May 29, 2017

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
P.O. Box 2319
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: EB-2016-0152 – Ontario Power Generation Inc. – 2017-2021 Payment Amounts – Final Argument of the Consumers Council of Canada

Please find, attached, the Final Argument of the Consumers Council of Canada in the above-referenced proceeding.

Yours truly,

Julie E. Girvan

Julie E. Girvan

CC: OPG, Regulatory Affairs
C. Keizer, Torys
C. Smith, Torys
All Parties

ONTARIO ENERGY BOARD

ONTARIO POWER GENERATION INC.
PAYMENT AMOUNTS
2017-2021

EB-2016-0152

FINAL ARGUMENT OF THE CONSUMERS COUNCIL OF CANADA

I. INTRODUCTION:

On May 27, 2016 Ontario Power Generation ("OPG") applied to the Ontario Energy Board ("OEB" or "Board") pursuant to section 78.1 of the Ontario Energy Board Act, 1988, (the "Act") for an order or orders approving payment amounts for its regulated hydroelectric facilities and its nuclear generating facilities for the period January 1, 2017 to December 31, 2021.

This Application is far more complex than any previous OPG Applications that have become before the Board. It is the first five-year application and the first where payment amounts have been derived under Incentive Rate-making Mechanisms ("IRMs"). The outcome of the Board's Decision in this case will impact Ontario electricity ratepayers for years to come, even beyond the test period. The most significant aspects of OPG's Application include:

- The Darlington Refurbishment Project (DRP") and the request by OPG for the OEB to approve over $5 billion in capital additions and over $100 million in Operating, Maintenance and Administration costs associated with the DRP over the 2017-2021 test period;

- Five years of payment amounts related to the nuclear assets based on a new Custom IRM proposal;

- A rate smoothing proposal for those payment amounts to reflect a constant 2.5% rate increase during the 2017-2021 test period;

- Hydroelectric payment amounts of $41.71/MWh effective January 1, 2017, and approval of a deferral and variance account rider of $1.44/MWh applied to the hydroelectric facilities;

- An proposal to set the hydroelectric payment amounts for the period 2018-2021 on the basis of a new IRM proposal;

- An increase in the equity level within OPG's capital structure from 45% to 49%;

- A mid-term review to update the nuclear production forecast and consequential update to the nuclear fuel cost for the final two and a half years of the test period and to dispose of audited deferral and variance accounts; and

- A request to approve enabling costs related to the Pickering Extended Operations proposal to operate the Pickering facility to 2024.[1]

OPG filed its Argument-in-Chief on May 3, 2017. OEB Staff filed its Submissions on May 19, 2017. This is the Final Argument of the Consumers Council of Canada ("Council").

The Council has worked closely with the other intervenors throughout this proceeding and has participated in the exchange of drafts or partial drafts of the arguments. We are aware of the fact that OEB Staff and some intervenors have chosen to focus on issues in a more detailed way, and on some of those issues we will either adopting those submissions or not taking a position at all. This has been a complex proceeding and therefore the Council will not be making submissions on all of the issues set out in the OEB's approved issues list. Not making a submission on an issue does not mean we accept OPG's proposals and the associated evidence in support of those positions.

The Council has focused in on what we believe to be the most significant issues before the Board - significant in terms of their important to ratepayers and those that from a cost perspective impact the payment amounts the most. The Council will address the following issues:

1. Nuclear:

    A. Darlington Refurbishment Project
    B. Pickering Extended Operations
    C. Operating Costs

2. Cost of Capital and Capital Structure
3. Nuclear Waste Management and Decommissioning Liabilities
4. Deferral and Variance Accounts
5. Reporting and Record Keeping Requirements
6. Methodologies for Setting Payment Amounts

    A. Hydroelectric

[1] Ex. A1/T2/S2/pp. 1-5

B. Nuclear

7. Mid-Term Review
8. Rate Smoothing
9. Implementation/Effective Date

II. ISSUES:

1. NUCLEAR:

A. Darlington Refurbishment Project:

Summary

OPG is requesting that its test period revenue requirement include amounts relating to the completion of the Unit 2 phase ("Unit 2") of the Darlington Refurbishment Project (the "DRP"). The bulk of the approval sought by OPG for Unit 2 relates to a forecast in-service amount of $4.7 Billion in 2020, the year that Unit 2 is forecast to go back into service.[2] It is in relation to this specific aspect of the requested approval that the Council will make submissions.

In the Council's view the Board should not approve an in-service amount of approximately $4.7 Billion in 2020 for the purpose of setting OPG's revenue requirement over the course of the test period. The Council respectfully submits that it would be appropriate to approve an in-service amount of approximately $4 billion, which represents the forecast in-service amount for Unit 2 in 2020 less the assumed contingency spending of $694 million that OPG has included in its forecast Unit 2 costs.[3]

The only caveat to this proposal is that the Council is aware that several parties, including Board Staff, may make or have made submissions with respect to discrete reductions in the non-contingency related amounts proposed for the test period.[4] The Council respectfully requests that the Board consider any such submissions as incremental to the Council's proposal.

To the extent that OPG incurs costs, including costs that would have been included within the $694 million contingency, beyond the costs that the Board approves in this proceeding, those costs will be tracked in the Capacity Refurbishment Variance

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[2] OPG AIC, p. 17
[3] OPG AIC, p. 54
[4] Board Staff Argument p. 38, for example, seeks approximately $125M in reductions to the approved in service additions for Unit 2 unrelated to the Contingency amount; if accepted those reductions would be incremental to the Council's proposal to eliminate the pre-approval of the $694 Million Contingency amount.

Account (the "CRVA"). On application by OPG to clear the CRVA, OPG will be at liberty to recover all of its prudently incurred costs in relation to Unit 2, and the Board will be at liberty to properly scrutinize OPG's performance in completing Unit 2 to determine which claimed costs beyond the "base" amount relate to prudently incurred contingency spending and which claimed costs, if any, were imprudently incurred by OPG and therefore should not be recoverable from ratepayers.

In this way, the Council respectfully submits, the Board can grant OPG an appropriate approval and ability to recover the "base" costs of completing Unit 2, while at the same time retain full regulatory oversight with respect to any variations from the base amount that result during the execution by OPG of its plan to complete Unit 2.

Context of DRP Approval

The Council believes that it is important to emphasize the fact that the Board, and therefore the intervenors including the Council, have no role in determining whether the DRP in general or whether Unit 2 specifically are "needed". Ontario Regulation 53/05 specifies at section 6 (2) 12 (v) that:

> . . . the Board shall accept the need for the Darlington Refurbishment Project in light of the Plan of the Ministry of Energy known as the 2013 Long-Term Energy Plan and the related policy of the Minister endorsing the need for nuclear refurbishment.

Accordingly, it would seem to the Council, OPG has been relieved of any obligation to justify the DRP in general, and the Board and intervenors have been excluded from questioning whether there is adequate justification for the DRP *ab initio*. Instead, the Board and intervenors are relegated to an examination of whether the costs incurred to undertake the DRP are prudent, as opposed to whether the DRP, at any cost, is appropriate.

The Council also believes that it is important to emphasize that any approval of costs in relation to the DRP in this proceeding are necessarily interim. In addition to dictating the need for the DRP, Ontario Regulation 53/05 specifies at section 6(2) 4 that:

> The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs and firm financial commitments incurred in respect of the Darlington Refurbishment Project . . . , including, but not limited to, assessment costs and pre-engineering costs and commitments,
>
> ii. . . . if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

In short, regardless of what this Board decides would be an appropriate cost for the completion of Unit 2 for the purposes of setting the test year revenue requirement, any variance in costs incurred by OPG relative to the Board's approval in this proceeding will be tracked in the CRVA and, subject to Board approval of those excess costs as having been prudently incurred, recovered by OPG (or returned to customers in the event there are revenue requirement amounts included in rates that are not realized by OPG, i.e. in the event Unit 2 does not go into service in 2020 as forecast).[5]

The Nature of OPG's Unit 2 Forecast Costs

In the Council's view OPG's forecast Unit 2 costs should be considered as comprising of two distinct components.

The first component is a "base" amount, which represents the forecast costs of Unit 2 based on the combination of OPG's planning process with the contracts and commitments it has entered into, and assuming "neutral" conditions and performance, i.e. the assumption that there are no contingency events, positive or negative, that cause a material variation from the base cost.

The second component is the "contingency" amount, which represents the possibility that conditions do not turn out to be neutral such that there are contingency events that cause material variations in the base cost.

Of the total forecast cost of Unit 2 of $4.8 Billion, approximately $4.1 Billion relates to what the Council considers the "base" amount, as set out in the evidence at Ex. D2/S2/T8 page 9 Chart 4, with the "contingency" amount consisting of approximately $694 Million.[6]

For the purpose of setting the revenue requirement over the course of the test period the Council does not oppose the inclusion of the "base" amount of $4.1 Billion, including approximately $4 billion to be added to rate base in 2020, subject to any submissions from other parties that establish "base" amounts that should not be approved in this proceeding. As a reflection of the actual contracts and commitments that OPG has entered into with 3rd parties in order to undertake the completion of Unit 2, and in consideration of the extensive planning that OPG has undertaken in preparing for the Unit 2 project, the Council believes that including this "base" amount in rates now is appropriate.

[5] Technical Conference Tr., Vol. 1, p. 150.
[6] Ex. D2/T2/S 8 p. 9 Chart 4 sets out the more precise amounts for the total Unit 2 forecast cost used by OPG, the contingency amount and the "base" amount before contingency.

For the purpose of setting the revenue requirement over the course of the test period the Council opposes the inclusion of the "contingency" amount of $694 Million for the following reasons.

The interim nature of the approval in this proceeding makes the approval of a particular level of contingency in advance moot

A lot of time was spent in the proceeding, from the interrogatory and technical conference phases right through to the hearing phase, exploring the manner in which OPG developed a forecast level of contingency spending and the appropriate "confidence level" to be employed in developing the contingency forecast. In the Council's respectful submission, while questions around the methodology behind and quantum of the contingency forecast are helpful to understanding how much the total DRP might cost (in terms of completion of all 4 units), the context of the Board's mandate with respect to the DRP in this proceeding makes precise approval of the contingency forecast irrelevant.

While it could have been critically important to approve a forecast contingency for Unit 2 in the context of a regulatory construct where OPG proposed to take on the risk associated with exceeding an approved contingency amount and benefitted from controlling costs below an approved contingency amount (as is the case with at least some of OPG's third party contractors)[7], OPG is not proposing such a construct. Instead, as noted, OPG does not propose to take any risk on any approved forecast of costs for Unit 2. In addition to the operation of the CRVA to capture any spending on Unit 2 beyond whatever the Board approves in this proceeding, OPG confirmed that it is focused on the total cost of the DRP as opposed to the cost of Unit 2:

> MR. BUONAGURO: Oh, almost. No, I ask the question because if you go back over the page -- so I think it's just one page over. Okay -- yeah, no, no, in between. I was reading this while that discussion was going on, and starting at near the top of the page, I think line -- see line 4 -- it says:
> "A detailed breakdown of the components of this estimate is provided in chart 4 in Figure 1 below. While actual costs may ultimately be different from the forecast for individual line items shown in Figure 1, OPG will complete the unit-2 refurbishment and return unit 2 to service within the total envelope budgeted for this purpose, being approximately 4.8 billion."

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[7] Tr. Vol. 3 pp. 45-46, wherein OPG explains that while a p50 confidence estimate was appropriate for use in a contract where the contractor assumed the risk of costs exceeding the p50 confidence estimate and could benefit if the costs fell below the p50 confidence level, that rationale has no bearing on OPG, as OPG is protected against the actual costs, no matter what they end up being, by operation of the CRVA.

So if we stop there for a second, your position on units 1, 3, and 4 kind of make sense to me based on that sentence, because you are saying here are the line items for unit 2, this is what we are proposing, but don't worry about the details because it's all going to come in under $4.8 billion. That's what I read, right?

MR. ROSE: That is what you read. That is the perfect plan.

MR. BUONAGURO: Okay. But then it goes on. It says:

"To the extent of any deviations, the overall DRP will still be completed within the four-unit estimate of 12.8 billion. As such, with respect to cost, OPG's success on refurbishing/returning unit 2 to service should be measured at the total envelope level."

MR. ROSE: Um-hmm.

MR. BUONAGURO: So that extra bit tells me, don't worry about the 4.8 billion because the whole thing is going to come in under 12.8 billion no matter what we spend on unit 2. That is how I interpret that. And if that's what you are saying, then that brings in an analysis of the 12.8 billion on its face, so I wanted to bring that to your attention and get a response.

MR. ROSE: So I think what we are saying is that we will deliver, and we have been saying for a number of OEB hearings now is that we will deliver the four units for the estimate that was provided at RQE, which is $12.8 billion. We are also saying in this evidence that we have high confidence in our ability to deliver the estimate for unit 2 of an in-service amount of $4.8 billion.

