6	1,201.8	1,210.6	1,226.0	1,248.4	1,264.7	1,276.3
2	**Project OM&A**	105.7	101.9	115.2	98.2	113.7	109.1	100.1	100.2	86.8
3	**Outage OM&A**	277.5	221.3	313.7	321.2	394.6	393.8	415.3	394.4	308.5
4	**Subtotal Nuclear Operations OM&A**	1,510.8	1,450.3	1,588.5	1,621.3	1,718.9	1,728.9	1,763.8	1,759.4	1,671.6
5	**Darlington Refurbishment OM&A**	6.3	6.3	1.6	1.3	41.5	13.8	3.5	48.4	19.7
6	**Darlington New Nuclear OM&A**[1]	25.6	1.5	1.3	1.2	1.2	1.2	1.2	1.3	1.3
7	**Allocation of Corporate Costs**	428.4	416.2	418.8	442.3	448.9	437.2	442.7	445.0	454.1
8	**Allocation of Centrally Held and Other Costs**[2]	413.5	416.9	461.0	331.9	80.2	118.2	108.3	91.1	81.3
9	**Asset Service Fee**	22.7	23.3	32.9	28.4	27.9	27.9	28.3	22.9	20.7
10	**Subtotal Other OM&A**	896.5	864.1	915.5	805.0	599.7	598.3	584.1	608.6	577.1
11	**Total OM&A**	2,407.3	2,314.5	2,504.0	2,426.3	2,318.6	2,327.1	2,347.9	2,368.0	2,248.7
12	**Nuclear Fuel Costs**	244.7	254.8	244.3	264.8	219.9	222.0	233.1	228.2	212.7
	Other Operating Cost Items:									
13	**Depreciation and Amortization**	270.1	285.3	298.0	293.6	346.9	378.7	384.0	524.9	338.1
14	**Income Tax**	(76.4)	(61.5)	(31.8)	(18.7)	(18.4)	(18.4)	(18.4)	51.2	51.7
15	**Property Tax**	13.6	13.2	13.2	13.5	14.6	14.9	15.3	15.7	17.0
16	**Total Operating Costs**	2,859.3	2,806.2	3,027.8	2,979.4	2,881.6	2,924.4	2,961.9	3,187.9	2,868.2

Notes:
1 Nuclear Operations expenditures to maintain the Nuclear New Build option. In addition there are allocated corporate costs (included in line 7) for Nuclear New Build of $0.8M in 2016, $1.1M in 2017, $0.2M in 2018, $0.5M in 2019, $0.5M in 2020 and $0.5M in 2021.
2 Comprises centrally-held costs from Ex. F4-4-1 Table 3 and amounts of approximately $1M-$6M per year for machine dynamics and performance testing services provided by Hydro Thermal Operations in support of Nuclear Operations.

200. The N1 impact statement increased test period OM&A by $252 million related to higher payments for pension deficit funding as a result in a decrease in discount rates, and by a further $41 million for the implementation of the CNSC Fitness for Duty requirements.

Total OM&A	**2,403.7**	**2,314.5**	**2,504.1**	**2,426.3**	**2,371.7**	**2,318.6**	**2,327.2**	**2,347.8**	**2,368.0**	**2,248.5**
Exh N1-1-1						**2,346.0**	**2,351.4**	**2,425.1**	**2,469.0**	**2,349.1**
Source: Exh F2-1-1 Table 1, Undertaking J14.2 Attachment 1										

201. 2016 Actuals for Total OM&A reflect a negative variance of $54.5 million.[123]

[123] J14.1 2016 Actual Operating Costs

2016 Operating Costs Variance	N1	J14.1	Variance $	%
1 Base OM&A	1201.7	1,182.40	-19.30	-2%
2 Project OM&A	98.2	89.3	-8.90	-9%
3 Outage OM&A	321.2	306.7	-14.50	-5%
4 ***Subtotal Nuclear Operations OM&A***	**1621.1**	**1,578.40**	-42.70	-3%
5 Darlington Refurbishment OM&A	1.3	3.1	1.80	
6 Darlington New Nuclear OM&A	1.2	0.6	-0.60	
7 Allocation of Corporate Costs	442.3	426.2	-16.10	
8 Allocation of Centrally Held and Other Costs	331.9	329.3	-2.60	
9 Asset Service Fee	28.4	34.1	5.70	
10 *Subtotal Other OM&A*	805.1	793.3	-11.80	
11 *Total OM&A*	**2,426.20**	**2,371.70**	**-54.50**	**-2%**
12 Nuclear Fuel Costs	264.8	263.1	-1.70	
13 Depreciation and Amortization	293.6	278.1	-15.50	
14 Income Tax	-18.7	-36.5	-17.80	
15 Property Tax	13.5	14.1	0.60	
16 Total Operating Costs	2,979.40	2,890.50	-88.90	-3%

202. OPG's average annual Nuclear Operations OM&A (Base, Project & Outage OM&A) spend for the years 2013 to 2016 is $1,532 million. Over the 2017 to 2021 period, the forecast average annual OM&A increases to $1,730 million, a 13% increase.

203. Outage OM&A accounts for 3 per cent of OPG's overall revenue deficiency. The remaining/other OM&A expenses account for 13 per cent of revenue deficiency.[124] Drivers of the increase in remaining/other OM&A include an increase in nuclear base OM&A costs due to labour costs, including escalation reflecting collective agreement provisions, as well as purchased services and new CNSC requirements as discussed above.

