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File 92805

October 3, 2016

VIA COURIER AND *RESS* FILING

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

Dear Ms. Walli:

**Re: Ontario Power Generation – Interrogatories
Payment Amounts 2017-2021
Ontario Energy Board File No. EB-2016-0152**

Please find enclosed the Interrogatories of Power Workers' Union in connection with the above-noted proceedings.

Yours very truly,
PALIARE ROLAND ROSENBERG ROTHSTEIN LLP

Richard P. Stephenson
RPS:pb

Encl.

Doc 1952344 v1

EB-2016-0152

Ontario Power Generation Inc.

2017-2021 Payment Amounts

Power Workers' Union Interrogatories

4. CAPITAL PROJECTS

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

4.2-PWU-1

Ref (a): Exhibit D2-1-3, Page 8 of 19, Lines 24-25:

> **One Tier 1 project continues to be deferred. The Feeder Repair by Weld Overlay project (#62568) was deferred in May 2010. A business case summary is provided in Attachment 1 to this exhibit.**

Ref (b): Exhibit D2-1-3, Attachment 1, Tab 17 (#62568), Page 1 of 27:

> **The business objective of this project is to reduce the cost of managing life-limiting feeder thinning by developing a repair alternative to the current exclusive use of Cut and Weld tooling for replacing thinned feeders. It is estimated that using weld overlay repair technology in conjunction with Cut & Weld tooling (as necessary), will provide a financial benefit in the range of approximately $35M - $143M (NPV) with a 19% - 45% IRR.**

a) Why has this project been deferred? Please provide the rationale and, if applicable, any documents to support the decision.
b) Are the stated financial benefit numbers for this project still valid or have they been updated?

4.2-PWU-2

Ref (a): Exhibit D2-1-3, Page 3 of 19, Lines 6-12:

> **Project #31524 Darlington Station Roofs Replacement: This project is to replace flat roofs on the main powerhouse and other protected area buildings. The roofs are approaching the end of their service lives and need to be replaced. The total project cost is $38.3M with an initial definition phase release of $0.8M. Initial planned final in-service date is December 2018. However, the 2016 capital project portfolio budget**

is currently oversubscribed (i.e. the number of approved projects exceeds available funding). As a result, this project has been deferred and a revised in-service date has not yet been determined.

Ref (b): Exhibit D2-1-3, Attachment 1, Tab 19 (#31524), Page 1 of 5:

The station's existing roofs have reached the end of their 25-year design life. Currently there are 135+ Station Condition Record's and 60+ work orders associated with roof leaks. There has also been an Aging Management Program Component Condition Assessment (NK38-REP-2000-10003) carried out for Roofing Construction for buildings inside the protected area which concluded that station roofing is in poor condition.

The current condition of the station roofs exposes Darlington to nuclear and conventional safety risks. Most, if not all systems on both the nuclear and conventional side were designed with the assumption that system operations will take place below a leak-proof roof and no precipitation introduced into the systems environment. Introducing leaked water into any system puts the station in an unpredictable condition that is outside the design basis and therefore creates a potentially hazardous situation.

In addition, addressing the problem of the station's roof condition has been added to the Fukushima response actions and as such will receive special attention from the CNSC and the public. At present, there is an opportunity to avoid threats to the station's Power Reactor Operations License.

Ref (c): Exhibit D2-1-3, Attachment 1, Tab 19 (#31524), Page 2 of 5:

Base Case: Status Quo – No Project
Water leaks into the station are wide spread and expected to increase due to continued degradation. If this project is not implemented, roof leaks will continue to occur, increase in overall cost and be disruptive to plant operations.

a) How many station condition records and work orders associated with roof leaks have arisen since November 2012, the BCS approval date?
b) Has the deferral of this project led to threats to the station's Power Reactor Operations License?
c) If the project is not proceeding due to the portfolio budget being exceeded, why is OPG not seeking to increase the portfolio budget?