In the end if we are higher on $4.8 billion, we are higher on unit 2, but overall able to deliver the four units within the $12.8 billion, I wouldn't -- my opinion, I wouldn't ascertain that to be a project failure.[8]

Accordingly, although it steadfastly refused to respond to inquiries about the total cost of the DRP,[9] OPG is ultimately asking the Board to reserve judgment on the appropriateness of its spending on all aspects of the DRP until all four units are complete.

This approach to the DRP by OPG on an "envelope" basis rather then a unit by unit basis is supported by the fact that the contingency amount included by OPG in its forecast costs was calculated on a total project basis, not on a unit by unit basis. As confirmed by OPG's expert Dr. Patricia Galloway, the methodology for forecasting a contingency amount was employed at the envelope level for all of the units of the DRP; the contingency amount allocated to Unit 2 was not, in fact, a result of the methodology for forecasting contingency being applied specifically to the Unit 2 phase of the project.[10]

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[8] Technical Conference Tr. Vol. 1 pp. 161-162.
[9] Technical Conference Tr. Vol. 1 pp 159-160.
[10] Transcript Vol. 6, pp 48-49.

The question for the Board to resolve, then, is what amount, if any, of contingency spending should it approve in this proceeding, knowing that any spending above an approved amount will be tracked in the CRVA and claimed by OPG in any event, and knowing that OPG ultimately views success with respect to the DRP in terms of cost control relative to the full project cost of $12.8 Billion.

OPG's Incentive to Manage the Costs of the DRP

The Council, throughout the hearing process, sought to establish precisely what incentive OPG as an organization had to manage and, more precisely, beat whatever forecast cost was approved by the Board.

OPG was able to refer to minor incentives embedded within its corporate scorecards, wherein individual executives at OPG would earn their annual incentive, in part, based on bringing Unit 2 into service under budget. As noted in the 2017 corporate scorecard, for example, incentives were determined to some extent by Unit 2 actual spending relative to budget, with the impact of under-spending contributing to 10% of the total scorecard.[11]

However, at no point was OPG able to demonstrate that it, as an organization, was itself incented to bring Unit 2 or the DRP project in general into service below budget. Instead, the Council respectfully submits, it became clear that the incentive for OPG relative to an approved level of spending was primarily to come at least on budget in order to avoid regulatory scrutiny:

> MR. BUONAGURO: So from your perspective, the fact that there is a CRVA and the fact that there is ability to recover amounts beyond what may or may not be approved in this case -- and indeed, when you come back to get the rest of it approved in that case, there is no risk?
> MR. ROSE: Well, I wouldn't suggest there isn't a risk. *I think everything greater than our in-service amounts will become subject to a review and ultimately, I can't predict what the outcome of that review might be.*
> But everything we are doing within managing this project and overseeing the costs, we are doing as prudently as we possibly can.[12] (emphasis added)
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> MR. BUONAGURO: Thank you. I will ask just one more question on that then, and it is the flip side, which is -- I understand what you are talking about in terms of when to create an incentive for the contractor to

[11] Ex. J3.1
[12] Technical Conference Tr. Vol. 1 pp. 164-165.

> perform better than what the contract anticipates, and give them an incentive to do it.
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> What is the incentive for OPG to beat its price? So let's -- if I say your price is $4.8 billion, for example, what's the incentive for OPG to the beat the price, particularly given the fact that you have said you can't contemplate any risks that you would have to bear and considering the fact that if that's true, any money that you spend on the program gets put into rate base and earns rate of return.
>
> So I am just wondering what is the incentive for OPG to actually beat its price?
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> MR. REINER: So as the -- we certainly see this as a destiny project for the company, and we deem success of the project to be execution within the 12.8 billion for the entire refurbishment, the 4.8 billion for -- 4.8 billion in service amounts for completion of unit 2.
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> *I would speculate that if we could not achieve that, that we would be involved in a regulatory process to have to justify the reasons behind the excess expenditures and go through some form of prudence review which, in all likelihood, is subject to a significant amount of risk.*
>
> *So there is every incentive for us to get this executed within the parameters that we have set forth here.*
>
> We also see -- you know, there were a lot of interrogatories and questions about off-ramps. There isn't a specific formula that has been derived to trigger an off-ramp, but if the cost of refurbishment ends up being significantly larger than what was anticipated in the long-term energy plan when the Province looked at all of the options available to meet Ontario's energy needs, there would be an option for our shareholder to make a different decision.
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> So that is another risk that we face as a company. If we do not -- if we do not have the Darlington asset in our asset base and in our operations base, that significantly reduces our revenues, significantly increases our costs, puts us on a completely different trajectory in terms of managing the business, so we have every incentive -- our goal is to grow the business. We have every incentive to execute this project on schedule and on budget.

In the Council's view it is clear that OPG is not, in fact, directly incented to "beat its price", and there is no explicit incentive built into OPG's proposal for OPG to find ways to bring Unit 2 into service under budget. OPG's primary incentive is to bring Unit 2 into service on (as opposed to under) budget for the express purpose of avoiding any *ex post facto* regulatory review of spending beyond an approved amount.

That being the context for this proceeding, the Council respectfully submits that it is appropriate for the Board to approve an amount for Unit 2 for the purpose of setting rates that will trigger a regulatory review of the actual expenditures at an appropriate level.

It is Appropriate for the Board to Review all Contingency Spending beyond the Approved "Base" Level of Spending

In the Council's view that appropriate level is a review of the spending for Unit 2 beyond the "base" amount of $4.1 billion, which, in short, means that any and all spending that would be considered part of the "contingency" amount would be subject to tracking in the CRVA and a prudence review by the Board prior to recovery by OPG.

The Council asserts that, having generally agreed that the $4.1 billion in spending that is included in the "base" amount is an appropriate level to approve in this proceeding as reflective of the cost of Unit 2 that is underpinned by OPG's extensive planning activity and contracts with 3rd parties, triggering a regulatory review prior to OPG being able to recover costs in excess of the "base" amount is appropriate, as that would allow the Board to properly review OPG's actual execution of its plans for bringing Unit 2 into service on budget and on time. In this way the Board can impose the maximum incentive on OPG to control its cost as closely to the approved "base" level as possible, and at the same time provide the maximum incentive on OPG to provide detailed explanations for any costs in excess of the base amount that it seeks to clear from the CRVA.

The Council respectfully submits that such a level of scrutiny is necessary in order to protect ratepayers from the inclusion of any costs that may properly be identified as having been imprudently incurred by OPG, since it appears that OPG is either incapable or unwilling to identifying imprudent spending on its own. When asked how OPG would self-identify costs that were imprudently incurred, OPG appears to be operating under the belief that such costs do not exist:

> MR. BUONAGURO: Thank you.
> I'll end by suggesting this, and then you can respond.
> It sounds to me that no matter what happens in the next fours years, any time a cost occurs, if I look back on OPG's recordkeeping with respect to those costs, it will appear like a cost that was prudent, because you're not -- it appears to me that you're not distinguishing between costs that were prudently planned for versus ones that you didn't. It sounds like it's all going to look the same.
> MR. KEIZER: Madam Chair, it is a point of argument, though, that it's not for -- I mean, I think the witness has already said that the objective is for OPG to manage this circumstances as best they can and take whatever actions they can, which may have certain cost consequences. But I think that ultimately the determination of what is prudent or not

prudent, if it reaches the point where we've exceeded the project cost, would be with you, with the Board.

MS. LONG: Can we take the word "prudent" out of this scenario, and can the witness answer: Is there any cost that you would not put forward to this Board to have recovered by ratepayers? So is there any scenario in which -- let's say OPG made a mistake or -- is there anything that you wouldn't put into that calculation to be recovered by ratepayers where you would say, "You know what? That's on us. We're not actually going to put that forward as a cost of this project"?

So forget what we're going to call it. Take prudent out of it. But I think that's where Mr. Buonaguro is trying to go. Is there any cost that won't be put forward as part of the project, because you deem that -- I'm going to say mistake, but whatever word.

I have an iPad that the ratepayers of Ontario pay for. If I take the subway home and I leave my iPad on the subway, that's on me. I can't go and ask the ratepayers to pay for that. That's a very simplistic example, but that's what I'm trying to get at. Is there anything that wouldn't be put forward as being an expense going toward this project because you decide you can't put it forward as a reasonable expense?

MR. REINER: I can't foresee that sort of thing even if I took your example on the iPad. People can make mistakes, and what we would do on the project -- it's how we, as management, respond to that. Do we turn a blind eye, or do we take a corrective action to deal with the issue so it doesn't repeat itself?

Everything we have built in our processes, it touches on corrective action, it touches on risk management, on oversight, on having external entities look in and advise us on things that they see that we might not be seeing. All of our processes are geared towards taking reasonable action to correct that event.

So, from our perspective, there isn't a set of costs that could occur where we would say, "No, that's not getting tracked somewhere else, and it's outside the project." It would all be a project cost. It would all get captured in our project costs and just, looking forward, provided that all of the right management actions were taken, our position would be those were prudently incurred costs. [13] (Emphasis added)

The Council understands OPG response to mean that, from its perspective, all costs its incurs are "project costs"; it is entirely up to the Board to distinguish between costs that are properly included for recovery as contingency amounts, and costs that were incurred imprudently and should be disallowed. In order to properly protect ratepayers from possibly imprudently incurred costs, the scope of any review by the Board to distinguish between prudently incurred contingency amounts and

[13] Tr., Vol. 4, pp. 111-114

imprudently incurred costs is the full amount of any costs beyond the "base" amount.

The Council notes that OEB Staff makes a similar argument, when it specifies the level of tracking with respect to the contingency amounts being claimed by OPG; the noted concern is that OPG should not be able to recover imprudent costs as a result of having included contingency amounts that did not manifest. The Council agrees, including agreement to the level of reporting proposed by Board Staff, but respectfully submits that in order to properly preserve the Board's ability to examine all of OPG's Unit 2 spending beyond the base amount it is most appropriate to exclude all "contingency" amounts from the spending approved in this proceeding. In this way the Board panel that reviews the final spending amounts by OPG on Unit 2 will have clear jurisdiction to approve or disallow all amounts beyond the base amounts.[14]

Periodic Reporting on the Progress of the DRP

The Council respectfully submits that, in order to ensure the Board has the appropriate level of information before it in any review of OPG's actual execution of the DRP, including specifically Unit 2, a substantial level of ongoing reporting will be required.

Schiff Harden was asked to provide a reporting template for OPG to use to Report to the Board on a periodic basis with respect to its progress on the DRP, that template having been provided at Exhibit J 7.1; the Council recommends that the Board establish reporting for the DRP in a manner consistent with this type of template, in order to provide the Board with an appropriate starting point for the review of DRP spending beyond the approved amounts. Beyond this type of template, and in addition to the level of specific reporting on project level contingency spending already recommended by OEB Staff as previously discussed, the Council would like to stress the importance of two specific types of evidence that the Board may require to be filed on a periodic basis to enhance its ability to assess contingency spending on the DRP, namely documents relating to the risk register and the corrective action program.

As explained in detail by OPG during the course of the proceeding, OPG will be tracking costs variations from the base cost amount in its risk register:

> MR. BUONAGURO: Thank you. But if we're talking about, then, events which cause costs which weren't predicted or forecast or somehow included in the risk register, they're not -- it sounds like they're not recorded in the risk register as an event. They might influence the risk

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[14] OEB Staff Argument, pp. 56-60, wherein OEB Staff recommends a detailed level of reporting on contingency level spending on a project by project basis.

register going forward in terms of making sure it doesn't happen again, but if it happens for the first time without it having been logged in the risk register or anticipated by the risk register, it sounds like it goes to the corrective action program. Is that right?

MR. ROSE: So if there's an issue -- so the corrective action program is -- it's a nuclear program that exists -- that existed in nuclear for quite some time. It's based on IMPO best practices that nuclear plants are self-critical of adverse conditions. They record those in a database, and they learn from them. Our organization would do the same.

However, when it comes to drawing of contingency, right, so to fund an event that has occurred, if there is a risk event that was -- that we already had that we need to draw contingency, that contingency -- and when we draw -- and I've talked about this previously that, every time we draw a contingency, we use a change control form that has different levels of authorization. Every one of those change control forms is evaluated against whether or not there was a risk in the risk register, how much contingency did we have for that, and what's the impact of that draw-down on that amount of contingency.

There are some CCF issues that we did not have a risk for that maybe we don't believe that there's ever a future risk for that that would have a CCF. So logging a device would be the change control forms of all events that ultimately drew down on contingency.

MR. BUONAGURO: So just -- I was sort of expecting something in there, and I'm looking to see if I just missed it or if it wasn't there or you didn't put it in.