204. AMPCO submissions on OM&A are focussed on Purchased Services and overtime with the following conclusions. Based on OPG's history of over-forecasting, Other Purchased Services should be reduced in each year of the test period by 20% in Base OM&A and by 24% in Outage OM&A which are substantiated in the sections that follow. This results in a $178.5 million and $272.3 million reduction in Base OM&A and Outage OM&A, respectively, over the test period.

205. OPG's Nuclear OM&A costs consist of forecasts for OPG's resource types: Labour (Regular, Non-Regular & Part-Time Staff); Overtime; Augmented Staff; Other Purchased Services; plus, Materials; Licence Fees; and other costs.

[124] A1-3-4 P4

206. OPG indicates Other Purchased Services represents the costs of specialized external services, including construction and maintenance services, personal protective equipment, laundry services and specialized technical services.

Other Purchased Services

207. OPG's Nuclear Operations OM&A Purchased Services forecast is shown in the Table below.[125]

Line No.		2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Total OM&A Purchased Service**	365.3	446.8	466.0	486.8	515.6	498.0

208. OPG is forecasting an increase of $81.5 million (22%) in OM&A Purchased Services from 2016 to 2017. Further increases are forecast over the next three years with a slight decrease in 2021. The average over the test period for Purchased Services is $482.6 million.

209. OPG indicates there are over 300 vendors that provide Purchased Services. Four vendors provided purchased services for Nuclear Base, Outage and Project OM&A at or above the $17M threshold (1% of OM&A) for the years 2013 to 2015: Black & McDonald Ltd., ES Fox Ltd. AMEC-NSS and Candu Owners Group. Total purchases for all four vendors was $136.2 million in 2013, $129.4 million in 2014, and $166.7 million in 2015. Black & McDonald Ltd. and ES Fox Ltd. are the same contractors undertaking capital work on the DRP and Nuclear operations. AMPCO submits OPG's proposed development and implementation of a long term purchased services and vendor quality strategy should address Purchased Services vendors.

210. The increase in Purchased Services over the test period is a primary driver for the increase in Base OM&A. The average annual Base Purchased Services cost over the test period is $178.5 million compared to an average of $108.9 million per year for the previous five-year period (2013 to 2016).

211. Purchased Services for both Base OM&A and Outage OM&A is underspent every year for the years 2010 to 2016.

Base OM&A

212. For Base OM&A, the average underspend over the seven-year period 2010 to 2016 for Purchased services is 20%. AMPCO submits that given OPG's history of over-forecasting, Base OM&A Other Purchased Services should be reduced by 20% each year over the test period. This results in a total reduction of $178.5 million: $32.2

[125] L-6.1-2-AMPCO-114 (b)

million in 2017; $37 million in 2018; $36.2 million in 2019; $35.7 million in 2020; and $37.5 million in 2021.

Base OM&A Purchased Services $M		2010	2011	2012	2013	2014	2015	2016	Total
	Plan	109.7	102.1	99.6	126.7	145.9	146.4	164.1	1,040.9
F2-2-1 Table 2	**Actual**	97.0	94.8	95.4	100.0	98.7	108.4	129.1	831.8
EB-2010-0008, EB-2013-0321, EB-2016-0152		-12.7	-7.3	-4.2	-26.7	-47.2	-38.0	-35.0	-209.1
		-12%	-7%	-4%	-21%	-32%	-26%	-21%	-20%
F2-2-1 Table 2									
EB-2010-0008, EB-2013-0321, EB-2016-0152									

Base OM&A Purchased Services $M	2017	2018	2019	2020	2021	Total
	161.1	185.1	180.8	178.3	187.3	
Less 20%	32.2	37.0	36.2	35.7	37.5	178.5
	128.9	148.1	144.6	142.6	149.8	

Outage OM&A

213. For Outage OM&A, OPG indicates Purchased Services is for contractors performing specialized inspection and maintenance work or conducting major component refurbishments.

214. For Outage OM&A, the average underspend over the six-year period 2010 to 2015 is 24%. AMPCO submits that Outage OM&A Other Purchased Services should be reduced by 24% each year over the test period to reflect historical actuals. This results in a total reduction of $272.3 million: $47.1 million in 2017; $47.6 million in 2018; $55.8 million in 2019; $63.0 million in 2020; and $58.7 million in 2021.

Outage OM&A Purchased Services $M		2010	2011	2012	2013	2014	2015	Total
	Plan	156.8	137.2	128.5	86.6	76.4	113.6	699.1
	Actual	121.2	98.5	53.3	67.1	64.7	123.3	528.1
		-35.6	-38.7	-75.2	-19.5	-11.7	9.7	-171
		-23%	-28%	-59%	-23%	-15%	9%	-24%
F2-4-1 Table 3								
EB-2010-0008, EB-2013-0321, EB-2016-0152								

Outage OM&A Purchased Services $M	2017	2018	2019	2020	2021	Total
	196.1	198.5	232.5	262.6	244.7	
Less 24%	47.1	47.6	55.8	63.0	58.7	272.3
	149.0	150.9	176.7	199.6	186.0	

Overtime

215. OPG's actual overtime for the years 2013 to 2016 and forecast amounts for the test period are shown in the Table below.

