Aiken & Associates
578 McNaughton Ave. West
Chatham, Ontario, N7L 4J6
Phone: (519) 351-8624
E-mail: randy.aiken@sympatico.ca

May 29, 2017

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

Dear Ms. Walli,

RE: EB-2016-0152- Final Submissions of London Property Management Association

Please find attached the final submissions of the London Property Management Association ("LPMA") in the above noted application.

Sincerely,

Udqg|#Dlnhq#

Randy Aiken
Aiken & Associates

cc: Applicant and Intervenors (by e-mail)

EB-2016-0152

Ontario Power Generation Inc. (OPG)
2017-2021 Payment Amounts

SUBMISSIONS
OF
LONDON PROPERTY MANAGEMENT ASSOCIATION

May 29, 2017

I. INTRODUCTION

Ontario Power Generation Inc. ("OPG") filed an application with the Ontario Energy Board ("OEB") on May 27, 2016 under section 78.1 of the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B), seeking approval for changes in payment amounts for the out of its nuclear generating facilities and most of its hydroelectric generating facilities. The request sought approval for nuclear payment amounts to be effective January 1, 2017 and for each following year through to December 31, 2021. The request also sought approval for hydroelectric payment amounts to be effective January 1, 2017 to December 31, 2017 and approval of the formula used to set the hydroelectric payment amount for the period January 1, 2017 to December 31, 2021.

The OEB issued a Notice of Hearing on June 29, 2016. OPG subsequently filed supplemental evidence on July 29, 2016.

The OEB issued Procedural Order No. 1 on August 12, 2016 in which it set dates, for among other things, an untranscribed application presentation, an untranscribed technical conference, interrogatories on the OPG evidence, responses to those interrogatories, a technical conference, technical conference undertaking responses, staff and intervenor evidence, interrogatories on that evidence, responses to those interrogatories, a motions hearing day, a settlement conference and an oral hearing.

While some dates were changed, the application generally followed the schedule as set out in the procedural order. For example, the settlement conference proceeded on the scheduled days, while the beginning of the oral hearing was delayed from February 21, 2017 to February 27, 2017.

OPG filed their Argument-In-Chief on May 3, 2017.

The following are the submissions of the London Property Management Association ("LPMA") on the issues of concern to its members. LPMA has had the opportunity to review the submissions of Board Staff ("Staff") filed on May 19, 2017 (Staff submission). LPMA supports those submissions on a number of issues. Where this is the case, LPMA has simply indicated its support of the Staff submissions, and in some cases, emphasized its agreement with the Staff rationale for the position taken and/or added additional rationale to support the position.

Similarly, LPMA has worked closely with other intervenors throughout this proceeding and has participated in the exchange of drafts or partial drafts on many of the outstanding issues in this proceeding. In particular, LPMA has had the opportunity to review the draft submissions of the School Energy Coalition ("SEC"), Energy Probe Research Foundation ("Energy Probe"), the Green Energy Coalition ("GEC"), the Consumers Council of Canada ("CCC"), the Vulnerable Energy Consumers Coalition ("VECC"), Canadian Manufacturers & Exporters ("CME") and the Ontario Association of Physical Plant Administrators ("OAPPA") on a number of issues. LPMA also shared their draft submissions on a number of issues with other parties.

LPMA also notes that Staff has provided detailed summaries of the evidence and requests of OPG for most of the issues. Rather than repeating these summaries, LPMA has relied on the Staff submissions.

II. SUBMISSIONS

1. GENERAL

1.1 Has OPG responded appropriately to all relevant OEB directions from previous proceedings?

LPMA submits that OPG has responded appropriately to the previous OEB directions shown in Exhibit A1, Tab 11, Schedule 1.

1.2 Are OPG's economic and business planning assumptions that impact the nuclear facilities appropriate?

LPMA accepts that the economic and business planning assumptions of OPG are appropriate, with two significant exceptions.

The first exception is the rate of inflation used by OPG in its business planning assumptions (Exhibit L, Tab 7.1, Schedule 15, SEC-089). This figure is higher than the 1.7% that will be used for OPG for 2017. Further, as indicated under Issue 11.4 below, the information used by the OEB to set the inflation index for 2018 (i.e. actual 2016 figures) is already available from Statistics Canada, and is approximately 1.2%. This is a 40% reduction from the assumption used by OPG and has a significant impact on the cost of service based OM&A for the nuclear operations.

The second exception deals with the economic and business assumptions used to estimate the ratepayer impact associated with the Pickering Extended Operations ("PEO") project. This is discussed in more detail in Issue 6.5 below.

<u>1.3 Is the overall increase in nuclear payment amounts including rate riders reasonable given the overall bill impact on customers?</u>

This issue is subsumed in a number of other issues, including in-service capital additions for both the Darlington Refurbishment Program ("DRP") and non-DRP related projects, the nuclear OM&A and nuclear allocated corporate costs, and the proposed nuclear stretch factor. It is also impacted by the rate smoothing proposal. As such LPMA is not making any direct submissions on this issue.

2. RATE BASE

<u>2.1 Are the amounts proposed for nuclear rate base (excluding those for the Darlington Refurbishment Program) appropriate?</u>

LPMA has no concerns with the methodology used to calculate rate base. It does, however, have submissions on two issues.

The first issue is related to the use of the updated forecast for in-service additions provided in the response to Undertaking J21.1. OPG indicated that it did not propose to update the rate base calculations even though based on the updated forecast, which includes actual in-service additions for 2016, rate base would average $30 million less per year than under the original forecast. The reason given by OPG for not updating rate base is that the 2016 through 2021 total in-service amounts are virtually identical between the original forecast and the updated forecast.

LPMA submits that the OEB should direct OPG to update its rate base calculations that reflect actual 2016 in-service additions but not the updated forecast. Rate base is a function of two things: the amount of in-service capital additions each year and the timing of those additions to rate base. OPG has ignored the timing issue with respect to the actual 2016 in-service additions.

LPMA submits that there is no defensible reason why ratepayers should be paying for a rate base that is known to be too high, given that the 2016 in-service additions on an actual basis is more than $200 million lower than the forecast. The net impact is a reduction in opening rate base for 2017 of more than $200 million, which OPG has chosen to ignore. OPG's proposal is clearly inappropriate and should be denied by the OEB.

As part of the response to Undertaking J21.1, OPG indicated that based on its updated forecast of in-service additions, the depreciation expense is $8 million higher, on average per year because of a change in the anticipated project mix.

OPG has filed no evidence in support of the anticipated change in the mix of projects. Parties have not had an opportunity to test this change. Indeed, parties do not know what the changes are or why they have been made. Consequently, LPMA submits that the OEB should not rely on the untested updated mix of projects. The original forecast of in-service additions should be used to calculate rate base, updated for the reduction of $200 million in opening rate base for the IRM period.

The second issue is related to imprudent incremental costs incurred associated with the Operations Support Building Refurbishment ("OSB") and the Auxiliary Heating System ("AHS") projects. LPMA agrees with the Staff and SEC submissions on this issue, including the quantum of the disallowance, which ranges from $23.2 million from SEC to $35 million from Staff. LPMA submits that the disallowance should be 100% of whatever portion of the incremental costs that the OEB deems to be the result of imprudent management of these projects.

Submissions with respect to the forecast of capital expenditures are found under Issues 4.2 and 4.4 below.

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

The proposed amounts for the nuclear rate base for the DRP are almost entirely driven by the amounts and timing of the in-service additions for this project. LPMA provides its submissions with respect to this under Issue 4.5 below.

3. CAPITAL STRUCTURE AND COST OF CAPITAL

3.1 Are OPG's proposed capital structure and rate of return on equity appropriate?

OPG is seeking to increase the equity thickness to 49% for the entire five-year term (2017-2021) from the current level of 45%. OPG says this increase is needed to reflect the material increase in the business and financial risks facing the company.

Where's the Increase in Risk?

Based on the evidence in this proceeding, there are a total of six areas where various parties have indicated there is increased risk. These parties include Concentric (on behalf of OPG), Brattle (on behalf of Board Staff) and OPG itself through their business plan.

The six areas on increased risk are the change in mix of hydro and nuclear assets, the execution risk associated with the DRP, the risk associated with the PEO project, the move to incentive regulation (including the 5-year term), pension/OPEBs recovery risk and rate smoothing recovery risk.

These risks are shown in a table provided in the submissions of SEC. Of these six risks identified by Concentric, only four of them are considered as increased risks by Brattle and only two were identified by OPG.

Taking into consideration whether or not the risks are material, only change in hydro/nuclear asset mix and the execution risk associated with the DRP were considered material by Concentric. Both Brattle and OPG only considered the DRP execution risk and the PEO as being material risks. In essence, all three parties agree that the only potential driver of increased risk that has been identified as being material is the execution risk associated with the DRP and the PEO projects. It is these projects (notably the DRP) that drives the change in the hydro/nuclear asset mix.

With respect to the DRP, LPMA agrees with the submissions of others, including Energy Probe and SEC, the Capacity Refurbishment Variance Account ("CRVA") essentially eliminates all risks of OPG not recovering its prudently incurred costs associated with the project. The provincial legislation that deals with this account ensures that OPG will recover all "capital and non-capital costs and firm financial commitments" for the investments made in the DRP.

LPMA further notes that the CRVA provides a recovery mechanism for overspending on components of the PEO project as well, again eliminating risk to OPG for this project.

Where is the risk to OPG? The risk has been placed squarely on the back of ratepayers by the government. Ratepayers do not know what benefit they will ultimately get or when they will get it. They do not know how much it actually cost them. What they do know is that they will be responsible for paying for all eventualities.

Staff highlights the execution/construction risks associated with a project as complex as the DRP and has noted that mega-projects have a history of going over budget and behind schedule. LPMA submits that none of these concerns are relevant. The CRVA clearly projects OPG from any of these outcomes, assuming the spending is prudent. If OPG spends it, they will be allowed to recover it, regardless of the outcome of the project. Again, LPMA asks, where is the risk to OPG? LPMA submits that the CRVA is a form of a regulatory safeguard that no other utilities that are undertaking major spending programs have access to. To try and compare them to other generators, as proposed by Concentric and Brattle is a waste of time.

All of the execution risk associated with the DRP is on the shoulders of ratepayers, as per government decree. If anything, the OEB should consider a reduction in the equity component of the capital structure from the current level of 45% as a result of the DRP. There is a clear shift of risk from OPG to ratepayers, not the other way around!

LPMA notes and supports the submissions of other parties with respect to the difference between the equity ratios in Canada as compared to those in the United States. None of the experts in this proceeding dealt with this issue, as they should have.

Finally, with respect to the DRP, LPMA notes the high level of confidence that OPG has put on its estimates for costs and timing of the project. OPG has indicated that it has done an exceptional level of planning in preparation for this project and is 90% confident that it will deliver the DRP on time and on budget. Again, this does not support any material increase in the level of risk for OPG, even if they did shoulder even part of the execution risk of the project.

In summary, LPMA submits that there is no evidence of any increase in business or financial risk that would require an increase in the equity component of the capital structure.

Step-Ladder Approach

LPMA submits that the OEB should consider a step-ladder approach to the capital structure if it determines that a change in the capital structure is appropriate. This is because there is no impact on the composition of rate base between the regulated hydroelectric assets and the nuclear assets until 2020 when Unit 2 is forecast to go into service. As shown in Exhibit L, Tab 3.1, Schedule 1, Staff-010, the nuclear proportion of rate base in 2017 through 2019 is 31% to 32%. The percentage only increases in 2020 and 2021.

LPMA submits that if the OEB determines that the equity component of the capital structure should be increased because of the higher nuclear proportion of rate base, it should not do so until there is an actual increase in that proportion, which on a forecast basis would be in 2020.

Given the lack of risks noted above, LPMA submits that there is no justifiable reason to increase the equity component of the capital structure prior to the expenditures being placed in service.

In addition, LPMA submits that the OEB should approve a variance account to reflect the difference between the current 45% equity ratio and that approved for 2020 and 2021 so that if Unit 2 is not placed into service in 2020 as is forecast, that the impact of the higher revenue requirement associated with the increase in the equity component applied to the higher rate base associated with Unit 2 being in rate base can be returned to ratepayers. LPMA believes that this amount would be over and above the credit to ratepayers calculated in the CRVA in this eventuality.

Separate DRP

It is the view of LPMA that a further option that the OEB should consider, if it is of the view that a change in the capital structure is required, is having a separate capital structure for the DRP relative to the remainder of the company.

As discussed elsewhere in this submission, the hydroelectric assets/operations of OPG are in a steady state. This is illustrated in the response to Exhibit L, Tab 3.1, Schedule 1, Staff-010 that shows the hydroelectric rate base growing gradually from $7.5 billion in 2017 to $7.7 billion in 2021. It also reflects OPG's statement in Exhibit A1, Tab 3, Schedule 2, page 8 that its regulated hydroelectric generation facilities are in a relative stable, steady state.

With respect to the non-DRP nuclear operations assets, as illustrated in the submissions related to Issue 11.4 below, non-DRP nuclear capital additions are actually forecast to decline in 2017 through 2021 relative to the 2013 through 2016 period by more than 8% or $23 million per year.

This is also illustrated in Exhibit L, Tab 3.1, Schedule 1, Staff-010 if the nuclear rate base is adjusted to remove the DRP related additions in 2020 and 2021. The DRP component of the incremental rate base in 2020 is about $4.0 billion and in 2021 is about $4.5 billion. These figures are derived from the table provided in Attachment 1 of Exhibit L, Tab 2.2, Schedule 1, Staff-009.

Similar to the hydroelectric assets/operations, LPMA submits that this illustrates that the non-DRP related nuclear assets/operations also exhibit a steady state of affairs.

With the removal of the DRP figures in 2020 and 2021, the nuclear proportion of rate base is 32% in 2020 and 31% in 2021, entirely consistent with the levels shown for 2017 through 2019. In other words, the need for a higher equity component of rate base because of the increase in the nuclear proportion of rate base does not exist for the largest portion of OPG, that being the regulated hydroelectric assets and the non-DRP nuclear assets. In 2017 through 2019, these assets account for 100% of rate base, and in 2020 and 2021, they represent approximately 74% and 72%, respectively, of rate base.

To account for this change, LPMA submits that the OEB could approve a separate equity component to the DRP component rate base to reflect a different level of risk to OPG, if the OEB finds that to be the case with the DRP. The bottom line is that the province has mandated OPG to do this project and has provided OPG with the CRVA which protects OPG from all prudent outcomes. The result is very little risk for OPG and much more risk for ratepayers. This would imply a lower equity component for the DRP component of rate base, not a higher level. As above, this capital structure would only be effective from the date that Unit 2 is placed in service and is included in rate base.

<u>3.2 Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?</u>

This issue is partially settled as noted in Exhibit O, Tab 1, Schedule 1, page 8. The settled part is related to the short and long-term interest rates used in the calculation of the debt cost.

The unsettled component of the issue relates to the proportion of the capital structure that is debt related, as well as the breakdown of the debt into short-term and long-term debt.