I understand -- if something was not in the risk register and it happens and it causes costs and you need to fund those costs, how do you recover and track the costs? Does it then become a draw on the contingency? Is that part of your change control system?

MR. ROSE: Yes. So it starts off as a forecast item. So, from a cost management perspective, we may forecast that we have an issue that came up today. We believe it's going to cost me $10,000 on this project. It sits in the forecast. When that claim materializes and we firm that up and we are drawing from contingency, we may draw from a discrete risk or cost uncertainty, or we might need to draw from a general contingency and look for other risks that get retired to fund those risks.

So it's always a netting-out exercise on the overall, and, you know, we've talked about risk management as a series of events, some that will occur; some that won't occur. Through this planning process, we develop what we believe to be a reasonable contingency amount for the risk profile of this project.[15]

Additionally, OPG explained how it would react to its own imprudence:

[15] Tr. Vol. 4 pp. 106-108

MR. BUONAGURO: Thank you.

The question is this: Because we're talking about a program that's been going on several years already and projected to go, for unit 2 at least, another four years before it goes into service?

MR. ROSE: Planed in-service is 2020. So four more years, that's correct.

MR. BUONAGURO: What happens if the company does act imprudently in that time? Is there a specific reaction?

MR. REINER: The specific reaction is management of the work and the processes we have built in the management of the work; the oversights, the assurance that we have built in to catch any problems that might be tied to imprudent decision-making.

MR. BUONAGURO: Fair enough. That's essentially what I would expect to happen. But, again, more nuanced then that, does the company self-identify it as an imprudent action, or do you simply treat it as a risk that has manifested that you hadn't forecast, and you are simply reacting to it? Is there a distinction between the two things?

MR. REINER: So there isn't a category of things called imprudence that we would itemize somewhere and run some kind of a ledger on. When we are in execution, if things do not unfold as planned, as part of our normal project management process, if in an event occurs and it ties to an event that might push schedule, an event that doesn't allow for completion of a specific task in the way contemplated, a human performance event, an error made by someone, a safety event, we have processes inside OPG that have us record all such events, and it's done through something called our corrective action program.

It gets captured as part of the corrective action program. The corrective action program is an integral part of the nuclear management system that I think we referenced earlier in the hearing and is a key element to allowing us to effectively take actions recognizing that something may have happened -- taking corrective actions to ensure that it doesn't happen again. So there are processes that very quickly take those issues, document them, assign people to evaluate and investigate, and then take a corrective action to ensure that it doesn't get repeated.[16]

In the Council's respectful submission it is primarily through a review of this level of information, including the history of OPG's risk register and its corrective action program, that will allow the Board to adequately determine the success of OPG in properly executing the refurbishment of Unit 2 and appropriately containing the costs associated with that execution, and identify and disallow any instances of imprudent costs being incurred by OPG.

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[16] Tr. Vol. 4, pp 103-104

The Council would also specifically note that the risk register in particular is a "living document", in that it is difficult to recreate the details of the risk register in any particular point in time unless it is specifically produced periodically.[17] Accordingly, the Council respectfully submits, it is important that such documents are provided to the Board on a period basis, in order that the Board can be in a position to review the manifestation and handling of risks by OPG as it happened, rather then only in summary after the fact.

To be clear, the Council understands that it is very likely that there will be some material level of prudently incurred contingency related spending as part of the completion of Unit 2, and that on review that spending will be recoverable by OPG. The Council's concern is that it is also possible that there will be, in a project such as DRP, material levels of imprudent spending that should not be recoverable by OPG. In the Council's view it is important that a future Board panel be granted the clear mandate to review the entirety of the costs incurred by OPG beyond the base amount in order to review such spending to determine which of those costs are recoverable by OPG and which should be disallowed.

OPG is not harmed by the Council's Proposal

OPG confirmed that in terms of its proposed Unit 2 rate base additions over the course of the test period the entire assumed "contingency" amount of $694 million is assumed to go into service and become part of the requested revenue requirement in 2020.[18]

OPG further confirmed that the approximate revenue requirement of the contingency amount is $56M in 2020 and $67M in 2021.[19]

Based on the current application, OPG's proposal is to defer $488 million in revenue requirement in 2020 and $142 million in revenue requirement in 2021 as part of the operation of the Rate Smoothing Deferral Account (the "RSDA").[20]

OPG is already proposing to defer amounts well in excess of the impacts of the contingency spending. Accordingly it is not the case that the Council's proposal defers 2020 and 2021 revenue requirement amounts that OPG is otherwise seeking to collect in those years; OPG's proposal is to defer well in excess of those amounts. In fact, the effect of the Council's proposal could be to accelerate the recovery of the contingency related revenue requirement

[17] Tr. Vol. 4, pp 113-115
[18] Ex. L/4.3/5 CCC-018
[19] J8.3
[20] Ex. N3/T 1/ S1 Attachment 2/ Table 17

amounts for 2020 and 2021. This may be the case since instead of deferring the contingency related revenue requirement for 2020 and 2021 as part of the RSDA, which will not be disposed of until the completion of the entire DRP, the contingency related revenue requirement would be deferred through the CRVA, which is subject to disposition as soon as OPG applies for approval of the CRVA related spending.

The only financial impact of requiring OPG to recover the contingency related revenue requirement through the CRVA instead of the RSDA is the different interest rates that are applicable to each of those accounts, with the CRVA attracting the "normal" interest rates applicable to deferral and variance accounts, while the RSDA attracts a higher interest rate pursuant to Ontario Regulation 53/05.[21] The Council calculates the difference between the interest collected in the CRVA on this amounts (assuming that OPG actually incurs a full $694 million in contingency amounts and seeks to add that amount to rate base in 2020) as opposed to the RSDA is approximately $4.4 million to 2021, after which OPG would be at liberty to clear the CRVA amounts.

The Council respectfully submits that aside from the fact that the difference between the interest amounts collected is, for a company the size of OPG, well below their materiality threshold, the shortfall in the interest collected is outweighed by the fact that OPG can recover those amounts much more quickly then they can through the RSDA. Even if the Board were to consider that the difference in interest amounts that can be recovered material, the Board could order a higher interest rate on the actual contingency amounts included in the CRVA if it deemed it necessary.

B. Pickering Extended Operations:

The Pickering Nuclear Generating Station ("Pickering") consists of six operating reactors that were placed into service between 1971 and 1986. OPG had originally planned to operate all six units until 2020. OPG's current plan, as approved by Province of Ontario on January 11, 2016, is to operate all six units until 2022, at which point two units would be shut down and the remaining four units would operate until 2024[22] OPG's plan to continue the operation of the Pickering reactors is subject to approval by the Canadian Nuclear Safety Commission ("CNSC") which must be granted by August 2018 when Pickering's current operating licence expires.[23]

The estimated cost of the incremental work above normal operating costs (enabling costs) is $307 million over the 2016-2021 period. Of this amount, $290 million is

[21] Ex. L/9.1/5 CCC-039
[22] Ex. L/T6.5/Staff-114
[23] Ex. L/T6.5/Staff-117

expected to be spent over the 2017-2021 test year period. This will allow OPG to generate 62 additional TWh over the remaining life of the plant.[24] The overall operating costs to enable the Pickering Extended Operations is $4.9 billion.[25] This includes the enabling costs, the costs associated with restoration of ongoing OM&A costs and the normal operating costs for 2021 and beyond.

Through this application OPG is seeking approval of its proposed Nuclear revenue requirement which includes forecast OM&A expenditures to enable Pickering Extended Operations and normal operating expenditures at Pickering during the test year period. OPG is also seeking approval of the nuclear rate base which includes Pickering related in-service additions. The production forecast included in the application for which OPG is seeking approval includes outages related to Pickering and the production attributable to the 2021 Pickering Extended Operations.[26]

The primary rationale for the Pickering Extended Operations is to mitigate capacity uncertainties during the proposed refurbishments of the Darlington and Bruce Stations. It is OPG's position that the overall system economic value is positive because having Pickering available reduces the need to operate more expensive gas fired capacity and the costs associated with siting and building new additional gas fired generation. [27]

OPG conducted a number of assessments regarding the Pickering Extended Operations. On its own analysis OPG concluded that the estimated potential benefits associated with pursuing the extension is between $500 and $600 million. [28] In addition, the IESO conducted an independent analysis for the Ministry of Energy that concluded that the benefits to the Ontario electricity system of the Pickering Extended Operations would be between $300 million and $500 million. That analysis was undertaken in March 2015 and updated on October 2015. The IESO has not updated its assessment of the extended operations since October 2015.[29]

OPG is requesting approval of its plans for the Pickering Extended Operations on the basis that is provides a reliable and cost effective source of economic base load generation. OPG relies on the IESO study and the fact that the Province has approved OPG's plans.

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[24] Ex. F2/T2/S3/p. 2
[25] Ex. L/6.5/Staff-118
[26] Ex. L.6.5.CCC-32
[27] Ex. F2/T2/S3/p. 7
[28] Ex. F2/T2/S3
[29] Ex. L.6.5-ED.30

The Council submits that it would be premature at this point for the OEB to approve OPG's proposals for the Pickering Extended Operations based on the following factors:

- CNSC approval has not been granted and may not be expected until August 2018. Even if approval from the CNSC is granted, the exact nature of that approval is not yet known;

- The IESO Report on which OPG relies on to justify the extension is out of date and should be updated. Furthermore, the IESO Report did not definitely conclude that OPG should proceed. Rather it recommended "further exploration" of the proposals. OPG should also be required to update the analysis it undertook internally to assess the economics of the Pickering Extended Operations proposals;

- There is no Government of Ontario decision to approve the costs. Unlike the Darlington Reinforcement Project where need has been established through regulation, the Pickering Extended Operations is not the subject of a regulation or a Government directive;

- The new Ontario Long Term Energy Plan has not been issued and it is still unclear as to what the plan will entail or the role of Pickering within the context of that plan;

- The OEB does not have sufficient information that demonstrates the extension of Pickering from a cost perspective is reasonable. In fact the evidence points in the other direction – the net costs or consequences associated with pursuing Pickering Extended Operations could be significant.

CNSC Approval:

OPG does not have CNSC approval to extend the life of Pickering beyond 2020. That approval is not expected until later in 2018. It is not clear at this point the nature of that approval or whether it will be granted at all. Furthermore, the CNSC may impose conditions on the approvals (if granted) that could potentially alter OPG's proposals for extension and the project economics. OPG expects to produce 62 TWh at Pickering if the extension goes forward, but the IESO's evidence was that at a production level of 56 TWh the Pickering Extended Operations project becomes uneconomic.[30] OPG's own evidence indicates that CNSC approval may not be granted or may not be granted in the way OPG has proposed:

> OPG is confident that the CNSC will provide approval to continue to operate the Pickering Station past 2020, but realizes there could be regulatory conditions

[30] Tr. Vol. 12, p. 104

> attached to that approval. OPG would likely plan to meet any regulatory requirements set by the Commission except in the unlikely event that such conditions are unreasonably onerous in terms of cost or practicality. If conditions imposed were to cause OPG to revise its plans to operate Pickering, it would consult with its shareholder regarding any potential changes to the planned end of commercial operation date. [31]

In the absence of CNSC approval it is unclear as why this Board would approve the costs.

IESO Report:

The IESO's Report, which was last updated in October 2015 did include a definitive endorsement for the Pickering Extended Operations project. At best it concluded that it was an option worth continuing to explore.[32] In addition, the IESO concluded that there are significant "potential pitfalls" including risks and uncertainties relating to gas prices and the cost and reliability of Pickering. [33] As was the subject of extensive cross-examination at the hearing, one of the problems with the IESO analysis is that many of the assumptions used in the cost-benefit analysis are now outdated. This is also true with respect to the economic analysis undertaken by OPG. As several intervenors including Environmental Defense and the Green Energy Coalition have pointed out in detail, the economics of the Pickering Extended Operations could change significantly if the assumptions used were based on more current information. The areas where updates could significantly impact the project economics include:

- Replacement energy costs including natural gas;
- Replacement capacity costs;
- System demand including the impact of demand response;
- Pickering's forecast operating costs – Which OPG has admitted are 22% higher than the costs included in the IESO study; and[34]
- Pickering's production forecasts.

The Council submits that there is no downside in requiring OPG and the IESO to provide updates to their studies. In fact, the Council would argue that in the absence of those updates the OEB does not have the information required to approve the costs for Pickering Extended Operations and their inclusion in the test period payment amounts.

OEB Jurisdiction:

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[31] Ex. L/T6.5/Staff-117/ p. 2
[32] Ex. F2/T2/S3/Att, 1, p. 9
[33] Ex. F2/T2/S3/Att 1, pp. 2-3
[34] Tr. Vol. 13 pp. 136-141

In its January 11, 2016, announcement approving the continued operation of the Pickering Generating Station beyond 2020 and up to 2024, the Government of Ontario referred to protecting 4500 jobs in the Durham region, avoiding 8 million tonnes of greenhouse gas emissions and saving Ontario consumers up to $600 million.[35] Although these are potential positive outcomes for Ontario, the OEB cannot base its decision regarding Pickering Extended Operations on these factors alone.