OPG Nuclear Overtime $ M	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total Test
Plan	127	109.3	122.3	111.7	117.5	115.7	118.6	101.9	81.1	534.8
Actual	159.2	117.6	132	136.4						
Variance $	32.2	8.3	9.7	24.7						
Variance %	25.4%	7.6%	7.9%	22.1%						

216. In 2013, OPG indicates the overtime variance of 25.4% from budget was largely due to the use of overtime to complete work programs due to regular labour resources being under complement. In its 2013 report, the Auditor General made recommendations regarding OPG's overtime usage to ensure that overtime hours and costs are minimized and monitored. Specifically, that OPG should decrease overtime costs for outages by planning outages and arranging staff schedules in a more cost-beneficial way; and review other ways to minimize overtime.[126]

217. In 2016, the overtime variance of 22.1% is largely due to the same reason as 2013, i.e. use of overtime to complete work programs due to regular labour resources being under complement.[127] OPG's actual 2016 Regular FTEs were 452 below target and Non-Regular FTEs (contracted staff) were 216 FTEs above target. AMPCO notes OPG pays a premium for completing work programs using overtime as employees are typically paid at time and a half or double-time.

2016 Nuclear Staff Summary	Nuclear Operations	DRP	Total	Variance
Regular Plan	5788.6	427.6	6216.2	-452.5
Non-Regular Plan	666.7	73.5	740.2	216.3
	6455.3	501.1	6956.4	-236.2
Regular Actual	5341.1	422.6	5763.7	
Non-Regular Actual	843.8	112.7	956.5	
	6184.9	535.3	6720.2	

F2 Tab 1 Schedule 1 Table 3; J13.3

[126] 2013 Auditor General Report Chapter 3 Section 3.05 P175
[127] L-6.6-2-AMPCO-135 (c)

218. OPG has experienced significant increases in overtime beyond 10% in 2013 and 2016 due to staff resources under complement. Going forward, AMPCO submits OPG needs to focus further on new strategies to improve resource planning and execution to minimize excessive use of overtime to ensure the required work is conducted at the lowest achievable cost.

PICKERING EXTENDED OPERATIONS

Issue 6.5: Are the test period expenditures related to extended operations for Pickering appropriate?

219. In light of the uncertainty regarding Pickering Extended Operations (PEO), including the need for the CNSC to determine whether, and if so under what conditions to approve an extension of Pickering's licence, and the ongoing updating of the province's Long Term Energy Plan (LTEP), OEB Staff is recommending approval in this proceeding only of the 2017 and 2018 enabling costs for the PEO project. With respect to enabling expenditures planned for 2019 and 2020, staff proposes that these be tracked (which we assume means dispositioned) through the CRVA, rather than included in payment amounts determined in this proceeding. Staff further recommends that the actual Pickering restoration costs should only be approved once the CNSC licence process for Pickering and the updated LTEP have both been determined.

220. AMPCO endorses these recommendations as a sensible balance between moving forward with planning while remaining prudent with respect to investment approvals pending.

221. In this respect, AMPCO notes that the mid-term review would be an appropriate point at which the balance of PEO costs could be properly considered in light of better information on licencing, provincial electricity planning assumptions, and an updated PEO economic analysis.

NUCLEAR COMPENSATION AND BENEFITS

Issue 6.6: Are the test period human resources related costs for the nuclear facilities (including wages, salaries, payments under contractual work arrangements, benefits, incentive payments, overtime, FTEs and pension costs, etc.) appropriate?

222. OPG's compensation costs for the Nuclear facilities is provided below.[128] Total compensation over the test period is $8,025 million. OPG's Total Compensation costs reflect Regular and Non-Regular staff, and includes Base Salaries and Incentives, Overtime and Pension and Benefits. Base Salaries and Incentives represent about 68 per cent of OPG's total compensation costs related to the Nuclear facilities over the test period. Overtime represents close to 7% and Pension and Benefits represent

[128] F4-3-1 P6

about 25%.

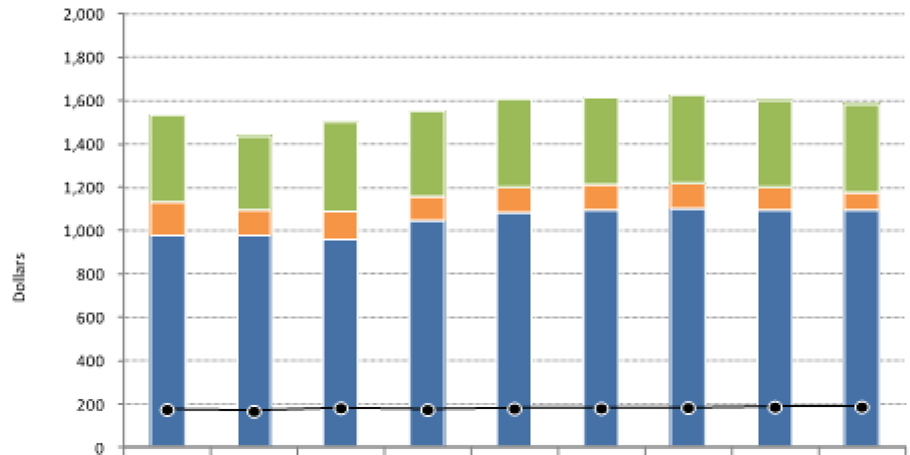
223. Forecast compensation costs include the Lump Sum Payment and Share Performance Plan obligations for PWU and Society employees. In exchange for pension reforms, existing PWU and Society employees are entitled to a Lump Sum Payment of 1% of salary in the first year of the contract and 2% in year two. In addition, under certain conditions, PWU and Society employees contributing to the pension plan will receive shares annually up to 15 years.[129]

224. For Management staff, below VP, OPG has reinstated an Annual Base Pay Increase program. For VP and above, OPG has a Shareholder Return Program which is a Pay at Risk program that compensates Management Employees based on achievement of corporate and performance objectives. The cost of the Stakeholder Return Program allocated to Nuclear (shown in Centrally Held Costs) is approximately $18.5 million annually or $92.5 million over the test period.[130] Performance incentive costs are projected assuming target performance is achieved. In AMPCO's view, OPG should forecast these costs based on historical performance on whether the target has been achieved, not on the assumption that it will be in each year.