LPMA submits that the total debt component of the capital structure will be determined by the OEB decision with respect to the equity component of the capital structure, which is dealt with under Issue 3.1 above. In other words, the total debt component of the capital structure will be 100% less the deemed equity component determined by the OEB in the above noted issue.

With respect to the composition of the debt between short-term and long-term, LPMA notes that the amount of short-term debt forecast by OPG remains constant at $37.1 million from 2016 through 2021 (Exhibit C1, Tab 1, Schedule 1, Tables 1 through 6) despite an increase in rate base of more than 50%. In fact, as shown in Tables 1 through 6, the short-term debt component of rate base declines from 0.4% in 2016 to 0.2% in 2021.

LPMA submits that the short-term debt component of rate base should be maintained at the 0.4% level shown for 2016. OPG has provided no evidence as to why the short-term debt component should decline by 50% between 2016 and 2021. LPMA further notes that the short-term debt component of rate base in 2016 (0.4%) is already lower than the actual figures for 2015 (0.5%) and 2014 (0.7%). These figures are shown in Tables 7 & 8 of Exhibit C1, Tab 1, Schedule 1. The corresponding reduction in debt would be reflected in lower long-term debt figures.

LPMA submits that any change in the debt component of the capital structure due to the OEB decision related to the equity component of the capital structure should be reflected in the long-term debt component and not in any reduction to the short-term debt component.

4. CAPITAL PROJECTS

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

LPMA has reviewed the Staff submissions on this issue and adopt those submissions.

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

Please see the submissions of LPMA under Issue 4.4 below.

4.3 Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Please see the submissions of LPMA under Issue 4.5 below.

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

LPMA is concerned that OPG will not be able to bring its forecasted expenditures in-service as quickly as it has forecast. As shown in the response to Undertaking J14.1, the budget additions to rate base were $497 million, but OPG was only able to bring $292 million into service. This is less tan 60% of the planned in-service additions.

This was not a problem associated with only 2016. As indicated in Table 7 in Exhibit D2, Tab 1, Schedule 3, of the 24 nuclear operations capital projects with a cost of $5 million or more identified in EB-2013-0321 and forecast to go in-service during that periods of 2014-2015, an astounding 21 were delayed, while only 4 went into service on time. Even more remarkable is that of the 21 delays, 14 were delayed by a year or more.

Based on this dismal track record, LPMA submits that the OEB should have little, if any, confidence that OPG can meet their in-service timetable.

LPMA has reviewed the Staff submission, and in particular, Table 8 of that submission where it is shown that OPG has over forecast in-service additions over the 2010 through 2016 period by more than $190 million, or 12.5% of their forecast.

Based on their historical performance, which has been reinforced by the track record in 2014-2015 as compared to the OEB approved projects and the significant over estimation of in-service additions in 2016 compared to actual, LPMA submits that the OEB should reduce the in-service capital additions forecast for each of 2017 through 2021 by 12.5%.

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

OPG has proposed a total budget for the DRP of $12.8 billion, which includes all of the definition and execution phase costs associated with the refurbishment of 4 units, the early in-service projects, the facility and infrastructure ("F&I") projects, the safety improvement ("SI") projects, contingency, interest and escalation (Exhibit D2, Tab 2, Schedule 1, page 6). The DRP has been mandated by provincial regulation.

OPG is seeking approve in this application for the in-service amounts associated with the refurbishment of Unit 2 (including allocated contingency, interest and escalation costs), along with the early in-service projects, F&I projects and the SI projects. OPG is not seeking approval with respect to any of the refurbishment costs associated with the other 3 Darlington units.

OPG's proposed in-service amounts reflecting both its original evidence at Exhibit D2, Tab 2, Schedule 1, page 6 and the update at Exhibit N2, Tab 1, Schedule 1 to reflect the removal of the heavy water storage facility project is $350.4 million in 2016, $8.5 million in 2017, $8.9 million in 2018, $0.00 in 2019, $4,809.2 million in 2020 and $0.4 million in 2021 (Argument-In-Chief, page 32).

Also, as mandated by provincial regulation, the OPG evidence indicates that if actual additions to rate base are different from the forecast amounts, the cost impact of the difference will be recorded in the CRVA and any amounts greater than the forecast amounts added to rate base would be subject to a prudence review in a future proceeding.

LPMA supports the in-service capital additions associated with DRP as proposed by OPG. The reasons for this agreement are discussed below. However, LPMA does not agree with OPG that the prudence review in the future proceeding should be limited to any amounts recorded in the CRVA greater than the forecast.

With respect to the in-service amounts, LPMA is aware that some parties will suggest reductions to the in-service amounts in their submissions. Much of this reduction is likely to be centered around the contingency amount included in the forecast or on the capitalized labour costs. OPG identifies the contingency amount associated with Unit 2 as $1.7 billion, of which $694.4 million is attributed to Unit 2. There is likely also a contingency amount associated with the F&I and SI projects, although it is not what this amount would be or if it would be material.

OPG's contingency forecast results from the use of a Monte Carlo model with a P90 confidence level, which means that there is a 90% confidence that the contingency value is sufficient to cover the risks and uncertainties that were included in the model. This means that a contingency forecast at the P90 confidence level means that there is a 90% chance that the actual required contingency will be less than the estimated amount.

On a purely probabilistic approach, it would appear that the use of a P50 confidence level for determining the amounts to be included for rate setting purposes would be appropriate. There would be a balanced 50% probability that the actual contingency costs would be above or below this level.

However, LPMA is not convinced that this is a good approach from the ratepayer point of view. Use of a lower P value does not change the ultimate recovery of prudently incurred costs. It only impacts the timing of the recovery through the CRVA. Use of the P90 confidence level results in more costs recovered up front with only a 10% risk of additional costs being recovered in the CRVA for future recovery beyond 2021.

On the other hand, the use of a lower P value, such as P50, increases the probability that there will be additional costs recorded in the CRVA for future recovery, shifting more costs out of the 2017 to 2021 period into the post 2021 period. While a balanced approach suggested by use of the P50 confidence level may seem appropriate, LPMA submits that it ignores a number of risks that could end up costing ratepayers more in the long run.

The costs associated with the remaining 3 Darlington units is forecast at $8 billion, but this figure was not the subject of any examination in this proceeding. Changes in inflation and interest rates over the next 5 years could significantly increase this cost estimate. Increasing the probability of CRVA amounts to be recovered post-2021 would only add the potential for significant rates increases beyond 2021.

LPMA notes that mega-projects like that of DRP rarely, if at all, come in under budget, no matter how extensive and comprehensive the budget process is. Some would say that projects of this magnitude are almost guaranteed (i.e. 100% confidence level) to come in over budget and/or behind schedule.

LPMA is concerned that reducing the amounts in rates over the 2017 through 2021 period increases the risk of significant increases post 2021. LPMA members do not oppose the possibility of recovering more than is needed in 2017 through 2021 if it results in a credit to be used to offset future costs. Of more concern is that the recovery in 2017 through 2021 under recovers costs, adding to the burden post 2021.

LPMA submits that using the P90 confidence level in place of a P50 (or some other) confidence level for setting rates in 2017 through 2021 is a form of insurance for ratepayers. While this insurance comes with a cost associated with the time value of money, LPMA notes that current low interest/low inflation environment has effectively minimized this cost.

In summary LPMA submits that using the P90 confidence level is appropriately conservative and provides ratepayers with a measure of protection against adding to the growing list of cost pressures that will be faced beyond 2021. The OEB is well aware of these potential cost drivers, including rising inflation rates, rising interest rates, and, of course, Ontario's Fair Hydro Plan consequences.

With respect to the need for a prudence review, OPG confirmed its opinion if that the Unit 2 related costs come in at or below the level included in rates that no prudence review would be necessary (Tr. Vol. 1, pages 114-115). LPMA disagrees.

LPMA has reviewed the Staff submissions on this issue and support them. In particular, LPMA supports the submissions found at pages 56-57 with respect to the need for a detailed prudence review. To not do so on the largest project approved by the OEB to date, would be an abdication of the OEB in its responsibility to ensure that rates are just and reasonable.

5. PRODUCTION FORECASTS

5.1 Is the proposed nuclear production forecast appropriate?

LPMA has reviewed the nuclear production forecasts in Exhibit E2 and submits that OPG has significantly understated the forecasts for both Pickering and Darlington.

LPMA has reviewed the Staff submission with respect to the production forecast for Pickering. While generally agreeing with the analysis, LPMA submits that the Staff proposal of a 0.5 TWh increase is too low.

OPG has provided no compelling evidence as to why the production at Pickering is forecast to drop by more than 4% from the 2008 through 2016 average of 20.1 TWh per year to 19.2 TWh on average over the 2017 through 2019 period. These figures are taken from the graph on page 70 of the Staff submission. Similarly, actual production for the last five years (2012 through 2016) average 20.3 TWh.

OPG is actually forecasting lower Pickering production in 2017 than has been recoded since 2008. In fact the production forecast for 2017 through 2019 are the lowest, second lowest (tied with 2010) and fifth lowest over the period 12 year 2008 through 2019. LPMA submits that these forecasts are not supported by the evidence in this proceeding.

LPMA, like Staff, notes that this decline in production is not consistent the OPG's evidence of the initiatives that have been undertaken to improve reliability at Pickering, including the aggressive maintenance programs over the last four years. LPMA also agrees with Staff that OPG has not justified the significant increase in planned outage days for Pickering (excluding PEO).

Based on the relatively stable production average of 20.1 TWh over the 2008 through 2016 period and the 201.3 TWh average over the 2012 through 2016 period, LPMA submits that the OEB should approve a Pickering forecast of 20 TWh for each of 2017, 2018 and 2019. This results in an increase of 0.9TWh in 2017, 0.8 TWh in 2018 and 0.6 TWh in 2019.

LPMA has had the opportunity to review the draft submissions of OAPPA with respect to the Darlington production forecast. LPMA adopts those submissions with respect to the Darlington production forecast and agrees that an increase of 2.95 TWh over the forecast period is warranted. It is submitted that the higher production forecast, if approved by the OEB would provide additional incentives to OPG to reschedule its planned outages for the benefit of ratepayers.

6. OPERATING COSTS

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

LPMA has reviewed the Staff submissions and submits that the OEB should reduce the labour and overtime component of base OM&A costs by $15 million per year and the base OM&A other purchased services by $25 million per year for the same reasons as detailed by Staff, for a total nuclear base OM&A reduction of $40 million per year..

LPMA has also reviewed the Staff analysis related to the historical over forecast of the nuclear outage OM&A. OPG has over forecast these expenses by an average of 5% over the 2010 through 2016 period. This is shown in Table 24 of the Staff submissions. Staff recommends that the costs should be reduced by 5% in each of 2017 through 2021.

LPMA submits that the appropriate reduction should be 8% in each of 2017 through 2021. This is based on the trends shown in Table 24 of the Staff submissions. As can be calculated from that table, actual expenses exceeded planned expenses by a reasonable level of 1% over the 2010 to 2012 period. Actual expenses were almost 13% below the forecast in 2013. For the 2014 through 2016 period, which were based on approved EB-3013-0321 figures, the under spend is 8%. Clearly the trend shown over the 2010 to 2016 period is that OPG has moved from a reasonable forecast to forecasts that over estimate the actual costs. As a result, LPMA submits that an 8% reduction in each of 2017 through 2021 would be reasonable. These reductions would be approximately $31.6 million in 2017, $31.5 million in 2018, $33.2 million in 2019, $31.6 million in 2020 and $24.7 million in 2020.

LPMA has also reviewed the SEC submissions with respect to the updated costs associated with the CNSC's Fitness for Duty program that is forecast to cost $41 million over the test years (Exhibit N1, Tab 1, Schedule 1, page 5 & Chart 2.0). OPG was not able to provide any documented support for this expense or the forecasted timing of the expense.

LPMA has assumed that this $41 million reduction over the 5-year test period is subsumed in the $40 million per year reduction in base OM&A noted above. LPMA supports the SEC recommendation that at the very least, the OEB should approve a variance account for this cost which may not materialize or which may be deferred to the latter part of the forecast horizon to ensure that ratepayers are not paying for something that is not implemented.

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

Ratepayers expect continuous improvement from OPG in the operation of its nuclear facilities. This is also a cornerstone of the OEB's RRFE. However, as shown in the analysis provided in the Staff submission at pages 81-88, the opposite appears to be happening. This should be of great concern to the OEB and to OPG. Significant measures need to be taken just to halt the decline in performance.

LPMA submits that the poor benchmarking results supports its submissions with respect to the need for a higher nuclear stretch factor, reductions in OM&A and reductions in in-service additions. It is the responsibility of the OEB to push OPG to improve by accepting these changes. It is then the responsibility of OPG to act responsibly and appropriate to the OEB findings.

6.3 Is the forecast of nuclear fuel costs appropriate?

This issue is partially settled as noted in Exhibit O, Tab 1, Schedule 1, page 9. The settled part is related to the fuel bundle unit cost forecast used in the calculation of the nuclear fuel cost.

As noted in Issue 6.1 above, LPMA has a n umber of issue with the nuclear production forecast. If the OEB makes any changes to the nuclear production forecast, then LPMA submits that these changes should be reflected in changes to the nuclear fuel bundle cost that are driven by the change in the production forecast.

LPMA has no concerns with the proposed fuel oil cost forecast that average approximately $4.5 million over the IR term.

6.4 Is the test period Operations, Maintenance and Administration budget for the Darlington Refurbishment Program appropriate?

The OM&A costs included in the revenue requirement associated with the DRP average approximately $25 million per year over the 2017 to 2021 period and are covered by the CRVA.

Given the protection provided to ratepayers by the CRVA and LPMA's proposal for a full prudence review when the CRVA is disposed of, regardless of whether the actual costs are above or below the forecast, LPMA accepts the OM&A forecast for these DRP related costs.

<u>6.5 Are the test period expenditures related to extended operations for Pickering appropriate?</u>

LPMA submits that the OEB does not have the information it would need to approve the test year expenditures related to the PEO. This lack of information is on a number of fronts.

First, OPG does not have Canadian Nuclear Safety Commission ("CNSC") approval to extend the life of Pickering beyond 2020. A decision by the CNSC is not expected until mid 2018 and it is not certain that approval would be granted or if it is, what conditions and resulting costs, would be imposed on the approval.

Second, there is uncertainty around whether the new Ontario Long Term Energy Plan will include Pickering, and to what extent. The OEB should not be approving costs associated with a project that may not even be in the plan.

Third, the economic justification in support of the PEO is out of date. If updated today, the positive benefits of the project could well turn into negative benefits.

Finally, LPMA notes that the OEB is not bound by government regulation or directive (at least not yet!) to approve the costs associated with the PEO.