In addition, Government endorsement is not binding on this Board. Unlike the DRP, with respect to which Ontario Re. 53/05 specifically requires the Board to assume need, the Board is not subject to any regulation regarding Pickering nor has it received any explicit directives from the Government. In fact the Deputy Minister of Energy, Mr. Serge Imbrogno has explicitly stated with respect to Pickering:

> We've given OPG the authority to go forward, to go through the OEB, and also to the CNSC for regulatory approvals, and then to return, closer to 2017, I believe for a final decision.[36]

From the Council's perspective the OEB must consider whether the costs associated with the Pickering Extended Operations should be included in the payment amounts. This should be based on whether the economics of the project make sense. OPG is relying on the economic analyses to justify the project and urging the Board to approve it on that basis. In addition, OPG is relying on the IESO's conclusion that there is a substantial benefit in having Pickering available at a time when the generation resources that supply the electricity system are going through unprecedented changes.[37] Having the necessary resources available is important, but the Council submits that based on an updated analysis there may be other viable alternatives available.

Long-Term Energy Plan:

The Ontario Government is currently putting together a new Long-term Energy Plan ("LTEP"). The last LTEP was released in 2013. It is not clear yet what role Pickering Extended Operations will play in the LTEP. The absence of information as to what will be included in the LTEP further adds to the argument that approving the Pickering Extended Operations may well be premature.

Costs vs. Benefits:

Although the 2015 IESO and OPG analyses pointed to benefits associated with the Pickering Extended Operations, it is possible that if the assumptions underlying

[35] Ex. L/T6.6/Staff-115
[36] Hansard, Legislative Assembly of Ontario, Oct. 26, 2016, E-10, Standing Committee on Estimates, p. E-162 (Exhibit J8.5, tab 19, p. 70).
[37] AIC, p. 91

those analyses are changed pursuing the extension could result in net costs for customers. Several intervenors have presented analysis to support this.

When asked in the hearing at what point would the "dis-benefits" cause OPG to consider the project not viable, Mr. Blazanin on behalf of OPG stated:

> I cannot put a number on it because, again the dis-benefit can swing over a period of time. You are talking about a significant asset that provides between 10 and 14 percent of the baseload generation, employs a significant number of employees, significantly contributes to the economy in the province. There's a lot of issues and factors that go into the decision-making process, so I couldn't put a value on whether minus 100 ($100 million) was the point or otherwise or if there's something else that would affect the decision making process by the Minister.[38]

It appears that the decision to go ahead will not necessarily be based on the economics, but rather to obtain provincial benefits regardless of the project economics. The Council would argue that the OEB has an obligation to assess what costs should be included in the payment amounts, and that this assessment should be based on a robust cost-benefit analysis.

Conclusion:

The Council is not saying at this time that OPG should not proceed with Pickering Extended Operations under any circumstances. The evidence in the proceeding has demonstrated, however, that it would be premature for the OEB to approve the costs at this time. CNSC approval has not been granted and the nature of that approval even if it was granted is not clear. The LTEP has not been released and the role of the Pickering Extended Operations within the context of the LTEP is not known. More critical, however, is the fact that the economic analyses upon which OPG relies to justify the project are out of date. The economics are clearly not what they were in 2015. Changes in many of the assumptions are enough to justify a fresh look at the project economics.

The Council submits that OPG and the IESO should be required to undertake updated economic studies regarding the Pickering Extended Operations project. One possibility is to review these studies at the time of the mid-term review. A review at that time would also allow the Board to fully assess these analyses and consider whether CNSC approval was obtained and any conditions associated with that approval.

Operating Costs:

- Benchmarking

[38] Tr. Vol. 15 pp. 90-91

The Council has reviewed the submissions of OEB Staff, Energy Probe and SEC. They have all demonstrated that OPG's nuclear benchmarking results are poor and they presented credible arguments that these results should be taken into consideration by the OEB when considering the application of the stretch factor and reductions the overall O&M costs. The Council agrees that OPG's benchmarking results should be considered by the Board when determining the overall costs to be recovered by the ratepayers.

- Corporate Costs

Support Services Costs or "Corporate Costs" include Business and Administrative Services, Finance, People and Culture, Commercial Operations and the Environment and Corporate Services Costs.[39] OPG uses an approved allocation methodology to allocate these costs between the nuclear and hydroelectric businesses.

On the last payment amounts decision the OEB directed OPG to undertake an independent benchmarking study of these costs. Not all of these costs were benchmarked, but the benchmarking analysis focused on Information Technology, Human Resources, Finance and Executive and Corporate Services.[40] The benchmarking analysis demonstrated that except with respect to IT costs OPG's costs are below the benchmark.

With respect to these costs OPG's budgets are typically more than what was actually spent. In fact, in 2016 the budget amount was $442 million and the actual amount was $426.2 million.[41] On this basis the Council submits that the starting point for 2017 which is $448.9 million is too high. The Council submits that OPG's Corporate Costs for 2017 should represent no more than an inflationary increase over the 2016 actual levels and the levels beyond 2017 subject to the same level of adjustments.

- Compensation

OPG's compensation costs have been contentious since the OEB first started regulating OPG. In each of the previous payment amount proceeding decisions the OEB has made significant reductions to OPG's compensation levels. From the Council's perspective these reductions have been justified as they have been based on sound evidence, and in large measure the compensation benchmarking studies undertaken by OPG.

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[39] Ex. F3/T1/S1

[40] Ex. F3/T1/S1/Attachment 1

[41] Ex. J 14.2

In this proceeding OPG's compensation levels have improved relative to previous proceedings, but they continue to remain higher than other comparators. The Council has reviewed SEC's non-confidential submissions on compensation and is of the view that SEC has presented a valid argument as to why OPG's compensation costs should be reduced. In particular SEC has presented a number of arguments regarding OPG's pension and benefits costs and why these costs continue to be unreasonable. OEB Staff has also presented a comprehensive analysis regarding OPG's pension and benefits costs. The Council urges the Board to consider those detailed submissions in order to arrive at an allowed budget for OPG's compensation costs. There is no doubt that OPG's overall compensation costs remain unreasonably high and should be reduced.

2. COST OF CAPITAL:

<u>Capital Structure and Return on Equity:</u>

Capital Structure:

OPG has applied to increase its current level of equity thickness with respect to the nuclear facilities to 49% from the current level of 45%. The deemed capital structure would include 49% equity and 51% debt. OPG's request is based on its position that there is a material increase in OPG's business and financial risks since the last payments amounts decision. [42]

In the EB-2013-0321 Decision the Board rejected OPG's request for a 47% equity level. The Board's decision in that case was based on its view that OPG's overall business risk had declined since the previous case and that a 45% equity level was more appropriate. The Board based its decision on the fact OPG has added 48 hydroelectric facilities to its regulated business and had completed the Niagara Tunnel Project.[43]

OPG is not changing the capital structure embedded in base payment amounts with respect to the hydroelectric facilities. Instead, OPG is capturing the impact of a change through its proposed Hydroelectric Capital Structure Variance Account. This account would be used to record the revenue requirement difference between the capital structure embedded in the current payment amounts (45:55 equity/debt) and the capital structure approved by the OEB in this proceeding. OPG's position is that this account is necessary to apply OPG's regulated operations-wide capital structure to the nuclear and regulated hydroelectric businesses consistently during the IRM term.[44] The ultimate effect of having this account is that OPG will be

[42] AIC, p. 18
[43] EB-2013-0321 Decision with Reasons, p. 113
[44] AIC, p. 18

updating the capital structure for the hydroelectric business relative to the capital structure embedded in base rates.

OPG relied on the expert evidence provided by Concentric Energy Advisors ("Concentric"). Concentric recommended that OPG's deemed common equity should be at a minimum set at 49%.

> Concentric concludes that OPG's overall risk level will increase over the period 2017-2021 from its level as of EB-2013-0321, driven by business risks related to the DRP, pursuit of extended Pickering operations, increasing risks associated with degradation of aging nuclear station components, the implementation of incentive regulation, and changes in the Company's regulatory treatment, among other factors. Increased financial risks, including those arising from OPG's rate-setting proposal for its prescribed nuclear facilities and risks related to future recovery of Pension and OPEB accrual costs will negatively affect the Company's credit metrics, leading to additional financial risks relative to prior risk levels. Concentric's opinion is that an appropriate equity ratio for the Company exceeds the currently deemed ratio of 45% previously set by the Board prior to the EB-2013-0321 rate proceeding.[45]

Concentric also relied on a comparison of a proxy group of U.S. companies is support of it recommendation to increase the equity thickness of OPG.

OEB Staff engaged the Brattle Group to prepare expert evidence regarding capital structure. The Brattle Group undertook a similar analysis to what Concentric did and recommended an equity ratio of 48%. Their analysis was based on a view that OPG's risk has increased materially since the last proceeding. The Brattle Group's view of risk was based on the following:

- OPG's prescribed facilities have minimal supply and competition risk and no price risk;

- Nuclear generation and large capital expenditures increase the operating and execution risks of a company. OPG's operating risk has increased relative to when the EB-2013-0321 decision was released;

- Switching from cost of service regulation to incentive regulation will increase the variability around a regulated entity's income over the short-term to interim horizon. However, the is exposure is likely to be reduced over time as the hydroelectric portion of the rate base will become smaller and as the details of the incentive regulation and its implementation are known;

- The regulatory risk related to the methodology to recover pension and OPEB costs is minimal;

[45] Ex. C/T1/S1/p. 29

- OPG faces some credit metric, construction and execution risk during the DRP period, but some of these risks are mitigated by the currently very strong balance sheet of OPG as well as the provincial government's explicit commitment to the refurbishment.[46]

The Brattle Group also undertook a peer group analysis using only eight companies in its peer group analysis. Both Concentric and the Brattle Group ignored the fact that traditionally there is a marked difference between the equity levels for U.S. and Canadian utilities. Neither expert made any adjustment to reflect this fact and that this results from very different regulatory and market environments.

Submissions

The Council submits that neither expert presented evidence to justify moving off the allowed 45% level of equity thickness for OPG. The Council believes there is strong evidence on the record to support maintaining the 45% level.

At a high level the Council has a number of key concerns about OPG's request for a higher level of equity. One of the key reasons that both experts concluded that an increase in the level of equity is required is the DRP. In addition, they pointed to the fact that the nuclear asset mix overall is increasing. The DRP has been endorsed by the Province, and the CRVA established to deal with cost overruns and delays. The OEB has no role in determining need and must ultimately approve the recovery of all prudent costs through the payment amounts. The Province is telling OPG to proceed with Darlington and has left that decision out of the hands of the OEB. OPG is effectively saying, if we proceed with Darlington we need extra money from ratepayers (through an increased equity level) to compensate our shareholders for the increased risk associated with the project. From a ratepayer perspective this is clearly not fair. Ratepayers bear the execution risks, which involves the risk of cost overruns and delays to the extent they are prudent. The shareholders, and ultimately the taxpayers bear the risk of imprudent costs. To ask the ratepayers now to pay more in payment amount for risks that they will bear makes no sense. It clearly amounts to a form of double counting.