4.2-PWU-3

Ref (a): Exhibit D2-1-3, Page 3 of 19, Lines 20-29:

Project #31535 Darlington Water Treatment Plant Replacement: This project is to replace the water treatment plant, which has been in-service since 1987 and is approaching the end of its 30 year design life. High quality demineralised water is required for station operation. While the plant is operating satisfactorily, operational experience from other stations indicates that their water treatment plants were replaced before the 30 year mark due to declining performance. The total project cost is $57.8M with an initial definition phase release of $5.2M. Initial planned final in-service is November 2019. However, the 2016 capital project portfolio budget is currently oversubscribed (i.e. number of approved projects

exceeds funding). As a result, this project has been deferred and a revised in-service date has not yet been determined.

Ref (b): Exhibit D2-1-3, Attachment 1, Tab 21 (#31535), Page 1 of 20:

Failure of the WTP plant would result in a four unit sequential shut-down of DNGS after 24-48 hours (the time required to deplete the stored de-mineralized water inventory) since there is no backup supply of water available. Equipment aging, degradation and obsolescence combined with higher maintenance requirements will increase the likelihood of extended WTP outages which could result in forced DNGS unit outages. In addition, the risk of environmental spills of acids and caustic liquids used in the current WTP process could increase as the condition of the equipment degrades and maintenance activities increase.

Ref (c): Exhibit D2-1-3, Attachment 1, Tab 21 (#31535), Page 6 of 20:

Alternative 2: Delay Work – Postpone Replacement of WTP
A previous review of the options for the existing WTP was conducted in 2005 and concluded that a replacement of the existing WTP was not justifiable at that time. However, WTP has aged significantly since that time. OPEX from other CANDU nuclear stations suggests that the average life span for IX based water treatment plants is 28 years [Ref 1] which is short of their nominal 30 year design life. As a result, the estimated design End of Life (EOL) of the current WTP is 2015. Despite past reliable operation, the WTP will be challenged to maintain satisfactory system health status and reliability as it reaches or exceeds the end of its design life if this project were to be postponed.

a) Has the DNGS water treatment plant experienced the same decline in performance near the estimated design End of Life that other stations have experienced?
b) Is OPG aware of any other nuclear generating stations that have continued to keep a water treatment plant in service five or more years past its estimated design End of Life?
c) Is the risk of shut-down of the DNGS caused by failure of the water treatment plant materially higher with the existing plant than it would be with a replacement plant?
d) Have maintenance activities related to the water treatment plant increased as the plant passed its estimated design End of Life?
e) If the project is not proceeding due to the portfolio budget being exceeded, why is OPG not seeking to increase the portfolio budget?

4.2-PWU-4

Ref (a): Exhibit D2-1-3, Page 5 of 19, Lines 18-22:

Project #73706 Darlington Highway 401 and Holt Road Interchange: This project is to improve traffic flow and capacity at the Holt Road interchange by replacing the existing partial interchange with a new interchange with additional access points. This project is cost-shared with the Ministry of Transport with OPG's share of the project cost being $28.6M. Planned final in-service is December 2016.

a) What is the Ministry of Transportation's share of the project cost?

b) How was the Ministry of Transportation's share determined?
c) Does OPG still expect the project to be completed by December 2016?

4.2-PWU-5

Ref (a): Exhibit D2-1-3, Tables 2a-2e

a) Please identify any projects with a final in-service date prior to October 2016 that are not yet in-service.
b) For projects related to safety please provide updated final in-service dates. Have project delays had a material effect on the safety of employees or the public?

4.2-PWU-6

Ref (a): Exhibit D2-1-3, Table 2e, Line No. 60:

Line No.	Facility	Project Name	Project Number	Category	Project Description	Start Date	Final In-Service Date	Total Project Cost ($M)
60	DN	DN Station Lighting Retrofit	31516	Sustaining	Replace obsolete florescent lighting in powerhouse with new efficient LED lights.	Dec-12	Deferred	11.4

a) Please provide the BCS for project no. 31516 DN Station Lighting Retrofit.
b) Why has this project been deferred? Please provide the rationale and, if applicable, any documents to support the decision.