LPMA has reviewed the Staff submissions on this issue at pages 93-99 of their submissions. LPMA supports those submissions as they provide a balanced approach on continuing with the enabling expenditures in 2017 and 2018. However, LPMA submits that the enabling costs included in the revenue requirement for 2019 and 2020, at about $100 million in each year should remain in the revenue requirement and continue to be tracked in the CRVA. This is consistent with LPMA's submission related to using the P90 confidence level in the amount of contingency built into the 2017 through 2021 revenue requirement.

If the costs are incurred, but not included in the revenue requirement, there will be a need to recover more than $200 million through the CRVA post 2021. On the other hand, if the costs are not incurred, there will be a $200 million credit to ratepayers that can be used to offset any DRP related costs to ratepayers and to help mitigate cost increases beyond 2021.

The OEB should also consider approving the 2019 and 2020 PEO enabling costs on an interim basis until the CNSC and LTEP decisions are known, at which time OPG would be directed to file an application to include or remove these cost on a final basis.

With respect to the restoration costs, LPMA agrees with Staff that the OPG should consider commencing the restoration costs only after it has received CNSC approval and the new LTEP confirms that the PEO is part of the plan. Further LPMA submits that these costs should disallow these costs at this time and direct OPG to include these costs in the application noted above once it has been determined that the PEO will proceed.

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

LPMA has reviewed the detailed submissions of SEC related to compensation and supports a reduction of $46.7 million per year at a minimum. LPMA has also reviewed the Staff submissions which recommend a reduction of $50 million per year.

LPMA notes that compensation is the largest cost category included in the nuclear revenue requirement and that it represents almost 50% of the nuclear revenue requirement (Argument-In-Chief, page 94). LPMA also notes that compensation has been a hotly contested issue in previous OPG proceedings.

LPKA submits that the use of a price cap I – X mechanism on the hydroelectric business has eased the concerns of ratepayers on the level of compensation included in that business. However, the cost of service approach to the Custom IR has built in limited benefits with respect to compensation.

Compounding the compensation issue is the poor nuclear benchmarking performance of OPG on total generating cost basis. Clearly there is a direct link between this poor performance and the high compensation costs which represent nearly 50% of the costs.

LPMA submits that the OEB needs to continue to push OPG to reduce its overall compensation costs in order to prod it into finding efficiency and productivity improvements so that its nuclear benchmarking performance improves, or at least does not decline further.

In order to do this, LPMA submits that the OEB should reduce the compensation expense on an annual basis by more than the $46.7 minimum recommended by SEC and $50 million recommended by Staff. LPMA submits that a decrease by an additional $10 to $20 million per year is needed to get the attention of OPG and to force them to focus on continuous improvement and improving their benchmarking performance.

<u>6.7 Are the corporate costs allocated to the nuclear businesses appropriate?</u>

LPMA has reviewed the analysis in the Staff submission at pages 114-117. LPMA has also reviewed the submissions of SEC that calls for a 2.5% reduction in each year based on the over forecasting history related to these expenses over the 2016 to 2016 period.

LPMA submits that a reduction of 2.5% is appropriate for each of 2018 through 2021, reflecting this tendency to over recover these costs. This would result in reductions of $10.9 million in 2018, $11.1 million in each of 2019 and 2020 and a reduction of $11.4 million in 2021.

LPMA submits that a larger reduction is needed for 2017 given that the forecast for 2017 reflected an increase of 1.5% over the 2016 forecast of $442.3 million. While LPMA believes that the 1.5% increase in 2017 is appropriate, the starting base of $442.3 million is not.

As shown in Attachment 1 of Undertaking J14.2, the actual allocation of costs to the nuclear business in 2016 was $426.2 million. LPMA submits that this is the appropriate starting point to increase by 1.5%. This would result in a 2017 forecast of $432.6 million, which represents a decrease from the request of $448.9 million of $16.3 million, which is in line with the difference between the actual and forecast 2016 costs.

In aggregate, the reduction proposed by LPMA over the 5-year term is approximately $60.8 million.

<u>6.8 Are the centrally held costs allocated to the nuclear business appropriate?</u>

The centrally held costs are related to pensions and OPEB costs, insurance, performance incentives and IESO non-energy charges. A portion of these company-wide costs are allocated to the nuclear business. LPMA has no issue with these costs or the amount allocated to the nuclear business.

6.9 Is the proposed test period nuclear depreciation expense appropriate?

LPMA has no specific issues with the calculation of the nuclear depreciation expense. However, LPMA notes that if the OEB approves a different level of capital expenditures placed into service than that requested by OPG, or makes changes in the in-service additions to reflect, for example, actual 2016 closures to rate base, then the OEB should direct OPG to file detailed fixed asset continuity schedules for each year that reflect the changes. In addition, OPG should provide the details of changes in the depreciation expense that would result from the capital changes.

In terms of reflecting actual 2016 capital expenditures as the opening balance for the 2017 rate base, which LPMA supports, OPG has indicated that while this would shift capital expenditures between years, the total expenditures over the 5-year period would not be materially different. However, OPG calculated that rate base would be lower, on average, by $30 million per year. At the same time OPG has indicated that the depreciation expense would be about $8 million higher, on average, over the same period.

LPMA submits that OPG should provide the details of the increase in depreciation expense despite the reduction in rate base. OPG should also indicate whether it has reflected the increase in depreciation expense in the calculation of the accumulated depreciation, and hence rate base, in these estimates.

6.10 Are the amounts proposed to be included in the test period nuclear revenue requirement for income and property taxes appropriate?

Income Taxes
LPMA has no concerns with respect to the calculation of the taxes associated with the nuclear assets, except for the allocation of the Scientific Research and Experimental Development ("SR&ED") investment tax credits ("ITCs").

LPMA has reviewed the Staff submissions on this issue and support them. Staff submits that the utilization of ITCs should no longer be on a combined basis (nuclear and regulated hydroelectric) going forward and that any unutilized amounts applicable to a particular business segment should be carried forward. Doing so on a combined basis may lead to ratepayers losing the benefit of ITCs when the payment amounts determined through cost-based rate applications are determined at different times.

LPMA believes that the OEB should ensure that ratepayers are not adversely impacted through the use of two different incentive regulation mechanisms within the same corporation. This would require that any SR&ED ITCs to be used by the business segment that generated them.

LPMA also supports the Staff submission that the ITCs should be updated to reflect the most recent information available, as it would be unfair to ratepayers if they were to not receive this additional reduction when OPG has indicated it has better up to date information at this time.

LPMA also supports the Staff submissions with respect to the Income and Other Taxes Variance Account.

Property Taxes

OPG is forecasting an increase of nearly 30% in nuclear related property taxes between 2015 and 2021, rising from $13.2 million in 2015 to $17.0 million in 2021 (Exhibit I1, Tab 1, Schedule 1, Table 2). LPMA submits that this increase has not been justified.

As shown in the above noted evidence, OPG has significantly over forecast nuclear related property taxes in both 2014 and 2015. The OEB approved figures for 2014 and 2015 were 11% and 20%, respectively, higher than the actual costs. This amounted to $1.8 million in 2014 and $3.2 million in 2015.

LPMA submits that the OEB should either reduce the property taxes by $2 million per year to reflect the tendency to over forecast these costs (for a $10 million reduction in the 2017 to 2021 revenue requirement), or include the property taxes in the OM&A costs to which the stretch factor is applied. This latter approach would be more in line with a Custom IR application.

6.11 Are the asset service fee amounts charged to the nuclear businesses appropriate?

This issue is settled as noted in Exhibit O, Tab 1, Schedule 1, page 10.

7. OTHER REVENUES

Nuclear

7.1 Are the forecasts of nuclear business non-energy revenues appropriate?

This issue is settled as noted in Exhibit O, Tab 1, Schedule 1, pages 10-11.

Bruce Nuclear Generating Station

7.2 Are the test period costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease appropriate?

LPMA supports the OAPPA submissions with respect to this issue, with the exception that LPMA believes the change as a result of the 2017 ONFA contribution schedule should be reflected in the revenue requirement and not captured in the Bruce Lease Net Revenues Variance Account.

LPMA agrees with the Staff submission that the intention of this variance account is to capture the revenue requirement impacts of certain events or transactions that occur after the payment amounts have been set. In this proceeding, there are know adjustments to the test period revenue requirement that OPG has proposed to exclude from the payment amounts despite they payment amounts not yet being set. LPMA submits that the best information should be used and the additional impact should be included in the payment amounts. Not only does this save ratepayers carrying charges on amounts that will ultimately be recovered from them, but it also improves cash flow for OPG, thereby reducing risk.

8. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

8.1 Is the revenue requirement methodology for recovering nuclear liabilities in relation to nuclear waste management and decommissioning costs appropriate? If not, what alternative methodology should be considered?

LPMA submits that the OEB should approve the cash methodology in calculating the revenue requirement for recovering nuclear liabilities in relation to nuclear waste management and decommissioning costs, rather then the accrual method.

LPMA has had the opportunity to the detailed submissions of SEC with respect to this issue. LPMA supports those submissions and adopts them.

LPMA further submits that the OEB should not feel it is constrained to continue to use the accrual methodology in calculating the revenue requirement. This application marks a significant change in the regulatory approach to setting payment amounts for OPG. The rates will be determined by a mix of price cap regulation for the regulated hydroelectric assets and Custom IR regulation for the nuclear assets. The OEB is emphasizing the need for continuous improvement across all aspects of OPG's operations. The Province (OPG's shareholder) is emphasizing the need for ratepayer relief from high electricity bills. What better way to accomplish this than to move to the cash methodology for the nuclear liabilities? There is a significant benefit to ratepayers of more than $400 million over the 2017 to 2021 period based on the SEC analysis.

There is no adverse impact on OPG, since all of its cash requirements continue to covered through the revenue requirement.

<u>8.2 Is the revenue requirement impact of the nuclear liabilities appropriately determined?</u>

OPG continues to seek recovery of $1,808M (Argument-In-Chief, page 132) as set out in Exhibit C2, Tab 1, Schedule 2, Chart 1, line 11) despite filing updated information that reflects the 2017 Ontario Nuclear Funds Agreement ("ONFA") Reference Plan, among other updates, approved by the Province. The updated summary of the revenue requirement impact of nuclear liabilities is shown in the response to Undertaking J21.2. The updated revenue requirement is $1503.3M, a reduction of approximately $305 million.

Instead of passing this substantial reduction in costs along to ratepayers, OPG proposes to reflect the difference as ratepayer credits in the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account over the IR term. LPMA submits that this is inappropriate and is out of step with goal of the Province (OPG's shareholder) to provide immediately reductions to electricity rates for consumers.

The only reason given for this by OPG is that the updated evidence was filed during the hearing and the proposal to flow the difference in the revenue requirement through the variance accounts was done to try to make the process simpler for discussion and that OPG didn't want to go through the process of the multiple updating that would have to happen (Tr. Vol. 21, pages 42-43).

LPMA submits that this is ridiculous. Instead of making the discussion simpler, it actually required significant cross-examination by a number of parties just to get what the new number is on the record.

Mr. Mauti, on behalf of OPG, stated that if the OEB ordered OPG to take the updates into account in the revenue requirement and not flow them through the variance accounts, it would not have a problem with that approach (Tr. Vol. 21, pages 42-43).

LPMA submits that the updated evidence should be relied upon by the OEB to set the revenue requirement. There is no justification for including more than $300 million in the revenue requirement and flowing it through the variance accounts. This is clearly not appropriate and certainly represents a significant amount of intergenerational transfers from current ratepayers to future ratepayers.

LPMA notes that this reduction of over $300 million is based on the accrual methodology proposed by OPG. As noted above under Issue 8.1, LPMA submits that the OEB should approve the use of the cash methodology. However, should the OEB continue to allow the use of the accrual methodology, LPMA submits that the revenue requirement should be reduced for the nuclear liabilities from $1,808M to 1,503.3M.

9. DEFERRAL AND VARIANCE ACCOUNTS

9.1 Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

This issue is partially settled as noted in Exhibit O, Tab 1, Schedule 1, page 12. The settlement covers all deferral and variance accounts other than the Capacity Refurbishment Variance Account (Nuclear), the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account.

LPMA's submissions with respect to these three accounts are dealt with under Issue 9.3 below.

9.2 Are the methodologies for recording costs in the deferral and variance accounts appropriate?

This issue is partially settled as noted in Exhibit O, Tab 1, Schedule 1, pages 12-13. The settlement covers all deferral and variance accounts other than the Capacity Refurbishment Variance Account (Nuclear), the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account.

LPMA's submissions with respect to these three accounts are dealt with under Issue 9.3 below.

9.3 Are the balances for recovery in each of the deferral and variance accounts appropriate?

This issue is partially settled as noted in Exhibit O, Tab 1, Schedule 1, pages 13-14. The settlement covers all deferral and variance accounts other than the Capacity Refurbishment Variance Account (Nuclear), the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account.

LPMA has no issues with respect to the three outstanding deferral and variance accounts with respect to the type of costs included in them, the methodologies for recording costs or the balances in the accounts.

<u>9.4 Are the proposed disposition amounts appropriate?</u>

Please see the submissions under Issue 9.3 above.

<u>9.5 Is the disposition methodology appropriate?</u>

OPG is requesting recovery of the audited December 31, 2015 balances in the deferral and variance accounts, less 2016 amortization amounts approved in EB-2014-0370, except for the Pension and OPEB Cash Versus Accrual Differential Deferral Account, through a hydroelectric payment rider and a nuclear payment rider to come into effect on January 1, 2017 and expire on December 31, 2018 (Exhibit H1, Tab 2, Schedule 1).

Separate riders have been calculated for the hydroelectric and nuclear payment rate riders.

OPG continues to propose that the Hydroelectric Deferral and Variance Over/Under Recovery account record the difference between the amounts approved for recovery in the hydroelectric deferral and variance accounts and the actual amounts recorded based on the actual regulated hydroelectric production and approved riders (Exhibit L, Tab 9.5, Sch. 11, LPMA-005). Similarly, OPG proposes that the Nuclear Deferral and Variance Over/Under Recovery account record the difference between the amounts approved for recovery in the nuclear deferral and variance accounts and the actual amounts recorded based on the actual nuclear production and approved riders (Exhibit L, Tab 9.5, Sch. 11, LPMA-006).

LPMA submits that the OEB should approve this methodology, as it is consistent with the methodology approved in past proceedings (Exhibit H1, Tab 1, Sch. 1).

However, LPMA submits that the OEB should shift the disposition period from the proposed 24-month period starting January 1, 2017 to a 24-month period from when rates are implemented as part of this proceeding. This could be used in conjunction with rate smoothing, allowing for a larger increase in the revenue requirement component of the weighted average payment amount in 2017. Similarly, using a three year period may also be useful when considering rate smoothing.

Finally, as discussed in more detail under Issue 11.5 below, LPMA submits that the OEB should require OPG to file annual applications for the disposition of deferral and variance accounts rather then waiting to the mid-term review. The rationale for this is provided under Issue 11.5.

9.6 Is the proposed continuation of deferral and variance accounts appropriate?

This issue is settled as noted in Exhibit O, Tab 1, Schedule 1, pages 14-15.