The Council also questions the extent to which the "Stand-alone" principle should be relied on in this case. Concentric has presented their analysis based on the stand-alone principle effectively claiming that Provincial ownership should not be a factor in determining the appropriate level of equity. [47] Clearly OPG is not operating at arms' length today. The very existence of O. Reg. 53/05, and the underlying requirement contained therein makes it difficult to accept that the stand-alone principle still applies to OPG despite the Board's acceptance of it in the EB-2007-

[46] Ex. M3, pp. 3-5 and pp. 43-45
[47] Ex. C1/T1/S1/Att. 1/p. 8/73

0905 proceeding (upon which Concentric relies). The Province also mandates a number of deferral and variance accounts for OPG as well, which provides OPG with enhanced levels of cost protection. The Brattle Group's witness acknowledged that the Province was not an arms' length shareholder of OPG.[48] In making its determination of the appropriate level of equity for OPG the Board cannot and should not ignore the fact that the Province provides ongoing financial support to OPG in a whole number of ways. Even OEB Staff referred to the "exceptional regulatory protection" OPG enjoys in respect of the DRP.[49]

With respect to the analysis provided by Concentric and the Brattle Group the Council does not accept that their conclusions are valid reasons to increase the OPG's equity thickness:

1. Both experts concluded that increasing the mix of nuclear assets within OPG constituted a higher level of business risk. Neither could provide any empirical studies to support this conclusion. [50]

2. Both experts concluded that moving to IRM for both the nuclear and hydroelectric businesses entailed a risk, but that the risk was not material. In addition, the OEB rejected this factor in the last proceeding:

   > OPG raised other arguments with respect to the need for at the same, or higher equity thickness. One of these arguments was that there is greater risk associated with the future move to incentive regulation. The Board does not accept that moving to incentive regulation significantly increases risk to the entity such that the capital structure should be reset, and has not done so for any of the other entities that it regulates. For example, the Board set the capital structure for all electricity distributors at 40% equity to debt ratio in December 2006. As new incentive regulation models for electricity distributors evolved in 2008 and 2012, this capital structure was not revisited. Similarly, the capital structure for the natural gas distributors did not change as a result of moving to a long-term incentive regulatory mechanism for the setting of rates for these distributors.[51]

3. Both experts took the position that without higher equity levels OPG's credit metrics could be negatively impacted.[52] Neither provided evidence that this would occur;

4. Both experts relied on comparator proxy groups but failed to factor in the marked differences between the equity levels between U.S. and Canadian utilities.[53]

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[48] Tr. Vol. 19, p. 66
[49] OEB Staff Submission, p. 6
[50] Tr. Vol. 18, p. 146, r. Vol. 19, p. 105
[51] Decision, EB-2013-0321, p. 114
[52] AIC, pp. 19-20

Overall, it is clear from the Council's perspective that no change in OPG's equity level is warranted. The expert recommendations, in our view did not hold up through cross-examination. The Council acknowledges that with the implementation of the DRP risk has increased. As the project is executed there remains a risk of cost overruns schedule delays. However, to the extent these overruns are prudent it is the ratepayers, not the shareholders that will pay for the overrun. The CRVA guarantees it.

Return on Equity:

OPG's has proposed a return on equity of 8.78% for its nuclear facilities. This is consistent with the Cost of Capital parameters published on October 27, 2016. OPG's proposal for the test period is to record the revenue requirement impact of the difference between the forecast ROE approved for 2018 to 2021 and the actual ROE set annually by the OEB into the proposed Nuclear ROE Variance Account.

OPG does not propose to update the ROE for the regulated hydroelectric business for the 2017-2018 period because the payment amounts will be set using the proposed price cap incentive regulation adjustment.[54]

The Council does not support OPG's proposal to establish the Nuclear ROE Variance Account. The effect of having this account is to update the ROE each year by capturing the difference between the ROE embedded in the payment amounts and the annual OEB approved ROE level. In its Handbook for Utility Rate Applications the Board stated:

> After the rates are set as part of the Custom IR application, the OEB expects there to be no further rate applications for annual updates within the five year term, unless there are exceptional circumstances with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate updates for the cost of capital, working capital allowance or sales volumes. [55]

OPG has not provided a rationale as to why ROE is "exceptional" and should be adjusted each year. The proposal is inconsistent with current Board policy and should not be approved.

3. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES:

Summary of OPG's Request Compared to The Council's Proposal

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[53] OEB Staff Submission, p. 9-10
[54] Ex. A1/T3/2
[55] Handbook to Utility Rate Applications, October 13, 2016, p. 26

OPG proposes to recover, over the test period, a total of approximately $1.503 Billion in its payment amounts in relation to Nuclear Liabilities.[56]

The Council respectfully submits that the appropriate amount to include in payment amounts for Nuclear Liabilities over the test period is approximately $1.0801 Billion.[57]

The result of the Council's proposal is a reduction in the test period revenue requirement of approximately $423.3 Million.

The Regulatory Requirement to include Nuclear Liability recovery in Payment Amounts

Ontario Regulation 53/05 requires that:

> The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.[58]

OPG's "nuclear decommissioning liability" is defined by Ontario Regulation 53/05 as:

> . . .the liability of Ontario Power Generation Inc. for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel . . .[59]

In determining payment amounts, including the payment amounts that allow OPG to recover the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan, the Board's discretion is set out by Ontario Regulation 53/05:

> . . .the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act.[60]

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[56] Ex. J21.1, Chart 1, line 11. Note that this is the total claimed amount including credit amounts that OPG currently proposes to collect in the Nuclear Liability Deferral Account.
[57] Ex. J20.8, Chart 1, line 6 + line 14
[58] Ontario Regulation 53/05, section .1 (1)
[59] Ontario Regulation 53/05, section 6 (2) 8
[60] Ontario Regulation 53/05, section 6 (1).

The issue before the Board is what properly constitutes the "revenue requirement impact" of OPG's "nuclear decommissioning liability arising from the current approved reference plan" that should be, over the test period, included in payment amounts.

In the EB-2007-0905 Decision the Board, for the first time, considered the " revenue requirement impact" of OPG's "nuclear decommissioning liability arising from the current approved reference plan" and developed a methodology for calculating an amount to be included in OPG's payment amounts.

In filing supplementary information with respect to its Nuclear Liabilities OPG filed information setting out the historical recovery from ratepayers based on the methodology established in EB-2007-0905 (the "prevailing methodology") and compared that recovery to the costs that OPG actually incurred over that same time period, concluding that in aggregate that OPG had under-recovered in rates relative to its actual costs.

Ex C2/1/ 2, Chart 3, OPG asserted, shows that it had under-recovered the costs of its Nuclear Liabilities from ratepayers by a total of $282.1 Million. The implication in that evidence is that it would be unfair to change the methodology going forward from 2017 onward to account directly for OPG's actual annual Nuclear Liability related costs, as the use of the prevailing methodology had, as of 2016, left OPG in the position of having under-recovered its revenue requirement in relation to Nuclear Liabilities.

The Council submits that it is revealing that OPG makes the comparison between the prevailing methodology and what OPG itself considers its actual costs of Nuclear Liabilities, those costs consisting of:

> . . . amounts expended by OPG on nuclear liabilities in the form of fund contributions and internally funded expenditures.[61]

The implication, with which the Council agrees, is that in any particular year OPG's revenue requirement with respect to Nuclear Liabilities is the amount it has to a) contribute to the both the Used Fuel and Decommissioning Segregated Funds pursuant to the ONFA, plus b) the internally funded expenditures OPG has to make in connection with nuclear liabilities in any particular year.

It would seem obvious, the Council respectfully submits, that in any particular year OPG is held whole if it recovers through payment amounts that year's contributions to the Used Fuel and Decommissioning Segregated Funds and its internally funded expenditures.

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[61] Ex. C2/ T1/S 2/ p. 23

The issue raised by OPG in defense of not simply including its contribution amounts and internally funded expenditures (OPG's "actual expenditures") is that the historical recovery in payment amounts under the prevailing methodology falls short of holding OPG whole, resulting in what OPG refers to as "transition implications" if the Board were to, going forward, consider a new methodology.[62]

For the following reasons the Council does not agree that there are any "transition implications" that need to be addressed in the event the Board agrees with the Council that, for the test period, the cost of OPG's Nuclear Liabilities is adequately included in payment amounts if determined on the basis of its forecast contributions to the Used Fuel and Decommissioning Segregated Funds plus its forecast of internally funded expenditures.

There are no transition issues for OPG with respect to the period during which its payments have been regulated by the Board

As noted, OPG presents Ex. C2/ T1/ S/2, Chart 3 as evidence that it has under-recovered the costs of its Nuclear Liabilities from ratepayers by a total of $282.1 million. The clear implication is that the forecast over-recovery in the test period is reasonable, as it is offset by the historical under-recovery.

In the Council's submission OPG's analysis is materially and demonstrably flawed in two specific ways.

First, OPG's analysis includes a net under-recovery of Nuclear Liability costs in the amount of $106.6 Million related to the failure by OPG to meet its forecast production forecast over the historical period.[63] The Council respectfully submits that this is an inappropriate adjustment to make, as it does not relate to the different impacts of different methodologies for determining the revenue requirement related to Nuclear Liabilities, but instead relates solely to OPG's ability to accurately forecast its nuclear production, coupled with the fact that OPG takes on production risk in its payment structure. Accordingly, the Council submits, any under or over-recovery based on OPG's production variances is an irrelevant consideration when comparing the amounts included in OPG's revenue requirement for Nuclear Liabilities against the amounts OPG actually expends with respect to Nuclear Liabilities.

Second, and more importantly, OPG's analysis at Ex. C2/T1/S/2 was performed on a pre-tax basis. As demonstrated in Ex. J20.7 Chart 3, including the after tax impacts of the prevailing methodology in comparison to the after tax amount of OPG's actual

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[62] Ex. C2/T1/S2/p. 27
[63] Ex. C2/T1/S/ 2, p. 24, Chart 3, line 2.

expenditures reveals that over the historical, regulated period, OPG has in fact over-collected from ratepayers by $108.5 million.[64]

Accordingly, instead of demonstrating that it has under-collected Nuclear Liability related costs from ratepayers over the historical period, OPG's updated analysis shows that it has in fact over-collected from ratepayers in relation to its Nuclear Liability related costs. As a result, the Council respectfully submits, the Board should not be concerned about any "unfairness" to OPG when considering changing the methodology for including the cost of Nuclear Liabilities in payment amounts going forward, as OPG is in the position of having benefited from excess recovery from the prevailing methodology over the period of time that the Board has been charged with the task of setting OPG's payment amounts.

There are no transition issues for OPG with respect to the period prior to regulation by the Board

At Ex. C2/ T1/S2 p. 25 OPG provides a comparison of "proxy amounts" in an attempt to demonstrate that, prior to regulation by the Board, the interim rates set by the Province, assuming that those rates included an amount for nuclear liabilities in accordance with the prevailing methodology, resulted in an apparent under-recovery in rates of approximately $1 Billion. The implication is that the Board should not be concerned with the proposed over-recovery during the test period, because that over-recovery will fail to result in a net over-recovery from ratepayers in respect of Nuclear Liabilities when one considers a recovery period from April 1, 2005 (the date the Province set interim rates) to December 31, 2021.

With respect, the Council does not agree that OPG's analysis is correct, and asserts that in any event it is irrelevant.

OPG's analysis of the Nuclear Liabilities amount "implicitly" included in interim rates is based on the assumption that interim rates were predicated on the inclusion of those costs using the methodology created by the Board in the EB-2007-0905 proceeding. The obvious problem is that Nuclear Liabilities were not included in rates in the period prior to regulation by this Board using the prevailing methodology; interim rates were set by the Province (the owner of OPG) before the Board was ever tasked with setting rates or specifically providing for the recovery of Nuclear Liabilities in rates.

The flaw in OPG's position with respect to the period before regulation by the Board is highlighted when one considers that it was open to the Board, in the EB-2007-

[64] Ex. J20.7 Chart 3, line 26. The Council notes that this over-includes an over-recovery amount due to production variance at line 3 of the Chart of $31 Million, such that removing that variance reduces (but does not eliminate) the net over-recovery over the period.

0905 proceeding, to pass through the actual expenditures of OPG in the test years that were then in issue as the appropriate methodology. Had that happened, not only would have the nuclear liability amounts included in payment amounts matched OPG's actual expenditures from 2008 to 2016 (assuming no changes to the methodology from 2008 to the present), but extending that methodology back to the period prior to 2008 to create "proxy amounts" in the same way that OPG purports to do in its evidence would result in the elimination of the apparent $1 Billion shortfall. The presumption in determining the "proxy amount" would be that interim rates were set inclusive of the cost of OPG's contributions to the Used Fuel and Decommissioning Segregated Funds pursuant to its obligations under the ONFA, coupled with the cost of its annual, internally funded expenses related to obligations that were not to be dealt with by the Funds.

In any event, the Council respectfully submits, consideration of the period prior to the regulation of payment amounts by the Board in 2008 is irrelevant. Prior to regulation by the Board OPG, through the act of its shareholder the Province of Ontario, set payment amounts at its leisure. It is not for this Board, the Council respectfully suggests, to attempt to a) evaluate whether there was any under or over-recovery in the payment amounts that were set by the Province prior to regulation, and b) retroactively correct any such under or over-recovery in rates during the period which the Board is charged with the task of setting rates.

In the Council's respectful submission the Board, beginning in 2008, was faced with regulating the annual revenue requirement for a power generator whose annual Nuclear Liability costs comprised of two specific items, annual contributions to Used Fuel and Decommissioning Segregated Funds pursuant to obligations under the ONFA, coupled with annual, internally funded expenses related to obligations that were not to be dealt with by those Funds. In The Council's view, so long as those two obligations are appropriately funded, any excess funding is not, in fact, related to Nuclear Liabilities, and should not be included in rates.

The Impact of passing through OPG's Actual Expenditures during the Test Period

The Council respectfully submits that including only the actual expenditures experienced by OPG with respect to nuclear liabilities during the forecast period will result in significant savings for ratepayers.

The total net revenue requirement sought for recovery by OPG over the test period in accordance with the prevailing methodology is $1.5034 Billion.[65]

[65] Ex. J21.1, Chart 1, line 11. Note that this is the total claimed amount including credit amounts that OPG currently proposes to collect in the Nuclear Liability Deferral Account.