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

4.3-PWU-7

Ref: Exhibit D2-2-8, Page 8

The reference states that OPG will complete the Unit 2 refurbishments within the total budget envelope of $4.8B. The Reference also indicates that the Unit 2 refurbishment cost includes all Definition Phase costs ($2.2 B to date) and common costs that are needed to complete common work required for 2 or more units.

a) Please provide a breakdown of the total refurbishment cost of $12.8B by unit (the cost of each of the four units) by apportioning the cost of the Definition Phase as well as the above cited common costs across the four units as appropriate.
b) Has OPG done analysis of the sunk cost (including cost incurred so far, cost that will be incurred until the completion of Unit 2, and any liability costs) that would

result from the cancellation of the refurbishment of the remaining three units? If so please provide the analysis.

4.2-PWU-8

Ref (a): Exhibit A2-1-1, Attachment 5, Page 55

The portions of OPG's contractual obligations and other significant commercial commitments related to the Prescribed Facilities as at December 31, 2015 were determined primarily using specific identification, and are as follows:

(millions of dollars)	2016	2017	2018	2019	2020	Thereafter	Total
Contractual obligations:							
Fuel supply agreements	153	154	144	78	47	54	630
Contributions under the ONFA [1]	177	156	175	266	35	1,162	1,971
Contributions to the OPG registered pension plan [2]	327	-	-	-	-	-	327
Operating lease obligations	15	15	15	14	14	47	120
Commitments related to Darlington Refurbishment [3]	284	-	-	-	-	-	284
Operating licence	41	43	37	23	24	142	310
Unconditional purchase obligations	60	54	51	50	49	4	268
Accounts payable and accrued charges	783	2	6	-	-	2	793
Other	38	14	5	2	2	69	130
Total	1,878	438	433	433	171	1,480	4,833

[1] Contributions under the ONFA are based on the 2012 ONFA Reference Plan contribution schedule approved in 2012. The updated ONFA Reference Plan is expected to be effective January 1, 2017.

[2] The pension contributions reflect current ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2014. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2017. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2016 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[3] Estimated currently committed costs to close the project, including demobilization of project staff and cancellation of existing contracts and material orders.

a) Please provide an updated figure for commitments related to Darlington Refurbishment for 2016, and any additional commitments in future years.
b) Are all commitments related to Darlington Refurbishment attributable to Unit 2? If not, please explain.

4.3-PWU-9

Ref: Exhibit A2-1-1, Attachment 5, Page 55

The reference indicates the total commitments related to the DRP, should OPG close the project, as $284M. OPG explains that the $284M represents estimated currently committed costs to close the project, including demobilization of project staff and cancellation of existing contracts and material orders.

a) Please explain how the $284M liability would be triggered in terms of the timeline of the DRP and under different scenarios-i.e., if the entire project closes now, if the refurbishment of the subsequent units is cancelled, etc. Will the $284M figure change (increase or decrease) depending on the stage of the DRP?
b) Please confirm if the contracts relating to the DRP are entered for the entire project (the refurbishment of all four units) or unit by unit?

6. OPERATING COSTS

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

6.2-PWU-10

Ref (a): Exhibit F2-1-1, Page 8 of 22, Chart 1: Comparison of OPG Nuclear Performance to Industry Benchmarks:

Ref (b): Exhibit F2-1-1, Page 15 of 22, Chart 4: Operational and Financial Targets

a) Please provide updated actual figures for the Rolling Average Collective Radiation Exposure (Person-rem per unit) and the Fuel Reliability Index (microcuries per gram) for 2015 and 2016, if available.
b) What steps have been taken to improve these two metrics since 2014?
c) In Chart 4, targets for Collective Radiation Exposure show the expectation of below-median performance. The targeted trends show further metric deterioration moving forward, particularly for Pickering. What initiatives, if any, are planned to improve this safety metric going forward?
d) In Chart 1, all safety metrics, aside from Collective Radiation Exposure and Fuel Reliability at Pickering, are shown to be better than the median. In Chart 4, the targets for 7 of the 9 safety metrics are set at the median or worse than the median. Why are the majority of safety metrics benchmarked to deteriorate from 2014 actuals to 2016 targets?