225. Through Business Transformation and OPG's change in its organizational structure to a centre-led matrix organization, OPG was able to reduce its regular headcount by nearly 2,700 positions between 2011 and 2015. While no accurate reconciliation of "headcount" versus "FTE" has ever been provided, the number of FTEs peaks in 2017 and then declines by over 500 FTEs by 2021. The significant increase in 2016 FTEs compared to 2015 (+607 FTEs) is primarily driven by DRP, followed by the extension of Pickering Operations. The number of FTEs is a primary driver of nuclear compensation costs and the growth in FTEs beginning in 2016 is driving compensations costs over the test period. Total compensation per FTE steadily increases from $182,000 in 2017 to $191,000 in 2021.

[129] F4-3-1 P18
[130] F4 Tab 4 Schedule 1 Table 1

Figure 3 - Compensation Costs for Nuclear Facilities



	2013	2014	2015	2016	2017	2018	2019	2020	2021
Pensions & Benefits (M$)*	399	342	417	397	407	400	405	404	405
Overtime (M$)	159	118	132	112	117	116	119	102	81
Base Salaries & Incentives (M$)	976	978	956	1,046	1,082	1,095	1,099	1,097	1,096
Total Compensation (M$)	1,534	1,438	1,506	1,554	1,606	1,611	1,623	1,603	1,582
Growth Rate (Total Compensation)	6%	-6%	5%	3%	3%	0%	1%	-1%	-1%
Total Compensation (K$ / FTE)	179	171	186	178	182	184	187	190	191
Full Time Equivalents**	8594	8432	8114	8721	8801	8761	8665	8430	8293

*Pension and benefits include current service costs and are shown on an accrual basis.
** FTE includes both regular and non-regular FTEs. The actual 2013 FTEs shown are adjusted from those provided in EB-2013-0321, J7.3, Attachment 1. The adjustment increases the number of FTEs by excluding the impact of banked overtime (overtime taken as time off rather than pay) and shows the 2013 Actual FTEs on a consistent basis with the remaining years in the table.

226. 90% of OPG staff belong to either the PWU or the Society, and 10% are management. Both the PWU and Society collective agreements provide for a one per cent escalation increase each year and cover a three-year period, running from April 1, 2015 to March 31, 2018 for the PWU and from January 1, 2016 to December 31, 2018 for the Society. OPG has made assumptions in the application regarding forecast escalation increases for PWU and the Society beyond 2018.

227. On average, approximately 40% of the proposed 2017-2021 nuclear revenue requirements is attributable to total compensation costs including overtime.[131]

Benchmarking

228. Compensation Benchmarking is vital in assessing whether OPG's compensation costs are reasonable, at market, competitive and affordable, and the Board has historically relied on these results in approving OPG's compensation costs.

[131] L-6.6-2-AMPCO-123

229. Willis Towers Watson's (WTW) benchmarking concludes that of the positions surveyed, OPG's Total Direct Compensation is at market relative to external labour markets. OPG's Pension and Benefit costs are above market.

<u>Benchmarking Total Direct Compensation</u>

230. WTW's Total Direct Compensations includes Base Salaries and pay at risk incentives. Overtime, Lump-Sum Payment and Share Performance Plan costs are not included. Pension and Benefits were looked at separately.

231. In its analysis, WTW looked at OPG Management, PWU and Society employee groups along three segments: Utility (69% of employee population), Nuclear Authorized (4%), and General Industry (27%).[132]

232. 78% of OPG incumbents were benchmarked (7,380 out of 9,513).

233. WTW considers compensation benchmarking results to be "at market" if they are within +/- 10 per cent of the target market positioning. OPG's target market positioning is the 50th percentile for positions in the Utility and General Industry segments, and 75th percentile for the Nuclear Authorized segment.[133]

234. Overall, WTW concludes OPG is at market for Total Direct Compensation (+5%). Specifically, OPG's Utility and Nuclear segments are at market, +2% and -3% respectively. OPG's General Industry is above market (+19%).134 Under the General Industry, PWU and Society are significantly above market, 27% for each.

235. AMPCO submits OPG's nuclear revenue requirement should be based on OPG's compensation at the 50th percentile for all its positions. The impact of OPG being 5% above the targeted market positioning is approximately $30 million for the nuclear facilities.[135]

236. The $30 million is based on targeted market positioning of 75th percentile for the Nuclear Authorized segment and 80% of headcount. AMPCO does not agree that the target market for the Nuclear Authorized segment should be at the 75th percentile based on a rationale that there is more complexity and responsibility for OPG's 4 units compared to 1-2 in the market. Positions within the Nuclear Authorized segment already get paid more than either Utility or General due to the perceived "level of complexity" associated with this work. To then target the 75th percentile simply adds to the already increased level of compensation. AMPCO submits the target market for the Nuclear Authorized segment should also be the 50th percentile, consistent with the other two segments. The impact of applying the benchmarking to 100% of headcount

[132] L Tab 6.6 Schedule 15 SEC-083 (a)
[133] F4-3-1 P18
[134] F4-3-1 P19
[135] L-6.6 Schedule 15 SEC-083 (b)

and moving the Nuclear Authorized segment to a target market at the 50th percentile is $46.7 million.[136]

Exclusion of Overtime and Other Costs

237. As indicated above, overtime and Lump Sum Payments and Share Performance Plan cost are excluded from the benchmarking. OPG's total projected overtime costs over the 2017 to 2021 period are $534.8 million. The total projected costs associated with the Lump Sum Payments and the Share Performance Plan are $92 million over the 2017 to 2021 period.