By comparison, the total forecast cost of Nuclear Liabilities to OPG over the test period, assuming that the Board continues to use the prevailing methodology, is only $1.1859 billion, such that OPG will recover from rates, after taxes, $317.5 million more then it will actually spend on Nuclear Liabilities.[66]

Note that this comparison shows the difference between what OPG will recover in rates and what OPG will actually pay assuming that rates are set pursuant to the prevailing methodology. If, instead, rates were set to recover only those costs OPG will actually incur during the test period, the forecast amount that OPG will pay goes down even further as a result of a reduction in tax liability.

More specifically, of the $1.1859 billion that OPG forecasts that it would actually pay during the test period if the Board were to approve the prevailing methodology, $105.8 million of that amount is related to income taxes that OPG only has to pay as a result of the prevailing methodology, because:

a) the inclusion of costs on the basis of the prevailing methodology produces revenue without a offsetting tax deductible expense, and

b) the actual, tax deductible expenses of OPG over the period, consisting of contributions to the Decommissioning Fund and the Used Fuel Fund pursuant to the ONFA combined with in period internally funded expenses, are lower then the amount included in rates as a result of the prevailing methodology,

with the gap between the revenue collected and OPG's actual expenses becoming subject to income tax.

This highlights a particular flaw in the prevailing methodology, in that when OPG's actual costs are lower then the amounts produced by the prevailing methodology, the result is tax liability in relation to the excess amount. Put more bluntly, the prevailing methodology results in the absurd result that the less OPG actually has to pay toward Nuclear Liabilities in a year, the more the payment amount is increased to account for tax liability. This is a flaw that is eliminated under the Council's proposal.

Were the Board to instead only include in the revenue requirement the actual forecast costs to OPG during the test period, the amount that OPG would pay on a forecast basis over the test period is reduced to $1.0801 Billion.[67] This represents a $423.3 Million difference between the amount sought by OPG over the test period and the costs OPG will actually incur during the test period.

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[66] Ex. J20.7, Chart 1, line 10 + line 20.
[67] Ex. J20.8, Chart 1, line 6 + line 14.

The Council respectfully submits that it would be appropriate for the Board to transition from the prevailing methodology to a methodology that passes through the actual costs to OPG for Nuclear Liabilities in the test period, with the resulting reduction in the Nuclear Liabilities amount embedded in the approved revenue requirement of $423.3M in aggregate over the test period, subject to the operation of the Nuclear Liability Deferral Account.

Volatility is not a material concern

OPG raises the specter of potential volatility if the Board were to transition to a methodology based on its actual expenditures, particular with respect to changes in the required contribution amounts:

> The current fully funded status of the segregated funds is not indicative of future funding requirements based on subsequent ONFA reference plans and, as shown in Charts 3 and 4, historically there have been differences, in both directions, between amounts recovered and amounts expended. The direction of such differences in the future will depend on inherent variability in market performance and economic conditions, and the evolving nature of cost estimates and planning assumptions. Potentially significant future changes in either the market value of fund assets or funding obligations are possible.[68]

The Council respectfully disagrees that volatility is material concern in the current regulatory context.

In the Council's view volatility should, in fact, be significantly reduced under the proposed new methodology, as the difference between what OPG pays in a year and what it collects from rates will be matched such that there is less likely to be any significant over or under-recovery in any particular year, unlike what has been experienced in the historical period as a result of the prevailing methodology.

Further, so long as OPG remains on a 5 year ratemaking cycle (which, in accordance with the current regulations, is assured for the next decade) and that cycle matches the 5 year cycle for ONFA updates, the amount embedded in rates for contributions, (the primary source of any material volatility), and the amount of the actual contributions will match. Even if the contribution schedule is changed as a result of an ONFA update, the Nuclear Liabilities Deferral Account will capture the difference, as it would capture any other difference attributable to an update to the ONFA Agreement, and the Board can manage the impact of any such captured amounts by recovering those deferred amounts over time as required.

4. DEFERRAL AND VARIANCE ACCOUNTS:

[68] Ex. C2/ T1/ S2/p. 26.

OPG is seeking approval of the Nuclear ROE Variance Account and the Hydroelectric Capital Structure Variance Account. In other sections of this argument the Council has set out why approval of these two accounts should be denied by the Board. (Section 2 and Section 5)

5. REPORTING AND RECORD KEEPING REQUIREMENTS:

In our submissions regarding the DRP the Council has advocated for ongoing reporting with respect the DRP. Specifically, the Council supports the recommendations by Mr. Roberts of Schiff Hardin set out in Exhibit J7.1. This will ensure than there is an adequate level of transparency with respect to the progress of the DRP for all stakeholders. OPG's proposed approach to report annually on a number of metrics and its monthly public reporting is not sufficient to allow for a meaningful assessment the DRP.

6. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS:

A. HYDROELECTRIC

OPG is proposing a price cap index rate-setting methodology for its regulated hydroelectric assets. Its approach was modeled on the OEB's 4th Generation IRM ("4th GIRM"), one of the options set out in the Renewed Regulatory Framework for Electricity ("RRFE"). The basis for choosing this approach rather than a customer approach is that with the completion of the Niagara Tunnel Project OPG's regulated hydroelectric facilities are in a relatively stable, steady state that is conceptually consistent with a price cap form of IR.[69]

The key elements of the proposed rate plan are as follows:

- A five year term;
- A price cap formula that applies to both OM&A and Capital of I-X;
- An inflation factor that is more heavily weighted towards capital to reflect the cost structure of the hydroelectric industry (more capital intensive than distribution);
- A productivity factor of 0%;
- A stretch factor of .3%;

[69] Ex. A1/T3/S2

- A Z-factor for "unforeseen events" with a company-wide materiality threshold of $10 million;

- Existing deferral and variance accounts to be continued;

- A new Hydroelectric Capital Structure Variance Account ("HCSVA")to effectively capture the impact of the Board's decision in this case regarding any changes to the capital structure;

- An off-ramp that would trigger an OEB review if annual reporting showed performance +/- 300 basis points relative to the Board approved ROE;

- Base rates are used as the starting point with an adjustment made to reflect a one-time allocation of nuclear tax losses; and

- The ROE, as established through base rates will not be adjusted on an annual basis.

The plan differs from the Board 4th GIRM model in the following ways:

- The inflation factor is generation industry weighted;

- The proposed stretch factor is based on the company's hydroelectric benchmarking performance undertaken by Navigant Energy Consulting Inc. ("Navigant"), but in the range of that applied to electricity distributor;

- The proposal for the HCSVA essentially captures the impact of a new capital structure depending upon the Board's decision in this case;

- The formula is applied to the Gross Revenue Charge ("GRC") a portion of the revenue requirement that are not subject to inflation; and

- The Capacity Refurbishment Variance Account ("CRVA") established through regulation applies to both the nuclear and hydroelectric generation assets.

The Council has submissions to make on the following element of OPG's rate-setting methodology for the prescribed hydroelectric assets:

1. Inflation
2. The Gross Revenue Charge
3. Productivity factor
4. Stretch Factor
5. Capital Structure Variance Account
6. Z-factor
7. CRVA

Inflation:

OPG has proposed an inflation factor ("I-factor) that is in large measure consistent with the OEB-approved composite index used to adjust electric distribution rates. The rate would be updated on an annual basis and the new value used in the annual price cap formula.

For capital and non-labour OM&A costs the sub-index is the Canadian Gross Domestic Product Implicit Price Index – Final Domestic Demand. For labour costs the index is the Average Weekly Earnings for Ontario – Industrial Aggregate. The only difference is that OPG's approach has a different weighting to reflect the fact that generation companies are more capital intensive than distribution companies.[70]

London Economics Inc. ("LEI") has proposed a 1.8% value for 2017 based on the sub index values for 2015 available as of March 21, 2016.[71] OEB Staff took issue with LEI's calculations and disagreed with the approach in two respects. LEI used the arithmetic formula function instead of the natural logarithmic to calculate annual growth rates. In addition, they rounded intermediate calculations as opposed to rounding final numbers only. It is the view of OEB Staff that OPG's approach is not consistent with the RRFE.[72] If the approved RRFE method of deriving the I-factor is used the result is 1.7%.[73] The Council supports the approach suggested by OEB Staff.

Gross Revenue Charge:

OPG is required to pay gross revenue charges ("GRCs") to the Province of Ontario for property taxes and water rentals associated with their hydroelectric facilities. It also includes water rental charges and other water agreement costs payable to other governments, agencies or companies. In addition, they include costs associated with funding the Ottawa River Regulation Planning Board and the Lake of the Woods Control Board as required by legislative agreements.[74] The amount included in 2015 base rates is $347.1.

The GRC amounts are subject to agreements OPG has with the Province and the other entities and are based on production. The GRC amounts are not subject to inflation.

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[70] Ex. A/T3/S2/p. 13
[71] Ex. A/T3/S2/p. 14
[72] OEB Staff Submission, pp. 150-151
[73] Ex. K9.1
[74] EB-2013-0321/Ex. F1/T4/S1

OPG has proposed that the EB-2013-0321 rates be the "going in" rates only adjusted for the one-time tax loss. The GRC amounts are included in those rates and accordingly would be subject to the price cap elements including inflation. In addition, the inflation factor derived by LEI assuming the GDP IPI FDD should apply to the GRC amounts.

OEB Staff has proposed that I-factor be adjusted to reflect the fact that the GRC is not subject to inflation. OEB Staff 's proposal is to use a 12.5% weighting factor. This would reduce the I-factor to 1.5%.

The Council agrees that some adjustment should be made to reflect the fact that the GRC is not subject to inflationary increases. One way of doing this would be to change the formula by applying a 0% rate to 25% of the overall index. Another option would be to remove the GRC amounts from base rates before the formula is applied. That way the GRC amounts would not be subject to an inflationary adjustment, nor would they be subject to an X-factor (productivity and stretch) adjustment. This latter option would be analogous to the Y-factor treatment currently in place for the natural gas and electric utilities regarding specific cost elements of their revenue requirement - remove the amounts before applying the formula and add them back in when deriving the new rates. These are legislated obligations that OPG cannot do anything about, so they should be recoverable, but should not be subject to the annual adjustment mechanism. The natural gas utilities use this flow-through approach to incorporate pre-approved demand side management budgets into their annual rate adjustments as well as to pass-through gas commodity costs.

The Council notes that in the EB-2013-0231 the OEB approved a Gross Revenue Charge Variance Account to record the cost impact of a gross revenue charge reduction under Ontario Regulation 124/02, once approved by the Ontario Ministry of Natural Resources and Forestry, pertaining to production increases at OPG's Sir Adam Beck plants due to the operation of the new Niagara Tunnel. As of May 2016 no decision by the Ministry of Natural Resources and Forestry had been issued.[75] It is not clear if and when the reduction will be made and how it may impact the payment amounts during the term of the IRM plan. The Council submits that OPG, in its Reply Argument, should clarify the status of this issue and how the reductions, to the extent they are realized will flow back to OPG's customers.

Productivity Factor:

LEI conducted a Total Factor Productivity ("TFP") study which concluded that a -1% productivity factor OPG's hydroelectric facilities was appropriate. OPG proposed a

[75] Ex. H1/T1/S1/p. 17

0% productivity factor for the IRM term on the basis that the OEB did not accept that at negative productivity factor was appropriate for the electricity distributors.[76]

The Council has, in the past, argued that at a high level when establishing a IRM formula it should be forward looking – it should be put in place to encourage the regulated entity to find efficiency gains and productivity improvements on a go forward basis. If productivity trends were negative or 0 in the past, why do they have to be in the future? The Council's perspective on this point has not changed. However, we accept that the Board, when establishing productivity factors has relied on empirically derived industry trends and requires this type of analysis in support of proposed productivity factors.

OEB Staff retained Pacific Economics Group ("PEG") to assess OPG hydroelectric IRM proposal and LEI's TFP analysis. The PEG analysis derived an historical .29% base X-factor. The Council has reviewed the submission of OEB Staff and the School Energy Coalition with respect to the LEI and PEG analyses. The Council agrees that PEG's approach represented a sounder methodology. Accordingly, the Board should accept a productivity factor of .29%.

Stretch Factor:

OPG has proposed a stretch factor of .3% based on a study undertaken by Navigant and the approach used by the OEB in its IRM model for electricity distributors. The Council accepts this as appropriate for the purposes of deriving the annual IRM formula.

Capital Structure Variance Account:

As part of its IRM plan OPG is not proposing to change the capital structure embedded in base rates, which is comprised of 45% equity and 55% debt. However, OPG proposes to capture the effect of a change in the capital structure arising out of the Board's decision in this case through the Capital Structure Variance Account. This has the same effect as changing base rates. Although OPG's is proposing an IRM model for its hydroelectric business it is proposing a cost of service approach to equity thickness.