9.7 Is the rate smoothing deferral account in respect of the nuclear facilities that OPG proposes to establish consistent with O. Reg. 53/05 and appropriate?

LPMA submits that the rate smoothing deferral account is consistent with the regulation.

9.8 Should any newly proposed deferral and variance accounts be approved by the OEB?

OPG has requested the establishment of four new accounts in this application. LPMA deals with each of the requests in turn.

The Mid-term Nuclear Production Variance Account

As indicated under Issue 11.5, LPMA submits that a mid-term nuclear production review is not consistent with the risks that a utility is expected to live with under a Custom IR application. As a result, LPMA submits that no variance account is required.

The Rate Smoothing Deferral Account

LPMA has provided its concerns with respect to the rate smoothing proposal under Issue 11.6 below. The account is required, by regulation, and much about the account is beyond the determination of the OEB, including the need for the account, the interest rate to be applied for the account and the timing of when balances in the account can begin to be collected from ratepayers. The regulation also requires a recovery period of not more than 10 years.

What the OEB does have control over, however, is the specific details of the "smoothing" which will directly determine the amount that gets recorded in the account and accumulates compound interest. This is dealt with in Issue 11.6 below.

The Nuclear ROE Variance Account

LPMA submits that the OEB should not approve a Nuclear ROE variance account.

In particular, the request to effectively change the revenue requirement each year for a change in the return on equity is not consistent with the October 13, 2016 Handbook for Utility Rate Applications ("Handbook").

At page 26 of the Handbook, the OEB clearly states that after the rates are set as part of a Custom IR application, it expected there to be no further rate applications for annual updates within the term of the Custom IR unless there are exceptional circumstances. The OEB then went on to provide some specific examples of things that it did not expect to address in annual rate applications. The first one listed is updates for the cost of capital.

While the OPG proposal does not change the approved revenue requirement since the difference between the two ROEs used would be put into a variance account for future clearance to ratepayers, it does change the actual or effective revenue requirement and pushes it off onto future ratepayers.

LPMA realizes that the Handbook was published after OPG filed their application. However, LPMA submits that the Handbook simply spells out the expectations of the OEB from the RRFE with respect to a Custom IR. The intent of what is in the Handbook comes from the RRFE. The OEB policy with respect to what is acceptable in annual updates under a Custom IR has only been clarified in the Handbook. It is not a new policy and it clearly should be applied to OPG.

LPMA further submits that if the OEB approves a price cap plan for the nuclear assets excluding the DRP and PEO project as submitted by LPMA under Issue 11.4, then there is no need for the variance account. As indicated there, the use of an I-X price cap factor methodology would automatically build in any changes in interest rates into the payment amounts that would affect the return on equity, as it does for any other type of cost.

If the OEB does approve such an account, LPMA submits that it should state that the clearance of any such account must meet the materiality threshold on annual basis; otherwise the account should not be recovered or rebated to ratepayers.

<u>The Hydroelectric Capital Structure Variance Account</u>

LPMA submits that the OEB should not approve this account because it is not consistent with the price cap incentive regime. There is no provision under the price cap methodology set out in the RRFE that would allow a utility to recover amounts in addition to that based on the application of the price cap formula for a change in capital structure.

Had OPG wanted to build in a higher return on equity in base rates it should have done so. However, OPG did not propose any such adjustment to the capital structure in the regulated hydroelectric payment amounts arising from EB-2013-0321 for establishing base rates for applying the hydroelectric incentive regulation mechanism. As shown in Exhibit O, Tab 1, Schedule 1, this is a fully settled issue and the only adjustment made was the one-time change associated the nuclear-tax loss that was allocated to hydroelectric in the EB-2013-0321 payment amounts application.

LPMA also submits that the OEB should not allow OPG to change the effective hydroelectric payment amounts through the use of a variance account record changes to the capital structure that were not proposed as changes in the base rates, while at the same time allowing OPG to build in an additional $25 million per year in base rates because of the higher return on equity percentage built into base rates (9.33%) than would be if the ROE was updated to the 2017 figure of 8.78% (Undertaking J20.2).

OPG could have reflected the proposed change in the capital structure by filing a price cap plan based on a 2017 cost of service rebasing year. OPG did not do this because it would have cost them $25 million base rates in return on equity.

This means that over the 5-year incentive period, OPG will recover $125 more than if had rebased based on a 2017 cost of service application and used the lower ROE of 8.78%. This windfall is more than what OPG estimates would be recorded in the variance account over the 2017 to 2021 period if the OEB approved the requested 49% equity ratio of $115 million (Exhibit L, Tab 9.8, Schedule 1, Staff-217). This amount would be significantly less if the OEB approves an increase in the equity ratio above the current 45% but less than the 49% requested by OPG.

LPMA submits that the OEB should not approve higher costs payable by ratepayers (whether directly through a cost of service revenue requirement, the application of a price cap formula to base rates or through the use of a variance account) when a balance approach is not taken. In this application OPG embedded a higher return on equity in base rates and seeks a capital structure change that will add another layer of additional costs on ratepayers. The OEB should reject this opportunistic proposal outright.

10. REPORTING AND RECORD KEEPING REQUIREMENTS

As indicated below, LPMA generally supports the Staff submissions with respect to reporting and record keeping requirements.

However, LPMA submits that in addition to the information proposed to be filed, OPG should file financial data for the historical year on the same bases as is done in the revenue requirement work form ("RRWF"). This would show, for example, the actual revenue deficiency or sufficiency achieved, return on equity, OM&A costs and capital expenditures.

LPMA also submits that the OEB should direct OPG to fund an annual stakeholder meeting to review all of the material filed on annual basis.

Both of these recommendations reflect the material filed by Union Gas and Enbridge Gas Distribution and the fact that they both have an annual stakeholder meeting to review the material and provide presentations. Stakeholders (including the OEB) then have an opportunity to ask clarification questions. The RRWF information provided makes it easy to track financial performance through the IR term and will avoid requests for the information at the next rebasing application in 5 years.

<u>10.1 Are the proposed reporting and record keeping requirements appropriate?</u>

LPMA has reviewed the Staff submissions and agree with those submissions.

<u>10.2 Is the monitoring and reporting of performance proposed by OPG for the regulated hydroelectric facilities appropriate?</u>

LPMA has reviewed the Staff submissions and agree with those submissions.

<u>10.3 Is the monitoring and reporting of performance proposed by OPG for the nuclear facilities appropriate?</u>

LPMA has reviewed the Staff submissions and agree with those submissions.

<u>10.4 Is the proposed reporting for the Darlington Refurbishment Program appropriate?</u>

LPMA has reviewed the Staff submissions on this issue and agree with those submissions, with the exception of the frequency of reporting to the OEB (and other stakeholders).

As the OEB is aware, the Darlington Refurbishment Program is the largest project undertaken by any regulated utility under the jurisdiction of the OEB. The potential for cost overruns and timing delays cannot be overlooked.

LPMA submits that annual reporting may be insufficient in terms of alerting the OEB and other interested parties to realized or potential cost and/or timing variances in the project. At the same time LPMA does not believe that quarterly reporting to the OEB would necessarily be required. As a result, LPMA submits that the OEB should require OPG to provide semi-annual reports to the OEB. This would provide more timely information to the OEB than under annual reporting, but would not be administratively as burdensome as quarterly reporting.

11.METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

Hydroelectric

11.1 Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

LPMA submits that OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts is generally appropriate and in compliance with the Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach Report of the Board dated October 18, 2012 ("RRFE Report"). However, while the approach may be appropriate, there are some aspects of the proposal that LPMA submits should be changed. These are discussed below.

The Inflation Factor

LPMA supports the two-factor price index as proposed by OPG. In particular, LPMA accepts the 12% weighting for the labour index and the 88% for the non-labour (capital and materials component. Both of these price indexes are the same as used by the OEB for the electricity distributors, only the weighting is different.

However, LPMA does not agree with the OPG calculation that resulted in a 1.8% inflation factor for 2017. LPMA supports the Staff submission that the appropriate rate is 1.7% based on use of the natural logarithm function and the proper use of rounding only at the end of the calculations.

LPMA does not support the Staff submission with the respect to the use of a three-factor price index to account for the fact that there is no inflation associated with the gross revenue charge ("GRC"), which represents more than 25% of the total regulated hydroelectric revenue requirement. Staff suggest that a 12.5% weighting applied to an inflation rate of 0% would account for the lack of inflation on this large cost.

LPMA submits that the Staff proposal is not based on any facts provided in the evidence of this proceeding. Staff suggests that other businesses may some inflation-less costs and that this is reflected in the non-labour component priced index, GDPIPIFDD. While LPMA agrees with this statement, OPG is likely faced with the same inflation-less costs as other businesses, over and above the GRC. In fact, OPG and other businesses are likely recipients of reduced costs (deflation) in many areas over the last few years, including the cost of capital (as interest rates declined), computer hardware and software and other technology that has declined in price.

Staff also make the statement that payments for land or water rights that natural resource firms (mining or forestry) or water bottlers pay **may** also not be subject to inflation. LPMA has highlighted the word "may" because Staff has not provided any evidence to support this statement.

Staff acknowledge that while OPG would not be the only business that may have some inflation-less costs, it does acknowledge that OPOG's situation is significantly different from most firms and business sectors.

Staff's proposal to use a 12.5% weighting factor (one-half of the 25% of the hydroelectric revenue requirement that represents the GRC) would imply that on average, most firms and business sectors have inflation-less costs that represents 12.5% of their costs. LPMA knows of no such firms or sectors. Again Staff has not provided any evidence to support this 12.5% weighting assumption, or anything close to it.

LPMA has had the opportunity to review the submissions of SEC on the inflation factor/GRC issue. If the OEB believes that the appropriate way to deal with this issue is through a 3-factor inflation factor, then LPMA submits that the OEB should give the GRC inflation factor (implicitly set at 0%) a weighting of 25%. This is supported by the evidence that a little more than 25% of the approved revenue requirement from EB-2013-0321 built into the base payment amounts is directly related to the GRC. LPMA notes that this approach would allow for a GRC inflation factor different from 0% (higher or lower) if the provincial government were to change the rates charged.

LPMA strongly believes that the OEB needs to take into account the significant GRC portion of the revenue requirement that does not attract any inflation in the application of the price cap I – X model. Variability in the GRC from one rate period to another is due solely to variations in volume. Application of any inflation rate to this cost would not be reasonable or justified.

Rather than trying to determine an appropriate weighting for a three-factor price index in the absence of any evidence to support the weights as proposed by Staff, LPMA submits that an alternative approach for the OEB to consider is the treatment of the GRC as a Y-factor pass through cost.

LPMA discusses the Y-factor treatment of the GRC in the following section.

Need for a GRC Y Factor

LPMA submits that the simplest approach to dealing with the fact that approximately 25% of the revenue requirement for the regulated hydroelectric assets does not attract any inflation is to break the EB-2013-0321 GRC approved amount out of the revenue requirement and apply the price cap I – X formula to the resulting value. The forecasted GRC rate (per MWh) would then be added on to this figure to arrive at the approved rate per MWh.

This ensures that the inflation rate does not get applied to costs that do not have any inflation associated with them. Similarly, the base productivity and stretch factor would not be applied to the GRC costs. To do so would imply that OPG could somehow reduce these costs, which is not possible given the formulaic determine of the cost based solely on volume.

The treatment of the GRC costs as pass through costs would be consistent with the pass through of the kWh commodity costs for electricity distributors and the pass through of gas commodity costs for natural gas distributors.

The removal of the GRC costs from the rate to which the price cap is applied would also be consistent with treatment of costs associated with an incremental or advanced capital module. In both cases, the price cap is not applied to the amounts built into rates for these modules.

The OEB could approve a variance account around the GRC Y-factor to ensure that ratepayers pay the forecasted costs and nothing more or less. This would ensure that ratepayers pay the actual costs related to the GTC and OPG recovers its costs. There would be no winners or losers based on this cost. In addition, if the provincial government were to change the applicable rates charged over the 2017 through 2021 period (increase or decrease), this change would protect both ratepayers and OPG by ensuring recovery of actual costs, not costs based on the assumption of no changes in the rates charged to OPG.

However, LPMA does not believe that a variance account would be necessary (assuming no changes by the government in the rates charged), since the GRC cost is directly proportional to the volume of production. An increase in production would lead to an increase in the GRC cost, but on a per unit of production basis, the difference would likely be minimal. The same would be true of a decrease in production. Any differences in GRC costs from that forecast in any given year will be offset by changes in revenues. Higher costs resulting from higher production are offset by higher revenues and lower costs resulting from lower production are offset by lower revenues.

Any changes resulting from a change in the rates charged by the government would qualify as a z-factor, in the view of LPMA. If the cost impact was material in any given year, OPG would simply bring forward this z-factor request as part of a future application.

LPMA submits that Y-factor treatment of GRC is an appropriate alternative to a thtee-factor inflation index. It is simple to administer and ensures that ratepayers do not pay inflation adjusted rates on a significant cost component that does not attract inflation. It also provides protection to OPG in that it will not have to find additional savings in other areas of its operations to match the base productivity and stretch factor "savings" from the GRC that it would need to find.

The Base X-Factor

LPMA has reviewed the detailed Staff submissions on the base X factor and adopts those submissions and will not repeat them here. LPMA agrees that the best evidence in this proceeding supports a base productivity figure of 0.29%. LPMA submits that this is more reasonable than the 0% proposed by OPG and is based on a sounder methodology.

If the OEB approves the continued use of the CRVA as originally proposed by OPG, then the base X-factor should be increased to reflect this, as discussed below under the heading 'Supplemental Capital Revenue – The CRVA'.

The Stretch Factor

LPMA accepts the 0.3% stretch factor as proposed by OPG based on the evidence provided in this proceeding. LPMA also supports the fixing of the stretch factor at this level over the 5-year term of the IRM. This reflects the fact that there is no process in place to undertake an annual benchmarking exercise to adjust the X-factor each year, as is done for the electricity distributors.

LPMA submits that the OEB may want to consider if doing an annual benchmarking exercise for OPG so that the stretch factor could change each year beginning in the IR term would be reasonable to pursue.

The Z-Factor

LPMA submits that there should be separate Z-factors for the hydroelectric and nuclear businesses. This is because of the different incentive mechanisms being used. Submissions related to the nuclear Z-factor are found under Issue 11.4 below.

OPG continues to request a Z-factor related to the regulated hydro-electric business with a materiality threshold of $10 million, unchanged from previous proceedings.

LPMA submits that the threshold should be updated given the movement to incentive regulation. What better time to update the threshold, especially considering the growth in rate base as part of the current price cap application.

As indicated in the response at Exhibit L, Tab 11.1, Schedule 5, CCC-047, the current $10 million threshold was based on 0.25% of the average annual hydroelectric rate base as approved in EB-2007-0905. LPMA submits that the materiality threshold should be updated to reflect the most recent approved rate base to bring it more up to date, including the significant increase in rate base that took place in EB-2013-0321 to reflect the addition of previously unregulated hydroelectric assets, as well as the Niagara Tunnel project. Indeed, as shown in the response the above noted interrogatory, the regulated hydro electric rate base nearly doubled between EB-2007-0905 and EB-2013-0321. This should be reflected in the materiality threshold.