238. AMPCO submits the exclusion of the above compensation costs in the benchmarking analysis significantly understates OPG's compensations costs and undermines the benchmarking results, especially considering the uniqueness of the Lump-Sum Payment and Share Performance Plan obligations that OPG comparator organizations are unlikely to have but reflect real costs for OPG. If the Lump-Sum Payment and Share Performance Plan costs had been included in the benchmarking, AMPCO expects that OPG's position would be greater than 5% above market for Total Direct Compensation.

239. OPG has not assessed its overtime costs relative to market.[137]

240. OPG has not assessed whether its total compensation, including salary, incentives, bonuses, overtime, pensions and benefits, is at market. AMPCO submits OPG should undertake this more comprehensive assessment as part of its next benchmarking study.

Benchmarking Pensions and Benefits

241. OPG indicates it has taken a broader approach to collective bargaining involving both Hydro One and the Government of Ontario. OPG has increased employee pension contributions beginning April 1, 2015 for PWU employees and January 1, 2016 for Society and Management employees. The Employee/Employer contribution ratio increases from 24%/76% in 2014 to 35%/65% in 2017.138 OPG's contribution ratio for 2019 to 2021 is confidential. The total projected savings associated with increased employee contributions attributed to the nuclear facilities are $88M over the 2017-2021 period.[139]

242. WTW concludes that OPG's pension and benefits as a % of base salary is above the 50th percentile of the market for the PWU, Society and Management Groups.[140]

[136] K17.1 P19
[137] L-Tab 6.6 Schedule 1 Staff-148
[138] F4-3-1 P16
[139] L Tab 6.6 Schedule 1 Staff-147
[140] F4-3-1 Attachment 2 Page 27

Pension & Benefits % of Base Salary		
OPG Group	**OPG**	**Market P50**
PWU	29.7%	20.2%
Society	30.3%	20.3%
Management	31.3%	22.8%

243. OPG indicates the cost impacts associated with OPG pension and benefits benchmarking above market are not available.[141] AMPCO submits the impact of OPG being above market P50 for OPG's Pension and Benefits should not be borne by ratepayers.

244. In its 2013 Report, the Auditor General noted that OPG has contributed disproportionately more to its pension plan than its employees have. Since 2005, the employer–employee contribution ratio at OPG has been around 4:1 to 5:1, significantly higher than the 1:1 ratio at Ontario Public Sector.[142] Although OPG has made some progress toward reducing OPG's Pension and Benefit costs, more Pension and Benefit controls are needed. To achieve further savings, AMPCO submits OPG should better align the design of all aspects its Pension and Benefit plans with the Ontario Public Sector.

245. AMPCO submits a 10% annual reduction in OPG's Pension and Benefits costs is appropriate and ensures OPG's costs are more reasonable in comparison to other similar and broader-public-sector organizations

<u>Summary</u>

246. In considering the above benchmarking results, AMPCO recommends a total annual disallowance of $85 million consisting of $46.7 million for excessive compensation costs above median and the balance to reflect a 10% reduction in Pension and Benefit costs to move closer to P50.

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[141] L-6.6 Schedule 15 SEC-083 (b)
[142] 2013 Auditor General Report - Chapter 3 Section 3.05 P155

NUCLEAR RATE SETTING

Issue 11.3: Is OPG's approach to incentive rate-setting for establishing nuclear payment amounts appropriate?

Issue 11.4: Does the Custom IR application adequately include expectations for productivity and efficiency gains relative to benchmarks and establish an appropriately structured incentive-based rate framework?

247. For its nuclear facilities, OPG developed a 5-year incentive rate-setting (Custom IR) framework that is tied to Total Generating Cost benchmarking and includes a benchmark-based Stretch Factor.

248. The Stretch Factor component of the X-factor is intended to reflect the incremental productivity gains that organizations are expected to achieve under IR and is a common feature of IR plans. These expected productivity gains can vary by company and depend on the efficiency of a given company at the outset of the IR plan.

249. OPG proposes a Stretch Factor of 0.3%, to be applied to the revenue requirement impact of Base OM&A and Allocated Corporate Support OM&A only, beginning in 2018 through to 2021, which represents approximately 75% of OPG's total nuclear OM&A in each year.

250. The Stretch Factor was derived based on total generation cost benchmarking performance. The stretch reduction is cumulative and it is applied in the determination of nuclear payment amounts. OPG is not proposing that the Stretch Factor be applied to Outage OM&A, Project OM&A or Capital.