Issue 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?

6.6-PWU-11

Ref (a): Exhibit F4-3-1, Pages 6-7 of 23

> **In 2015, Nuclear attrition was at its highest level in years, with over 300 retirements. This represents a 20 per cent increase in the number of retirements in Nuclear compared to 2014. Over two thirds of the 2015 retirements were in critical operations, maintenance, engineering and technical roles and will need to be replaced.**

Ref (b): 2014 Nuclear Staffing Benchmark Analysis, Exhibit F2-1-1, Attachment 2, Page 31 of 39 (OPG Functional Variance from 2014 Benchmark tables)

a) Operations, maintenance, and technical engineering positions were identified by the 2014 Nuclear Staffing Benchmark Analysis as positions in which OPG fell below the benchmark staffing levels. How is OPG addressing the staffing deficiencies in the wake of increasing deficiencies?
b) Technical engineering staffing was deficient by nearly 100 FTEs in 2014. How many technical engineering FTEs are there in 2016 compared to 2014?
c) Is OPG's intention to target the benchmark staffing levels or to replace retired workers to return to 2014 staffing levels?

6.6-PWU-12

Ref (a): Exhibit F4-3-1, Attachment 2, Page 8 of 37:

> **Market data for the US nuclear peer group used for the Nuclear Authorized segment were converted to CAD, consistent with Willis Towers Watson's practice, using an average annual exchange rate to February 2016 of $1 USD - $1.29676 CAD to moderate fluctuations.**

a) Please provide the start date of data range used to determine the average annual exchange rate. Please provide rationale for that date.

6.6-PWU-13

Ref (a): Exhibit F4-3-1, Pages 6-7 of 23:

> **In 2016, staffing levels for OPG's Nuclear facilities are expected to increase by over 600 FTEs due largely to the Darlington Refurbishment Project ("DRP") and, to a lesser extent, the workforce renewal required to sustain Pickering operations. In 2015, Nuclear attrition was at its highest level in years, with over 300 retirements. This represents a 20 per cent increase in the number of retirements in Nuclear compared to 2014. Over two thirds of the 2015 retirements were in critical operations, maintenance, engineering and technical roles and will need to be replaced. As shown in Figure 4, staffing levels peak in 2017 and then decline by over 500 FTEs by 2021.**

a) Would attrition lead to a continuing declining trend in FTEs if FTEs associated with the DRP and the Pickering Operations Extension were excluded?

b) Will the refurbishment of Units 1, 3, and 4 require similar FTE increases?
c) Is attrition the primary cause of declining FTEs from 2017 to 2021?

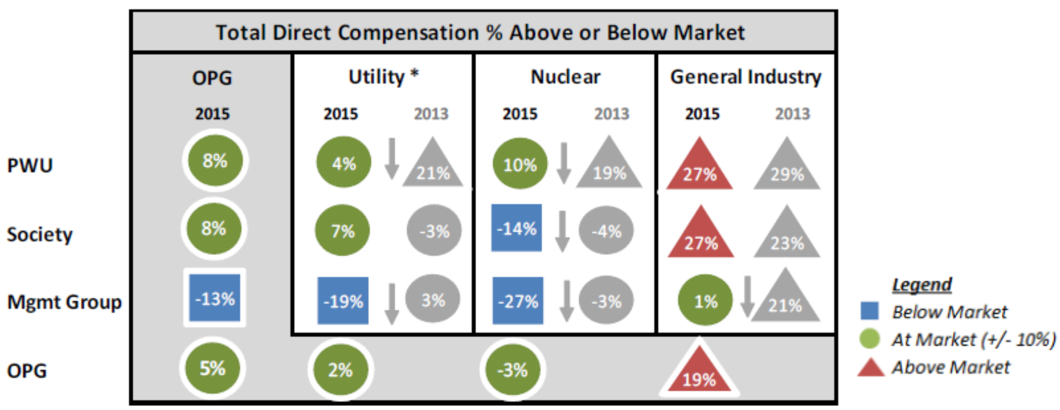
6.6-PWU-14

Ref (a): Exhibit F4-3-1, Page 18:

> **This assessment included reviewing OPG's Base Salaries, Total Direct Compensation, as well as Pensions and Benefits. Total Direct Compensation reflects the cash compensation paid to employees, excluding overtime. It includes Base Salaries and pay at risk incentives.**

Ref (b): Exhibit F4-3-1, Page 19, Figure 11:

Figure 11



** Largest portion of OPG employees are in the Utility segment (69%).*

a) Overtime is excluded in the Towers Watson compensation study. Please confirm overtime was excluded from AON Hewitt's 2013 compensation survey presented for comparison in this chart?
b) The Towers Watson study indicates that the largest (69%) portion of OPG employees are in the Utility segment. What portions of OPG employees are in the Nuclear and General Industry segments, respectively?

6.6-PWU-15

Ref (a): Exhibit F4-3-1, Page 8 of 23:

> **OPG, with the direct involvement and support of the Government, negotiated agreements with both the PWU and Society in 2015 that will keep wage escalation below inflation. Both agreements provide for a one per cent escalation increase each year and cover a three year period, running from April 1, 2015 to March 31, 2017 for the PWU and from January 1, 2016 to December 31, 2018 for the Society.**

a) PWU and Society wage escalation is at a level below inflation. Please quantify the impact on the test period revenue requirement had wage escalation been set at inflation.

6.6-PWU-16

Ref (a): Exhibit F4-3-1, Page 16 of 23, Figure 10:

Figure 10[6]

Employee Pension Contributions	% of Pensionable Earnings Contributed by Employees (% below / above YMPE)			Contribution Ratio (Employee/Employer)
	MG	PWU	Society	
2014	7 / 7	5 / 7	7 / 7	24% / 76%
2015	7 / 7	6 / 8	7 / 7	
2016	7.3 / 8.25	7 / 9	8 / 8	
2017	7.6 / 9.5	7.5 / 10	9 / 9	35% / 65%

a) Figure 10 shows the increasing ratio of employee pension contributions to employer contributions. Please quantify the impact on the 2017 revenue requirement had the ratio remained at 24% / 76% instead of 35% / 65%.
b) When measured in dollar terms, what is the percentage change in employee pension contributions on annual basis from 2014 through 2017, and over the period as a whole?

9. DEFERRAL AND VARIANCE ACCOUNTS

Issue 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?

9.7-PWU-17

Ref: Exhibit H1-1-1, Page 30

> **The regulation [O. Reg. 53/05] stipulates that the OEB shall ensure that OPG recovers the balance recorded in the deferral account and shall authorize recovery of the account balance on a straight line basis over a period not to exceed ten years commencing at the end of the deferral period.**

a) Please confirm if the 'deferral period' in the reference represents the period January 2017-2026?
b) If (a) is confirmed, please confirm that as per the reference above the Board is expected to authorize recovery of the account by 2036 the latest?

11. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

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

11.1-PWU-18

Ref: Exhibit A1-3-2, Pages 18 & 19

> **LEI calculated TFP results using two methods: average index growth, and a trend regression approach. The results of the Initial TFP Study and the Updated TFP Study are summarized in Chart 5.**

Chart 5 – Summary of Hydroelectric TFP Results

Approach	2002-2012 Information	2013-2014 Update
Average Index	(1.02)	(1.01)
Trend Regression Index	(1.00)	(1.19)