LPMA also submits that the materiality threshold should be based, at least in part, on the regulated hydroelectric revenue requirement to bring its calculation more in line with the methodology used for electricity distributors, where the threshold is based on 0.5% of the revenue requirement.

LPMA submits that a 50/50 weighting of 0.25% of the regulated hydroelectric rate base and 0.50% of the regulated hydroelectric revenue requirement should be used to set the materiality threshold for the regulated hydroelectric operations under the price cap IRM. As seen in interrogatory response to CCC-047 noted above, updating these figures to the approved EB-2013-0321 figures results in an average threshold value of $12.7 million. LPMA submits that the OEB should set the regulated hydroelectric materiality threshold using this methodology, and using the last OEB figures from EB-2013-0321.

Continuing to use a threshold based on numbers that are more than 10 years out of date is no longer reasonable, especially in light the nearly doubling of the regulated hydroelectric rate base that is being paid for by ratepayers.

<u>Supplemental Capital Revenue – The CRVA</u>

OPG proposes to retain the operation of the CRVA for its regulated hydroelectric facilities. This has the potential to generate supplemental capital revenue on top of the additional revenue generated through the application of the price cap. LPMA further notes that the type of capital expenditures that are eligible for the CRVA are those that are routinely incurred by utilities in their normal operations.

LPMA is concerned about the potential and magnitude of double recovery that exists under a price cap incentive mechanism that includes supplemental revenue from a mandated CRVA.

This issue was identified in the PEG Research LLC report *IRM Design for Ontario Power Generation* filed as Exhibit M2 in this proceeding.

OPG updated its evidence in Exhibit H1, Tab 1, Schedule 2 on April 4, 2017 in which in introduced a CRVA Recoverability Threshold. In that evidence OPG states that it acknowledges that it would only be appropriate for it to recover any balance in the CRVA if it can demonstrate that the costs of the projects recorded in the account have not been funded through base payment amounts during the 2017-2021 period.

LPMA agrees with the above noted concept, but strongly disagrees with the mechanics of the OPG proposal to calculate the CRVA recoverability threshold. Only the revenue requirement of CRVA-eligible capital expenditures in excess of the sum of the CRVA-eligible and sustaining capital projects combined would be eligible for recovery.

The OPG proposal calculates the threshold based on depreciation only, adjusted each year by the I – X price cap factor. LPMA submits that this approach does not conform with the OEB determination of the level of capital that can be supported under a price cap incentive mechanism.

A formula for the determination of the materiality threshold to be used in determining the applicable eligible capital for an incentive capital module ("ICM") in the EB-2007-0673 Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, dated September 17, 2008. In that report, the OEB determined a formula based on approved rate base and depreciation, along with growth and the price cap index to be used in determining the materiality threshold.

The formula that was adopted was in response to concerns that a price cap index may not be adequate to support new capital expenditures, especially for utilities that were experiencing significant growth and/or replacement costs. At the same time, some level of capital expenditures could be met through existing rates. The OEB summarized this as follows in the report (page 32):

> *"With rebasing at the end of 2nd Generation IR, and before commencing 3rd Generation IR, a distributor's rates include a CAPEX component. The adequacy of such CAPEX provision in rates during 3rd Generation IR depends on whether or not the need for CAPEX during 3rd Generation IR can be met through existing rates, as adjusted under the 3rd Generation IR regime and considering organic growth. There is no dispute among participants that the price adjustment and organic growth factors should be captured in the calculation of the threshold and that not doing so would amount to "double-dipping"."*

The OEB determined that the appropriate CAPEX to depreciation threshold value to establish materiality for the incremental capital module should derived using the following formula:

Threshold Value = 1 + (RB/d) x (g + PCI x (1 + g)) + 20%
Where:
RB = rate base included in base rates ($);
d = depreciation expense included in base rates ($);
g = distribution revenue change from load growth (%); and
PCI = price cap index (% inflation less productivity factor less stretch factor

This formula was based on an analysis provided in the OEB Report at page 27. It has been reproduced as Appendix B to this submission. In summary, the formula approved by the OEB was based on the following equation (excluding the 20% dead band):

CAPEX = d + RB x (g + PCI x (1 + g)).

This formula remains in use today, with two modifications as set out in the EB-2014-0219 Report of the OEB dated January 22, 2016. The first change was a reduction in the dead band from 20% to 10%. The second change was the addition of a multiplicative term to account for changes in the threshold value due to the compounding of the growth and price cap figures beyond the first year of the IR period.

OPG calculated the threshold and CAPEX figures using this formula in the response to Exhibit L, Tab 11.1, Schedule 11, LPMA-009, using OEB approved figures from EB-2013-0321. OPG assumed a price cap index of 1.5% and set growth to 0%. The resulting threshold was 188.6% and the CAPEX was $270.14 million.

LPMA is amenable to setting the growth rate to 0% for this analysis. This simplifies the CAPEX equation noted above to:

CAPEX = d + RB x PCI + 0.1 x d (the last term incorporates the 10% stretch factor).

In other words, the capital expenditures that can be financed under a price cap plan are equal to 110% of the approved depreciation, plus the price cap times the rate base value. This value would then be increased by the price cap index for each subsequent year in the IR period.

The threshold proposed by OPG, on the other hand, is equal to only 100% of the depreciation cost, adjusted annually by the price cap index. The OPG proposal excludes the addition of the 10% stretch factor. More importantly, it ignores the contribution to the amount of capital expenditures that can be financed based on the revenue derived from the application of the price cap index to the rate base.

LPMA submits that the CRVA recoverability threshold should be identical to the ICM threshold test. The ICM test determines the amount of capital expenditures that can be financed under the price cap index parameters, and the CRVA threshold proposed by OPG is meant to determine the amount that is beyond that available from the price cap index. They should be and need to be the same.

The OEB has already determined how this level is to be calculated. The OPG proposal significantly underestimates the amount of capital expenditures that can be financed under a price cap index model. LPMA submits that if the OEB decides to use the CRVA recoverability threshold test, it should use the same formula as is used for the ICM threshold calculation.

LPMA submits that the use of the threshold test as proposed by OPG is not reasonable because it fails to eliminate the double counting problem.

In support of this conclusion, LPMA draws the OEB's attention to Scenario 1 in the illustrative example provided in Exhibit H1, Tab 1, Schedule 2, Chart 1. In this scenario, OPG shows that based on its total hydroelectric capital expenditures, its total revenue requirement impact of service additions not funded through the payment amount (line 10) is $58.7 million in total over the 2017 to 2021 period. At the same time, the revenue requirement impact of the CRVA related in-service additions (line 2) is $31.1 million. This is based on $25 million per year of CRVA related in-service additions. OPG indicates that the amount recoverable would be the lower of these figures ($31.1 million).

For simplicity, LPMA has ignored the $4.7 million in credits that accrue to ratepayers that result from the EB-2013-0321 decision.

Now consider the same scenario, but with the $25 million in CRVA eligible capital expenditures reduced to $0 in each year and the sustaining capital increased by the same $25 million each year. The result shows that the revenue requirement impact of in-service additions not funded through the payment amount (line 10) would still be $58.7 million. This is because the total in-service additions at line 8 would not change. Only the composition of the total changes, but this has no impact on the revenue requirement impact. However, at line 2, the revenue requirement impact of the CRVA related additions would be $0 in every year, since there are no CRVA related projects. Based on the OPG methodology and their calculation of the threshold, they would collect nothing (i.e. the lesser of $0 and $58.7 million).

This illustrates that OPG would recover nothing in the absence of the CRVA (or in the absence of any CRVA related projects). In other words, the amount recovered by OPG is not dependent on the capital expenditures, but on the composition of the capital expenditures.

However, if the ICM threshold calculation ($270 million) was used in line 5 of Chart 1 – as is proposed by LPMA - line 10 would be $0 under both of the above scenarios, and OPG would not collect anything associated with the CRVA since it would not exceed the threshold, regardless of the makeup of the capital expenditures. LPA submits that this would be the proper outcome. The level of capital expenditures would not qualify for an ICM under the price cap IR. If the same level of capital expenditures result in CRVA recoveries then there is obviously an issue of double counting under the price cap IR.

The alternative to the above approach of calculating a CRVA recoverability threshold would be simply to revert to the original OPG proposal, which would simplify the use of the CRVA. OPG has indicated that over the 2017 through 2021 period, it forecasts capital expenditures of $952 million in aggregate, of which $335 million is associated with CRVA-eligible projects (Exhibit L, Tab 11.1, Schedule 15, SEC-095). CRVA entries each year would be based on the breakdown of the $335 in CRVA-eligible capital, which is also provided in the above noted interrogatory response. In aggregate, approximately 35% of the OPG capital spending during the IR term would be addressed by the CRVA.

To ensure no double recovery, LPMA submits that the OEB should approve an increase in the base X-factor, as recommended by PEG. The base x-factor would increase from 0.29% to 0.74% (Exhibit M2, Tab 11.1, SEC-001, Revised). As indicated in the interrogatory response, removing 35% of the capital spending during the IR term and using the same analysis used by PEG to arrive at a base X-factor of 0.29% increases this factor by 45 basis points. This was discussed in some detail during cross examination (Tr. Vol. 11, pages 25-27).

Finally, LPMA supports the Staff submission with respect to the need to escalate the $0.9 million credit to ratepayers as a result of EB-2013-0321 by the price cap I – X formula. Clearly the price cap adjusted payment amounts will capture some amount greater then $0.9 million in each year during the IR term and this amount should be credited back to ratepayers.

In summary, LPMA submits that the use of the CRVA in addition to a price cap I – X approach to incentive regulation requires an adjustment to either of the two OPG proposals. In the first instance, the CRVA recoverability threshold needs to be adjusted to reflect the true impact on the level of capital expenditures that can be financed under the price cap mechanism. The second, and simpler, approach is to simply increase the base X-factor to take into account the percentage of the hydroelectric capital spending that is forecast to be covered by the CRVA.

<u>11.2 Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?</u>

This issue is settled as noted in Exhibit O, Tab 1, Schedule 1, pages 15-165.

Nuclear
<u>11.3 Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?</u>

The OPG approach to incentive rate-setting for establishing the nuclear payment amounts is not appropriate as it does not meet the requirements of a Custom IR application as defined by the OEB through the RRFE and subsequent decisions.

The OEB sent a letter to OPG, dated February 17, 2015 (Re: Incentive Rate-setting for Ontario Power Generation's Prescribed Generation Assets). In that letter, the Board stated (page 2):

> *"The Board expects OPG to develop an IR framework for its hydroelectric assets, and a* ***<u>custom IR framework for its nuclear assets based on the principles outlined in the RRFE</u>****."* (emphasis added)

The OPG Custom IR plan is described succinctly in Chart 8 of Exhibit A1, Tab 3, Schedule 2 as including the revenue requirements of 5 future test years and then layering elements of incentive regulation onto this base. This was confirmed by Mr. Fralick (Tr. Vol. 6, page 171).

LPMA submits that this effectively means that OPG did a 5-year cost of service application that resulted in the 5 individual revenue requirements and then made some adjustments to these revenue requirements based on the application of a stretch factor that was applied to $1.7 billion of nuclear OM&A costs, which represents only about 75% of the total nuclear OM&A costs (Exhibit A3, Tab 2, Schedule 1, page 29). LPMA further notes that the stretch factor does not apply to any portion of the capital costs.

In the EB-2013-0416/EB-2014-0247 Decision dated March 12, 2015 in the Hydro One Networks Inc. application for approval of distribution rates for 2015 to 2019 the OEB stated (pages13-14):

> *"Hydro One chose to interpret the OEB's Custom IR option, referred to in the RRFE Report as "custom index", to include "custom cost of service". The OEB does not accept this interpretation.* ***<u>All three rate-setting methods are described in the Report as incentive rate-setting, not cost of service</u>****.*
>
> *Cost of service rate-setting has an important role in performance-based regulation regimes to periodically examine in detail the costs and activities underpinning rates. However, the OEB continues to believe that multi-year incentive rate-setting, with its emphasis on results, is the most effective way to incent behaviour similar to that seen in commercially-oriented, consumer market-driven companies.* ***<u>Incentive rate-setting differs from cost of service rate-setting in that it relies less on a utility's internal cost, output, and service quality to establish rates, and more on benchmarks of cost, output, and service quality that are external to the utility revealing superior performance and encouraging best practice. The decoupling of rates from the utility's own costs simulates a competitive market environment and is more compatible with an outcomes-based approach to regulation</u>****."*
> (emphasis added)

LPMA submits that the so-called Custom IR application for the nuclear generating assets does not reflect the principles outlined in the RRFE or in the Hydro One Decision noted above for a custom IR application.

In the October 13, 2016 Handbook the OEB set out a number of specific considerations for custom incentive rate setting at pages 25 through 28.

Under the bullet titled 'Index for the Annual Rate Adjustment" the Handbook states that Custom IR is not a multi-year cost of service and that explicit financial incentives for continuous improvement and cost control targets must be included in the application. The Handbook then goes on to state that these incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan, and not simply built into the cost forecast.

LPMA submits that the OPG approach – cost of service and 5 individual revenue requirements with some IR adjustments applied to the cost of service – is backwards from what is expected by the OEB. That is, Custom IR defined by the OEB should not be based on cost of service. Rather it should be based on outcomes. The 5-year cost of service forecast is only be used to inform the derivation of the custom index (see below). OPG did not do this – the 5-year cost of service revenue requirements form the basis of their Custom IR application.

The Handbook goes on to state that custom index used in a Custom IR must be informed by an analysis of the trade-offs between capital and operating costs. The Handbook further states that if a 5-year forecast is provided, it is to be used to inform the derivation of the customer index, not solely to set rates on the basis of multi-year cost of service. Again, OPG used the cost of service as the base of its Custom IR. Further, the custom index proposed by OPG only applies to 75% of the OM&A and not to capital. Clearly there is been no analysis of the trade-offs between OM&A and capital.

The OEB accepted that the large capital expenditures and reduced production associated with the DRP and the Pickering closure did not favour the implementation of a "pure IR" regime in the immediate future in the March 28, 2013 Report of the Board: Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets (EB-2012-0340).

LPMA submits that there are unique circumstances in the current application that need to be dealt with as an add-on to a Custom IR filing. These circumstances are the DRP and the PEO.

LPMA submits the costs associated with the DRP and PEO should be dealt with on a cost of service basis. The costs of these two items should be added onto the incentive regulation plan outcomes associated with the remainder of the nuclear operations.

Submissions with respect to the parameters of the incentive regulation plan that would be applied to the non-DRP and non-PEO components of the nuclear operations are provided below under Issue 11.4.

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

LPMA has broken its comments on this issue down into a number of sub-issues.