251. A Stretch Factor of 0.3% applied to Base OM&A and Allocated Corporate Support OM&A, represents a total revenue requirement reduction of $50.7 million for Base and Allocated Corporate Support OM&A over the IR period; $5 million, $10.1 million, $15.2 million, and $20.4 million for the years 2018, 2019, 2020, and 2021, respectively.143

[143] A1-3-2 Page 33 Chart 10

Chart 10 – Stretch Reduction Amounts

($M)	2018	2019	2020	2021
Base & Corporate Support OM&A	1,663.2	1,691.1	1,709.7	1,730.4
Stretch Factor	0.3%	0.3%	0.3%	0.3%
Annual Stretch Reduction to Nuclear Revenue Requirement	**5.0**	**10.1**	**15.2**	**20.4**
Base & Corporate Support OM&A Used to Determine Payment Amounts	**1,658.2**	**1,681.0**	**1,694.5**	**1,710.0**

252. To derive the Stretch Factor, OPG assessed its Total Generating Cost (TGC $/MWh) ranking from the 2015 Nuclear Benchmarking Report (2014 data) for Darlington and Pickering separately and then used a production-weighted average to determine a combined stretch factor value of just under 0.3%. The Stretch Factor reflects Darlington's TGC in the top quartile (stretch = 0%) and Pickering in the fourth quartile (stretch = 0.6%), based on 2014 performance.

253. OPG filed its 2016 Nuclear Benchmarking Report showing 2015 performance as part of the interrogatory process. Darlington's TGC results have slipped from top quartile to second quartile and Pickering remains in the fourth quartile. Based on the latest results, OPG calculates that with the Darlington stretch factor now at median (0.3%) Pickering at fourth quartile (0.6%), the updated production weighted average produces a Stretch Factor of 0.43%.[144]

254. AMPCO supports OPG's use of Total Generating Cost per MWh as the metric to benchmark performance but submits it should be looked at and assessed on an enterprise-wide basis, not weighted by nuclear facility (Pickering and Darlington). The OM&A costs that the Stretch Factor applies to reflect nuclear enterprise-wide costs. In 2016 OPG adopted TGC as an enterprise-wide measure of operational cost-effectiveness in addition to TGC metrics for each of the nuclear and hydro operations.

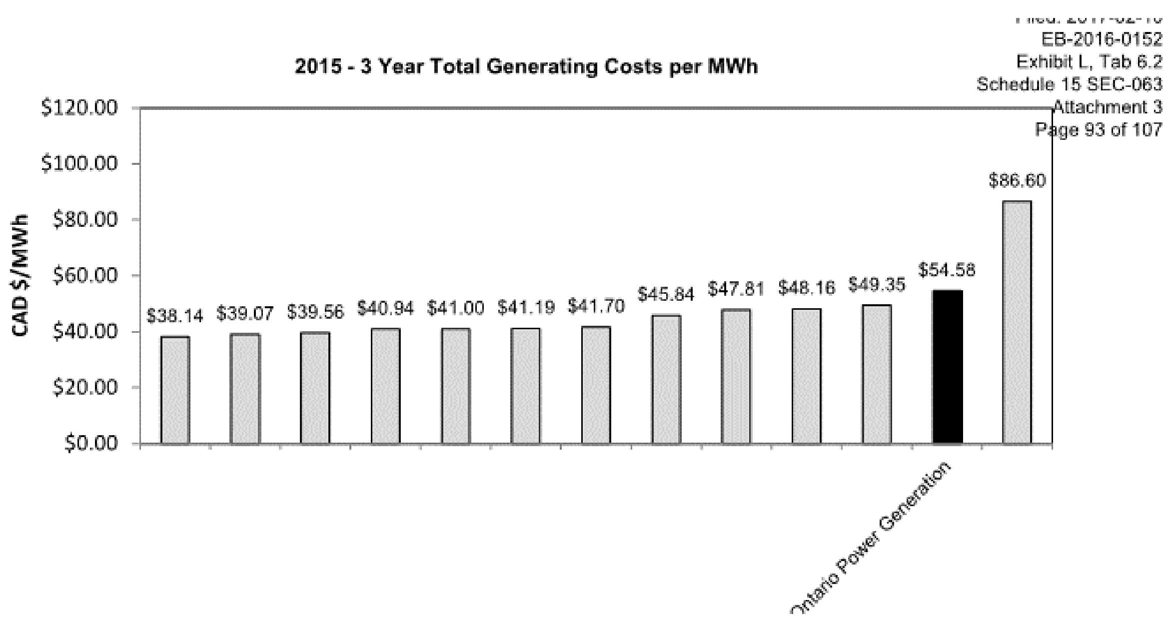
255. This enterprise-wide measure aligns with AMPCO's recommendation that TGC should be reviewed on an enterprise-wide basis.

256. In terms of rankings, out of 13 nuclear operators, OPG's overall ranking in TGC in 2015 is 12th, the second worst. This represents a decline in performance compared to 2013 and 2014, using 3 year rolling averages.

[144] Transcript Volume 6 Page 129

Table 5: Three-Year Total Generating Cost per MWh Rankings

	2010	2011	2012	2013	2014	2015
	9	7	4	1	1	1
	4	4	5	4	4	2
	1	2	2	6	5	3
	3	1	1	2	2	4
	2	3	3	3	3	5
	10	8	7	7	6	6
	NA	NA	NA	11	7	7
	14	13	14	14	12	8
	5	5	6	5	8	9
	11	11	11	9	9	10
	7	9	9	10	11	11
Ontario Power Generation	12	12	10	8	10	12
	13	14	13	13	13	13
	8	10	12	12	NA	NA
	6	6	8	NA	NA	NA



257. Given this decline in TGC ranking over the past three years, AMPCO submits a Stretch Factor of 0.60% is appropriate and will motivate OPG to continuously improve its performance at Darlington and Pickering.