> **…LEI explained that a negative productivity factor for the hydroelectric generation industry is expected, given it is an industry with substantially fixed productive capability, fixed capital stock, and increasing operating and maintenance costs that would naturally lead to negative productivity growth.**
>
> **The results of the TFP studies notwithstanding, OPG has elected to increase the productivity factor from negative 1% to zero. OPG believes this approach is consistent with OEB policy. In the electricity distribution context, the OEB has elected not to set rates based on negative productivity growth in the electricity distribution context. In its report on the distribution productivity factor under the RRFE, the OEB stated that it "does not believe it appropriate for a rate setting regime to project and entrench declining productivity expectations into the future." The OEB determined that the productivity factor value would be zero, despite the negative result of the industry TFP study.**
>
> **While OPG believes that the -1% TFP factor resulting from both the Initial TFP Study and the Updated TFP Study is accurate, it understands the OEB's policy position and proposes a zero 18 productivity factor in this application.**

a) Does OPG agree with LEI's explanation of the reasons or factors that lead to negative productivity growth and why negative productivity growth should be expected for hydroelectric generation?
b) Does OPG agree with the Board's reasons why the Board has elected not to set rates based on negative productivity growth in the electricity distribution context?
c) Does OPG think or believe that the Board's position on negative productivity growth in the electricity distribution context is equally relevant and applicable to hydroelectric generation?
d) If OPG believes, as indicated above, that the -1% TFP factor resulting from both the Initial TFP Study and the Updated TFP Study is accurate, why is OPG

proposing a zero % TFP just because it would be consistent with the Board's position in the context of electricity distribution?

e) Please confirm that by proposing a zero % TFP and not the -1% TFP, and given that OPG is proposing a 0.3 Stretch factor, OPG is essentially proposing a 1.3% Stretch factor?

f) Please provide a chart comparing rates and payment amounts under a zero % and -1% TFP assumptions for each of the 5 years covered by the application.

g) Please confirm if the reason why OPG chose to not rebase hydroelectric payment amounts and instead file an IR mechanism is because it was so directed by the Board?

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

11.1-PWU-19

Ref: Exhibit A1-3-2, Attachment 2, Pages 4 & 5

	Cost Performance Metrics (USD)									Reliability Metrics	
	Operations (K$/Unit)	Plant Maint. ($/MWh)	WW&D Maint. (K$/MW)	B&G Maint. (K$/MW)	Support (K$/MW)	Partial Function ($/MWh)	PA&R (K$/MW)	Total Function ($/MWh)	Invest-ment (K$/MW)	Avail-ability Factor (%)	Forced Outage Rate (%)
OPG Reg. Hydro	$87	$1.41	$1.2	$1.9	$11.8	$5.01	$40	$13.19	$17	92.8	1.3

Top Quartile
Second Quartile
Third Quartile
Bottom Quartile

(1) Quartiles are determined by comparing OPG's 2013 performance to the peer group values in each functional area.
(2) Partial Function Cost is the sum of Operations, Plant Maintenance, WW&D Maintenance, B&G Maintenance, and Support (all functions except for Investment and PA&R).
(3) Total Function Cost is the sum of Operations, Plant Maintenance, WW&D Maintenance, B&G Maintenance, Support, and PA&R (all functions except for Investment). OPG's Total Function Costs are bottom quartile on average primarily due to high PA&R Costs (Gross Revenue Charges)
(4) Costs on pages 3 and 13-20 are in USD; all other pages are in CAD.
(5) All costs in this report are for 2013.

a) The Charts on pages 4 and 5 show that OPG hydro`s cost performance based on Partial Function is in the second quartile whereas based on Total Function OPG is in the third quartile. However, Note 3 on page 4 states that `` OPG's Total Function Costs are bottom quartile on average primarily due to high PA&R Costs (Gross Revenue Charges)``. Please clarify the discrepancy.

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

11.4-PWU-20

Ref (a): Exhibit A1-3-2, Page 29 of 54:

> **The proposed stretch reduction targets elements of the company's nuclear costs that constitute a significant amount of OPG's nuclear revenue requirement during this application. The stretch factor applies to an average of $1.7 billion or approximately 75% of OPG's total nuclear OM&A in each year of the application.**

Ref (b): Exhibit A1-3-2, Page 32 of 54, Chart 9:

Chart 9 – Derivation of Nuclear Stretch Factor

Input	Value
OEB-approved 2015 Darlington production (TWh)	25.0
OEB-approved 2015 Pickering production (TWh)	21.6
Darlington stretch factor (based on benchmark performance)	0.0%
Pickering stretch factor (based on benchmark performance)	0.6%
Production-weighted average stretch factor	0.3%

a) What is OPG's view on the appropriateness of a custom IR application for its nuclear business?
b) The Pickering stretch factor is 0.6%. Does OPG consider applying the 0.6% stretch factor to Pickering appropriate as poor benchmark performance may reflect that it is an ageing nuclear asset?
c) Does the stretch factor apply to OM&A costs that are related to safety measures?