This is simply not fair. Over the term of the plan OPG would be collecting an additional $114 million from ratepayers if OPG's proposal to move from 45% to 49% were to be accepted by the Board.[77] The Council has presented submissions earlier in this argument as to why a change in the capital structure is not appropriate. However, if the Board accepts that a change is required it should not be applied to the hydroelectric business. Changes of this nature should only be

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[76] Ex. A1/T3/S2/p. 9
[77] Tr. Vol. 21, p. 17

made when the company rebases. That is how IRM works. OPG should not be permitted to cherry-pick in this regard. OPG's proposal to increase its equity thickness is in large measure based on the fact that they are proceeding with the DRP and this represents a significant risk for OPG. If the Board accepts OPG's analysis, then an adjustment should be made to the capital structure related to the nuclear business alone.

The Council notes that the ROE embedded in rates is 9.33%. OPG is not proposing to change that rate although the Board's current approved ROE for 2017 is 8.78%. OPG's proposal to effectively update one cost of capital parameter but not others is not consistent with generally accepted rate-making principles. It is simply an attempt to extract extra money from the ratepayers.

Z-Factor:

OPG has requested a Z-factor relief for the hydroelectric business to deal with the treatment of unforeseen events. Z-factors are a common element of all IRM plan. The materiality threshold OPG is proposing is $10 million.[78] This is the same threshold that has been historically applied to OPG. It was based on .25% of the average annual hydroelectric rate base approved in EB-2007-0905.[79]. From the Council's perspective this materiality threshold is clearly out of date, given the changes to OPG's since that time. Using the EB-2013-0321 rate base amount the corresponding figure would be $18.8 million. OPG calculated a threshold of $12.7 if both rate base and revenue requirement were incorporated.[80]

However, the Council notes that OPG operates financially as an integrated company. The ability to deal with unforeseen costs should be considered in that context. The off-ramp proposed for OPG is on a company-wide basis; the Council submits that Z-factor treatment should be as well. In undertaking J8.1 OPG calculated an updated Z-factor threshold amount for OPG's nuclear business based on using a combination of rate base and revenue requirement of $14.4 million. In light of these numbers the Council respectfully submits that a combined threshold amount for Z-factor treatment of $25 million is appropriate for OPG.

Capacity Refurbishment Variance Account:

Normally under IRM the formula applies to both capital and OM&A. However, in the case of OPG the Capacity Refurbishment Variance Account ("CRVA") is required by regulation. It applies to both nuclear and regulated hydroelectric assets. Under a cost of service approach the operation of the CRVA is relatively simple. If OPG spends money related to capacity refurbishment or expansion of capacity the

[78] Ex. A1/T3/S2/p. 23
[79] Ex. L-11.1-CCC-47
[80] Ex. L-11.1-CCC-47

amounts are booked to the account for review by the Board when they are brought forward for clearance.

The Board, in this case, is required to allow for amounts to be booked into the CRVA for projects that qualify.

OPG filed updated evidence setting out it proposal as to how the CRVA would operate in the context of the hydroelectric IRM proposal. Variances would be recorded in the CRVA in the same way that they have been done in prior periods. OPG's proposal is as follows:

To record the revenue requirement impact of variances in costs and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to the prescribed hydroelectric generation facilities relative to the forecast.[81]

OPG expects that the CRVA would continue to record the revenue requirement variance between (a) the forecast capital and non-capital costs underpinning the OEB-approved revenue requirement for CRVA eligible projects in EB-2013-0321 (base rates) and actual, prudent capital and non-capital costs.[82]

The concern in the proceeding was that mixing IRM with cost of service elements could result in double counting. OPG would get full recovery for the CRVA eligible projects while at the same time have funds available to fund a portion of those projects by applying the formula to base rates. In effect, OPG would not need to recover the full amount of the CRVA eligible projects through the CRVA account.

The Council respectfully submits that OPG's revised proposal to address the issue of double recovery arising from the operation of the CRVA in the context of incentive regulation is appropriate, with two modifications:

a) the threshold for CRVA recoverability in relation to the total level of capital spending supported in base rates should not be determined simply by using the depreciation embedded in rates and escalated by the (I-X) price cap escalator, rather the threshold should be calculated in the same manner as it is calculated in the context of Incremental Capital Module claims, as described in detail in the submissions of LPMA, and
b) the CRVA reference amount of $.9 Million should also be escalated by the (I-X) price cap escalator, as described in detail in the submissions of OEB Staff at pages 161-163.

B. NUCLEAR:

[81] AIC, p. 164
[82] Ex. H1/T1/S2/p. 2

In accordance with a direction from the OEB OPG has proposed a custom IR approach for its nuclear operations. From OPG's perspective its proposal is in accordance with the RRFE and previous guidance the OEB gave to OPG though its 2012/2013 consultation on incentive rate-making.

The major elements of the plan include:

- Five future test years with individual revenue requirements for each of those years;

- Applying a stretch factor to 75 % of OM&A costs (base OM&A and Corporate Service) that are independent of the major projects being undertaken during the IRM period;

- The stretch factor of .3% is based on the values from 4th GIRM and applying the range to OEB approved nuclear total cost benchmarking. The total reduction over the term of the plan is approximately $50.6 million;

- Annual reporting on performance measures. This will include all of the measures used in OPG's nuclear benchmarking;

- An off-ramp that is applied to OPG's combined regulated operations (Nuclear and Hydroelectric). An OEB review would be triggered if earnings exceeded or were below 300 basis points relative to the allowed ROE;

- OPG also takes the position that the fact it has a 100% variable rate design further enhances its incentives to find efficiency gains and improve performance.

- OPG is proposing to adjust its production forecast at the time of the mid-term review;

- The ROE for 2017 will be 8.78 %;

- For 2018-2021 the revenue requirement impact of the variance between the forecast ROE approved for 2017 and the ROE set annually by the OEB will be recorded in the proposed Nuclear ROE Variance Account.[83]

During the 2012/2013 Consultation the Council took the position that until Darlington and the extension of operations are Pickering were complete IRM for OPG should limited to the hydroelectric side of the business. Our view was based on the fact that IRM works best in a steady state environment and OPG was moving into an extremely variable period. The OEB has, however, effectively mandated custom

[83] Ex. A1/T3 S2/pp. 28-34

IR for OPG. Therefore, the Council submits that OPG should be held to the same standard as all other utilities when reviewing whether their plan. The plan should result in an appropriate balance between the interests of ratepayers and shareholders and comply the OEB's requirements and expectations regarding Custom IR.

From the Council perspective OPG has not proposed a Custom IR consistent with what has been defined by the OEB through the RRFE and subsequent rulings on Custom IR applications. What OPG has proposed is 5 years of Cost of Service applying some selected elements of IRM.

The Council has concerns with the following elements of OPG's plan:

1. The stretch factor and the scope of the application of the stretch factor;
2. The Z-factor materiality threshold;
3. The production forecast adjustment at the mid-term review; and
4. The establishment of the Nuclear ROE Variance Account.

Stretch Factor:

OPG is proposing a stretch factor of .3% to be applied to 75% of its nuclear operating costs (nuclear base OM&A and allocated corporate support services).[84] The application of a stretch factor to a portion of the nuclear OM&A costs that were derived on a Cost of Service basis is OPG's way of producing a Custom IR plan for the test year period.

If the Board is prepared to accept OPG's approach to rate-setting it should impose a stretch factor above the .3% for several reasons and apply that stretch factor to a more comprehensive portion of the revenue requirement. A reduction of approximately $50 million on an OM&A level that exceeds $2 billion a year over a five-year period provides no meaningful up-front benefits to ratepayers. In addition, there is no stretch applied in 2017.[85]

OPG derived the .3% from data arising from its 2015 Nuclear Benchmarking Report. That report was used to create an average of the performance of Darlington (first quartile – 0%) and Pickering (fourth quartile - .6%).[86] If the 2016 Report was referenced and used to derive the stretch factor the Council submits that the stretch factor would be higher. OPG, on a company-wide basis ranked 12th out of the 13 companies benchmarked.[87]

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[84] Ex. A1/T3/S2/p. 28
[85] Ex. A1/T3/S2/p. 32
[86] Ex. A1/T3/S2/p. 32
[87] Ex. L.6.2-SEC-63 Attachment 3, p. 93

The Council submits that the Board could send OPG back to the drawing Board and reject its proposed Custom IR plan on the basis that it is not compatible with the OEB's expectations and requirements. An alternative would be to impose a model similar to Toronto Hydro-Electric System Limited's ("THESL") Custom IR proposal that was approved by the Board in EB-2014-0116. In that case, THESL had applied a stretch factor to its overall OM&A budgets for the five-year term. In addition, the Board required that the stretch factor be applied to capital spending as well. The Board's rationale was that utilities are required to make continuous productivity improvements.[88] This should not be limited in any way to a portion of the OM&A and it should be applicable to capital.

In order to ensure that ratepayers are provided with meaningful up-front benefits with respect to the nuclear payment amounts the Council recommends that at stretch factor of .6% should be applied to all of OPG's nuclear OM&A and capital. Given clear evidence that OPG's benchmarking results are poor as clearly articulated by OEB Staff[89], the Council submits that this is an appropriate and fair adjustment to make.

Z-factor:

OPG has requested a Z-factor relief for the nuclear business to deal with the treatment of unforeseen events. The materiality threshold OPG is proposing is $10 million.[90] This is the same threshold that has been historically applied to OPG. From the Council's perspective this materiality threshold is clearly out of date, given the changes to OPG's since that time. Using the EB-2013-0321 rate base amount the corresponding figure would be $14.4 million.[91]

OPG operates financially as an integrated company. The ability to deal with an unforeseen cost should be considered in that context. The off-ramp proposed for OPG is on a company-wide basis. As stated above, the Council submits that Z-factor treatment should be as well. In light of the numbers derived for both the hydroelectric and the nuclear businesses the Council proposes a combined threshold amount for Z-factor treatment of $25 million.

Mid-Term Review:

OPG is proposing a mid-term review to review and update the nuclear production forecast. The mid-term review will also seek disposal of applicable audited deferral and variance account balances as well as any remaining unamortized portions of

[88] EB-2014-0116 OEB Decision with Reasons, dated December 29, 2015, p. 18.
[89] OEB Staff Submission, pp. 82-87
[90] Ex. A1/T3/S2/p. 23
[91] Ex. L-11.3-CCC-47

previously approved amounts with recovery periods extending beyond December 31, 2018.

The Council supports the mid-term review to consider deferral and variance account balances and the proposed disposition of those accounts. Many of OPG's accounts have the potential to accumulate large balances and it would be appropriate at the time of the mid-term review to consider any disposition proposals.

The Council also supports a consideration of the nuclear production forecast. Elsewhere in this submission the Council has recommended that approval of the Pickering Extended Operations costs is premature at this time. Before OEB approval is granted OPG should be required to bring back its proposals regarding Pickering at the time of the mid-term review. OPG should be required to provide updated cost/benefit analyses, the status of CNSC approval and the most recent LTEP. At that time it would be appropriate for the Board to consider how the Pickering proposals, ultimately decided by the Board, may impact the production forecast going forward. The Council submits that the only element of the production forecast that should be considered at the mid-term review is the impact on the forecast of the Pickering Extended Operations.

Nuclear ROE Variance Account:

For 2017 the proposed ROE is 8.78%. OPG's proposal for the period 2018-2021 is that the revenue requirement impact of the variance between the forecast ROE approved for 2017 and the ROE set annually by the OEB will be recorded in the proposed Nuclear ROE Variance Account. The account is the equivalent of changing the ROE every year. (Ex. A1/T3 S2/p. 34) The Council is opposed to this proposal. The ROE should be fixed in 2017 and held constant in each year of the plan term. This is consistent with the requirements of the Board's RRFE.

Capacity Refurbishment Variance Account:

As noted earlier, OPG recognized that there is a potential for double counting as a result of the interaction between the CRVA and incentive rate making, and in response that concern proposed a solution in Exhibit H/1/1 that sought to eliminate that potential in the context of the Hydroelectric IRM proposal, which the Council has supported with two modifications as suggested by LPMA and OEB Staff respectfully.