258. OPG indicates the Stretch Factor is in addition to the gap-based performance improvement initiatives from the 2016-2018 Business Plan listed below.[145]

[145] A2-2-1 Attachment #1, Page 31

-Workforce Planning & Resourcing Initiative
- Outage Performance
- Equipment Reliability
- Human Performance
- Parts Improvement Project
- Inventory Reduction Initiative

259. A new initiative, the Project Excellence Initiative, was added as part of the 2017 to 2019 Business Plan.[146] OPG is unable to quantify specific OM&A savings from any of these initiatives, and do not track such savings on an initiative by initiative basis in any case.[147]

Application of the Stretch Factor

260. OPG is not proposing that the Stretch Factor apply to the remaining 25% of OM&A that includes Project OM&A and Outage OM&A.

261. AMPCO does not agree that the Stretch Factor should only be applied to Base OM&A and Allocated Corporate Support OM&A. AMPCO submits the Stretch Factor should be applied to all Nuclear OM&A costs including Project and Outage OM&A as well as Nuclear Operations Capital.

262. In the Board's Decision in Toronto Hydro's Custom IR application, the Board stated "The OEB has consistently applied stretch factors to total costs 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. As discussed later in this Decision, the OEB is concerned that the Application does not contain enough productivity incentives. Application of the stretch factor to the C factor is one way to remedy this deficiency.[148]

263. AMPCO submits the same rationale is applicable to OPG and OPG should be further incented to find operational savings across its organization including capital.

264. As shown in the Table below, the Revenue Requirement reduction increases from $50 million to $140.2 million over the test period when a Stretch Factor of 0.60% is applied to total Nuclear OM&A, noting that the actual reduction will be based on the Board's Decision with respect to approved Nuclear OM&A amounts, considering the OM&A increases specified in N1.

[146] N1-1-1 Attachment #1 Page 25
[147] L-11.3-3-CME-010 9 (a)
[148] EB-2014-0116 THESL Decision Page 18

Nuclear Incentive Rate Setting
2018 to 2021 Reductions in Nuclear Revenue Requirement ($ million)
A1-3-2 Page 33 Chart 10
L-11.3-Schedule 3-CME-009

Stretch Factor	Rev Reqmt Reductions OM&A (Base & Corporate Support)	Rev Reqmt Reductions Total Nuclear OM&A
0.30%	$50.7	$70.0
0.45%	$74.6	$104.9
0.60%	$101.3	$140.2

265. Project OM&A is included in the Nuclear Projects Portfolio capital budget. Project OM&A includes management oversight and direction, administration and coordination of project portfolio activities, and ensures compliance with OPG governance and standards. Given the ongoing project management and oversight issues raised by AMPCO under the Nuclear Operations Capital section, AMPCO believes the Stretch Factor should apply to Project OM&A. Further project management efficiency improvements are achievable regardless if the projects are temporary endeavours and outside of the normal work program.[149]

266. Given OPG's ongoing challenges with delivering projects on time and on budget and with high quality, AMPCO submits it is appropriate that the Stretch Factor also apply to capital. AMPCO notes Sustaining and Value Enhancing capital projects represent close to 88% of the capital budget; 12% of the budget is for Regulatory capital projects.150 Further, a major portion of OPG's application deals with the Darlington Refurbishment Project – the single biggest capital project that the OEB has ever been asked to opine on. In AMPCO's submission, this project represents the cornerstone of OPG's capital program, and should therefore represent a cornerstone in terms of OPG's commitment to continuous improvement. AMPCO submits the Board apply the Stretch Factor as a direct offset to the entire capital budget. In addition, AMPCO submits the Board apply the Stretch Factor as a direct offset to DRP OM&A.

267. OPG indicates Outage OM&A costs are tied to specific outages, and vary year over year depending on the number and scope of outages and therefore cannot be trended over time. AMPCO submits regardless of the variation in outage scope, the underlying work requirements are repetitive and suitable for improvements under a Stretch Factor. Outage OM&A is a driver of deficiency for the nuclear facilities (3 per cent of revenue deficiency).151 AMPCO submits the Stretch Factor should apply to Outage OM&A.

<u>Productivity Factor</u>

[149] F2-2-1 P1
[150] D2-1-2 Table 3 (Regulatory = $61.9/$503.8=12%)
[151] A1-3-4 P4

268. OPG is not proposing a nuclear industry productivity adjustment as part of the proposed X-factor on the basis that the nature and scale of capital work planned for the IR period mean that past productivity trends would not be a reasonable indicator of predicted productivity for OPG during the IR period.

269. AMPCO is not proposing a nuclear industry productivity adjustment as part of the proposed X-factor.

Summary

AMPCO submits a Stretch Factor of 0.60% derived from TGC enterprise wide results should be applied as a Revenue Requirement reduction of total OM&A consisting of Base OM&A, Project OM&A and Outage OM&A. In addition, AMPCO submits the Stretch Factor should be applied as a direct offset to Nuclear Operations Capital to drive the company to further improve its operational cost effectiveness and value for money.

SCOPE OF MID-TERM REVIEW

Issue 11.5: Is OPG's proposed mid-term review appropriate?

270. AMPCO is concerned that the DRP early in service project delays and cost overruns reviewed elsewhere in this argument are a harbinger of things to come. History indicates that nuclear megaprojects are always over-budget and behind schedule.

271. It is trite to note that there will be more certainty about whether 2020 and 2021 payment amount inclusions for Unit 2 are appropriate as we get closer.[152] In AMPCO's view, a decision on rate base inclusions in nuclear payment amounts can be better made with greater certainty some years from now.

272. Nonetheless, the CRVA provides some comfort that if things go off the rails, ratepayers will be spared the burden of paying for facilities not yet in service. (Such a result might even be contrary to law, and it would certainly be contrary to accepted regulatory practice. As no party is advocating this result[153], AMPCO will not address these arguments further at this time.)