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

11.6-PWU-21

Ref: Exhibit A1-3-3, Page 6 (Chart 1 - Nuclear Revenue Requirement and production)

a) Please explain what the numbers under the column 'Total' ($3,617M of proposed revenue requirement and 26.01 TWh production forecast) represent and how they are arrived at?

Issue 11.7
Is OPG's proposed mid-term review appropriate?

11.7-PWU-22

Ref: Exhibit A1-3-3, Pages 10-14

OPG seeks approval of a mid-term production review in the first half of 2019 (i.e., prior to 9 July 1, 2019). The application will present the impact of the production variance from July 1, 2019 to December 2021. The production variance will be the difference between: (i) the nuclear production forecast approved in this Application and, (ii) the nuclear production forecast proposed by OPG in the mid-term review application.

OPG is also proposing a Mid-Term Nuclear Production Variance Account to record revenue variance arising from an updated production forecast.

OPG states that since the inception of regulation by the OEB, there have been a number of variances between OEB approved and actual production. It has proven difficult to forecast nuclear production in the past where OPG's Pickering and Darlington facilities were operating in a comparatively steady state compared to the operating circumstances that will be facing these facilities during the application period.

Ref: Exhibit E2-1-1, Page 2

> **The OEB approved nuclear production for the period 2008 to 2015 was greater than actual production. As shown on Chart 2 below, the average annual production shortfall for this period was 3.2 TWh. This resulted in an average negative revenue impact of $154.0M borne each year by OPG's shareholder.**

Chart 2

OPG Nuclear Production Variance and Revenue Impact

Line No.		2008	2009	2010	2011	2012	2013	2014	2015	Average	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	OPG Application - TWh	51.4	49.9	-	48.9	50.0	-	48.5	46.1		
2	OEB Approved - TWh+	51.4	49.9	50.7	50.4	51.5	51.0	49.0	46.6		
3	Actual -TWh	48.2	46.8	45.8	48.6	49.0	44.7	48.1	44.5		
4	Variance (TWh) (line 3 - line 2)	-3.2	-3.1	-4.9	-1.8	-2.5	-6.3	-0.9	-2.1	-3.2	-24.7
5	Revenue Impact - $M#	-159.9	-154.9	-242.4	-87.3	-121.3	-305.7	-45.9	-114.3	-154.0	-1231.8

\+ 2010 is the average of 2008 and 2009 Board Approved; 2013 is average of 2011 and 2012 Board Approved.

\# At OEB-approved rates of $52.98/MWh for 2008-2010 less fuel cost, and $51.52/MWh for 2011-2013 less fuel cost.
For 2014, 10 months at OEB–approved rate of $51.52/MWh and 2 months at OEB approved rate of $59.29/MWh, less fuel cost (average $52.82/MWh).
For 2015, at OEB approved rate of $59.29/MWh less fuel cost

Given OPG's experience that even for applications involving shorter test periods (2-3 years) there have been production forecast variances, let alone a 5 year forecast:

a) Why is OPG proposing a nuclear production variance account only for the 2nd part of the application (i.e., only for difference between the nuclear production forecast approved in this Application and, (ii) the nuclear production forecast proposed by OPG in the mid-term review application) and not for the first half of the application?
b) Given that both the nuclear production forecast approved in this Application and the nuclear production forecast that will be proposed by OPG in the mid-term review application are forecasts, why is OPG not proposing a production forecast variance account covering the entire test period?
c) Please clarify if OPG's proposal for mid-term production forecast review is conditional on the materiality of the variance between current production forecast and production forecast that OPG will present at the mid-term review application or whether OPG will apply for review anyway.