Custom Index

LPMA notes that OPG has not developed a custom index as part of the Custom IR application. Instead, OPG has embedded an inflation rate of 2% in its calculation of the revenue requirement using the cost of service methodology for each of the 5 years in the term of the Custom IR. The 2% inflation rate is consistent with OPG's Business Plan (Exhibit L, Tab 7.1, Schedule 15, SEC-089).

OPG then uses the stretch factor to reduce a portion of the OM&A costs.

LPMA submits that the use of an embedded inflation rate of 2% in the cost of service determination of the revenue requirements for each of the 5 years is too high. This is especially true in the near term, starting in 2018.

The OEB already has the information that will be used to calculate the weighted inflation rate based the average weekly earnings ("AWE") and the implicit price index for final domestic demand ("GDPIPIFDD"). This information is available from Statistics Canada for the 2016 year, which is the data that is used to calculate the inflation rate for 2018. As shown in Appendix A to this submission, the AWE increase for 2016 was 1.1% and the GDPIPIFDD increase was 1.2%. As a result, any weighting of these factors will result in an inflation rate of 1.2% at most for 2018. This is a substantial reduction from the 2.0% used by OPG.

How Should the OEB Proceed?

As noted above in the submission for Issue 11.3, LPMA submits that the OPG application does not meet the OEB's definition of a Custom IR. If the OEB accepts these submissions, then the question becomes how does the OEB determine the nuclear payment amounts?

LPMA submits that there are two ways the OEB could proceed. The first approach is to accept the cost of service based methodology used by OPG. The OEB would then make any adjustments it deems to be appropriate in terms of the OM&A and capital expenditures included in the cost of service forecast. Once these figures are determined, the OEB would then apply a stretch factor approved by the OEB to calculate the additional reductions to the resulting OM&A and/or capital costs to arrive at the nuclear payment amounts.

This approach requires the OEB to make decisions on each of the nuclear cost of service components of the application for each of 2017 through 2021.

The second approach is to use a custom index and apply it to the approved nuclear payment amount for 2017. This 2017 amount would be exclusive of the costs associated with the DRP and the PEO. The custom index, which would be a comprehensive I - X, would then be applied to the 2017 approved payment amount for each subsequent year, in the same manner that the price cap methodology is to be used for the regulated hydroelectric assets. This would result in the calculation of pre-DRP and pre-PEO nuclear payment amounts ($/MWh) for each of 2018 through 2021 based on the 2017 payment amount and the subsequent application of the inflation less productivity and stretch factor adjustments. The cost impacts associated with DRP and the PEO would then be added to this approved payment amount each year to arrive at the total nuclear payment amount.

This would require the OEB to make decisions on the various components of the 2017 nuclear cost of service, as does the first option noted above. However, unlike the first option, the OEB would not need to make any determinations with respect to OM&A and capital for the 2018 through 2021 years.

LPMA submits that the second approach is a simpler approach and ensures that productivity is incented in both capital and OM&A expenditures. It is an appropriate approach to the nuclear assets that exclude DRP and the PEO as the remaining expenditures (both OM&A and capital) are stable.

The only reasons that the price cap IR does not work for the nuclear assets are the DRP and PEO projects. The OEB confirmed this in the March 28, 2013 Report of the Board: Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets (EB-2012-0340) in which it stated that (page 8):

> *"The Board accepts that the large capital expenditures and reduced production associated with the DRP and the Pickering closure do not favour the implementation of a "pure IR" regime (i.e., one based on TFP with input cost indices, Z-factors and off-ramps) in the immediate future. The Board*

also accepts that introducing an IR regime for the nuclear generation assets will be a longer-term process than is the case for the hydroelectric assets given the greater degree of uncertainty and risk inherent in the nuclear capital investment program."

With the treatment of the DRP and PEO projects on a cost of service basis (and the accompanying mandatory variance account), LPMA submits that the remaining nuclear capital investment program is comparable to previous years. This submission is based on the evidence provided in Exhibit D2, Tab 1, Schedule 2.

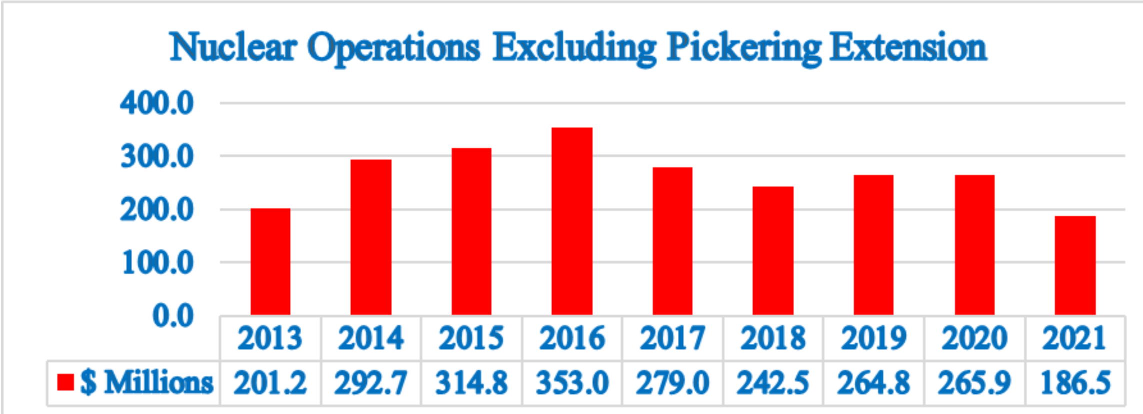
Tables 1 and 2 in the above noted exhibit show the nuclear operations capital expenditure summary for 2013 through 2021, excluding DRP capital. Table 2 provides a break down of the nuclear operations capital into portfolio projects (Darlington, Pickering, nuclear support division, unallocated), Darlington new fuel and minor fixed assets.

A review of these figures shows that average nuclear operations capital expenditure for the bridge (2016) and test (2017-2021) years is $275 million. Excluding the bridge year, the average is $259 million. Actual nuclear operations capital expenditure in 2013 through 2015 averaged $270 million.

Included in the unallocated portfolio projects shown in Table 2 in the above noted exhibit are the capital costs associated with the PEO project. The capital expenditures associated with this project in the test years is shown in Exhibit L, Tab 6.5, Schedule 1, Staff-120, and average $11.7 million.

When the PEO project capital expenditures are removed from the nuclear operations figures, the resulting nuclear operations average over the 2017 through 2021 period drop to about $247 million. This is about 8.5% or $23 million per year less than the historical average of $270 million recorded in 2013 through 2015.

The following chart illustrates this by showing the actual/forecast nuclear operations capital expenditures excluding the PEO. The figures provided in the chart are taken from Table 2 in Exhibit D2, Tab 1, Schedule 2 and subtracting the PEO figures from Exhibit L, Tab 6.5, Schedule 1, Staff-120.



Based on the evidence provided in this proceeding of the nuclear capital expenditures excluding the DRP and the PEO project, LPMA submits that the standard comprehensive price cap approach is appropriate for OPG's remaining nuclear assets. LPMA submits that this approach to Custom IR for OPG – standard comprehensive price cap for the non-DRP and non-PEO projects and cost of service for the DRP and PEO projects is more line with the RRFE than is the OPG proposal, which starts with a cost of service determine of revenue requirement accompanied by a partial adjustment to OM&A through a stretch factor, and no adjustment to capital costs.

LPMA submits that its proposed approach is more in line with the RRFE than that of OPG because it eliminates the need for a cost of service review of the test years beyond the 2017 rebasing year and ensures that the stretch factor applies to total costs. This incents productivity in both capital expenditures and OM&A and more effectively addresses one of the key aspects of the OEB's RRFE, being the requirement to continue to make productivity improvements.

LPMA also notes that the proposed use of an inflation less stretch factor methodology for the regulated nuclear assets excluding the DRP and PEO projects costs ensures that a better indicator of inflation is used each year. As noted above under the "Custom Index" heading in this submission, OPG has used an inflation rate of 2.0% in its cost of service determination of the revenue requirement for each of the test years, while the inflation rate that will be used by the OEB for price cap plans for 2018 will be closer to 1.2%.

In summary, there is no need for a departure from the use of a price cap IR methodology for the non-DRP and non-PEO project nuclear assets. There are no large capital expenditures that are out of the ordinary for the nuclear operations. The net plant for the nuclear rate base, excluding DRP, is relatively constant throughout the forecast period. This is shown in Table 6 in the Staff submission.

LPMA also notes that this price cap approach is comparable to the hydroelectric proposal and ensures that the same inflation rate is applied to the regulatory regime for the regulated hydroelectric assets and the nuclear operations assets. It is a simpler approach and provides better incentives to OPG to continue to make productivity improvements in all aspects of its operations.

Application of the Stretch Factor

OPG has proposed a stretch factor that would be applied to the base nuclear OM&A and the nuclear allocation of corporate costs. It would not apply to project OM&A, outage OM&A, Darlington refurbishment OM&A, Darlington new nuclear OM&A, the allocation of centrally held and other costs, asset service fees or property tax. All of these categories are shown in Table 1 of Exhibit F2, Tab 1, Schedule 1. In aggregate, the two categories of OM&A costs that OPG proposes to apply the stretch factor to represent about 75% of the nuclear OM&A costs. The stretch factor would not apply to any capital costs.

LPMA submits that the stretch factor should be applicable to 100% of the OM&A costs, excluding those costs associated with the DRP and the PEO. Similarly, LPMA submits that the stretch factor should be applied not only to the OM&A costs, but also to the capital costs. Both of these extensions to the use of the stretch factor beyond that proposed by OPG reflect the expectations that OPG should be able to improve its cost performance in all aspects of its operations, and not a subset of those activities.

OPG has provided no evidence to support the application of the stretch factor to only 75% of its OM&A, rather than to all of the nuclear OM&A, excluding DRP and the PEO. In fact, OPG readily agreed that it could find additional savings in the OM&A expenditures that it proposes to exclude from the stretch factor:

> *"MR. FRALICK: What we're suggesting is for the reasons we outlined earlier with our -- some of the compensation restraints, regulatory and safety requirements, and other things that are inherent within the base OM&A where we are applying the stretch factor, we will necessarily be required to look elsewhere in order to come up with that savings.*
>
> ***So I'm not saying that we cannot find or won't be looking to get better within those cost categories****, but as a category, they are much more discrete, and they do not lend themselves to efficiency gains the way the base OM&A cost category does."* (Tr. Vol. 6, page 174) (emphasis added)

LPMA submits that the stretch factor should also be applied to the capital cost component of the revenue requirement and not only to the OM&A component. The capital cost component of the revenue requirement includes not only the cost of capital (debt and equity) but also depreciation and income taxes.

As stated in the Decision and Order for EB-2014-0116 for the Toronto Hydro-Electric System Limited ("Toronto Hydro") application for distribution rates effective from May 1, 2015 and for each year through to 2019 dated December 29, 2015, the OEB stated that it had consistently applied stretch factors to total costs in order to incent productivity in both the areas of capital expenditures and OM&A.

Like OPG, Toronto Hydro did not propose to apply the stretch factor to its capital. The OEB found that while the application put forward by Toronto Hydro may be a custom application, one of the key aspects of the OEB's RRFE is the requirement to continue to make productivity improvements.

In the Handbook, the OEB stated that the index used in a Custom IR must be informed by an analysis of the trade-offs between capital and operating costs. LPMA submits that the only way to ensure that these trade-offs are made in an efficient manner is to apply the stretch factor to both OM&A and capital.

LPMA notes that Staff does not recommend applying the stretch factor to capital as part of this Customer IR plan in part because the compatibility with the CRVA was not sufficiently tested in the proceeding (Staff Submission, page 170). LPMA submits that this is not a valid reason for not applying the stretch factor to the capital component. Under the LPMA proposal, the stretch factor is applied to all OM&A and capital that is not associated with the DRP and PEO. The CRVA is applicable to these costs and not to the costs where the stretch factor would be applied. By definition, there would be no overlap of the costs/projects covered by the CRVA and the costs/projects that do not fall under the CRVA where the stretch factor would be used.

In summary, LPMA submits that the OEB should direct OPG to apply the stretch factor to all of the OM&A costs and capital costs (exclusive of DRP and PEO related costs) to ensure that productivity improvements are made in a fair and rational manner across both areas of costs.

Stretch Factor Level

LPMA submits that the proposed stretch factor of 0.3% is not appropriate and does not reflect the evidence in this proceeding. The 0.3% was based on Darlington having a stretch factor of 0.0% and Pickering having a stretch factor of 0.6%. The 0.0% and 0.6% figures are taken from top (Group I) and bottom (Group V) of the stretch factor assignments that the OEB have put in place for electricity distributors.

The evidence in this proceeding is clear. Based on the most recent information available, that being the 2016 Nuclear Benchmarking Report filed in Exhibit L, Tab 6.2, Schedule 15, SEC-63, Attachment 3, (with data up to and including 2015) OPG's total generating cost ranked 12th out of a comparator group of 13. This ranking is based on a 3-year rolling average. This ranking also shows that OPG has slid down the ranking from 8th in 2013 to 10th in 2014 and now to 12th in 2015.

Based on this overall total generating cost, OPG would be placed in the final group, with an associated stretch factor of 0.6%. LPMA submits that this is the appropriate stretch factor that the OEB should approve.

If the OEB determines that the stretch factor should be based on a weighting of Darlington and Pickering, rather than on OPG overall, then LPMA submits that the OEB should approve a stretch factor not less than 0.5%. This figure is determined as follows.

OPG stated (Tr. Vol. 6, page 129) that it had calculated the stretch factor using the 2015 data and the station specific total generating costs for Darlington and Pickering and the resulting weighted figure was 0.43%. Based on the response provided in Exhibit L, Tab 11.3, Schedule 2, AMPCO-156, OPG would round this figure to the nearest 4GIRM stretch factor, which would 0.45%. This is the stretch factor assigned to utilities in Group IV, the second worst group in terms of stretch factor assignments.

The October 13, 2016 Handbook, under the heading 'Specific Considerations for Custom Incentive Rate Setting' states (page 26):

> *"It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications. Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors."*

It is clear that OEB expects an applicant using the Custom IR methodology to use an X factor that is greater than the standard X factor. Given that the standard X factor calculated by OPG would be 0.45%, LPMA submits that an increase to at lease 0.5% is appropriate, especially in light of the declining performance of OPG relative to its comparables as noted above from 2013 through 2015.

<u>Z-Factor</u>

OPG continues to request a Z-factor related to the nuclear business with a materiality threshold of $10 million (Undertaking J8.2), unchanged from previous proceedings.

LPMA submits that the threshold should be updated given the movement to incentive regulation. What better time to update the threshold, especially considering the growth in rate base as part of the current nuclear application.

As indicated in the response at Exhibit L, Tab 11.1, Schedule 5, CCC-047, the current $10 million threshold was based on 0.25% of the average annual hydroelectric rate base as approved in EB-2007-0905. LPMA submits that the Z-factor materiality threshold should reflect the nuclear rate base and not the hydroelectric rate base. LPMA also submits that the materiality threshold should reflect the nuclear revenue requirement to bring its calculation more in line with the methodology used for electricity distributors, where the threshold is based on 0.5% of the revenue requirement.