273. These considerations do, however, commend a more involved mid-term review than OPG contemplates.

274. OPG initially proposed the mid-term review of only OPG's nuclear production schedule, and associated fuel costs.

[152] Tr. 2, p.46, lines 27 *et seq*.
[153] Tr. 2, p.77, lines 26 *et seq.*

275. When OPG decided to remove the D2O facility from the current application, it also determined that the costs associated with this facility will now be submitted for review at the mid-term review.

276. Mr. Lyash in testimony also agreed that it would be appropriate for the Board to review the then current status of the DRP.[154] To AMPCO this is critical.

277. If the OEB is going to approve at this time inclusion in approved nuclear payment amounts of rate base inclusions resulting from the biggest electricity infrastructure project ever undertaken in this province, and the first refurbishment of a CANDU reactor, it is critical to ensure that when greater certainty regarding the status and timing of the Unit 2 phase of the project is available, it be considered, and payment amounts be adjusted if and as required.

278. For this reason, AMPCO urges the Board to establish 2020 and 2021 payment amounts on an interim basis at this time, subject to finalization following a mid-term review of the then current status and timing of the Unit 2 phase of the DRP. This mechanism will allow the Board to proceed to establish expected (i.e. interim) 2020 and 2021 payment amounts based on the extensive record developed in this case (promoting regulatory efficiency), while at the same time reserving the opportunity to adjust the payment amounts if and as appropriate once we really know when, and at what cost, the Unit 2 refurbishment will be completed.

279. While a similar outcome could be managed through the CRVA (rather than ordering 2020 and 2021 payment amounts on an interim basis), the course proposed by AMPCO would make it clear that the mid-term review will be of a substantive and substantial nature, sufficient to allow the Board to make final determinations in respect of the quantum and timing of DRP inclusion.

280. At the same time, such review need only entail evidencing, and exploring, changes relative to OPG's current DRP plans and forecasts, rather than an entire re-exploration of the basis for 2020 and 2021 DRP costs and associated revenue requirements. The Board could direct in its order in this proceeding that the scope of the mid-term review in respect of DRP would be so limited.

281. If the Hearing Panel accepts Staff's submissions on the PEO topic, further approvals required in respect of PEO could be examined at the time of the mid-term review as well.

282. A similar approach to scoping of a mid-term Custom IR review as a process to update certain aspects of later year interim rate decisions was taken by the Board in the Oshawa PUC Networks Custom IR decision155.

[154] Tr. 2, p.47, lines 26 *et seq*.
[155] EB-2014-0101.

283. The unique nature of the instant application commends an approach tailored to its particular circumstances, which could be fashioned expressly without an intention to signal a shift in the OEB's general ratemaking policy.

284. As noted by OPG in opening of its Argument in Chief;

285. By any measure, this is a significant Application. It includes review of the ..DRP.., the single largest capital project ever to come before the OEB, and requests approval of some $5,177.4M of DRP-related in-service additions. ....

286. In the course of this Application, OPG filed thousands of pages of evidence supported by dozens of company witnesses. It responded to more than a thousand interrogatories and undertakings. Numerous benchmarking reports were filed covering nuclear performance, compensation and benefits, corporate costs and hydroelectric costs. In certain key areas, OPG sponsored the testimony of expert witnesses. All this material was provided in aid of explaining what is a complex business.

287. OPG is the only generator regulated by the OEB. It is a large generating company producing over half the energy generated in Ontario. It operates two nuclear facilities that differ in size, number of units and vintage of CANDU technology employed. It has extensive regulated hydroelectric facilities that range from the very large and complex generation at Niagara Falls to much smaller facilities on rivers across the Province. The diversity of technology, the numerous facilities of different sizes and vintages, the geographic dispersion and the shear scope of OPG, all contribute to making it a complicated entity to operate and to regulate.

288. In this Application, as in past filings, OPG has tried to present a large volume of information in an organized and understandable way. But these efforts cannot make simple what is inherently complex. Even without the DRP, OPG is unique among Ontario regulated companies, electric or natural gas, in terms of scope, scale and complexity.

289. In recognition of these inherent differences, OPG respectfully requests that the OEB evaluate the evidence and decide the issues in this proceeding based on the size, nature and complexity of OPG's business and develop regulatory approaches that fit OPG.

290. In this context, it would be completely appropriate for the Board to proceed with some caution, and fashion a remedy suited to the particular, complex and unprecedented circumstances addressed by OPG in this application, and which are of tremendous import to Ontario's electricity consumers.

IMPLEMENTATION

Issue 12.1: Are the effective dates for new payment amounts and riders appropriate?

291. AMPCO has had the benefit of reviewing a draft of SEC's argument, including its argument in respect of effective date. For the reasons argued by SEC, AMPCO supports an effective date for the final payment amounts determined in this proceeding being the beginning of the month following the date of issuance of the order herein.

292. We will not simply repeat SEC's points in argument in support of this result, other than to note that AMPCO has reviewed them, has considered them, and endorses them.

293. In the section of this argument that addresses Issue 11.3, and the appropriate scope for the mid-term review and the ratemaking approach associated therewith, the opening of OPG's AIC is excerpted. That entire section of OPG's argument underscores the scale, scope and complexity of this application. OPG's own view of the scale, scope and complexity of this application supports the argument well articulated by SEC, and supported by AMPCO, for an effective date following issuance by the Board of the order herein.