The Council raised the issue in the oral hearing as to why the same potential for double counting would not also apply in the context of the proposed Nuclear Custom IR:

MR. BUONAGURO: Well, your response on the line suggests to me that you assumed that for it to be a line, it has to be a straight line. It wouldn't be a straight line. It would be a line that would go up and down, based on the individual characteristics of each year.
But you could map out over the next five years an implicit -- or an amount that's presumed for sustaining capital each year, right?
MR. FRALICK: We have asked for a certain amount of sustaining capital, and asked for our DRP spending explicitly through nuclear through explicit amounts in each of the five years.
MR. BUONAGURO: And it's possible that in any particular year, you could under or over spend relative to that amount, correct?
MR. FRALICK: Absolutely, yes.
MR. BUONAGURO: Just like it is the case on the hydroelectric side, you could over or under spend relative to the red threshold line you've put out here, right?
MR. FRALICK: We fully expect that our actual cost trajectory will unfold at a different level than what we have in our plan.
MR. BUONAGURO: Right. And on the hydroelectric side, as we just discussed, if you under spend that sustaining capital, it will make available more room to absorb CRVA eligible capital, if such capital is being put into service, right? I think we just confirmed that.
MR. FRALICK: Yes, that's what's shown here.
MR. BUONAGURO: But you're not proposing that on the nuclear side, right?
MR. FRALICK: Fundamentally, this is -- IRM is a different compact than a custom IR. But to the extent to which we under spend on nuclear, say sustaining capital, if that were to unfold over the full five years, I'm sure that the Board would take that into consideration when we go back to rebase, in terms of whether or not we've asked for -- we've done what we were expected to do.
MR. BUONAGURO: If you under spend on sustaining capital on the nuclear side, that means that there are funds and rates aren't being applied towards any capital, even though that's what they're for, correct?
MR. FRALICK: On sustaining capital, if that were to happen, yes.[92]

In the Council's view it is clear that the same "double counting" issue with respect to OPG's Custom IR proposal and the CRVA exists as with its Hydro Electric Rate Setting Mechanism.

The only difference is that instead of the annual amounts for capital spending being included implicitly within the IRM proposal, and therefore having to be calculated as a function of the depreciation amount embedded in base rates, the annual capital

[92] Tr. Vol. 20, pages 82-84.

amounts are specified as part of the requested 5 year approval. This difference does not, however, change the fact that under-spending in sustaining capital relative to any of the approved years leaves revenue requirement amounts available to support CRVA eligible spending, exactly as it would in the Hydroelectric IRM proposal.

It appears to the Council that OEB Staff agrees that the risk of double counting exists in the context of both the Hydro and Nuclear rate setting contexts, and proposes that:

> OPG should be required to file, in its Draft Payment Amounts Order, the aggregate revenue requirement associated with its approved nuclear operations and nuclear support services in-service amounts for the test period (2017- 2021). If at the end of the test period, on an actual basis, less revenue requirement than approved (on an aggregate basis) was required to support the in-service additions, the variance in revenue requirement should be used to offset nuclear capital related debits recorded in the CRVA.[93]

The Council respectfully submits that OEB Staff's proposal adequately addresses the risk of double recovery and should be implemented by the Board.

7. MID-TERM REVIEW:

The Council supports the mid-term review to consider deferral and variance account balances and the proposed disposition of those accounts. Many of OPG's accounts have the potential to accumulate large balances and it would be appropriate at the time of the mid-term review to consider any disposition proposals.

The Council also supports a consideration of the nuclear production forecast. Elsewhere in this submission the Council has recommended that approval of the Pickering Extended Operations costs would be premature at this time. Before OEB approval is granted OPG should be required to bring back its proposals regarding Pickering at the time of the mid-term review. OPG should be required to provide updated cost/benefit analyses, the status of CNSC approval and the most recent LTEP. At that time it would be appropriate for the Board to consider how the Pickering proposals, ultimately decided by the Board, may impact the production forecast going forward. The Council submits that the only element of the production forecast that should be considered at the mid-term review is the impact on the forecast of the Pickering Extended Operations.

8. RATE SMOOTHING:

[93] OEB Staff Argument, page 63.

The Council has reviewed and generally agrees with the submissions of Board Staff with respect to OPG's rate smoothing proposal.

In the Council's view the benefit of smoothing under OPG's current proposal (an average monthly bill impact of $.65 per year for the next 5 years instead of an average monthly bill impact of $.82 per year[94]) does not warrant the cost associated with deferring approximately $1 Billion in revenue requirement.

The Council specifically agrees with Board Staff's proposal that the Board should focus its efforts on "rounding the edges", which in the context of the 2017-2021 rate period likely means, after the Board renders a decision on the unsmoothed revenue requirement, smoothing the impact in 2020 caused by the in-service additions related to Unit 2 of the DRP.[95]

The Council notes, however, that the calculated average monthly bill impacts over the 5 year test period, in both OPG's proposal and in Board Staff's unsmoothed analysis, assume impacts in 2017 relative to prevailing 2016 rates including riders which OPG has not charged since December 31, 2016.[96] Accordingly, it seems to the Council, it doe not make sense to discuss the 2017 impact in relation to the 2016 payment amounts; customers will experience the 2017 payment amount order relative to the existing interim payment amount, which is significantly lower then the 2016 payment amount.[97]

Accordingly, subject to the Board's decision on the 2017 revenue requirement and the appropriate effective date for its 2017 rates, the Council is concerned that there may be an "edge" to "round" in 2017 based on the increase from the existing, interim payment amounts absent riders and the eventual change in payment amounts as a result of this proceeding.

Both Board Staff and OPG agree, and the Council concurs, that the Board should not make a decision approving a specific smoothing proposal until it renders a decision on the unsmoothed revenue requirement. The Council makes the further suggestion that the Board should give parties an opportunity to provide submissions as to the appropriate smoothing proposal subsequent to the release of the Board's decision

[94] Board Staff Argument Appendix A lines 14 and 15.
[95] Board Staff Argument pages 178-180.
[96] Tr. Vol. 23, pp. 16 and 17.
[97] While both OPG and Board Staff calculate the impacts of their proposals relative to the 2016 payment amount of $60.97/MWh further to Ex. N3/T1/S1 Table 2 line 8, the existing interim rate, exclusive of 2016 riders, is $51.86/MWh, which can be derived by substituting in the 2016 Tax Adjusted Production-Weighted Regulated Hydroelectric Payment Amount found at Ex. I1/2/1 Table 1A of $41.09/MWh and the 2016 Nuclear Payment Amount of $59.29/MWh for the equivalent payment amounts inclusive of riders in Ex. N3/T1/S1 Table 2 at lines 1 and 2.

on the unsmoothed revenue requirement, as it expects that different parties may wish to provide different perspectives on how much “smoothing” is appropriate, given the approved revenue requirements for the test period.

The Council would like to note the possibility of potentially unfair consequences as a result of the interaction of the RSDA and the CRVA.

The Council is concerned about a scenario where the Board may approve a significant amount of deferred revenue for tracking in the RSDA for a particular year, while in reality, for that same year, OPG may end up tracking a material amount of revenue requirement in the CRVA as a credit to ratepayers.

By way of example, OPG is proposing to defer $488 Million in revenue requirement in 2020; in the event that Unit 2 does not come into service in 2020, there will be $4.7 Billion in spending that will not be closed to rate base, with the result that hundreds of millions of dollars in revenue requirement will need to be recorded in the CRVA for refund to ratepayers.

As noted in Ex. L/4.3/5 CCC-018, the CRVA and the RSDA have different rates of interest applied to them, with the RSDA attracting interest at a higher, compounded rate.

In the scenario provided, it is possible that that OPG will be booking revenue requirement in 2020 in the RSDA and earn interest on that amount for over a decade at the higher, compounded interest rate, even though much of that revenue requirement will be tracked as a refund to ratepayers in the same year it was booked to the RSDA as a debit, and potentially paid back to customers on clearance of the CRVA even though the money was never in fact collected, with the result that clearance of the CRVA results in the payment of money to customers, only to have that same amount accrue a high rate of compound interest for over a decade and then collected from ratepayers.

To avoid this patently unfair scenario, the Council suggests that the Board require amounts that would otherwise be credits to customers in the CRVA to instead be tracked as credits against the RSDA in order to avoid paying money to customers for amounts that will then be collected back from customers more then a decade later after having earned the enhanced rate of interest in the RSDA. Alternatively, if the Board does not wish to track such amounts in the RSDA, the Council submits that the Board should allow the same compound interest rate applicable to the RSDA to be applied to the CRVA with respect to credit amounts that are linked to the refund of revenue requirement amounts that were tracked in the RSDA instead of being included in payment amounts, with the potential that such amounts remain in the CRVA until they can be cleared in tandem with the RSDA, effectively offsetting the RSDA recovery.

9. RATE IMPLEMENTATION/EFFECTIVE DATES:

OPG is requesting an effective date of January 1, 2017, with respect to the payment amounts for both the nuclear and hydroelectric facilities. This includes a request for payment riders to recover the difference between existing payment amounts and the payment amounts sought in this Application from the effective dates to the implementation date.

From OPG's perspective the requested effective date for new payment amounts should be approved because OPG complied in all material respects with the OEB's filing guidelines and any directions provided in OPG's last payment amounts proceeding. It is OPG's position that it worked diligently with all parties and OEB Staff to advance the application in a reasonable and efficient manner.[98]

The Council submits that for OPG's rates to be effective January 1, 2017, the Application should have been filed earlier. The OEB has made it clear in recent years that applicants need to file well in advance of the date on which they are seeking to have their rates effective. The Board has become less inclined to allow for retroactive recovery, and from the Council's perspective this is important for electricity consumers. As the Council submitted in OPG's last application (EB-2013-0321) it is simply not fair to say to Ontario customers, "By the way, we are asking you now to pay more for the electricity you consumed over the last year." There may be isolated reasons to allow for retroactive adjustments, but in this case the Council urges the Board to reject an effective date, as requested by OPG, of January 1, 2017. The Council supports an effective date, one month following the final payment amounts order.

The Council notes that the effective date was a contentious issue in the last proceeding. OPG filed its Application in that proceeding on September 27, 2013, and was seeking an effective date of January 1, 2014, for the nuclear and previous regulated hydroelectric facilities. In its Decision the Board stated:

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

[98] AIC, p. 173

> The Board must control its regulatory process. The Board hears a large number of cases throughout the year and must plan its resources accordingly to ensure cases are completed and decisions are rendered. In cases where utilities have not filed their applications in time to have rates in place prior to the effective date, the Board's practice has typically been not to allow the utility to retrospectively recover the amounts from the period where the interim order was in effect. All applicants are aware of the Board's metrics. The process for an oral hearing is expected to take 235 days from the filing of the application and to the issuance of the final decision, and 280 days until the issuance of the rate order.[99]

The OEB also cited a number of Decisions where it denied retroactive adjustments. These in include: EB-2012-0165 (Sioux Lookout); EB-2013-0139 (Hydro Hawksbury); EB-2012-0113 (Centre Wellington); and EB-2013-0130 (Fort Frances). The Council notes a further Decision issued on August 18, 2016, where Grimsby Power was denied its request to have rates approved retrospectively on the basis of when its filed its application.

OPG filed its application on May 27, 2016. As OPG noted in its Argument-in-Chief:

- By any measure this is a significant Application. It includes a review of the Darlington Refurbishment Program, the single largest project ever to come before OEB and requests some $5,177.4 of DRP-related in-service additions. It requests funding to extend Pickering's operation. It introduces new ratemaking methodologies for both the nuclear and hydroelectric payment amounts. It covers five years;

- 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;

- OPG is the only generator regulated by the OEB. It is a large generating company producing over half of the energy generated in Ontario. It operated two 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 vintage, the geographic dispersion and the shear scope of OPG, all contribute to making it a complicated entity to operate and regulate;

[99] Decision with Reasons, EB-2013-0321, pp. 134-135

- Even without DRP, OPG is unique among regulated companies, electric or gas, in terms of scope, scale and complexity. [100]

The Council agrees with all of these assertions. The complexity of this case, the scope of the issues and the size of the "ask" go beyond any application the OEB has had to consider. It is also important to recognize that OPG has a large and experienced regulatory staff that closely follow Board decisions and policies. They are not new to regulation submitting the first payment amounts application in November 2007 for payment amounts effective April 1, 2008. The regulatory staff is undoubtedly aware of the Board's position on setting retrospective rates, as the position was clearly articulated in the previous OPG proceeding decision.

If OPG wanted an effective date of January 1, 2017, it should have submitted the Application much sooner. This is not a typical rate case and the timelines set by the OEB for other applicants, especially the smaller electric utilities is not sufficient for an OPG application, especially this one.

The Council remains concerned about the implications of retrospective rate-making and its impact on customers. Except under very exceptional circumstances the Board should not permit an applicant to recover amounts from customers for a prior period, even if it is rolled into a rate rider and the recovery is spread out over a future period. In this case customers were not given notice that their bills could be impacted in this way. The Council supports the current policy and is of the view this panel should adhere to it in this case. As noted above, the Council supports an effective date that flows one month from the final payment amounts order.

COSTS:

The Council requests that it be awarded its reasonably incurred cost associated with its participation in this proceeding. The Council has worked extensively with other intervenors throughout this proceeding in order to reduce duplication and has managed its participation efficiently and effectively.

All of which is respectfully submitted,

May, 29, 2017

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[100] AIC, p. 1