LPMA submits that a 50/50 weighting of 0.25% of the nuclear rate base and 0.50% of the nuclear revenue requirement should be used to set the materiality threshold for the nuclear operations under the Custom IR. As seen in Undertaking J8.1, this would result in an average threshold value of $14.4 million. LPMA submits that the OEB should set the nuclear materiality threshold using this methodology, updating the nuclear revenue requirement and rate base to reflect the outcome of the OEB decisions that impact these figures.

This will ensure that the materiality threshold grows in conjunction with the growth in the revenue requirement and rate base of the associated business. Continuing to use a threshold based on numbers that are more than 10 years out of date is no longer reasonable, especially in light the additional costs that will be paid by ratepayers for the growth forecast.

<u>Annual Update of Return on Equity</u>
OPG proposes to update the return on equity on an annual basis for its nuclear assets and record the difference in the revenue requirement between that return on equity and the 8.78% built into the revenue requirement for each of the 5 years in a variance account for later disposition to ratepayers.

LPMA submits that proposal is appropriate for a cost of service application, which the Custom IR effectively is. While OPG has included forecasts of inflation into the cost of service and a forecast for the cost of debt into the cost of service (Exhibit C1, Tab 1, Schedule 2, page 4), it did not attempt to forecast a rate for the return on equity beyond the 2017 test year. Instead, it proposed to update the return on equity each year based on the OEB approved rate and record the difference in a variance account.

If he OEB were to accept the submissions of LPMA related to the incentive mechanism to use for the nuclear assets (i.e. comprehensive price cap I-X approach to the non-DRP and non-PEO projects) and a cost of service approach (along with the CRVA) for the DRP and PEO projects, then the return on equity should only be updated for the DRP and PEO projects which are under a cost of service approach.

There should be no return on equity adjustment for the remaining nuclear assets for the same reason that OPG is not requesting a return on equity adjustment for the regulated hydroelectric assets, which are also proposed to be under a comprehensive price cap I-X approach.

Based on the evidence at Exhibit A1, Tab 3, Schedule 2, page 4, OPG made a number of changes to the planned application based on its stakeholder consultation. One of the changes made was the elimination of a capital variance account that was proposed to record the differences in the hydroelectric return on equity during the IR term. As indicated in the response to an interrogatory (Exhibit L, Tab 11.1, Schedule 3, CME-004), OPG removed the request for this account because it was pointed out to them that in the EB-2006-0088 *Report of the Board on 2nd Generation IRM,* the OEB addressed the issue of changes in return on equity and debt during an IRM term. At page 30 of that Report, the OEB indicated that it was satisfied that during the term of a plan, changes in the GDP-IPI inflation factor would implicitly recognize changes in the return on equity and debt rates. The OEB concluded that no further adjustment for the return on equity (or debt costs) would be required.

LPMA submits that the same reasoning would apply to the base nuclear assets that would be under a comprehensive price cap I-X incentive mechanism. Changes in the return on equity rate would be implicit in the inflation rate.

<u>11.5 Is OPG's proposed mid-term review appropriate?</u>

OPG seeks approval of a mid-term production review in the first half of 2019 (i.e., prior to July 1, 2019) for an update of the nuclear production forecast and the related updates to nuclear fuel costs underpinning the payment amounts for the final two-and-a-half years of the 5-year application period (July 1, 2019 to December 31, 2021) and the disposal of applicable audited deferral and variance account balances (most accounts would reflect amounts accumulated over the period January 1, 2016 to December 31, 2018) as well as any remaining unamortized portions of previously approved amounts with recovery period extending beyond December 31, 2018. (Exhibit A1, Tab 3, Schedule 3, page 10).

As noted above under Issue 11.3, LPMA submits that the Custom IR mechanism approved by the OEB should be consistent as possible with the Custom IR mechanism that was designed as part of the RRFE Report.

Nuclear Production Forecast

LPMA submits that the OPG proposal to review and, if necessary, adjust the nuclear production forecast for the final 2.5 years of the 5 year Custom IR period is not consistent with RRFE Report. The RRFE Report clearly states (at page 18) that *"In the Custom IR method, rates are set based on a five year forecast of a distributor's revenue requirement and **sales volumes**."* (emphasis added). While OPG wants the revenue requirement for the full 5-year period to be determined by the OEB in this proceeding, rates are only set for the first 2.5 years. This is because the nuclear production forecast could change as part of the mid-term review. This would either change the rate in the second half of the Custom IR term or the difference in the new rate and the rate approved in this application are tracked in a variance account for future disposition, the result is the same. The Custom IR plan effectively has a term of only 2.5 years. Rates for the second 2.5 years would be determined as part of a separate application as part of the mid-term review. This clearly violates the minimum 5-year term of a Custom IR as set out on page 13 of the RRFE Report.

On page 19 of the RRFE Report, the OEB expected that distributors would file robust evidence of its cost and revenue forecasts over a 5-year horizon. The OEB also indicated that any distributor's application under Custom IR would demonstrate the ability of that distributor to manage within the rates set, *"given that actual costs **and revenues** will vary from forecast."* (emphasis added)

As noted above under Issue 11.3, in the October 13, 2016 Handbook the OEB set out a number of specific considerations for custom incentive rate setting at pages 25 through 28.

Under the bullet titled 'Index for the Annual Rate Adjustment" the Handbook states that Custom IR is not a multi-year cost of service. LPMA submits that the ability for OPG to seek a mid-term adjustment to the sales volumes and revenues is similar to a multi-year cost of service adjustment. Under the OPG proposal, rates could be adjusted for the second half of the IR term based on changes to the production (volume and revenue) forecast. LPMA submits that this is in violation of the definition of a Custom IR.

Under the bullet titled "Updates", the OEB is quite clear that after rates are set as part of the Custom IR application, the expectation is that there would be no further rate applications for annual updates within the 5-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. The OEB then goes on to list specific examples which it does not expect to address (page 26):

> *"For example, the OEB does not expect to address annual rate applications for updates for cost of capital, working capital allowance or* ***<u>sales volumes</u>****."* (emphasis added)

The Handbook also states that a utility that cannot forecast its needs within the 5-year term, or does not believe it can operate with this level of uncertainty, should consider whether the Custom IR option is appropriate for its circumstances. OPG filed a Custom IR knowing the OEB requirements. As a result, LPMA submits that OPG should be required to live with its forecasts, as approved by the OEB, including the nuclear production forecast.

LPMA submits that the mid-term review clearly violates the Custom IR methodology as set out by the OEB in both the RRFE Report and the Handbook. LPMA submits that the OEB should not approve the mid-term review proposed by OPG.

It should further be noted that if there is a material change in the nuclear production forecast there may also be material changes in OM&A, income taxes and/or capital expenditures. LPMA submits that if the net change is material and meets the other qualifications of a Z-factor, OPG would be able to file such an application with the OEB. In other words, the availability of a Z-factor event negates the need for the mid-term review.

<u>Deferral and Variance Accounts</u>

With respect to the disposal of applicable audited deferral and variance accounts, LPMA notes that the OPG proposal could result in significant large balances to be disposed of since OPG proposes to accumulate the balances for 2016, 2017 and 2018 and clear them as part of the mid-term review in mid-2019.

LPMA submits that the OEB should reject OPG's proposal for dealing with the disposal of these accounts as part of the mid-term review. Not only could the balances in these accounts grow to significant amounts over the three years proposed for accumulation, but these balances could also accrue a significant amount of interest. If the balances are amounts to be collected from ratepayers, this only adds to the future burden of customers.

If the balances are amounts to be refunded to ratepayers, it should be refunded to them as soon as possible to help alleviate the burden on ratepayers of high and increasing electricity costs in this province.

Finally, LPMA notes that accumulating balances over a three year period before disposition leads to a significant possibility that the balances will be disposed of over a multi-year period in order to reduce rate impacts. This means that balances accumulated over a 3-year period could be disposed of over the following 3-year period. There would also be an intervening period from the end of the period when the balances are accumulated (December 31, 2018) to when the OEB would approve disposition of the amounts, which would likely be in the second half of 2019 since the mid-term review does not need to be filed until the end of June. The resulting accumulation/disposition period would, therefore, approach a period of close to seven years. LPMA submits that this introduces a significant level of intergenerational inequity into the proposal.

LPMA submits that the OEB should direct OPG to file annually to dispose of deferral and variance account balances. This would reduce the potential for large balances and reduce the need for extended disposition periods. It would reduce to a minimum the issue of intergenerational inequity. LPMA notes it would also be consistent with the current five year IRM plans of Union Gas and Enbridge Gas Distribution.

If the OEB does allow for a mid-term review of the nuclear production forecast, then it should also allow for a change in the forecast fuel costs. However, LPMA still submits that in this scenario, the OEB should still direct OPG to file annual disposition applications for the deferral and variance accounts.

11.6 Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

LPMA has two major concerns with rate smoothing. The first is that the deferral account attracts compound interest at the OEB-approved long-term debt rate for OPG and that the balance in the deferral account cannot begin to be recovered until the completion of the DRP. This means that there is a risk of a substantial amount of carrying costs being added to the deferred revenue in the account due to both high and possible increasing long term debt rates and the length of time until the account can be recovered. OPG's proposal would result in about $1 billion in revenue requirement being deferred to future generations. OPG has estimated that over the 5-year test period, the cumulative interest associated with the proposed rate smoothing would be $116 million (Tr. Vol. 22, page 46) and that over the total 10-year deferral period and 10-year recovery period, the cumulative interest would amount to $1.4 billion.

The second major concern of LPMA with respect to rate smoothing is the magnitude of the revenues that will be deferred to future customers and the overall impact that will have on rates in the future.

LPMA submits that the OEB needs to keep in mind that rate smoothing has negative consequences as well as positive impacts for ratepayers. The positive impact is the avoidance of rates that would go up in some years and down in others, along with the avoidance of a large variance in the changes on a year-to-year basis.

The largest increase in the WAPA, as shown in Appendix A to the Staff submission is $3.67, in 2020. Based on an average residential bill of $150, this represents an increase of just under 2.5%. LPMA submits that this change may also be somewhat misleading, as the total bill impact is also influenced by distribution rate changes, the movement to a 100% fixed rate charge for residential customers and transmission rates. Another important factor that could dwarf any changes (up or down) in OPG's WAPA in terms of the total bill is the weather. A hot summer will increase total bill impacts by more than 2.5%, while a cool summer will have the opposite effect.

The negative consequences on ratepayers is a significant shift of costs to future generations and magnified by a significant accumulation of interest costs. This deferral of costs and the associated increase in carrying costs results in an average monthly bill increase of 17 cents less than if no rate smoothing took place (82 cents from Schedule A of the Staff submission versus 65 cents of OPG's WAPA proposal). With all due respect, this difference will not be noticeable to residential customers. In other words, the cost associated with the rate smoothing proposal of OPG will be significant and the benefits will not even be noticeable.

Like Staff, LPMA believes that WAPA smoothing is comparable to choosing a longer amortization period when taking out a home mortgage. The longer amortization period will result in lower monthly payments, but ends up costing the home owner more over the life of the mortgage. Similarly, LPMA submits that the rate smoothing has the same impact as making only the minimum payment on a credit card bill. While this lowers costs in the immediate term, it ends up costing customers much more in the end.

LPMA submits that like credit card or mortgage payments, customers are better off if they can pay more of the costs off up front. While they may not be able to pay all of the costs right away, they more they can pay now, the less they will have to pay down the road.

The major difference is that in the mortgage example, the decision to pay now or more later is made by the homeowner. Ratepayers do not get to make the decision with respect to the trade off between current and future costs with respect to the level of rate smoothing. This is especially important to residential customers and long-lived commercial activities such as rental properties. These properties will be around for generations. Ownership may change from time to time, but the underlying need for places to live remains. Deferring costs to the future simply means that the cost for these customers will be higher in the future than they would be in the absence of the deferred revenue.

LPMA also notes that while OPG is guaranteed recovery of any amounts placed in the smoothing deferral account, there is an associated cost to OPG. The revenue that is deferred has a negative impact on cash flow and increases the borrowing requirements of OPG. This would have negative impacts on OPG's credit metrics and could result in higher costs of borrowing. This would also ultimately result in higher costs for ratepayers in the longer term.

The recovery of more revenue up front, relative to that proposed by OPG should also result in less of a need for a higher equity component of the capital structure as this would improve cash flow and reduce the need for borrowing. Again, this is a benefit to OPG and has positive impacts (less costs) for ratepayers.

LPMA also supports the Staff submissions with respect to the Fair Hydro Plan and the smoothing impact that has.

LPMA echoes the three other points made in the Staff submission. First, OPG's smoothing proposal is dependent on the requested revenue requirement. If the OEB reduces that revenue requirement, the need for the degree of rate smoothing proposed by OPG would likely be reduced. Second, the OEB could use the disposition of the various variance and deferral accounts to smooth bill impacts. Third, if the OEB approves a lower amount of the DRP contingency as compared to that requested by OPG, the need for – and cost – of revenue deferral would be reduced.

This final point on the DRP contingency has the benefit of effectively shifting dollars out of the high carrying cost rate smoothing deferral account into the lower carrying cost CRVA. However, this could also result in larger balances included in the CRVA than would have been in RSDA, offsetting the benefit of lower rates in the CRVA.

Finally, LPMA agrees with the Staff and OPG submissions that the OEB should hold off on making a decision on the level of smoothing until the payment amount order stage.

LPMA submits that the OEB should direct OPG to provide the unsmoothed WAPA figures as part of the draft payment order and allow all parties, including OPG, to provide submissions on an appropriate soothing proposal that balances the impacts on both ratepayers and the company.

General

11.7 Is OPG's proposed off-ramp appropriate?

The OPG proposal related to an off-ramp indicates that a regulatory review may be initiated if OPG's annual reporting shows performance outside of the +/- 300 basis points ROE dead band, or if performance erodes to unacceptable measures (Exhibit A1, Tab 3, Schedule 2, page 7). LPMA has taken measures to mean levels.

OPG states that the regulated return on equity would be calculated on a combined basis, including both regulated hydroelectric and nuclear generation lines of business (Ex. L, Tab 11.7, Schedule 11, LPMA-012).

OPG further states (Exhibit L, Tab 11.7, Schedule 1, Staff-271) that the calculation of the regulated return on equity would not impacted by the rate smoothing mechanism. The regulated ROE would be reflective of the unsmoothed revenue and the amount included in RSDA each year would continue to be included in income for the purposes of calculating the actual ROE.

LPMA submits that the proposed off-ramp is appropriate and should be approved by the OEB. The off-ramp is consistent with that set out in the RRFE Report and as noted earlier under Issues 11.1 and 11.3, LPMA believes that the incentive mechanism used by OPG should be aligned and as consistent as possible with the RRFE Report. The use of 300 basis point dead band and calculating the ROE based on actual income (i.e. excluding the impact of rate smoothing) and calculating the ROE based on the entire regulated entity are all consistent with the RRFE Report.

12.IMPLEMENTATION

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

LPMA notes that OPG has requested rates be effective January 1, 2017. LPMA submits that the Board should deny this request and make rates effective the first day of the month following the Board Decision and approval of the rate order. There should be no recovery of any shortfall from the beginning of 2017 to the implementation date.

OPG did not file its evidence until near the end of May, 2016 and should have known that with only seven months to the end of the year, it would be almost impossible to have rates in place for January 1, 2017. In fact, LPMA submits that OPG should have filed several months earlier than it did in order to get new rates implemented for January 1, 2017.

OPG was, or should have been, acutely aware of the OEB's practice of not allowing a utility to retrospectively recover amounts from the point where the interim order was in effect in cases where utilities did not file their applications in time to have rates in place prior to the effective date. This was spelled out in great detail by the OEB in the EB-2013-0321 Decision with Reasons dated November 20, 2014 for OPG. In that decision, the OEB stated in response to the request for a January 1, 2014 effective date proposed by OPG that (pages 134-135):

> *The Board is not prepared to accept the January 1, 2014 effective date proposed by OPG as it is contrary to the Board's long-standing practice of setting rates on a forecast (i.e. forward test year) basis.*
>
> *The Board's general practice with respect to the effective date of its orders is that the final rate becomes effective at the conclusion of the proceeding. This practice is predicated on a forecast test year which establishes rates going forward, not retrospectively. Going forward, the utility knows how much money it has available to spend and the ratepayer knows how much it is going to cost to use electricity in order to make consumption decisions. The forecast test year enables both the utility and the 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.*
>
> *The Board must control its regulatory process. The Board hears a large number of cases throughout the year and must plan its resources accordingly to ensure cases are completed and decisions are rendered. In cases where utilities have not filed their applications in time to have rates in place prior to the effective date, the Board's practice has typically been to not allow the utility to retrospectively recover the amounts from the period where the interim order was in effect.*[124]

The footnote (124) in the above passage referred to the following decisions: EB-2012-0165 (Sioux Lookout); EB-2013-0139 (Hydro Hawkesbury); EB-2012-0113 Centre Wellington; and EB-2013-0130 Fort Frances.

In the even more recent EB-2015-0072 Decision and Order dated August 18, 2016 for Grimsby Power Inc., OEB staff submitted that 266 days is the established metric to issue a decision and rate order after an application is filed and an oral hearing is held. Grimsby filed its application on December 23, 2015. As a result, OEB staff submitted that the appropriate effective date for 2016 rates was September 1, 2016.

Under the Findings heading (page 11) of the August 18, 2016 EB-2015-0072 Decision and Order the Board stated:

> *The OEB approves September 1, 2016 as the effective date of Grimsby Power's 2016 rates. The OEB finds that the delay in filing the application was within Grimsby Power's control and sufficient time must be allowed for the OEB's open and transparent rate setting process. The OEB finds that September 1, 2016 is appropriate given the date of this Decision and the time provided for the rate order process.*

Ratepayers have been very clear on the issue of retroactive rates, whether changes are made retroactively for energy already consumed, or through rate riders that collect foregone revenues based on future consumption. In either case, ratepayers do not want to pay for past consumption based on rates that were not in place at the time consumption took place. The onus is on the utility to ensure a timely filing is made in order to have new rates in place when requested. LPMA submits that OPG failed to meet this onus.

OPG was well aware that this application would be significant, complex and unique. It said so on the very first page of its Argument-In-Chief (emphasis added):

> ***By any measure, this is a significant Application***. ***It includes review of the Darlington Refurbishment Program ("DRP" or the "Program"), the single largest capital project ever to come before the OEB****, and requests approval of some $5,177.4M of DRP-related in-service additions*. ***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 the energy generated in Ontario. It operates two nuclear facilities that differ in size, number of units and vintage of CANDU technology employed. It has extensive regulated hydroelectric facilities that range from the very large and complex generation at Niagara Falls to much smaller facilities on rivers across the Province.* ***The diversity of technology, the numerous facilities of different sizes and vintages, the geographic dispersion and the shear scope of OPG, all contribute to making it a complicated entity to operate and to regulate.***
>
> *In this Application, as in past filings, OPG has tried to present a large volume of information in an organized and understandable way.* ***But these efforts cannot make simple what is inherently complex.*** ***Even without the DRP, OPG is unique among Ontario regulated companies, electric or natural gas, in terms of scope, scale and complexity.***

OPG was fully aware that its application was complex, even without the DRP and that it is unique among the companies regulated by the OEB. Not only is OPG complicated to operate, it is complicated to regulate. This is the first OPG application that is not based on a cost of service application, but rather splits the organization into two parts, with different regulatory instruments proposed to be used to regulate the hydroelectric assets versus the nuclear assets. This is the first OPG application that covers a period of 5 years. Adding to complexity are the various provincial government regulations that the OEB must abide by, but are difficult to mesh with price cap and custom incentive regulation frameworks developed by the OEB and intervenors. In short, this application bears no resemblance whatsoever to a typical application before the OEB under cost of service, custom IR or price cap methodologies.

LPMA notes that the OEB set a deadline for electricity distributors filing a cost of service or custom IR application or April 29, 2017 for rates effective January 1, 2017. OPG failed not only to meet this deadline by a month, but it failed to account for the additional time that could reasonably be expected to be needed to deal with a significant, complex and unique application.

On page 1 of its Argument-In-Chief, OPG requests the following:

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

In recognition of the inherent differences between the OPG application and other applications that come before the OEB, LPMA respectfully submits that OPG should have been aware that based on the size, nature and complexity of its application, it should have known that filing 7 months before the proposed implementation date was not only unreasonable but also unachievable. Rather than expecting the OEB to "develop regulatory approaches that fit OPG", OPG should have developed a timetable for their regulatory approach that fit the OEB general practice with respect to effective dates.

Recently, in the EB-2016-0105 proceeding for Thunder Bay Hydro, the Presiding Member made this point succinctly (Tr. Vol. 1, page 54):

> *MS. DUFF: I mean, At the same time, you have asked for rates to be effective May 1st. It is April 20th, and, you know, we have a saying here at the OEB: Applicant; own your application; Board, own your process.*

LPMA submits that OPG has failed to own its process by filing an application significantly later than what would reasonably be expected to have rates approved for January 1, 2017.

LPMA further submits that the OEB should not approve a revenue requirement for that portion of 2017 between January 1 and the implementation date. In other words, there should be no retrospective change in the payment amounts and no recovery of any such amounts through charges on future consumption. The interim payment amounts that were declared interim on December 8, 2016 should be declared final for the period from January 1, 2017 through to the end of the month prior to the implementation date for the new payment amounts. The new payments amount should only reflect that portion of 2017 from the implementation date to the end of 2017. This would uphold the EB-2013-0321 Decision noted above that the general practice of the OEB is that final rates become effective at the conclusion of the proceeding, which is predicated on a forecast test year which establishes rates going forward, not retrospectively.

III. COSTS

LPMA requests that it be awarded 100% of its reasonably incurred costs. LPMA worked with other intervenors throughout the process to eliminate duplication while ensuring that the record was complete. LPMA's key areas of concern were fully addressed through the evidence, interrogatory responses and technical conference question responses, along with cross-examination by other parties. This eliminated the need for LPMA to elongate the hearing by doing any separate or repetitive cross-examination. Finally, as noted in the Introduction, there was a significant sharing of draft submissions on a number of issues between several intervenors.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

May 29, 2017

Randy Aiken
Consultant to London Property Management Association

Government of Canada / Gouvernement du Canada

APPENDIX A

Canada

Statistics Canada

Home
> CANSIM

Table 281-0027 [4, 15, 16, 18]

Survey of Employment, Payrolls and Hours (SEPH), average weekly earnings by type of employee, overtime status and detailed North American Industry Classification System (NAICS) (Percentage Change (year-to-year))

annual (current dollars)

Data table | Add/Remove data | Manipulate | Download | Related information | Help

The data below is a part of CANSIM table 281-0027. Use the Add/Remove data tab to customize your table.

Note: Scaling and units of measure are not applicable because these figures represent percentage change, year to year and not raw data.

Selected items [Add/Remove data]

Geography = Ontario
Type of employees = All employees [19]
Overtime = Including overtime
North American Industry Classification System (NAICS) [18] = Industrial aggregate excluding unclassified businesses [11-91N] [5, 6]

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Percentage Change (year-to-year)														
	2.45	2.78	3.65	1.61	3.85	2.34	1.26 A	3.83 A	1.36 A	1.42 A	1.53 A	1.99 A	2.63 A	1.10 A

Back to original table

Footnotes:

1. Although the creation of Nunavut officially took place in April 1999, the Survey of Employment, Payrolls and Hours (SEPH) was only able to begin publishing separate estimates for Northwest Territories and Nunavut with the release of the January 2001 data. Efforts were undertaken to estimate the employment for Nunavut back to April 1999. These are available upon request by contacting Client Services at 1-866-873-8788 (toll-free) or 613-951-4090 (labour@statcan.gc.ca).
2. Since January 2001, the Survey of Employment, Payrolls and Hours (SEPH) program no longer combines Northwest Territories and Nunavut. They are produced as two separate territories.
3. These terminated series are based on the North American Industry Classification System (NAICS) 2002.
4. Data quality indicators are based on the coefficient of variation (CV). Quality indicators indicate the following: A - Excellent (CV from 0% to 4.99%); B - Very good (CV from 5% to 9.99%); C - Good (CV from 10% to 14.99%); D - Acceptable (CV from 15% to 24.99%); E - Use with caution (CV from 25% to 34.99%); F - Too unreliable to publish (CV greater than or equal to 35% or sample size is too small to produce reliable estimates).
5. Industrial aggregate covers all industrial sectors except those primarily involved in agriculture, fishing and trapping, private household services, religious organisations and the military personnel of the defence services.
6. Unclassified businesses (00) are businesses for which the industrial classification (North American Industry Classification System [NAICS] 2012) has yet to be determined.
7. Goods producing industries (11-33N) includes the following sectors: forestry, logging and support (11N), mining, quarrying, and oil and gas extraction (21), utilities (22), construction (23) and manufacturing (31-33).
8. Forestry, logging and support (11N) includes the following industries: forestry and logging (113) and support activities to forestry (1153).
9. Non-durable goods (311N) of the manufacturing sector includes the following industries: food manufacturing (311), beverage and tobacco products manufacturing (312), textiles mills (313), textile products mills (314), clothing manufacturing (315), leather and allied products manufacturing (316), paper manufacturing (322), printing and related support activities (323), petroleum and coal products manufacturing (324), chemical manufacturing (325) anc plastics and rubber products manufacturing (326).

10. Durable goods (321N) of the manufacturing sector includes the following industries: wood products manufacturing (321), non-metallic mineral products manufacturing (327), primary metal manufacturing (331), fabricated metal products manufacturing (332), machinery manufacturing (333), computer and electronic products manufacturing (334), electrical equipment, appliances and components manufacturing (335), transportation equipment manufacturing (336), furniture and related product manufacturing (337) and miscellaneous manufacturing (339).
11. Service producing industries (41-91N) includes the following industries: trade (41-45N), transportation and warehousing (48-49), information and cultural industries (51), finance and insurance (52), real estate and rental and leasing (53), professional, scientific and technical services (54), management of companies and enterprises (55), administrative and support, waste management and remediation services (56), educational services (61), health care and social assistance (62), arts, entertainment and recreation (71), accommodation and food services (72), other services (except public administration) (81) and public administration (91).
12. Trade (41-45N) industry includes the following sectors: wholesale (41) and retail trade (44-45).
13. Education special (611N) industry includes the following industries: elementary and secondary schools (6111), community colleges and CEGEP (6112), universities (6113), business schools and computer management training (6114) and technical and trade schools (6115).
15. The introduction of administrative data in 2001 and the associated change in methodology resulted in level shifts for some series. This affects the comparability of pre- and post-2001 estimates.
16. Earnings data are based on gross payroll before source deductions.
17. These terminated series are based on the North American Industry Classification System (NAICS) 2007.
18. Industry estimates in this table are based on the 2012 North American Industry Classification System (NAICS).
19. "All employees" is the sum of employees paid by the hour, salaried employees and other employees.

Source: Statistics Canada. *Table 281-0027 - Survey of Employment, Payrolls and Hours (SEPH), average weekly earnings by type of employee, overtime status and detailed North American Industry Classification System (NAICS) (Percentage Change (year-to-year)), annual (current dollars),* CANSIM (database). (accessed:)
Back to search

Date modified: 2017-03-31

Government of Canada Gouvernement du Canada

Canada

Statistics Canada

Home
> CANSIM

Table 380-0066
Price indexes, gross domestic product (Percentage Change (year-to-year)) annual (2007=100)

Data table | Add/Remove data | Manipulate | Download | Related information | Help

The data below is a part of CANSIM table 380-0066. Use the Add/Remove data tab to customize your table.

Note: Scaling and units of measure are not applicable because these figures represent percentage change, year to year and not raw data.

Selected items [Add/Remove data]

Geography = Canada
Index = Implicit price indexes
Estimates = Final domestic demand

2012	2013	2014	2015	2016
Percentage Change (year-to-year)				
1.7	2.3	1.7	1.2	

Back to original table

Source: Statistics Canada. *Table 380-0066 - Price indexes, gross domestic product (Percentage Change (year-to-year)), annual (2007=100 unless otherwise noted),* CANSIM (database). (accessed:)
Back to search

Date modified: 2012-09-28

Mr. Aiken, on behalf of LPMA and Energy Probe for the purposes of this part of the consultation, proposed a formulaic approach to calculate an individual threshold for each distributor. The formula incorporates both the impact of the price cap and organic growth:

$$\frac{CAPEX}{d} = 1 + (\frac{RB}{d}) * (g + PCI * (1 + g)) \qquad (1)$$

Where:

RB = rate base included in base rates;

d = depreciation expense;

g = distribution revenue change based on load growth; and

PCI = price cap index (inflation less productivity factor less stretch factor).

(Mr. Aiken noted that the values for RB, d, and g, would be taken from the Board-approved base year rate decisions.)

Mr. Aiken arrived at this formula by first establishing a means of estimating the level of CAPEX that can be financed by increases in revenues due to the price cap formula and by load growth as follows:

$$CAPEX = d + RB * (g + PCI * (1 + g)) \qquad (2)$$

The premise of the above is that the approved base year revenue requirement covers OM&A costs and rate base costs (which include depreciation, interest on debt, return on equity and the associated taxes). Mr. Aiken noted that, similar to the other proposals, his proposal recognizes that the revenue generated under a price cap plan automatically generates more revenue for capital investment. Further, the revenue generated under a price cap plan is equal to the approved revenue requirement from the last rebasing year adjusted for the price cap index, as well as load growth.